From:	Nelms, Scott (MOF)
To:	Gadi Mayman
Cc:	Steen Hume (CAB); Mike Manning; Ronald Kwan
Subject:	Draft Fees Regulation
Date:	Tuesday, September 26, 2017 12:18:21 PM
Attachments:	Blackline_24180663v1 - 24180663v3.pdf
Importance:	High

Hi Gadi,

I hope NYC is going well and you are finding air conditioning.

We have been working with Steen's team and Energy legal on a draft of the fees regulation for OPG Trust and OFHP. As we progress through this, there are some elements of the regulation that we were hoping you and the OFA team might be able to consider (please see attached a black line for your reference):

- The draft reg outlines a base fee as well as a variable fee.
    - The base fee is provided monthly at an annual rate of 10-basis points for the first two years (we had this initially set at one year but Torys' markup changes this to two years). After 2019, the base fee is provided at an annual rate of 8 basis points should the funding obligations exceed $10B. Does this seem reasonable?
  - The variable fee structure seems consistent with previous discussions (5 basis point fee provided on the spread). Do you think this makes sense?
  - It would also be helpful if the OFA could let us know if the method for calculating the monthly funding obligation is reasonable.
- With respect to costs, our understanding is that these sorts of costs are typically a pass through; can the OFA confirm? The Torys markup removes OEB oversight on costs but we are wondering if there should be a role for the OFA in reviewing / providing oversight in this regard?
  - Also, do the costs they've outlined seem reasonable? In particular, LSB is wondering whether this leaves the door open for OPG to pass through any overhead costs (i.e. should we be explicit about excluding them)?
- On timing, the draft reg currently contemplates a fee application by OPG every two years regardless of what interest rates are in the market. Do we think this is fair or should the application occur annually? (Note that until new fees are established, the old fees are still in effect).

In terms of next steps, OPG would like to get a draft to their Board in time for the meeting on Friday. ENERGY LSB is hoping for comments by tomorrow. I don't think we need anything too detailed or formal, but a quick sniff test would be useful to ensure we are on the right track.

Thanks for your help,
Scott

CONFIDENTIAL
FOR DISCUSSION PURPOSES ONLY

ONTARIO REGULATION

made under the

ONTARIO FAIR HYDRO PLAN ACT, 2017

FEES

Definitions

1. (1) In this Regulation,

"average monthly funding obligation" means, in respect of a month, the amount determined in accordance with subsection (2);

"average annual funding obligation" means, in respect of a year, the sum of the average monthly funding obligations for the year;

"comparison fees" means ~~typical fees~~**market comparable fees, expressed as a per annum percentage rate,** charged by ~~[service providers?~~**asset** managers~~?]~~ ~~in Ontario~~ **in Canada and any other jurisdiction as may be determined by the Board** for services that are similar to the services provided by the Financial ~~Service Manger~~**Services Manager** under the Act in terms of,

(a) the type of services provided, being services in respect of funds including securitization vehicles, pension funds, other investment funds, hedge funds and other similar funds ~~in Ontario~~,

(b) the scope of the services provided, ~~and~~

(c) the level of the services provided**, and**

(d) the amount of assets under management;

"forecast interest rate" means, in respect of each tranche of funding obligations, an interest rate forecast to be applicable to such tranche of funding obligations after taking into account (i) the interest rate for debt of or guaranteed by the Province of Ontario with a corresponding term or duration, (ii) the estimated credit spread for such tranche of funding obligations with a comparable term and based on the type of instrument and risk of the issuer, and (iii) anticipated fees and commissions expected to be payable in connection with the issuance of such tranche of funding obligations.

"net annual funding obligation" means, in respect of a year, the sum of the principal amounts of funding obligations incurred by financing entities in a year~~, other than any refinancing~~;

(2) For the purposes of determining the average monthly funding obligation for a month, the following formula applies:

$$(A + B) / 2$$

Where,

A = the sum of the balances**, as** at **12:00 am on** the ~~start~~**first calendar day** of the month**,** of the principal amount of all **outstanding** funding obligations ~~incurred by~~**for all** financing entities,

2

B = the sum of the balances**, as** at **11:59 pm on** the ~~end~~**last calendar day** of the month**,** of the principal amount of all **outstanding** funding obligations ~~incurred by~~**for all** financing entities.

Fees that may be established, charged

2. (1) For the purposes of subsection 19 (3) of the Act, the fees established and charged by the Financial Services Manager may be charged to financing entities in relation to **the management and administration of financing entities and the investment asset, including in relation to** funding obligations incurred or that are planned to be incurred by the financing entities.

(2) A fee mentioned in subsection (1) shall be comprised of a base fee calculated under section [3, 4 or 5], as the case may be, and a variable fee calculated under section [6].

(3) ~~For the purposes of subsection 19 (3) of the Act, fees may be~~**Out-of-pocket costs and expenses of the financing entities incurred by the Financial Services Manager on behalf of the financing entities and for which the Financial Services Manager is entitled to reimbursement under a** management agreement with **such financing entity shall not constitute a fee** established and charged by the Financial Services Manager ~~to financing entities for the recovery of costs and expenditures, as provided for in section 7.~~**under subsection 19(3)**

of the Act.[1] The costs and expenditures of the financing entities referred to in this subsection (3) may include costs and expenditures in respect of the following:

1. Underwriters or selling agents for funding obligations**;**

2. **Banking fees, including structuring fees or work fees;**

3. Fees of issuing and paying agents for funding obligations**;**

4. **Fees of trustees;**

5. Fees incurred in the preparation of financial statements, financial reports, compliance certificates and tax returns**;**

6. Fees of legal counsel**;**

7. **Rating agency fees; and**

8. Filing or registration fees.

(4) The Financial Services Manager shall not establish or charge any fees to financing entities other than those provided for under this ~~R~~egulation.

Base fee, 2018 and 2019

3. Subject to section 5.1, the base fee for a month in the ~~year~~**calendar years** 2018 **and 2019** shall be calculated using the following formula:

$$(0.1 \times B) / 12$$

Where,

B = the average monthly funding obligation for the preceding month.

Base fee, after ~~2018,~~2019, average annual funding obligation greater than $10 billion

4. (1) This section applies for the purpose of calculating the base fee for a month in any year following ~~2018~~**2019** if the average annual funding obligation for the preceding year was greater than $10 billion.

[1] These represent third party costs and expenses of the financing entity, not part of the fees that OPG is charging the financing entity. From time to time, OPG may have to pay these upfront costs on behalf of financing entities but they will be a pass-through cost for which OPG would simply be reimbursed by the financing entity. Other than OPG's fees, the costs and expenditures of financing entities are not subject to OEB review under the Act but rather are recoverable as expenses through the CEA (and through IESO during the moratorium). Subsection (3) in this draft was added for greater certainty to ensure there was no misunderstanding.

(2) Subject to section 5.1, the base fee for the month shall be calculated using the following formula:

$$(0.08 \times B) / 12$$

Where,

B = the average monthly funding obligation for the preceding month.

Base fee, after ~~2018,~~2019, average annual funding obligation $10 billion or less

5. (1) This section applies for the purpose of calculating the base fee for a month in any year following ~~2018~~2019 if the average annual funding obligation for the preceding year was equal to or less than $10 billion.

(2) Subject to section 5.1, the base fee for the month shall be calculated using the following formula:

$$(0.1 \times B) / 12$$

Where,

4

B = the average monthly funding obligation for the preceding month.

Board review of base fee

5.1 If the Board, after reviewing a submission in respect of a proposed base fee by the Financial Services Manager under section 9, is of the view that applying the applicable formula set out in section 3, 4 or 5 results in a base fee that is inconsistent with prevailing comparison fees, the Board may refuse to approve the proposed fee. If the Board refuses to approve the proposed base fee submitted by the Financial Services Manager under section 9, the Board shall provide its reasons for such refusal and ~~may~~ make recommendations to the Financial Services Manager regarding the determination of a base fee that is consistent with comparison fees~~.~~ and based on the methodology used in the formulas set out in section 3, 4 and 5.

Variable fee

6. (1) Subject to subsection (2) and section 6.1, the variable fee for a year shall be the sum of the amounts of each tranche of net annual funding obligations for the year, calculated by using the following formula~~:~~ (which in respect of individual tranches may result in a negative number):

$$(A \times (B - C)) \times 0.05$$

Where,

A = the principal amount of the tranche,

B= the forecast interest rate for the tranche, as determined by the Financial Services Manager before the start of the year, based on the term of the tranche, and

C = the actual interest rate for the tranche.

(2) If the circumstances set out in Column 1 of the following Table apply in a year, the variable fee payable for a year is subject to the rules set out opposite the circumstances in Column 2 of the Table:

Item	Column 1 Circumstances	Column 2 Rules
1.	The average annual funding obligations are $10 billion or less.	The variable fee payable for the year shall not be more than 1 per cent of the amount that is 5 per cent of the net annual funding obligation for the year. The variable fee payable for the year shall not be less than -1per cent of the amount that is 5 per cent of the net annual funding obligation.
2.	The average annual funding obligations are greater than $10 billion.	The variable fee payable for the year shall not be more than 2 per cent of the amount that is 5 per cent of the net annual funding obligation for the year. The variable fee payable for the year shall not be less than -2 per cent of the amount that is 5 per cent of the net annual funding obligation for the year.

Board review of variable fee 5

6.1 If the Board, after reviewing a submission in respect of a proposed variable fee by the Financial Services Manager under section 9, is of the view that the forecast interest rate used for the purposes of the formula set out in subsection 6 (1) is ~~[unreasonable]~~**not consistent with market comparable forecast interest rates**, the Board may refuse to approve the proposed fee**. If the Board refuses to approve the proposed variable fee submitted by the** Financial Services Manager **under section 9, the Board shall provide its reasons for such refusal** and ~~may~~ make recommendations to the Financial Services Manager regarding the forecast interest rate that is ~~reasonable.~~**consistent with market comparable forecast interest rates.**

~~**Fees for costs and expenditures**~~

~~**7.** (1) The Financial Services Manager may establish and charge fees for the recovery from a financing entity of any costs and expenditures incurred in connection with the Financial Services Manager's duties under the Act in relation to the financing entity or under any management agreement with the financing entity.~~

~~(2) The costs and expenditures referred to in subsection (1) may include costs and expenditures in respect of the following:~~

~~1. Underwriters or selling agents for funding obligations.~~

~~2. Banking fees.~~

3. ~~Fees of issuing and paying agents for funding obligations.~~

4. ~~Fees of trustees.~~

5. ~~Fees incurred in the preparation of financial statements, financial reports, compliance certificates and tax returns.~~

6. ~~Fees of legal counsel.~~

7. ~~Filing or registration fees.~~

8. ~~Fees of any third party independent consultants required to be retained under the Act.~~

~~**Board review of fees for costs, expenditures**~~

~~**7.1** If the Board, after reviewing a submission in respect of a proposed fee for costs and expenditures by the Financial Services Manager under section 9, is of the view that the proposed fee is in respect of costs and expenses that were [not prudently incurred, or not incurred in relation to funding obligations incurred or that are planned to be incurred by financing entities], the Board may refuse to approve the proposed fee or a portion of the proposed fee and may make recommendations to the Financial Services Manager regarding the proposed fee.~~

Charging of fees

8. (1) In charging fees, the Financial Services Manager shall provide for,

(a) the base fee for a month to be payable within **[x]** days after the end of the month; and

(b) the variable fee for a year to be payable in the following calendar year in twelve equal monthly instalments that coincide with the payment of the base fee for each month.

(2) If the variable fee is a negative amount, it shall be deducted from the base fee payable in the following calendar year in twelve equal monthly instalments.

(3) Where there is more than one financing entity, the portion of the fees allocated to and payable by a financing entity shall be based on its proportionate share of the average principal amount of funding obligations for the applicable period.

Submissions to Board re fees

9. (1) The Financial Services Manager shall make submissions to the Board in respect of the fees proposed to be charged under section ~~5.1, 6.1~~**5.1** and ~~7.1~~**6.1.**

(2) The first submission **for proposed fees to be charged for a two year period commencing in 2018** shall be made no later than [October 31, 2017].

(3) ~~The submission for each calendar year starting with 2019~~**Submissions for proposed fees to be charged for a two year period commencing in 2020 and for every two year period thereafter** shall be made no later than [120 days] before the start of the **applicable two** year **period**.

(4**) Submissions to amend the proposed fees for a month in any year following approval of the proposed fees for any two year period may be made from time to time but no more frequently than once in any 12 month period and no later than 120 days before the start of the year in which such fees are proposed to be effective.**

(5) If the Board makes recommendations as described in section ~~5.1, 6.1~~**5.1** or ~~7.1,~~**6.1,** the Financial Services Manager shall submit to the Board,

(a) a revised proposed fee that takes into consideration the recommendations of the Board, and in the case of the base fee is consistent with comparison fees;

(b~~)~~ ~~a description of the methodology that the Financial Services Manager has applied to determine the revised proposed fee;~~

(~~c~~) in the case of the base fee, details concerning the comparison fees that the Financial Services Manager considered; **and**

(~~d~~**c**) in the case of the variable fee, a description of the methodology that the Financial Services Manager has applied to determine forecast interest rates in respect of tranches of the net annual funding obligations~~; and~~**.**

(~~e) in the case of a proposed fee for costs and expenditures by the Financial Services Manager, the rationale for the costs and expenditures having been [prudently incurred, and having been incurred in relation to funding obligations incurred or that are planned to be incurred by financing entities]~~ **6) Until the Board has approved the fees in respect of any two year period, the fees approved for the prior two year period shall remain in effect.**

Board approval, general

10. (1) ~~The Board may approve a proposed fee submitted by the Financial Services Manager or refuse to approve and refer the proposed fee back to the Financial Services Manager with the Board's recommendations.~~

~~[OLC Note: As noted by ENE LSB, there is some redundancy at the moment between section 10 and sections 5.1 and 6.1. This matter will be addressed in a subsequent draft when we have settled the Board approval process for each of the various scenarios (e.g. base fee; variable fee; costs/expenditures fee).]~~

~~(2) The Board may specify in its approval that a fee payable in respect of any period beginning on or after July 1, 2017.~~(3) For the purpose of determining whether to approve a proposed fee~~,~~ **described in section 5.1 or 6.1,**

(a) the Board shall consider the information provided by the Financial Service Manager in its submission relating to the proposed fee~~.~~**; and**

(~~4) For the purpose of determining whether to approve a proposed fee,~~ **b)** the Board may consider advice provided by the Ontario Financing Authority [with respect to comparison fees, annual rates and forecast interest rates].

[OLC Note re DEFERRAL ACCOUNT:
1. You included the following instruction that would require the FSM to establish a deferral account -- what is the authority for imposing this requirement? Recall that in subs. 34 (1) of the Act, the Board is given authority to require that the FSM maintain specific accounts.

2. ENE LSB note: *Necessity of this provision to be discussion with the OEB given that fees will be recovered as a financing entity expense through the Fair Hydro program and not as part of the fees to be approved by the Board.*]

[If needed, deferral provision could be along the following lines: The Financial Services Manager shall establish a deferral account in connection with subsection 19 (3) of the Act that records costs incurred by the Financial Services Manager in providing services referred to in section 1 during the period from July 1, 2017 to the day before the date of the Board's first order under subsection 19 (3) of the Act.]

[OLC Note re FINANCE AMOUNT: You included the following instruction, but I think this more properly belongs somewhere in section 5 of O. Reg. 206/17? In fact, are these fees not already covered in that section (perhaps under "financing entity expenses"?). Please confirm: *Fees established by the Financial Services Manager and approved by the Board, and any applicable taxes on such fees, shall be included in the definition of "expenses" for the purposes of determining finance amounts under the Act.*]

[Notes Re: Determining Fees:

(1) An alternative approach involves the Board approving the initial base fee and variable fee, with any changes to those fees being triggered by the FSM submitting to the Board proposed amendments to those fees (or the Board triggering a review on its own initiative (not more than once per year). However, because interest rates (and hence forecast interest rates) change over time (and can change even within a year), consider whether variable B of the variable fee should be approved annually. Similarly, because trends for "market comparable fees charged by service providers for similar services" change over time, consider whether variable A of the base fee should be approved annually.]

(2) Once every three years after the Board has approved the fees submitted by the Financial Services Manager under section 3, or more frequently if the Board requires but not more frequently than annually, the Board may require the Financial Services Manager to engage, on behalf of and at the cost of the financing entities, a third-party independent consultant to review and advise as to the appropriate benchmarks and range of values for [annual rates?] used for the purpose of determining the base fee and forecast interest rates used for the purposes of determining the variable fee and shall give due consideration to such advice.]

Commencement

x. This Regulation comes into force on the day it is filed.

Document comparison by Workshare Compare on September-23-17 6:39:45 PM

Input:	
Document 1 ID	interwovenSite://INVENTORYS1/TorysAtWork/24180663/1
Description	#24180663v1<TorysAtWork> - Fair Hydro Fee Regs (Torys Comments)
Document 2 ID	interwovenSite://INVENTORYS1/TorysAtWork/24180663/3
Description	#24180663v3<TorysAtWork> - Fair Hydro Fee Regs (Torys Comments)
Rendering set	Firm_Standard

Legend:	
Insertion	
~~Deletion~~	
~~Moved from~~	
Moved to	
Style change	
Format change	
~~Moved deletion~~	
Inserted cell	
Deleted cell	
Moved cell	
Split/Merged cell	
Padding cell	

Statistics:	
	Count
Insertions	70
Deletions	58
Moved from	8
Moved to	8
Style change	0
Format changed	0
Total changes	144

From:	John Kim
To:	Ronald Kwan
Cc:	Shajee Kathirgamanathan; Bruno Amara
Subject:	ESDI Quaterly Update v12_Markup_clean.pptx
Date:	Wednesday, November 29, 2017 6:05:23 PM
Attachments:	ESDI Quaterly Update v12_Markup_clean.pptx

Hi Ron,

This deck is to update you on where we propose the 2017-18 estimated ESDI value to be versus $525M that was in the Q1 2017 financials and $140M FTD recently is booking in the draft Q2 2017. This is more for internal discussion for now but could be transition to a full deck quickly.

We would propose updating it to $306M for Q2 2017. We label it as “Budget 2018” but is to represent our latest outlook.

We have asked for a draft financials earlier and following up again now.

Thanks,

John

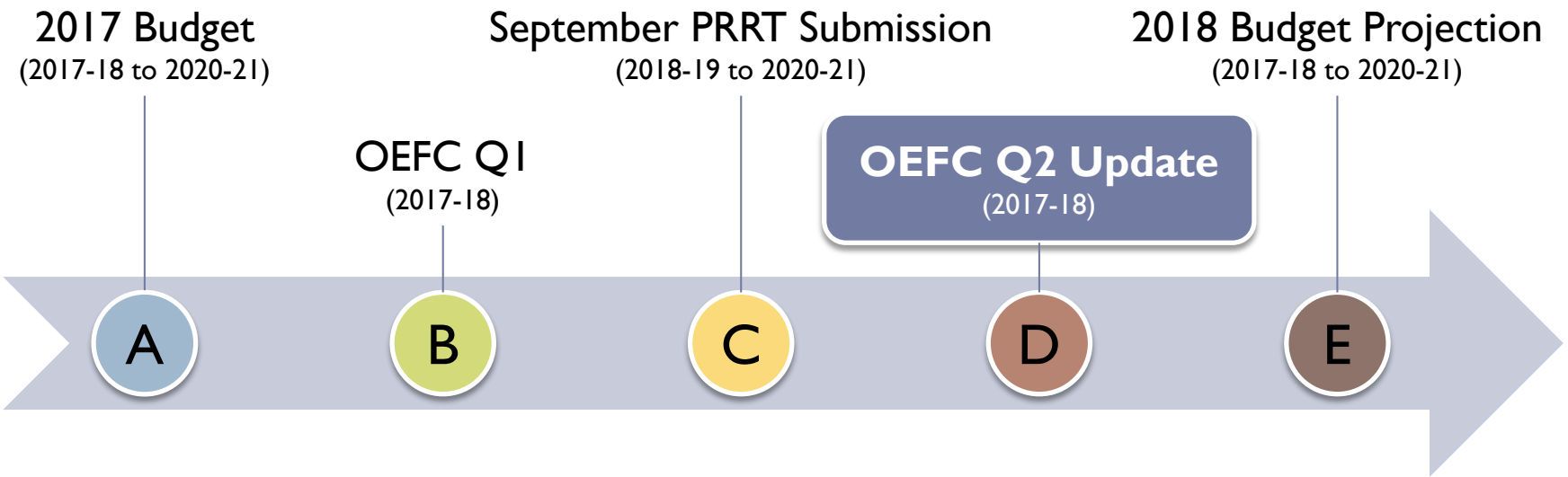
DRAFT

Updating ESDI 2017-18 OEFC Financials

Corporate and Electricity Finance Division
[DATE]

Overview

- This presentation provides a brief overview of anticipated 2017-18 ESDI and an extended outlook to 2020-21 if ESDI is to be approved to continue beyond 2017-18.
- Revised ESDI outlook proposed for OEFC Q2 financial statements reflects:
  - 'unpacking' of asset optimization net impacts previously reported under 'Sales and Rentals
  - full estimated IFRS reporting impacts to OPG
  - revised projections not previously incorporated into the fiscal plan.
- Numbers are subject to further updates as results get finalized.
- The timeline of changes from 2017 Budget is shown below along with relevant years of projected ESDI. Details provided on the following slides.



DRAFT

ESDI Updates - Overview

- The following summary provides an overview of the changes since Budget 2017 and projections for Budget 2018. Detailed explanation provided on the slides following.
- Note, projections for all years were not provided for every update.

	$ Millions	2017-18	2018-19	2019-20	2020-21
A	**2017 Budget**	**125**	**802**	**737**	**1,225**
	1. OPG - Removed IFRS Risk	*400*	*-*	*200*	*-*
B	**OEFC Q1 Update**	**525**			
	2. OPG - Re-Pack IFRS Risk	*(400)*	*-*	*(200)*	*-*
	3. OPG - August Update	*40*	*-*	*-*	*-*
	4. Hydro One - Preferred Shares	*6*	*6*	*6*	*6*
	5. Public Debt Interest Expense	*38*	*38*	*38*	*38*
C	**September PRRT Submission**		***846***	***780***	***1,269***
	6. OPG - September Update	*15*	*-*	*-*	*-*
	7. OPG - Updated Fair Hydro Trust Interest Revenue	*(5)*	*(12)*	*(17)*	*(24)*
	8. Hydro One - Updated Net Income Forecasts	*(79)*	*(84)*	*(43)*	*(45)*
D	**OEFC Q2 Update**	**140**			
	9. OPG - Updating for IFRS Risks	*0*	*(475)*	*(500)*	*(750)*
	10. 'Unpacking' - OPG Head office sale	*283*	*-*	*-*	*-*
	11. 'Unpacking' - Hydro One net income	*(113)*	*(142)*	*(171)*	*(185)*
	12. Hydro One - Updating Net Income Projections	*(5)*	*(15)*	*(8)*	*(9)*
E	**Budget 2018**	**306**	**118**	**41**	**255**

Note: Numbers may not add up due to rounding.

DRAFT

ESDI Updates - Details

	$ Millions	2017-18	2018-19	2019-20	2020-21
A	**2017 Budget**	**125**	**802**	**737**	**1,225**
	1. OPG - Removed IFRS Risk	*400*	*-*	*200*	*-*
B	**OEFC Q1 Update**	**525**			
	2. OPG - Re-Pack IFRS Risk	*(400)*	*-*	*(200)*	*-*
	3. OPG - August Update	*40*	*-*	*-*	*-*
	4. Hydro One - Preferred Shares	*6*	*6*	*6*	*6*
	5. Public Debt Interest Expense	*38*	*38*	*38*	*38*
C	**September PRRT Submission**		***846***	***780***	***1,269***

- The updates from 2017 Budget to OEFC Q1 Update are as follows:
  1. The original ESDI estimate of $525M shown in Q1 2017-18 financial statements did not include the IFRS adjustment of $400M that was incorporated in 2017 Budget separately from OPG outlook provided by Corporate and Electricity Finance Division (CEFD).

- The updates from OEFC Q1 Update to the September PRRT Submission includes:
  2. Incorporating OPG's IFRS Risk as per Budget 2017
  3. OPG's August 2017 shareholder update with increased projected net income (803M vs 702M at Budget 2017), partially as a result of increased returns from OPG headquarter sales (283M vs 222M at Budget 2017) that are removed and attributed to Sales and Rental rather than OPG/ESDI line at this point.
  4. Adjusting Hydro One net income to incorporate Preferred Shares 100% attributable to the province.
  5. Changes in Public Debt Interest (ie. government's annual interest cost in investments of OPG and Hydro One) due to reduced provincial Hydro One share ownership.

Note: Numbers may not add up due to rounding.

DRAFT

ESDI Updates - Details

	$ Millions	2017-18	2018-19	2019-20	2020-21
C	**September PRRT Submission**		***846***	***780***	***1,269***
	6. OPG - September Update	*15*	*-*	*-*	*-*
	7. OPG - Updated Fair Hydro Trust Interest Revenue	*(5)*	*(12)*	*(17)*	*(24)*
	8. Hydro One - Updated Net Income Forecasts	*(79)*	*(84)*	*(43)*	*(45)*
D	**OEFC Q2 Update**	**140**			
	9. OPG - Updating for IFRS Risks	*0*	*(475)*	*(500)*	*(750)*
	10. 'Unpacking' - OPG Head office sale	*283*	*-*	*-*	*-*
	11. 'Unpacking' - Hydro One net income	*(113)*	*(142)*	*(171)*	*(185)*
	12. Hydro One - Updating Net Income Projections	*(5)*	*(15)*	*(8)*	*(9)*
E	**Budget 2018**	**306**	**118**	**41**	**255**

- The updates from the September PRRT Submission to the current OEFC Q2 Update are as follows:
  6. Increased OPG projected net income attributable to ESDI from the September OPG Shareholder Update.
  7. Revised projections from OPG Trust Revenue due to lower than originally anticipated Fair Hydro Plan borrowing needs.
  8. Revised Hydro One net income forecasts due to: model refinements, incorporating debenture interest costs as part of the Avista merger, and preliminary assessment of Hydro One Rate Decision on September 28, 2017.
- The updates from OEFC Q2 Update to Budget 2018 includes:
  9. Incorporated remaining OPG IFRS Risks not previously included.
  10. 'Unpacking' the gains from OPG Head Office sale, previously incorporated in the Sales and Rental line.
  11. 'Unpacking' reduced Hydro One net income from reduced Provincial ownership; previously incorporated in Sales and Rental.
  12. Additional revisions in Hydro One model to further incorporate subsequent rate order from Hydro One Rate Decision.

Note: Numbers may not add up due to rounding.

PRRT Submission Update

DRAFT

PRRT Submission Update

- As part of the PRRT process, the Ministry of Finance submitted the below ESDI provision:

II. Requested Program Changes

$M	17-18	18-19	19-20	20-21	Growth Rate 18-19 to 20-21
Proposed Allocation					
MOF Expense		*(846)*	*(780)*	*(1,269)*	
OEFC Consolidation Expense		*846*	*780*	*1,269*	
Operating Expense	0.0	0.0	0.0	0.0	
Capital Expense	0.0	0.0	0.0	0.0	
Total Expense	0.0	0.0	0.0	0.0	
% Growth		0.0%	0.0%	0.0%	X.X%
Operating Assets	0.0	0.0			
Capital Assets	0.0	0.0	0.0	0.0	

$M	21-22	22-23	23-24	24-25	25-26	26-27	27-28
Capital Expense	X.X	X.X	X.X	X.X	X.X	X.X	X.X
Capital Assets	X.X	X.X	X.X	X.X	X.X	X.X	X.X

Notes:

1. Table should be presented on a fully consolidated basis. Capital assets include acquisitions of consolidated entities. Consolidation information should be consistent with information in ORBIT and information submitted to the Office of the Provincial Controller Division (OPCD).
2. See ORBIT for current allocation.

* Reflects sum of all financial impacts related to Key Operating, Capital, Climate Change, FTE and Technical Decisions

PRRT Submission Update

- The continuation of ESDI beyond April 1, 2018 was proposed in this PRRT submission as OEFC is expected to continue to have significant debt and other liabilities to service and pay down.
- However, any payments under this statutory line item would be fiscally neutral as the payment from the Ministry to the OEFC is fully offset against the consolidation of revenue of OEFC into the Province's Public Accounts.
- Corporate Quality Service Division (CQSD) has confirmed that there will be opportunity to revise ESDI amounts submitted in the PRRT note.
- The timing of these revisions is to be confirmed with TBS.

From: Nelms, Scott (MOF)
To: Ronald Kwan
Subject: ESDI
Date: Monday, March 27, 2017 10:58:10 AM

Hi Ron,

Would OPG's involvement in GA financing have any implications for ESDI? I assume no, but wanted to double check.

Thanks,
Scott

Scott Nelms
Electricity Investment and Governance Secretariat | Ministry of Finance
7th Floor | 375 University ave. | Toronto, ON
w: (416) 212-6469 | c: (647) 330-2681
scott.nelms@ontario.ca

From: Bruno Amara
To: Ronald Kwan
Cc: John Kim
Subject: Electricity Outlook with AO unpacking
Date: Monday, January 08, 2018 5:51:43 PM
Attachments: Electricity Sector Outlook (2018 01 08)_unpacked_v05.xlsm
image003.png

Hi Ron

Attached is our Electricity Outlook that we sent to OB/OEP last week, with the unpacking of AO impacts. The changes are shown below and consist of
i) adding OPG head office properties sale impact back to OPG NI and PILs and
ii) changing provincial Hydro One ownership assumption from Budget assumption of about 70% to current assumption of 50% to 47% over the outlook.

Happy to discuss.

Thanks
Bruno

	2017-18	2018-19	2019-20	2020-21
OPG net income	283	-	-	-
OPG PILs	95	-	-	-
Hydro One net income	(117)	(147)	(176)	(191)
Total	261	(147)	(176)	(191)

Electricity Sector Outlook
October 2017

Disclosure:

All information contained in this workbook is confidential and commercially sensitive

All projected numbers are estimates and subjected to change

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Commercially Sensitive and Confidential Advice to Cabinet for Consideration of Options for Discussion Purposes Only

Electricity Sector Outlook
Including Line Items for Consolidation

Electricity Summary - On Deck

			MOF Expense Items (consolidated)	Current Outlook			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**38**	Power Supply Contract Costs	(182)	(183)	(134)	(103)
Expense	**MOF (OEFC)**	**40**	Demand Management Support Costs	(10)	-	-	-
Expense	**MOF (OEFC)**	**41**	Provision for Electricity Sector	24	9	-	48
Expense	**MOF**	**17**	Provision for Electricity Sector	(24)	(9)	-	(48)
Expense	**MOF (OEFC)**	**42**	Other (Finance)	(6)	(7)	(7)	(7)
			Total MOF Expense	**(198)**	**(190)**	**(141)**	**(110)**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**7**	OPG Income	149	137	(7)	156
Revenue	**ENE**	**8**	OPG - ONFA and other Fair Value Adjustments	171	-	-	-
Revenue	**ENE**	**10**	HOI Income	329	327	388	419
Revenue		**11**	Brampton Income	-	-	-	-
Revenue	**MOF (OEFC)**	**26**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	377	452	503	635
Revenue	**MOF (OEFC)**	**29**	Electricity Debt Retirement Charge	623	-	-	-
Revenue	**MOF (OEFC)**	**30**	Power Supply Contract Recoveries	182	183	134	103
Revenue	**MOF (OEFC)**	**31**	Net Reduction of Power Purchase Contracts	74	41	30	28
Revenue	**MOF (OEFC)**	**34**	Miscellaneous	-	-	-	-
			Total MOF Revenue	**1,906**	**1,138**	**1,048**	**1,341**
			OFA IOD Expense				
			Public Debt Interest - Electricity Sector	(454)	(454)	(454)	(454)
			Interest on Debt	(475)	(438)	(411)	(348)
			Total OFA IOD Expense	**(929)**	**(892)**	**(865)**	**(802)**
			Impact on Surplus/Deficit	**779**	**57**	**42**	**429**
			check	*-*	*-*	*(0)*	*-*

Electricity Summary - Budget 17

For Discussion			MOF Expense Items (consolidated)	Plan			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**38**	Power Supply Contract Costs	(292)	(325)	(301)	(273)
Expense	**MOF (OEFC)**	**40**	Demand Management Support Costs	(10)	0	0	0
Expense	**MOF (OEFC)**	**41**	Provision for Electricity Sector	125	0	0	0
Expense	**MOF**	**17**	Provision for Electricity Sector	(125)	0	0	0
Expense	**MOF (OEFC)**	**42**	Other (Finance)	(6)	(6)	(6)	(6)
			Total MOF Expense	**(308)**	**(331)**	**(307)**	**(279)**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**7**	OPG Income	97	732	625	1,066
Revenue	**ENE**	**8**	OPG - ONFA and other Fair Value Adjustments	0	0	0	0
Revenue	**ENE**	**10**	HOI Income	520	562	603	652
			Brampton Income				
Revenue	**MOF (OEFC)**	**25**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	405	476	538	679
Revenue	**MOF (OEFC)**	**29**	Electricity Debt Retirement Charge	623	0	0	0
Revenue	**MOF (OEFC)**	**30**	Power Supply Contract Recoveries	292	325	301	273
Revenue	**MOF (OEFC)**	**31**	Net Reduction of Power Purchase Contracts	74	41	30	28
Revenue	**MOF (OEFC)**	**34**	Miscellaneous	0	0	0	0
			Total MOF Revenue	**2,011**	**2,136**	**2,098**	**2,697**
			OFA IOD Expense				
		17	Public Debt Interest - Electricity Sector	(492)	(492)	(492)	(492)
		36	Interest on Debt	(422)	(374)	(342)	(250)
			Total OFA IOD Expense	**(914)**	**(866)**	**(834)**	**(742)**
			Impact on Surplus/Deficit	**789**	**939**	**957**	**1,676**
			check	**-**	**-**	**-**	**-**

Electricity Summary - Change

			MOF Expense Items (consolidated)	Variance from Plan			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**69**	Power Supply Contract Costs	110	142	167	170
Expense	**MOF (OEFC)**	**71**	Demand Management Support Costs	0	0	0	0
Expense	**MOF (OEFC)**	**72**	Provision for Electricity Sector	(101)	9	0	48
Expense	**MOF**	**48**	Provision for Electricity Sector	101	(9)	0	(48)
Expense	**MOF (OEFC)**	**73**	Other (Finance)	0	(1)	(1)	(1)
			Total MOF Expense	**110**	**141**	**166**	**169**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**38**	OPG Income	52	(596)	(632)	(909)
Revenue	**ENE**	**39**	OPG - ONFA and other Fair Value Adjustments	171	0	0	0
Revenue	**ENE**	**41**	HOI Income	(190)	(235)	(216)	(233)
			Brampton Income	0	0	0	0
Revenue	**MOF (OEFC)**	**25**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	(28)	(24)	(35)	(43)
Revenue	**MOF (OEFC)**	**60**	Electricity Debt Retirement Charge	0	0	0	0
Revenue	**MOF (OEFC)**	**61**	Power Supply Contract Recoveries	(110)	(142)	(167)	(170)
Revenue	**MOF (OEFC)**	**62**	Net Reduction of Power Purchase Contracts	(0)	(0)	(0)	(0)
Revenue	**MOF (OEFC)**	**65**	Miscellaneous	0	0	0	0
			Total MOF Revenue	**(105)**	**(997)**	**(1,049)**	**(1,356)**
			OFA IOD Expense				
		17	Public Debt Interest - Electricity Sector	38	38	38	38
		36	Interest on Debt	(53)	(64)	(69)	(98)
			Total OFA IOD Expense	**(15)**	**(26)**	**(31)**	**(60)**
			Impact on Surplus/Deficit	**(10)**	**(882)**	**(914)**	**(1,247)**
			check	-	-	-	-

Track Changes in Surplus/Deficit

Date	Change ID#	Source	Tab
5/1/2017	20170501-1	Link	ONFA
5/1/2017	20170501-2	Link	Hydro One
5/1/2017	20170501-3	Link	Hydro One
5/1/2017	20170501-4	Link	Other Data
5/2/2017	20170502-1	Link	OPG
5/9/2017	20170509-1	Link	OPG
5/10/2017	20170510-1	Link	Hydro One
5/10/2017	20170510-2	Link	Other Data
5/12/2017	20170512-1	Link	Hydro One
5/15/2017	20170515-1	Link?	
5/15/2017	20170515-2	Link	OPG
5/17/2017	20170517-1	Link	Hydro One
5/17/2017	20170517-2	Link	ONFA
5/17/2017	20170517-3		
5/18/2017	20170518-1	Link	OPG
5/18/2017	20170518-2	Link	OPG
5/18/2017	20170518-3		
6/15/2017	20170615-1	Link	OPG
6/22/2017	20170622-1	Link	Hydro One
6/22/2017	20170622-2	Link	Hydro One
6/26/2017	20170626-1		
6/29/2017	20170629-1		

7/6/2017	20170706-1		
7/11/2017	20170711-1		
7/13/2017	20170713-1	Link	Provision
7/17/2017	20170717-1	Link	Revenue (Risks)
7/24/2017	20170724-1	Link	Revenue (Risks)
7/25/2017	20170725-1	Link	Revenue (Risks)
7/26/2017	20170726-1	Link	Revenue (Risks)
7/27/2017	20170727-1	Link	Revenue (Risks)
7/27/2017	20170727-2	Link	Revenue (Risks)
7/31/2017	20170731-1		
7/31/2017	20170731-2	Link	Hydro One
7/31/2017	20170731-3	Link	Other Data
8/11/2017	20170811-1	Link	OPG
8/15/2017	20170815-1		
8/15/2017	20170815-2		
8/15/2017	20170815-3		
8/15/2017	20170815-4		
8/15/2017	20170815-5		Other Data
8/15/2017	20170815-6		Other Data
8/15/2017	20170815-7		Other Data
8/15/2017	20170815-8		Other Data
8/15/2017	20170815-9		Other Data
8/15/2017	20170815-10		Other Data
8/17/2017	20170817-1	Link	Provision
8/17/2017	20170817-2	Link	Hydro One
8/18/2017	20170818-1	Link	Revenue (Risks)
8/22/2017	20170822-1	Link	OPG
8/25/2017	20170825-1		Hydro One
8/29/2017	20170829-1		Revenue (Risks)
8/31/2017	20170831-1		Revenue (Risks)
9/5/2017	20170905-1		Other Data
9/5/2017	20170905-2		Other Data
9/5/2017	20170905-3	Link	OPG

9/6/2017	20170906-1	Link	Other Data
9/6/2017	20170906-2	Link	Revenue (Risks)
9/8/2017	20170908-1	Link	Hydro One
9/8/2017	20170908-2	Link	OPG
9/11/2017			
9/12/2017			
9/13/2017			
9/21/2017			
9/22/2017			
10/2/2017			Hydro One
10/2/2017			
10/2/2017			
10/2/2017			
10/4/2017	20171004-1		OPG
10/4/2017	20171004-2		OPG
10/4/2017			
10/4/2017			
10/5/2017			
10/6/2017			
10/7/2017			
10/8/2017			
10/10/2017	20171010-1		Hydro One
10/10/2017			
10/10/2017			
10/11/2017	20171011-1		OPG
10/11/2017			
10/11/2017			
10/12/2017			OPG
10/12/2017			
10/12/2017			
10/12/2017			
10/18/2017	20171018-1		Hydro One
10/18/2017	20171018-1		Hydro One
10/18/2017	20171018-1		Hydro One
10/19/2017	20171019-1		Revenue (Risks)
10/19/2017	20171019-2		Revenue (Risks)
10/20/2017	20171020-1		Revenue (Risks)
10/20/2017	20171020-2		
10/20/2017	20171020-2		
10/20/2017	20171020-2		
10/20/2017	20171020-3		Revenue (Risks)
10/20/2017	20171020-4		OPG
10/20/2017	20171020-4		OPG
10/20/2017	20171020-4		OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017	20171114-1		Hydro One

11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017		Hydro One
11/14/2017		Hydro One
11/14/2017		Hydro One
11/30/2017	20171130-1	Revenue (Risks)
12/8/2017		Hydro One
12/11/2017	20171211-1	Other Data
12/11/2017	20171211-1	Other Data
12/22/2017	20171222-1	OPG
1/2/2018		Hydro One
1/2/2018		Hydro One
1/2/2018		Hydro One
1/2/2018	20180102-1	OPG
1/2/2018	20180102-1	OPG
1/2/2018	20180102-1	OPG
1/2/2018	20180102-2	OPG
1/2/2018	20180102-3	OPG
1/2/2018	20180102-3	Revenue (Risks)
1/2/2018	20180102-4	Revenue (Risks)
1/2/2018	20180102-5	Revenue (Risks)
1/2/2018	20180102-6	Revenue (Risks)
1/2/2018	20180102-7	Revenue (Risks)
1/2/2018	20180102-8	Revenue (Risks)
1/2/2018	20180102-9	OPG
1/2/2018	20180102-9	OPG
1/2/2018	20180102-9	OPG
1/2/2018	20180102-9	OPG
1/3/2018		OPG
1/3/2018		OPG
1/3/2018		OPG
1/3/2018		OPG
1/3/2018		Hydro One
1/3/2018		Hydro One
1/3/2018		Hydro One
1/4/2018	20180104-1	OPG
1/4/2018	20180104-1	OPG
1/4/2018	20180104-1	OPG
1/4/2018	20180104-1	OPG
1/4/2018	20180104-2	Other Data
1/4/2018	20180104-2	Other Data
1/5/2018		
1/5/2018		
1/5/2018		
1/5/2018		
1/5/2018		
1/5/2018		
1/5/2018		
1/8/2018		
1/8/2018		
1/8/2018		

FOR EFB USE ONLY

Budget 2017 Outlook
Current Outlook
Change Since Budget

Description of Update
ONFA Update as of March 31 2017
s. 50.3 Update for 2016-17
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Debt Interest
OPG IFRS Risk in 2019-20
Revised OPG 2016-17 Net Income
Revised OPG 2016-17 Net Income
Revised OPG 2016-17 Net Income
tech change: slight update to assumed Prov share 70.05% from 70%
tech change: slight update to assumed Prov share 70.05% from 70%
tech change: slight update to assumed Prov share 70.05% from 70%
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
Updating H1 2016-17 Net Income for ESDI
Updating H1 2016-17 Net Income for ESDI
Updating H1 2016-17 Net Income for ESDI
Power Purchase Supply
H1 Model Forecasts - No Fiscal Update Resaving Data
Update Budget 2017 Tabs to reflect fiscal plan
Update OPG forecasted PILS to reflect sources
Update H1 2016-17 CIT
Re-inputting ONFA updates
Updating H1 Net Income to include Pref Shares in 16-17
Updating OPG Income Tax Expense for 2016-17
Updating OPG non-income tax PILs
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2017
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2018
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2019
Updating with actual OPG IFRS Adjustment 2016-17
Updating with actual OPG IFRS Adjustment 2016-17
Updating with actual OPG IFRS Adjustment 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
[NOT APPLIED] Updating H1 Brampton (Interim Adjustments)
Shifted H1 Brampton 2016-17 NI to the 2017-18
Removed H1 Brampton for 2016-17 (pending finals)
Removed H1 Brampton for 2016-17 (pending finals)
Removed H1 Brampton for 2016-17 (pending finals)

add prior-year adjustment for 2016-17

add prior-year adjustment for 2016-18
Reconfigured calculation of ESDI and MOF ESDI Expense
Reconfigured calculation of OPG 2017-18 Net Income
Backup for the Provincial Interest cost
Linking source for Revenue Risks Tab
New source for Revenue Risks Tab
Revenue Risks Tab - ROE Risks
Updating OEB Risk for OPG
OEB Staff Report - H1 Tx - Revenue Risks
OPG Pensions - Cash vs Accrual Deferral Accounts
Updating Links in Electricity Summary Change and OEFC Change
Preliminary estimate for Hydro One Brampton
Preliminary estimate for Hydro One Brampton
Preliminary estimate for Hydro One Brampton

Updating DRC for Actuals 2016-17 (Based on draft FS)
Updating PILs for 2016-17 Baced on Actuals
OPG: Non-ONFA Fair Value Adjustment
Round all Hydro One ownership assumptions to two decimal places
H1 Equity Adjustment rounding.
Round all Hydro One ownership assumptions to two decimal places
Round all Hydro One ownership assumptions to two decimal places
Revising source of ESDI, Dedicated Electricity Earnings
2016-17 - Update Power Supply Recoveries to actuals
2016-17 - Update Power Supply Recoveries to actuals
2016-17 - Updating Miscellaneous OEFC Revenue to Actuals
Adj: Exclude Bramton $15m add prior year adjustment +$3M
Adj: Exclude Bramton $15m add prior year adjustment +$3M
Public Accts: Updated IESO debt interest Interest On Debt, 2016-17
Public Accts: 2016-17 - Demand Management Support Costs Update
2017-18 - Demand Management Support Costs (no change)
Public Accts: 2016-17 - Updating Operating Expense in OEFC
Sourcing Provision for Electricity Sector from Actual Public Accounts
Revised 2016-17 Brampton Amount for Public Accounts
OPG Pensions - Cash vs Accrual Deferral Accounts (Revenue Risks Tab)
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
Reclassification
Reclassification
Reverting H1 Ownership change (undoing 20170518-3)
Reverting H1 Ownership change (undoing 20170518-3)
Reverting H1 Ownership change (undoing 20170518-3)
Updating Risks based on Hydro One Q2 Results Model
Avista Acquisition Risks
NUG Amortization Liability (sourcing amortization schedule)
2016-17 Actuals - Debt Guarantee Fee
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results

Interest Revenue for IESO and "Other"
OPG Revenue Risks from OEB Filings
Net income corrected for Preferred Shares
Net income corrected for Preferred Shares
Net income corrected for Preferred Shares
Made link edits to OPG sheet so that the "Net Income Before Tax" 2017-18 number is not a hardc
Updated PILs to include OPCD public accounts adjustment
Provision tab fix to pick up Hydro One preferred share net income
Provision tab fix to pick up Hydro One preferred share net income
FTD Update to OEFC Outlook (Sep 19, 2017) OPG Interest
FTD Update to OEFC Outlook (Sep 19, 2017) Other Interest
Update to Hydro One PILs from information in Transmission rate application material
OEB September 28, 2017 Hydro One decision and order impact - incl. rebasing
OEB September 28, 2017 Hydro One decision and order impact - incl. rebasing
OEB September 28, 2017 Hydro One decision and order impact - incl. rebasing
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Debenture Interest Costs - Removing from Revenue (Risks) and adding it ot H1 Model
Debenture Interest Costs - Removing from Revenue (Risks) and adding it ot H1 Model
Debenture Interest Costs - Removing from Revenue (Risks) and adding it ot H1 Model
Updated OPG Net Income and PILs based on monthly report (August 2017 results)
Updated OPG Net Income and PILs based on monthly report (August 2017 results)
Updated OPG Net Income and PILs based on monthly report (August 2017 results)
Correction to PILs on OPG sheet
Correction to PILs on OPG sheet
Correction to PILs on OPG sheet
Correction to PILs on OPG sheet
Switch to Direct from Model
Switch to Direct from Model
Switch to Direct from Model
Updating ROE Risks
Updating H1 Load Risks based on model output
Updating ONFA Risks for September 2017
Adjust OEB decision/rebasing to ~50% provincial ownership
Adjust OEB decision/rebasing to ~50% provincial ownership
Adjust OEB decision/rebasing to ~50% provincial ownership
Updating OPG
OPG IOD impact from GA Financing, FHP
OPG IOD impact from GA Financing, FHP
OPG IOD impact from GA Financing, FHP
Unpacking updated OPG Gain on sale (net income)
Unpacking updated OPG Gain on sale (net income)
Unpacking updated OPG Gain on sale (net income)
Unpack PILs related to HQ gain on sale
Updating IFRS Risk
Adjustment for lower Provincial share (from 70.1% to 50.9 2017-18 & 47.4% after)
Adjustment for lower Provincial share (from 70.1% to 50.9 2017-18 & 47.4% after)
Adjustment for lower Provincial share (from 70.1% to 50.9 2017-18 & 47.4% after)
November 1 and November 7 Hydro One model updates

November 1 and November 7 Hydro One model updates
November 1 and November 7 Hydro One model updates
Revise Hydro Model to reverse OEB tax decision ongoing annual impact
Revise Hydro Model to reverse OEB tax decision ongoing annual impact
Revise Hydro Model to reverse OEB tax decision ongoing annual impact
Undo allocation adjustment in H1 tab (now that provincial shares are updated)
Undo allocation adjustment in H1 tab (now that provincial shares are updated)
Undo allocation adjustment in H1 tab (now that provincial shares are updated)
Updating OPG Revenue Risks from rate application
Update Hydro One PILs (reverses update on line 119 whuich did not account fro Dx side)
Updating Debt Guarantee Fee
Updating OEFC Operating Expense
small changes - linking the net income numbers

Updated number of shares sold for First Nations (Dec 2017) sale
Updated number of shares sold for First Nations (Dec 2017) sale
Updated number of shares sold for First Nations (Dec 2017) sale
Implemented OEB's Dec 2017 payment amounts decision for OPG (CEFD Analysis)
Implemented OEB's Dec 2017 payment amounts decision for OPG (CEFD Analysis)
Implemented OEB's Dec 2017 payment amounts decision for OPG (CEFD Analysis)
Updated OPG Net Income (based on their Q3 update, Sep 30, 2017)
Updated OPG ONFA adjustment (up to Sep 30, 2017) in OPG tab (removed it from Risks table)
Removal of OPG ONFA Sep 2017 adjustment in Risks table
Included possible range (-50M to 50M) of impact for future OPG ONFA adjustment in the negative
Removal of negative regulatory risk: "OPG Switch from accrual based to cash based accounting f
Removal of negative regulatory risk: "Timing of OPG Rate Decision" from Risks table
Removal of negative regulatory risk: "OEB Staff Recommendations wrt OPG rate application(May
Removal of negative regulatory risk: "Nuclear Liabilities Cash vs. Accrual" from Risks table
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month
Updated estimates of NUG costs.
Updated estimates of NUG costs.
Unpacking OPG (Head Office sale)
Unpacking OPG (Head Office sale)
Unpacking OPG (Head Office sale)
Unpacking OPG (Head Office sale)
Unpacking Hydro One for AO (from 70.1% ownership to as of January 2018)
Unpacking Hydro One for AO (from 70.1% ownership to as of January 2018)
Unpacking Hydro One for AO (from 70.1% ownership to as of January 2018)
Update H1 allocations for additional shares (SIFB edits)
Update H1 allocations for additional shares (SIFB edits)
Update H1 allocations for additional shares (SIFB edits)

This line show net impact of latest change. READ COMMENT

Expense
Expense
Expense
Expense
Expense
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue

Expense
Expense
Expense
Expense
Expense
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue

$ Millions

		2016-17	2017-18	2018-19	2019-20
		930	789	939	957
	File	915	779	57	42
		-15	-10	-882	-914
	check	*0*	*0*	*0*	*0*
		Impacts by FY →			
Outlook line affected	**Expense / Reve**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
ONFA and other Fair Value Adjustments	Revenue	41.0	0.0	0.0	0.0
N/A		0.0	0.0	0.0	0.0
?		0.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		38.1		
Provision for Electricity Sector (MOF)	Expense		(38.1)		
Public Debt Interest - Electricity Sector	Expense	0.0	38.1	38.1	38.1
Interest on Debt	Expense	0.0	(69.1)	(79.1)	(75.1)
OPG Income	Expense	0.0	0.0	0.0	
OPG Income	Revenue	(2.0)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**(2.0)**			
Provision for Electricity Sector (MOF)	Expense	2.0			
HOI Income	Revenue	0.4			
Provision for Electricity Sector (OEFC)	Expense	0.4			
Provision for Electricity Sector (MOF)	Expense	(0.4)			
Public Debt Interest - Electricity Sector	Expense	1.7			
Provision for Electricity Sector (OEFC)	Expense	(1.7)			
Provision for Electricity Sector (MOF)	Expense	1.7			
Interest on Debt	Expense	(1.7)			
HOI Income	Revenue	(39.8)	0.0	0.0	(0.0)
Provision for Electricity Sector (OEFC)	Expense	**(39.8)**			
Provision for Electricity Sector (MOF)	Expense	39.8			
	Revenue	-	-	-	-
	Revenue	-	-	-	-
	n/a	-	-	-	-
		-	-	-	-
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	4.7	0.0	0.0	0.0
	Revenue	0.0	0.0	0.0	0.0
HOI Income	Revenue	18.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	7.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	8.0	9.0	12.0	3.5
HOI Income	Revenue	0.0	(141.5)	(181.4)	(194.9)
Provision for Electricity Sector (OEFC)	Expense		(141.5)		
Provision for Electricity Sector (MOF)	Expense		141.5		
OPG Income	Revenue	(3.0)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**(3.0)**			
Provision for Electricity Sector (MOF)	Expense	3.0			
HOI Income	Revenue	7.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**7.0**			
Provision for Electricity Sector (MOF)	Expense	(7.0)			
	Revenue	-	-	-	-
	Revenue	0.0	0.0	0.0	0.0
Brampton Income	Revenue	(14.7)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**(14.7)**			
Provision for Electricity Sector (MOF)	Expense	14.7			

Provision for Electricity Sector (OEFC)	Expense		3.2			
Provision for Electricity Sector (MOF)	Expense		(3.2)			
	Revenue	-	-	-	-	
		-	-	-	-	
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
Brampton Income	Revenue		15.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		**15.0**			
Provision for Electricity Sector (MOF)	Expense		(15.0)			
Provision for Electricity Sector (OEFC)	Expense		3.2			
Provision for Electricity Sector (MOF)	Expense		(3.2)			
Electricity Debt Retirement Charge	Revenue		(4.0)	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue		(29.0)	0.0	0.0	0.0
OPG Income	Revenue		(6.0)	0.0	0.0	0.0
HOI Income	Revenue		(0.0)	(0.0)	0.0	0.0
HOI Income	Revenue		(1.7)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense			(0.0)		
Provision for Electricity Sector (MOF)	Expense			0.0		
	Revenue		0.0	0.0	0.0	0.0
Power Supply Contract Recoveries	Revenue		99.0	0.0	0.0	0.0
Power Supply Contract Costs	Expense		(99.0)			
Miscellaneous	Revenue		14.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		(12.0)			
Provision for Electricity Sector (MOF)	Expense		12.0			
Interest on Debt	Expense		(3.0)	0.0	0.0	0.0
Demand Management Support Costs	Expense		1.8	0.0	0.0	0.0
			0.0	0.0	0.0	0.0
Other (Finance)	Expense		(1.0)	0.0	0.0	0.0
	Revenue	-	-	-	-	
Brampton Income	Revenue		3.0	0.0	0.0	0.0
			0.0	0.0	0.0	0.0
OPG Income	Revenue		0.0	85.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue			(6.0)		
Provision for Electricity Sector (OEFC)	Expense			**85.0**		
Provision for Electricity Sector (MOF)	Expense			(85.0)		
OPG Income	Revenue		6.0			
ONFA and other Fair Value Adjustments	Revenue		(6.0)			
HOI Income	Revenue		0.0	141.9	181.8	195.4
Provision for Electricity Sector (OEFC)	Expense			141.9		
Provision for Electricity Sector (MOF)	Expense			(141.9)		
	n/a		0.0	0.0	0.0	0.0
			0.0	0.0	0.0	0.0
Net Reduction of Power Purchase Contracts	Revenue		0.1	(0.1)	(0.1)	(0.1)
	Revenue		0.0	0.0	0.0	0.0
OPG Income	Revenue		0.0	16.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue			(1.0)		
Provision for Electricity Sector (OEFC)	Expense			**16.0**		
Provision for Electricity Sector (MOF)	Expense			(16.0)		

		0.0	0.0	0.0	0.0
	n/a	0.0	0.0	0.0	0.0
HOI Income	Revenue	0.0	5.3	5.3	5.3
Provision for Electricity Sector (OEFC)	Expense		(12.4)		
Provision for Electricity Sector (MOF)	Expense		12.4		
oded formula in the cell	n/a	0.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	(30.4)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		17.8		
Provision for Electricity Sector (MOF)	Expense		(17.8)		
Interest on Debt	Expense	(0.0)	1.0	(0.0)	1.0
Interest on Debt	Expense	0.0	15.0	15.0	5.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	0.0	(7.8)	(8.7)	(10.3)
HOI Income	Revenue	0.0	(47.4)	(54.0)	(54.0)
Provision for Electricity Sector (OEFC)	Expense	0.0	(47.4)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	47.4	0.0	0.0
OPG Income	Revenue	0.0	(61.0)	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	0.0	(21.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	(61.0)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	61.0	0.0	0.0
OPG Income	Revenue	0.0	(21.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	(21.0)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	21.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	0.0	21.0	0.0	0.0
HOI Income	Revenue	0.0	(23.6)	(27.4)	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	(23.6)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	23.6	0.0	0.0
OPG Income	Revenue	0.0	15.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	15.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	(15.0)	0.0	0.0
OPG Income	Revenue	0.0	21.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	0.0	(18.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	21.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	(21.0)	0.0	0.0
HOI Income	Revenue	0.0	(23.8)	(28.9)	(10.1)
Provision for Electricity Sector (OEFC)	Expense	0.0	(23.8)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	23.8	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
HOI Income	Revenue		16.1	26.7	20.6
Provision for Electricity Sector (OEFC)	Expense		16.1		
Provision for Electricity Sector (MOF)	Expense		(16.1)		
n/a	n/a	0.0	0.0	0.0	0.0
OPG Income	Revenue		(4.9)	(11.9)	(17.1)
Provision for Electricity Sector (OEFC)	Expense		(4.9)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		4.9	0.0	0.0
OPG Income	Revenue		283.0		
Provision for Electricity Sector (OEFC)	Expense		283.0		
Provision for Electricity Sector (MOF)	Expense		(283.0)		
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue		95.0		
OPG Income	Revenue		0.0	(475.0)	(500.0)
HOI Income	Revenue		(112.6)	(142.1)	(170.6)
Provision for Electricity Sector (OEFC)	Expense		(112.6)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		112.6	0.0	0.0
HOI Income	Revenue		(3.3)	(3.0)	(0.1)

Provision for Electricity Sector (OEFC)	Expense		(3.3)		
Provision for Electricity Sector (MOF)	Expense		3.3		
HOI Income	Revenue		14.7	14.4	12.9
Provision for Electricity Sector (OEFC)	Expense		14.7	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		(14.7)	0.0	0.0
HOI Income	Revenue		(16.1)	(26.7)	(20.6)
Provision for Electricity Sector (OEFC)	Expense		(16.1)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		16.1	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)		0.0	7.8	8.7	10.3
n/a	n/a	0.0	0.0	0.0	0.0
Other (Finance)			0.0	(1.0)	(1.0)
OPG Income	Revenue		0.0	0.0	0.0
HOI Income	Revenue		0.1	0.5	0.6
Provision for Electricity Sector (OEFC)	Expense		0.1	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		(0.1)	0.0	0.0
OPG Income	Revenue		(477.1)	(145.2)	(153.1)
Provision for Electricity Sector (OEFC)	Expense		(305.7)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		305.7	0.0	0.0
OPG Income	Revenue		39.0	0.0	0.0
OPG - ONFA and other Fair Value Adjustments	Revenue		171.5	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
OPG Income	Revenue		119.3	36.3	38.3
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue		(119.3)	(36.3)	(38.3)
Provision for Electricity Sector (OEFC)	Expense		0.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		0.0	0.0	0.0
OPG Income	Revenue		(283.0)	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue		(95.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		0.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		0.0	0.0	0.0
HOI Income	Revenue		116.8	147.1	176.1
Provision for Electricity Sector (OEFC)	Expense		0.0	0.0	80.3
Provision for Electricity Sector (MOF)	Expense		0.0	0.0	(80.3)
OPG Income	Revenue		37.5	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue		12.5	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		0.0	14.4	23.1
Provision for Electricity Sector (MOF)	Expense		0.0	(14.4)	(23.1)
Power Supply Contract Recoveries	Revenue		(109.9)	(142.1)	(166.7)
Power Supply Contract Costs	Expense		109.9	142.1	166.7
OPG Income	Revenue		283.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue		95.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		141.1	141.9	0.0
Provision for Electricity Sector (MOF)	Expense		(141.1)	(141.9)	0.0
HOI Income	Revenue		(116.8)	(147.1)	(176.1)
Provision for Electricity Sector (OEFC)	Expense		(116.8)	(147.1)	(103.4)
Provision for Electricity Sector (MOF)	Expense		116.8	147.1	103.4
HOI Income	Revenue		(0.0)	(0.2)	(0.2)
Provision for Electricity Sector (OEFC)	Expense		(0.0)	(0.2)	0.0
Provision for Electricity Sector (MOF)	Expense		0.0	0.2	0.0

	0	*0*	*0*	*0*

Summary of Track Changes Above

Power Supply Contract Costs	(99.0)	0.0	0.0	0.0
Demand Management Support Costs	1.8	0.0	0.0	0.0
Provision for Electricity Sector OEFC)	(44.4)	180.9	0.0	0.0
Provision for Electricity Sector (MOF)	44.4	(180.9)	0.0	0.0
Other (Finance)	(1.0)	0.0	(1.0)	(1.0)
OPG Income	(5.0)	333.1	(486.9)	(517.1)
ONFA and other Fair Value Adjustments	35.0	0.0	0.0	0.0
HOI Income	(16.1)	(190.4)	(235.3)	(216.1)
Brampton Income	3.3	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	(39.7)	79.0	12.0	3.5
Electricity Debt Retirement Charge	(4.0)	0.0	0.0	0.0
Power Supply Contract Recoveries	99.0	0.0	0.0	0.0
Net Reduction of Power Purchase Contracts	0.1	(0.1)	(0.1)	(0.1)
Miscellaneous	14.0	0.0	0.0	0.0
Public Debt Interest - Electricity Sector	1.7	38.1	38.1	38.1
Interest on Debt	(4.7)	(53.1)	(64.1)	(69.1)
Impact on Surplus/Deficit	**(14.6)**	**206.7**	**(737.3)**	**(761.7)**
check	***0.0***	***216.5***	***144.9***	***152.7***

Check - Summary of Track Changes Above vs. Electricity Summary Change Worksheet

Power Supply Contract Costs	0.0	(110.2)	(142.2)	(167.0)
Demand Management Support Costs	(0.0)	0.0	0.0	0.0
Provision for Electricity Sector OEFC)	8.4	281.4	(9.0)	0.0
Provision for Electricity Sector (MOF)	(8.4)	(281.4)	9.0	0.0
Other (Finance)	0.0	0.0	0.0	0.0
OPG Income	0.0	281.3	108.9	114.8
ONFA and other Fair Value Adjustments	0.0	(171.5)	0.0	0.0
HOI Income	(0.0)	(0.1)	(0.3)	(0.4)
Brampton Income	0.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	(0.0)	106.8	36.3	38.3
Electricity Debt Retirement Charge	0.0	0.0	0.0	0.0
Power Supply Contract Recoveries	0.0	110.2	142.2	167.0
Net Reduction of Power Purchase Contracts	(0.0)	(0.0)	(0.0)	(0.0)
Miscellaneous	0.0	0.0	0.0	0.0
Public Debt Interest - Electricity Sector	23.4	0.1	0.1	0.1
Interest on Debt	(23.4)	(0.1)	(0.1)	(0.1)
Impact on Surplus/Deficit	**(0.0)**	**216.5**	**144.9**	**152.7**

2020-21
1,676
429
-1,247
0

2020-21	Further Explanation of Change and source of data
0.0	Regular quarterly ONFA Update
0.0	Benefit to OEFC under s.50.3: $411M gain, SIFB
0.0	Change to OEFC payment for interest costs of Debt for Equity Swap
38.1	Revised Provincial Debt Interest related to Hydro One Equity
(104.1)	From FTD, revised Debt Interest (net of revisions to Provincial and OPG debt interest)
0.0	Revised numbers from OEP with 2019-20 Risk
0.0	Updated numbers from OPG Q1 2017 FS
0.0	Updating H1 Net Income for actuals. Note does not update Brampton Income at this point. Will
-	No Change to numbers, just re-inputting data and saving sources
-	No Change to numbers, just re-inputting data and saving sources
-	No change to fiscal impact numbers. Deleting Budget 2016 and adding Budget 2017 fiscal imp
-	No Change to numbers, just re-inputting data and saving sources
0.0	Updated with CIT Numbers received from H1 as part of s.91.2 MB20 allocation from MOF
0.0	No Change to numbers, just re-inputting data and saving sources
0.0	Only included H1 Net Income - Common Shareholders before. Added preferred shareholder im
0.0	Updating OPG Income Tax Expense with info from OPG Monthly Presentation to Shareholder
1.8	Updating OPG GRC payable to OEFC and Proxy Property Tax from Answer back from OPG al
(210.6)	Based on H1 final offering and expected First Nations Sale by the end of 2017 (CY), with a wei
0.0	Based on EY analysis, and then applying fiscalization. Confirmation also received from OPCD.
0.0	Based on KPMG analysis, then fiscalization and other adjustments from OPCD.
-	**[NOT APPLIED, CALCULATIONS AND DATA LEFT ON THE FILE]** Used Brampton's Financ
0.0	Don't expect finalized 2016-17 data to become available in time for ESDI allocation. Will shift th
0.0	make decision on shifting when we know 2016-17 status.

-	No change to numbers. Just re-organizing spreadsheet. No backup data.
-	No change to numbers. Just re-organizing spreadsheet. No backup data.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided another scenario backup/source
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just updated the links to refer ot the delta between 2017 and On Deck
0.0	Adjustment to ESDI to include Hydro One Brampton
0.0	Finalizing 2016-17 DRC Based on Draft OEFC AR
0.0	Received actual PILs amounts from FTD with breakdown of source. Updated 2016-17 numbers
0.0	2016-17 - Non-ONFA Fair Value Adjustment
0.0	Round Hydro One ownership assumptions to 70.05% two decimal places to be consistent with
0.0	Revising Hydro One Amount for consistency with OPCD. Equity Adjustments
0.0	Updated Provision tab. Made two separate Provision amounts for ESDI in OEFC AR and Dedic
0.0	Updating Power Supply Recoveries to Public Accounts/OEFC AR actuals
0.0	Updating Miscellaneous to OEFC AR actuals
0.0	Updated 2016-17 Interest on Debt (IESO, OPG, Other (Net))
0.0	
0.0	2017-18 - Demand Management Support Costs (no change) - Linking correctly
0.0	2016-17 - Updating Operating Expense in OEFC and corresponding changes elsewhere and s
-	No change to numbers. Just re-organized spreadsheet
0.0	Revised H1 Brampton Net Income (for GBE Line only)
0.0	Revising for OPG's Q3 Finances
0.0	Revising OPG's Net Income for latest monthly report
211.1	Reverting ownership back to 70.05% from change 20170518-3. Will coordinate with other area
0.0	Updating Risks based on Hydro One Q2 Results Model
0.0	Updated two Risk components for the Avista Acquisition.
(0.0)	No significant changes, but used actual amortization liability schedule. Hence the rounding imp
0.0	Updating Debt Guarantee for actuals based on OEFC AR
0.0	Revising OPG's Net Income for latest monthly report

0.0	Linking interest revenue data for 2017-18 to 2020-21
0.0	OPG Revenue Risks from: OEB Staff Submission and OPG Updated Filings
5.3	Corrected Net income for 100% ownership in preferred shares and 70.05% in Commons Share
0.0	Updated the formula in the cell for 2017-18 Net Income Before Tax so that the numbers are no
0.0	Updated PILs to include OPCD public accounts adjustment
1.3	
5.0	
(12.2)	
(54.0)	
0.0	
0.0	
0.0	increase built into net income was $82m between NI and PILs
0.0	Remove $21m from PILs
0.0	expense impacts
0.0	expense impacts
0.0	need to also remove the $21m PILs built into OPG net incme
0.0	
0.0	
0.0	We removed $21m from PILs above, before having added it in (check is that lines 123 to 130 a
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
(13.0)	variances include: 2017-18 preferred vs common share fix, 2018-19 largely ROE change from
0.0	
0.0	
0.0	
0.0	
0.0	
21.6	
0.0	
(24.1)	
0.0	
0.0	**Distribution (October)**
(750.0)	
(185.3)	
0.0	
0.0	
(2.3)	

15.2	
0.0	
0.0	
(21.6)	
0.0	
0.0	
0.0	Updating OPG Rate application Revenue Risks based on revised calculations
12.2	
0.0	
(1.0)	Received Revised FTD Forecast
0.3	
0.7	
0.0	
0.0	
(180.7)	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	Removed based on Dec 2017 OEB decision
0.0	Removed based on Dec 2017 OEB decision
0.0	Removed based on Dec 2017 OEB decision
0.0	Removed based on Dec 2017 OEB decision
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(45.2)	
44.2	
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44.2	
190.8	
311.7	
(311.7)	
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M
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Data Validation:

Options
Revenue (F
OPG
Hydro One
Provision

ONFA
Other Data

update once revised numbers are received.

acts

ıpact as well.

bout the BP
ghted average ownership for 2017-18. Also adjusted future net income attributed to the province.

ial Statements to produce an estimate. May require additional calculations.
ıis to 2017-18.

(from 2016 and On Deck)

s to reflect this.

OPCD.

:ated Earnings in Public Accounts.

ources.

s to ensure broadening change and reduction in net income happens concurrently in forecasts.

acts/changes.

es

t hardcoded directly

dd up to -$82m gain that we wanted to remove.

9.09% to 8.78% not previously captured.

Risks)

Electricity Sector Outlook

$ Millions

	Actual 2015-16	Interim 2016-17	Plan 2017-18	2018-19	2019-20	2020-21
On Deck Outlook as of March 2017						
Income from Investment in Government Business Enterprises						
OPG Income[1]	291	304	97	732	625	1,066
OPG - ONFA and other Fair Value Adjustments[2]	172	8	-	-	-	-
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	-
HOI Income[3]	236	516	520	562	603	652
Brampton Income	20	15	-	-	-	-
Total OPG and HOI Income	**719**	**842**	**617**	**1,294**	**1,229**	**1,717**
Other Fees and Licences	**127**	**122**	**102**	**91**	**88**	**81**
Electricity Expenses of the Province						
Provision for Electricity Sector[4]	(3)	(342)	(125)		-	-
Public Debt Interest - Electricity Sector	(520)	(492)	(492)	(492)	(492)	(492)
Subtotal	(523)	(834)	(617)	(492)	(492)	(492)
Public Debt Interest - Impact of ONFA						
Amortization of Deferred Revenue re profit on sale of H1 notes						
Total Electricity Expenses of the Province	**(523)**	**(834)**	**(617)**	**(492)**	**(492)**	**(492)**
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	3,228	373	405	476	538	679
Other Revenue						
Electricity Debt Retirement Charge[5]	859	625	623	-	-	-
Power Supply Contract Recoveries	875	739	292	325	301	273
Net Reduction of Power Purchase Contracts	172	129	74	41	30	28
Other Fees and Licences	(127)	(122)	(102)	(91)	(88)	(81)
Miscellaneous	9	-	-	-	-	-
Expenses						
Interest on Debt	(596)	(532)	(422)	(374)	(342)	(250)
Power Supply Contract Costs	(875)	(739)	(292)	(325)	(301)	(273)
Electricity Consumer Price Protection Fund	-	-	-	-	-	-
Demand Management Support Costs[6]	(8)	(10)	(10)	-	-	-
Provision for Electricity Sector	3	342	125	-	-	-
Other (Finance)	(7)	(6)	(6)	(6)	(6)	(6)
Total OEFC Income	**3,533**	**800**	**687**	**46**	**132**	**370**
Impact on Surplus/(Deficit)	**3,856**	**930**	**789**	**939**	**957**	**1,676**

Notes: The Hydro One net income outlook above (2016-17 to 2020-21) reflects the Province's 70% ownership share after the initial IPO in 2015 and the secondary offering in April 2016. At the time of 2017 Budget, net estimated fiscal impacts from future Hydro One offerings are reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

Notes:

1.OPG's 2016-17 outlook reflected its reported earnings. 2017-18 to 2019-20 reflects OPG's preliminary 2017-2019 business plan (as fiscalized by OPG). 2020-21 estimates are based on OPG's calendar year-based business plan projections. OPG net income also reflects IFRS adjustments fiscal impact decisions that were made centrally.

2. Provincial consolidation adjustments for unrealized earnings on the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds, as of the end of December 2016.

3. Hydro One 2016-17 income reflects its reported net income, adjusted for Hydro One IPO impacts. 2017-18 to 2020-21 projections are based on CEFD projections using the latest public information. The Hydro One net income outlook above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering as of 2017 Budget were reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial ONFA consolidation adjustments, less the interest on the Province's OPG/Hydro One debt payable to OEFC. The provision is currently assumed to end once the DRC ends on a legislated fixed end date of April 1, 2018.

5. Reflects April 23, 2014 announcement that DRC will be eliminated for residential users, after December 31, 2015. The end date of DRC for remaining users is legislated to be on April 1, 2018. Estimates are subject to change based on actual consumption.

6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Electricity Sector Outlook

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
On Deck Outlook as of October 2017						
Income from Investment in Government Business Enterprises						
OPG Income[1]	291	299	149	137	(7)	156
OPG - ONFA and other Fair Value Adjustments[2]	172	43	171	-	-	-
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	-
HOI Income[3]	236	500	329	327	388	419
Brampton Income	20	18	-	-	-	-
Total OPG and HOI Income	**719**	**860**	**650**	**463**	**381**	**575**
Other Fees and Licences (Debt Guarantee fee)	**127**	**122**	**102**	**99**	**98**	**91**
Electricity Expenses of the Province						
Provision for Electricity Sector[4]	-	(290)	(24)	(9)	-	(48)
Public Debt Interest - Electricity Sector	(520)	(514)	(454)	(454)	(454)	(454)
Subtotal	(520)	(803)	(478)	(463)	(454)	(502)
Public Debt Interest - Impact of ONFA						
Amortization of Deferred Revenue re profit on sale of H1 notes						
Total Electricity Expenses of the Province	**(520)**	**(803)**	**(478)**	**(463)**	**(454)**	**(502)**
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	3,247	334	377	452	503	635
Other Revenue						
Electricity Debt Retirement Charge[5]	859	621	623	-	-	-
Power Supply Contract Recoveries	875	838	182	183	134	103
Net Reduction of Power Purchase Contracts	172	129	74	41	30	28
Other Fees and Licences	(127)	(122)	(102)	(99)	(98)	(91)
Miscellaneous	9	14	-	-	-	-
Expenses						
Interest on Debt	(596)	(513)	(475)	(438)	(411)	(348)
Power Supply Contract Costs	(875)	(838)	(182)	(183)	(134)	(103)
Electricity Consumer Price Protection Fund	-	-	-	-	-	-
Demand Management Support Costs[6]	(8)	(8)	(10)	-	-	-
Provision for Electricity Sector	-	290	24	9	-	48
Other (Finance)	(7)	(7)	(6)	(7)	(7)	(7)
Total OEFC Income	**3,549**	**737**	**506**	**(42)**	**17**	**265**
Impact on Surplus/(Deficit)	**3,876**	**915**	**779**	**57**	**42**	**429**
variance to OEFC check	*(156)*	*(454)*	*(550)*	*(0)*	*(0)*	*-*

Notes:

1.OPG's 2016-17 outlook reflected its reported earnings. 2017-18 reflects OPG's lates monthly update. 2018 to 2019-20 reflects OPG's 2017-2019 business plan (as fiscalized by OPG). 2020-21 estimates are based on OPG's calendar year-based business plan projections. OPG net income also reflect projected IFRS adjustments as provided by OPCD at the time of the 2017 Budget and OEB Dec. 28 rate decision. Note rate decsion impact is alloacted to net income and PILs on a 75%/25% basis respectively.

2. Provincial consolidation adjustments for unrealized earnings on the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds, as of the end of September 2017.

3. Hydro One 2016-17 income reflects its projected net income adjusted for the Province's ownership share in Hydro One following the final offering in May 2017 and including the First Nations sale in December 2017. 2017-18 to 2020-21 projections are based on CEFD projections using the latest public information.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial ONFA consolidation adjustments, minus the interest on debt payable to OEFC. The provision is now assumed to continue after 2017-18. There is currently a PRRT submission to continue ESDI payments to OEFC beyond 2017-18.

5. Reflects that DRC eliminated for residential users, after December 31, 2015. The end date of DRC for remaining users is legislated to be on April 1, 2018. Estimates are subject to change based on actual consumption.

6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Electricity Sector Change Since Budget	$ Millions					
($million)	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Changes from Budget 2017 as of October 2017						
Income from Investment in Government Business Enterprises						
OPG Income	(5)	52	(596)	(632)	(909)	2016-17 small decrease due to IFRS adjustment revision and OPG Net Income revision. 2017-18 due largely to OEB Dec. 28, 2017 rate decision including effective date of June 1, 2017 rather than jan. 1, 2017. Decrease in 2018-19 onward is due mainly to taking on projeceted IFRS adjustment impacts in those years as well as OEB Dec. 28, 2017 rate decision. The OEB Dec. 28, 2017 rate decision estimated impacts are allocated between OPG net income and PILs on a 75%/25% basis.
ONFA and other Fair Value Adjustments	35	171	-	-	-	Largely revision to ONFA fair value as of September 30, 2017
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	
HOI Income	(16)	(190)	(235)	(216)	(233)	2016-17 slight decrease from Budget 2017 Interim projection. 2017-18 onwards reflects i) impact of OEB Sep. 2017 decision on Hydro One transmission rates and ii) interest expense on Avitsa debentures (in 2017-18 and 2018-19).
Brampton Income	3.3					
Total OPG and HOI Income	**17**	**33.0**	**(831)**	**(848)**	**(1,143)**	
Other Fees and Licences	**-**	**-**	**8**	**10**	**10**	
Electricity Expenses of the Province						
Provision for Electricity Sector	53	101	(9)	-	(48)	Changes to the Proviision (ESDI) expense in 2017-18 mainly reflect lower OPG net income due to OEB's Dec. 28, 2017 rate decision and lower Hydro One net income due to OEB's Sep. 2017 transmission rate decision. The projected change in 2019-20 and 2020-21 is due to the continuation of ESDI beyond 2017-18 (approved in principle in the current PRRT). In the 2017 Budget outlook, ESDI was assumed to end after 2017-18. ESDI estimates for 2018-19 and 2018-19 are reduced due to negative balances in 2017-18 and 2018-19,
Public Debt Interest - Electricity Sector	(22)	38	38	38	38	2016-17 PDI at ($514m) was slightly larger than ($492m) projected at Interim. 2017-18 change reflects revised projections for Provincial debt interest related to HydroOne's April 2016 offering. Note the impact of the final offering will be refelected in PDI during 2018.
Total Electricity Expenses of the Province	**31**	**138**	**29**	**38**	**(10)**	

Electricity Sector Change Since Budget	$ Millions					
($million)	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs)	(40)	(28)	(24)	(35)	(43)	2016-17 decrease largely due to an OPCD Public Accounts PILs adjustment related to reconciling between OPCD and OEFC net opening assets. OPG PILs also slightly lower than projected.
Other Revenue						
Electricity Debt Retirement Charge	(4)	-	-	-	-	
Power Supply Contract Recoveries	99	(110)	(142)	(167)	(170)	Variance is largely due to retroactive payments that the OEFC made to certain non-utility-generators (NUGs) with former Ontario Hydro power purchase agreement contracts with OEFC. OEFC was required to make these payment following the dismissal by the Supreme Court of Canada of OEFC's application for leave to appeal a judgment of the Court of Appeal of Ontario on a 2015 court decision.
Net Reduction of Power Purchase Contracts	0.1	(0)	(0)	(0)	(0)	
Other Fees and Licences	-	-	(8)	(10)	(10)	
Revenue Pool Residual	-	-	-		-	
Miscellaneous	14	-	-	-	-	
Expenses						
Interest on Debt	19	(53)	(64)	(69)	(98)	2017-18 reflects revised debt interest outlook net of revisions to OEFC interest revenue from OPG and Province.
Power Supply Contract Costs	(99)	110	142	167	170	Same as Power supply contract recoveries above. Power supply contract costs are fully recovered by power supply contract recoveries.
Electricity Consumer Price Protection Fund	-	-	-	-	-	
Demand Management Support Costs	1.8	-	-	-	-	
Provision for Electricity Sector	(53)	(101)	9	-	48	see explanation above for "Provision for Electriocty Sector" (line 17)
Other (Finance)	(1.0)	-	(1)	(1)	(1)	
Total OEFC Income	**(63)**	**(181)**	**(88)**	**(115)**	**(105)**	
Impact on Surplus/(Deficit)	**(14.6)**	**(10)**	**(882)**	**(914)**	**(1,247)**	
Information: Breakdown of change between revenue and expense						
Total Revenue Impact	87	(105)	(997)	(1,049)	(1,356)	
Total Expenditure impact	101	(95)	(115)	(135)	(109)	

Electricity Sector Outlook (PSAB)

Negative Revenue Risks	$ Millions			
($ millions)	**Plan**			
	2017-18	**2018-19**	**2019-20**	**2020-21**
Generic				
OPG Generation Risk: Nuclear Reliability (-1.6 TWh)[1]	(120)	(120)	(120)	(120)
1% decrease in Hydro One actual load[2]	(57)	(59)	(62)	(63)
Lower OPG's Equity weighting & Return on Equity (ROE)[3]	(12)	(20)	(26)	(45)
Lower Hydro One Return on Equity (ROE)[4]	(9)	(36)	(38)	(40)
Regulatory				
Hydro One Distribution rate application[5]	(50)	(50)	(50)	(50)
OPG Switch from accrual based to cash based accounting for pension and OPEB[6]	—	TBD	TBD	TBD
Regulatory Risk - Timing of OPG Rate Decision[7]	—			
OEB Staff Recommendations wrt OPG rate application(May 2017)[8]	—			
Nuclear Liabilities Cash vs. Accrual[9]	—			
OEB decision on Hydro One tax recapture (if one-time write-down)[10]	(440)			
Accounting				
OPG IFRS Consolidation Risks[11]		—	—	—
Other Risks				
ONFA adjustment decrease[12]	(50)			
Avista Acquisition - Termination fee		(49)		

Note: These risks do not reflect the impacts on electricity sector revenue and expense of reclassification of the Asset Optimizat

1. OPG's market and generation risks related to nuclear reliability similar to the scenarios OPG developed for its sales margins to capture major market risk factors (e.g., natural gas prices, coal prices, foreign exchange, nuclear reliability) in its 2012 business plan. Currently, only the nuclear reliability risk is captured at the current regulated rate for OPG's nuclear generation.

2. Estimated revenue impact if Hydro One load for Transmission and Distribution is 1% lower than projected for all years in CEFD Hydro One Forecast. Based on the assumption a 1% increase in load is directly proportional to a 1% change in revenue requirements.

3. Risk range for Hydro One transmission and distribution reflects potential risk of lower ROE by 0.5% vs assumed ROEs in business plan along with reduced deemed debt to equity weighting of 55%/45% from the current 51%/49%.

4. Risk range for Hydro One transmission and distribution reflects potential risk of lower ROE by 0.5% vs assumed ROEs in CEFD Hydro One Forecast based on the most recent rate applications and forecasted ROE rates.

5. OEB is expected to make a decision on Hydro One's Distibution rate application for 2018 during the first half of 2018.

6. Previous risk removed from 2017-18. OEB September 2017 Report, established accrual accounting method as default rate setting method to recover Pension and Other Pension Benefits (OPEBs) costs and recommended continuance of variance account tracking the difference between cash vs. accrual basis reporting for Pension and OPEB. OEB December 28, OPG rate decision instructs OPG to submit request to dispose of Pension and OPEB deferral and variance account balances during 2018 for its 2019 payment application.

7. **Previous risk removed with timing impact now reflected in OPG outlook.**. OEB December 28, decision and order provides an effective date for new rates of June 1, 2017. OPG's business plan assumed OEB decision would be effective as of January 1, 2017. OPG estimated an impact of -$60M for each month for which OEB decsion is not retroactive. The resulting $300M estimated impact has been included in the OPG outlook.

8. **Previous risk removed .** Estimated impact of OEB December 28the decision and order with respect to OPG rates is now reflected on the OPG Outlook.

9. **Previous risk removed.** Risk is related to potential switch to cash-basis accounting for regulated recovery of nuclear payment anmounts. OEB December 28, 2017 Decision and Order has deferred this issue to next OPG rate application in 2021 for 2022 to 2027 period.

10. The OEB's Sep. 28, 2017 ruling on Hydro One's Transmission rate application included direction on sharing, with ratepayers, tax savings related to the Hydro One IPO. Hydro One filed a Motion to Review this decision with the OEB and has also filed a court appeal. Hydro One's 2017 Q3 financial report notes that if the Motion to Review and appeal are unsuccesful teh company would record a one-time write-down of $885 million reflecting the OEB decision. The risk above reflects this risk at teh Province's 49.9% average share allocation for 2017-18. Hydro One noted that timing for the Motion to Review and appeal is uncertain. It expects the OEB Review to start in Q1 but noted that it could run in to Q2.

11. **Previous risk removed.** OPCD provided IFRS impact estimates (largely related to OPG) at the time of Budget 2017. A portion of these were reflected in in OPG's and Hydro One's net income outlook at the time of the 2017. The current Electricity Outlook now reflects this additional IFRS risk. Table below outlines OPG IFRS Risks versus what is built into the 2017 Budget Fiscal Plan.

	2017-18	**2018-19**	**2019-20**	**2020-21**
OPG IFRS Risk	(400)	(475)	(700)	(750)
Risks Built into Fiscal Plan at 2017 Budget	(400)	0	(200)	0
Additional Risks now picked up in this Electricity Outlook	0	(475)	(500)	(750)

Electricity Sector Outlook (PSAB)

Positive Revenue Risks				
($ millions)	**Plan**			
	2017-18	**2018-19**	**2019-20**	**2020-21**
Generic				
OPG Generation Risk: Nuclear Reliability (+1.1 TWh)[1]	85	85	85	85
1% increase in Hydro One actual load[2]	57	59	61	63
Higher OPG Return on Equity (ROE)[3]	6	22	19	33
Higher Hydro One Return on Equity (ROE)[4]	19	69	50	50
Regulatory				
Accounting				
Other Risks				
ONFA adjustment increase[5]	50			

ion strategy or updates to AO strategy.

1. OPG's market and generation risks related to nuclear reliability similar to the scenarios OPG developed for its sales margins to capture major market risk factors (e.g., natural gas prices, coal prices, foreign exchange, nuclear reliability) in its 2012 business plan. Currently, only the nuclear reliability risk is captured at the current regulated rate for OPG's nuclear generation.

2. Estimated revenue impact if Hydro One load for Transmission and Distribution is 1% higher than projected for all years in CEFD Hydro One Forecast. Based on the assumption a 1% increase in load is directly proportional to a 1% change in revenue requirements.

3. Risk range for OPG reflects potential risk of higher ROE in 2018-2021 (for nuclear base) vs assumed ROE in OPG's 2016 business plan and corresponding rate application. Assumed ROE is 9.85%, respresenting recent in 2010.

4. Risk range for Hydro One transmission and distribution reflects potential risk of higher ROE vs assumed ROEs in the Hydro One CEFD Forecast for 2018-2021. Assumed ROE is 9.85%, representing recent high in 2010.

5. Reflects risk around the consolidation adjustment to OPG net income, whereby the realized portion of gains or losses of OPG's nuclear funds are added or subtracted from OPG net income. Currently $171M positive adjustment is included in the OPG outlook. The ONFA adjustment is expected to be finalized in February 2018.

ONTARIO ELECTRICITY FINANCIAL CORPORATION
On Deck Outlook as of March 2017

$ Millions

	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Revenue						
Revenue Pool Residual						
Debt Retirement Charge	859	625	623	-	-	-
Payments-in-lieu of tax:						
OPG	268	302	315	366	408	537
Legacy Hydro One (Including Brampton)	2,929	7	2	2	2	2
Hydro One CIT dedicated to OEFC	3	20	20	22	23	25
MEUs	27	44	68	86	105	114
Total PILs & CIT dedicated to OEFC[1]	3,228	373	405	476	538	679
Interest :						
OPG	173	179	168	153	135	135
H1						
IESO	2	3	3	3	3	3
Province	520	492	492	492	492	492
Other	28	10	5	5	5	5
Total Interest	723	684	668	653	635	635
Power Supply Contract Recoveries	875	739	292	325	301	273
Amortization of NUG liability	172	129	74	41	30	28
Electricity sector dedicated income	3	342	525	-	-	-
Gain to OEFC under s. 50.3	172	-	-	-	-	-
Miscellaneous	9	-	-	-	-	-
	6,041	2,893	2,587	1,495	1,504	1,615
Expense						
Debt interest	1,319	1,216	1,090	1,027	977	885
Interest on nuclear risk funding						
Demand Management Support Costs	8	10	10	-	-	-
Amortization of deferred debt costs	-	-	-			
Power Supply Contract Costs	875	739	292	325	301	273
Debt Guarantee fee	127	122	102	91	88	81
Operating	7	6	6	6	6	6
	2,336	2,093	1,500	1,449	1,372	1,245
Excess (Deficiency) of Revenue over Expense	**3,705**	**800**	**1,087**	**46**	**132**	**370**
Prior period adjustment	87					
Stranded Debt - Year End	**4,393**	**3,593**	**2,506**	**2,460**	**2,328**	**1,958**

Note: All the Hydro One ownership broadening impacts, other than the ownership change from the initial IPO in 2015 and the secondary offering in April 2016, were reflected in Sales and Rentals as of the 2017 Budget.

ONTARIO ELECTRICITY FINANCIAL CORPORATION
On Deck Outlook as of October 2017

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Revenue						
Revenue Pool Residual						
Debt Retirement Charge	859	621	623	0	0	0
Payments-in-lieu of tax:						
OPG	268	224	287	342	373	494
Legacy Hydro One (Including Brampton)	2,929	4	2	2	2	2
Hydro One CIT dedicated to OEFC	3	25	20	22	23	25
MEUs	27	112	68	86	105	114
Total PILs & CIT dedicated to OEFC[1]	3,228	364	377	452	503	635
Interest :						
OPG	173	167	169	179	175	148
H1						
IESO	2	2	3	3	3	3
Province	520	514	454	454	454	454
Other	28	20	20	20	10	10
Total Interest	723	703	646	656	642	615
Power Supply Contract Recoveries	875	838	182	183	134	103
Amortization of NUG liability	172	129	74	41	30	28
Electricity sector dedicated income	3	302	24	9	0	48
Gain to OEFC under s. 50.3[2]	172	411	550	0	0	0
Miscellaneous	9	14	0	0	0	0
	6,041	3,382	2,477	1,340	1,309	1,429
Expense						
Debt interest	1,319	1,216	1,121	1,094	1,053	963
Interest on nuclear risk funding						
Demand Management Support Costs	8	8	10	0	0	0
Amortization of deferred debt costs	0	0	0			
Power Supply Contract Costs	875	838	182	183	134	103
Debt Guarantee fee	127	122	102	99	98	91
Operating	7	7	6	7	7	7
	2,336	2,191	1,421	1,383	1,292	1,164
Excess (Deficiency) of Revenue over Expense	3,705	**1,191**	**1,056**	**(42)**	**17**	**265**
Prior period adjustment	87					
Stranded Debt - Year End	4,393	**3,202**	**2,146**	**2,189**	**2,172**	**1,906**

1

Payments-in-lieu of tax:	**2015-16 Public Accounts**
OPG	290
Legacy Hydro One (Including Brampton)	2,941
Hydro One CIT dedicated to OEFC	0
MEUs	15
	3,247

2 2017-18 value preliminary estimate, subject to change.

ONTARIO ELECTRICITY FINANCIAL CORPORATION

Changes from Budget 2017 as of October 2017 **$ Millions**

	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Revenue						
Debt Retirement Charge	(4)	-	-	-	-	
Payments-in-lieu of tax:						
OPG	(78)	(28)	(24)	(35)	(43)	2016-17 decrease largely due to reconciling between OPCD and OEFC net opening assets. OPG PILs also slightly lower than projected. 2017-18 and onward decrease is due to estimated impact of OEB Dec. 29=8, 2017 rate decision.
Legacy Hydro One (Including Brampton)	(3)	-	-	-	-	
Hydro One CIT dedicated to OEFC	5	-	-	-	-	Adjustment based on updated information in Hydro One rate application
MEUs	68	-	-	-	-	Large increase in 2016-17 from $80M payment during transfer of H01 Brampton to new consolidated MEU Alectra.
Total PILs	(9)	(28)	(24)	(35)	(43)	
Interest :						
OPG	(12)	1	26	40	13	Update to OPG interest outlook (wrt interest on OEFC loan).
H1	-	-	-	-	-	
IESO	(1)	-	-	-	-	
Province	22	(38)	(38)	(38)	(38)	2016-17 PDI at ($514m) was slightly larger than ($492m) projected at Interim. 2017-18 change reflects revised projections for Provincial debt interest related to Hydro equity.
Other	10	15	15	5	5	
Total Interest	19	(22)	3	7	(20)	
Power Supply Contract Recoveries	99	(110)	(142)	(167)	(170)	Variance is largely due to retroactive payments that the OEFC made to certain non-utility-generators (NUGs) with former Ontario Hydro power purchase agreement contracts with OEFC. OEFC was required to make these payment following the dismissal by the Supreme Court of Canada of OEFC's application for leave to appeal a judgment of the Court of Appeal of Ontario on a 2015 court decision.
Amortization of NUG liability	0	(0)	(0)	(0)	(0)	
Electricity sector dedicated income	(41)	(501)	9	-	48	The decrease in OEFC ESDI in 2017-18 reflects i) the IFRS adjustment of $400 million in 2017-18 that was not reflected in the OEFC ESDI projection at the time of the 2017 Budget (Note the IFRS adjustment was reflected in OPG net income for the 2017 Budget fiscal plan) and ii) the lower OPG and Hydro One net income due to OEB's 2017 rate decisions. The projected change in 2019-20 and 2020-21 is due to the continuation of ESDI beyond 2017-18 (approved in principle in the current PRRT). In the 2017 Budget outlook, ESDI was assumed to end after 2017-18. ESDI estimates for 2018-19 and 2018-19 are reduced due to negative balances in 2017-18 and 2018-19,
Gain to OEFC under s. 50.3	411	550	-	-	-	
Miscellaneous	14	-	-	-	-	
	489	(111)	(155)	(195)	(186)	
Expense						
Debt interest	-	31	67	76	78	Revised outlook for OEFC debt interest outlook
Interest on nuclear risk funding	-	-	-	-	-	
Demand Management Support Costs	(2)	-	-	-	-	
Amortization of deferred debt costs	-	-	-	-	-	
Power Supply Contract Costs	99	(110)	(142)	(167)	(170)	Same as Power supply contract recoveries above. Power supply contract costs are fully recovered by power supply contract recoveries.
Debt Guarantee fee	-	-	8	10	10	
Operating	1	-	1	1	1	
	98	(79)	(66)	(80)	(81)	
Excess (Deficiency) of Revenue over Expense	**391**	**(31)**	**(88)**			
Stranded Debt - Year End	**3,202**	**2,146**	**2,189**	**2,172**	**1,906**	

Provision for Electricity Sector (Dedicated Electricity Earnings/Electricity Sector Dedicated Earnings)

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Income from Investment in Government Business Enterprises						
OPG Income	291	299	149	137	(7)	156
Hydro One Income[1]	232	501	329	327	388	419
Hydro One Brampton (if applied separately)		15				
Total Income	**523**	**815**	**478**	**463**	**381**	**575**
Public Debt Interest - Electricity Sector						
OPG			(300)	(300)	(300)	(300)
Hydro One[1]			(154)	(154)	(154)	(154)
Public Debt Interest - Electricity Sector (OEFC Interest revenue)	**(520)**	**(514)**	**(454)**	**(454)**	**(454)**	**(454)**
MOF Provision Expense (before adjustments)	**3**	**302**	**24**	**9**	**(73)**	**121**
Other Adjustments						
Prior-year Adjustment[2]		3				
Exclude Brampton[3]		(15)				
MOF Provision Expense (after other adjustments)	**0**	**290**	**24**	**9**	**(73)**	**121**
Cumulative Shortfall Adjustment						
Opening Balance	0	0	0	0	0	(73)
Deduction / (Addition)	0	0	0	0	(73)	73
Ending Balance	0	0	0	0	(73)	0
Dedicated Electricity Earnings (all adjustments) (Public Accounts)	**0**	**290**	**24**	**9**	**0**	**48**
Electricity Sector Dedicated Income (OEFC Annual Report)	**3**	**302**	**24**	**9**	**0**	**48**

Notes:

1. The Hydro One financials above currently reflects the Provincial share allocation as the May 2017 final offering.

2. 2016-17 Adjustment was due to the discrepancy between the numbers in MOF expense in PA 2015-16 and OEFC Financials in 2015-16 due to timing issues. $3M adjustment rectifies this discrepancy

3. Brampton was excluded from the Ministry of Finance's ESDI allocation.

Ontario Power Generation

OPG Income - Budget 2017

$ Millions

	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
OPG Net Income After Tax (Adjusted)	291	304	97	732	625	1,066
OPG Net Income After Tax	*291*	*379*	*480*	*678*	*726*	*913*
Extraordinary Gains	-	-	-	-	-	-
GA - OPG Trust Interest Revenue			*17*	*54*	*99*	*153*
OPG IFRS consolidation risk picked up in Fiscal Plan		(75)	(400)		(200)	
ONFA and other Fair Value Adjustments	(75)	8				
ONFA Adjustments	-	8				
Other Fair Value Adjustments	(75)					

OPG PIL - Budget 2017

$ Millions

	Actual	Interim		Pl
	2015-16	2016-17	2017-18	2018-19
Net Income Before Tax	383	396	572	867
Net Income After Tax (Adjusted)	291	304	97	732
Income Taxes	92	92	92	135
GRC: Payable to OEFC	198	196	205	212
Proxy Property Tax	16	14	18	19
Ontario Capital Tax	0	0	0	0
Total	**306**	**302**	**315**	**366**

OPG Income - January 2018

$ Millions

	Actual	Actual	Current Outlook			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
OPG Net Income	291	377	857	678	726	913
Adjustment for OPG HQ gain on sale[1]			(283)			
Unpacking updated OPG Gain on sale (net income)			283.27			
OEB December 28, 2017 Rate Decision Impact[2]			(320)	(109)	(115)	(136)
Extraordinary Gains	0	0	0	0	0	0
GA Financing - OPG Trust Interest Revenue[3]			12	42	82	128
OPG IFRS consolidation risk reflected in Fiscal Plan[4]		(78.00)	(400)		(200)	
Update IFRS Risk			0	(475)	(500)	(750)
OPG Net Income (Adjusted before ONFA)	**291**	**299**	**149**	**137**	**(7)**	**156**
ONFA Adjustments	247	49	171			
Other Fair Value Adjustments	(75)	(6)				
ONFA and other Fair Value Adjustments	**172**	**43**	**171**			
OPG Net Income	**463**	**342**	**320**	**137**	**(7)**	**156**

OPG PIL - January 2018

$ Millions

	Actual	Actual		Current
	2015-16	2016-17	2017-18	2018-19
Income Before Tax	383	308	723	235
OPG Net Income (Adjusted before ONFA)	291	299	149	137
OPG Income Tax (PILs)	92	9	162	135
OEB December 28, 2017 Rate Decision Impact[2]			(107)	(36)
Tax adjustment for OPG HQ gain on sale[1]			(95)	
Unpack PILs related to HQ gain on sale			95	
GRC: Payable to OEFC	198	201	214	224
Proxy Property Tax to OEFC	16	14	18	19
Ontario Capital Tax	0	0	0	0
Total OPG PILs	**306**	**224**	**287**	**342**

1. OPG's May 2017 head office facilities sale impacts are re-categorized from Sales and Rentals to OPG net income and PILs in the current Electricity Outlook update.
2. OEB December 28, 2017 estimated rate decision impacts are split between net income and PILs and a 75%/25% basis.
3. This reflects interest earnings on GA financing costs which are consolidated back to Province
4. See Risks tab for IFRS impacts that were not reflected in Fiscal Plan, and table below.

	2017-18	2018-19	2019-20	2020-21
OPG IFRS Risk	(400)	(475)	(700)	(750)

Hydro One Ownership Calculation:		SOURCE:
Total number of shares outstanding[1]	595,000,000	1. Hydro One Ltd Annual Report 2015, pg 94 of PDF, pg 92 of the Report.
Additional Common Shares Issued since IPO	386,711	
IPO November 2015		
Initial Public Offering(2015)[2]	81,100,000	2. From news release: http://hydroone.mediaroom.com/2015-11-05-Hydro-One-Limited-Announces-Closing-of-IPO
Over allotment option (2015)[3]	8,150,000	3. From news release: http://hydroone.mediaroom.com/2015-11-12-Hydro-One-Limited-Announces-Closing-of-IPO-Over-Allotment-Option
Sales to PWU/SEP Trusts	5,646,340	
Total	94,896,340	
Province's remaining ownership, Nov 2015 (# Shares)	**500,103,660**	
Province's remaining ownership, Nov 2015 (%)	**84.05%**	
Secondary Offering April 2016		
Secondary Offering (2016)	72,434,800	4. Hydro One Ltd. Q2 Report, pg 1 http://www.hydroone.com/InvestorRelations/FinancialReporting/Documents/Hydro%20One%20Ltd%20Second%20Quarter%20
Over allotment option (2016)	10,865,200	
Total	83,300,000	
Province's remaining ownership, Apr 2016 (# Shares)	**416,803,660**	
Province's remaining ownership, Apr 2016 (%)	**70.05%**	
Final Offering May 2017		
Final Offering (2017)	120,000,000	Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by-the-Provin
Over allotment option (2017)	-	Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by-the-Provin
Total	120,000,000	
Province's remaining ownership, May 8, 2017 (# Shares)	296,803,660	Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by-the-Provin
Province's remaining ownership, May 8, 2017 (%)	**49.88%**	
First Nations Sale, closed on December 29, 2017	14,391,012	Source: http://www.S:\Users\CEF\Hydro 2018\OEFC\RbP\Outlook\01. January\Backup\20180103-0 - H1 First Nations Sales\
	2.4170865%	Source: https://news.ontario.ca/mei/en/2017/05/ontario-raises-28-billion-from-final-hydro-one-share-offering.html
Province's remaining onwership - post First Nations Sale (#Shares)	282,412,648	
Province's remaining onwership - post First Nations Sale (%)	**47.43%**	
Avista Impact (projected closing date 2nd half of 2018)		
Contingent Convertible Debenture	$1,540,000,000	
Conversion Price	$21	
Potential Dilution (# Shares)	71,962,617	
Revised Total number of shares outstanding	**666,962,617**	
Province's remaining onwership - post Avista Acquisition (#Shares)	282,412,648	
Province's remaining onwership - post Avista Aquisition (%)	**42.34%**	

Ownership Percentage in 2017-18 Fiscal Year	Number of Months	Percentage of Year
70.05%	1	8.3%
49.88%	8	66.7%
47.43%	3	25.0%
	12	
Average 2017-18 FY Ownership:	**51.0%**	

Ownership Percentage in 2018-19 Fiscal Year (assume Avista closing end of September 2018)	Number of Months	Percentage of Year
47.43%	6	50.0%
42.34%	6	50.0%
	12	
Average 2018-19 FY Ownership:	**44.9%**	

Ownership Percentage in 2019-20 Fiscal Year Onwards
42.34%

Accretive to earnings per share and cash flow for Hydro One in the first full year post closing
above is from Hydro One transaction overview. Check what this means for timing of additional shares and /or earnings.

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Hydro One Net Income and PILs

Hydro One Income - Budget 2017
($ millions)

	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Hydro One Net Income After Tax	685	737	742	802	862	931
Hydro One - Unrealized Gains Adjustment						

2016-17 to 2020-21 from CEFD Hydro One 2016 model.

Hydro One PIL - Budget 2017
($ millions)

	2015-16	2016-17	2017-18	2018-19
Net Income After Tax	685	737	742	802
Income Taxes PILs	132	160	181	205
Proxy Property Tax	2	2	2	2
Ontario Capital Tax	0	0	0	0
Total	**134**	**162**	**183**	**207**

Hydro One Income - December 2017
($ millions) **$ Millions**

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Hydro One Net Income After Tax			645	690	780	845
Debenture Costs Impacts (After Tax)			(34)	(39)		
Hydro One Net Income After Tax - Including Adjustments	670	680	612	651	780	845
Hydro One - Net Income Attributable to Preferred Shareholders	15	18				
Hydro One - Unrealized Gains Adjustment						

Hydro One (100% Ownership)
($ millions) **$ Millions**

	Actual 2015-16	Actual 2016-17	2017-18	Current 2018-19
Net Income After Tax - Common Shares	670	680	612	651
Net Income After Tax - Preferred Shares	15	18		
Income Taxes PILs	132	160	181	205
Proxy Property Tax	2	2	2	2
Ontario Capital Tax	0	0	0	0

Public Debt Interest and Section 50.3 payments

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Hydro One Public Debt Interest and Section 50.3 payments						
Government Annual Interest Costs - Hydro One	220	220	220	220	220	220
Reduction in Interest Costs due to Broadening[1]		(29)	(66)	(66)	(66)	(66)
Province Annual Interest Costs - Hydro One Debt	**220**	**191**	**154**	**154**	**154**	**154**
Province Annual Interest Cost - OPG Debt	300	300	300	300	300	300
Total Public Debt Interest	**520**	**514**	**454**	**454**	**454**	**454**

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Gain to OEFC under s. 50.3	172	411	550	0	0	0

1. The Hydro One reduction in interest costs above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering are currently reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

ID# (Track Cha	Fiscal Year	alue (Hardcode	Value (Linked)	Description	Source Details	Source (Link)
20170501-2	2016-17	411,152,733	411,152,733	s 50.3 Gain for	Calculation provided by SIFB	
20170501-3	2016-17	29	29	Reduction in Int	Internal Calculation	
20170501-3	2017-18	66	66	Reduction in Int	Internal Calculation	
20170501-3	n/a	220	220	Annual Interest	Internal Calculation	

ID# (Track Cha	Fiscal Year	alue (Hardcode	Value (Linked)	Description	Source Details	Source (Link)
n/a	n/a	5126		($M) Provinces	OEFC 1999-2000 FS, pg 24	
n/a	n/a	5.85%		Annual Interest	OEFC 1999-2000 FS, pg 26	
		299.871				

OPG's Annual Interest Costs: 300

20170713-1	2016-17	-513,768,361	Provincial interest cost for equity investment in OPG, H1 in 2016-17 Monthly Balances Sheet (from FTD) S:\Users\CEF\Hydro 2017\OEFC\RbP\Outlook\07. July\Backup\20170713-1\interest fr

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PROVINCIAL CONSOLIDATION ADJUSTMENTS
Ontario Nuclear Funds Agreement

Adjustment for Change in OPG Reported Net Income

Adjustment for DSF Unrealized Earnings

Unrealized Earnings as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Bruce Variance Account Adjustment
OPG Net Income Adjustment

Adjustment for UFSF Unrealized Earnings

Unrealized Earnings as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Bruce Variance Account Adjustment
OPG Net Income Adjustment

Unrealized Earnings -- Fiscal YTD

Adjustment for Change in Due to Province

Adjustment for DSF Due to Province
Due to Province (cost basis) as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Change in Due to Province -- Fiscal YTD

Adjustment for UFSF Due to Province

Due to Province (cost basis) as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Change in Due to Province -- Fiscal YTD

Provincial Consolidation Adjustment

Other Data

	Actual 2016-17	2017-18
Debt Retirement Charge	621	0

	2016-17	2017-18
Power Supply Contract Recoveries	838	182

	2016-17	2017-18
Interest		
OPG	167	169
IESO	2	3
Other (Net)	20	20
Expense		
Debt interest	1216	1121

	Actual 2016-17	2017-18
MEU - PIL Income Tax	109.8	
MEU - PIL Property Tax	0.6	
MEU - GRC	1.2	
TOTAL MEU PILs	111.6	

	Actual 2016-17	2017-18
Miscellaneous/Other (OEFC FS)	14	
Demand Management Support Costs (IEI)	8	10
Operating [Expense]	7	6
Interest on nuclear risk funding	-	-
Amortization of deferred debt costs	-	-
Amortization of NUG liability	129	74
Debt Guarantee Fee	122	102

Expense (Electrictiy Summary Tab)		
Other (Finance)	-7	-6
Demand Management Support Costs (IEI)	-8	-10
Debt Guarantee Fee	(122)	(102)

Plan		
2018-19	2019-20	2020-21
0	0	0

Plan		
2018-19	2019-20	2020-21
183	134	103

Plan		
2018-19	2019-20	2020-21
179	175	148
3	3	3
20	10	10
1094	1053	963

Plan		
2018-19	2019-20	2020-21

Plan		
2018-19	2019-20	2020-21
7	7	7
-	-	-
-	-	-
41	30	28
99	98	91
-7	-7	-7
(99)	(98)	(91)

ID# (Track Changes	Fiscal Year	Value (Hardcoded)	Value (Linked)
20170510-2	2016-17	$ 739,216,115	
20170510-2	2017-18	$ 291,629,707	
20170510-2	2018-19	$ 324,906,017	
20170510-2	2019-20	$ 300,648,570	
20170510-2	2020-21	$ 273,240,858	
20170501-4	2016-17	179	179
20170501-4	2017-18	169	169
20170501-4	2018-19	179	179
20170501-4	2019-20	175	175
20170501-4	2020-21	148	148
20170501-5	2016-17	1216	1,216
20170501-5	2017-18	1121	1,121
20170501-5	2018-19	1094	1,094
20170501-5	2019-20	1053	1,053
20170501-5	2020-21	963	963
20170731-3	2016-17	621	
20170811-1	2016-17	109.8	
20170811-1	2016-17	0.6	
20170811-1	2016-17	1.2	
20170815-5	2016-17	$ 838,000,000	
20170815-6	2016-17	$ 14,000,000	
20170815-8	2016-17	8	
20170815-9	2017-18	10	
20170815-10	2016-17	7	
20171211-2	2017-18	6	6
20171211-2	2018-19	7	7
20171211-2	2019-20	7	7
20171211-2	2020-21	7	7
20170815-7	2016-17	167	
20170815-7	2016-17	2	
20170815-7	2016-17	20	
20170815-7			

ID# (Track Changes	Fiscal Year	Value (Hardcoded)	Value (Linked)
20170905-1	2016-17	129	129
20170905-1	2017-18	74	74

20170905-1	2018-19	41	41
20170905-1	2019-20	30	30
20170905-1	2020-21	28	28
20170905-2	2016-17	122	
20170906-1	2017-18	3	3
20170906-1	2018-19	3	3
20170906-1	2019-20	3	3
20170906-1	2020-21	3	3
20170906-1	2017-18	20	5
20170906-1	2018-19	20	5
20170906-1	2019-20	10	5
20170906-1	2020-21	10	5
20171211-0	2017-18	1121	1,121
20171211-0	2018-19	1094	1,094
20171211-0	2019-20	1053	1,053
20171211-0	2020-21	963	963
20171211-1	2017-18	102	102
20171211-1	2018-19	99	99
20171211-1	2019-20	98	98
20171211-1	2020-21	91	91
20171211-1			
20171211-1			
20171211-1			
20171211-1			
20171211-1			
20171211-1			
20171211-1			
20171211-1			
20171211-1			

ID# (Track Changes	Fiscal Year	Value (Hardcoded)	Value (Linked)
20180104-2	2017-18	$ 181,776,685	
20180104-2	2018-19	$ 182,785,215	
20180104-2	2019-20	$ 133,962,519	
20180104-2	2020-21	$ 102,554,665	

Description	Source Details	Source (Link)
The table below contains an updated preliminary N	SPFB Estimates, Email	
• The tables below provides both last year's submission for NUG costs by CEFD and this year's estimates (both of which exclude HST) based on the most recent NUG model.	SPFB Estimates, BN SPFB Estimates, BN SPFB Estimates, BN SPFB Estimates, BN	
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
Updating DRC from OEFC AR (Drafts)	2017 OEFC DRAFT FS	S:\Users\CEF\Hydro 2017\OEFC'
MEU - PIL Income Tax	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
MEU - PIL Property Tax	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
MEU - GRC	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
Updating to actuals	2017 OEFC AR	2017 OEFC Annual Report - Eng
Updating to actuals	2017 OEFC AR	2017 OEFC Annual Report - Eng
Updating to Actuals	2017 OEFC AR	S:\Users\CEF\Hydro 2017\OEFC'
OEFC 2017-18 IEI/Demand Management Suppor	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Operating Expense - Updating to Actuals	2017 OEFC AR	S:\Users\CEF\Hydro 2017\OEFC'
Revised Operating Expense from FTD Forecast	FTD - October PRRT	
OPG Interest Revenue - Actuals 2016-17	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
IESO Interest Revenue - Actuals 2016-17		
Other (Net) Interest Revenue - Actuals 2016-17		

Description	Source Details	Source (Link)
		S:\Users\CEF\Hydro 2017\OEFC'
	Amortization Schedule.	S:\Users\CEF\Hydro 2017\OEFC'

Sourcing the NUG liability amortization schedule.	Tab: Summary Fiscal Impact	S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Gurantee Fee - Updating to Actuals	2017 OEFC AR (pg 13 (	\\ofina.on.ca\ofadfs\Users\CEF\H
IESO Interest Revenue Plan	OEFC Revenue Forecast for Board - April 2017	\\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H
Other Interest Revenue Plan		\\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H
OEFC Debt Interest Expense (no change, just re-linking)	FTD - October PRRT	S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Guarantee Fee	FTD - October PRRT	S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC'

Description	Source Details	Source (Link)
Updated FY 2017-18 estimates of NUG costs	SPFB Estimates, BN	Power Purchases and Sales Fore
Updated FY 2017-18 estimates of NUG costs	SPFB Estimates, BN	Power Purchases and Sales Fore
Updated FY 2017-18 estimates of NUG costs	SPFB Estimates, BN	Power Purchases and Sales Fore
Updated FY 2017-18 estimates of NUG costs	SPFB Estimates, BN	Power Purchases and Sales Fore

\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board

\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board

\RbP\Outlook\07. July\Backup\20170731-3 - DRC Update\2017 OEFC Annual Report - English - DRAFT.PDF

\RbP\Outlook\08. August\Backup\20170811-1 - Updating PILs for 2016-17\OEFC 2016-17 Pils summary.pdf
\RbP\Outlook\08. August\Backup\20170811-1 - Updating PILs for 2016-17\OEFC 2016-17 Pils summary.pdf
\RbP\Outlook\08. August\Backup\20170811-1 - Updating PILs for 2016-17\OEFC 2016-17 Pils summary.pdf

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\RbP\Outlook\08. August\Backup\20170815-8 - 2016-17 Demand Management Support Costs (IEI)\2017 OEFC
\RbP\Outlook\08. August\Backup\20170815-9 - 2017-18 Demand Management Support Costs (IEI)\OEFC rever
\RbP\Outlook\08. August\Backup\20170815-10 - 2016-17 Operating (Expense)\2017 OEFC Annual Report - Enc

\RbP\Outlook\08. August\Backup\20170815-7 - 2016-17 Updated Interest on Debt Revenue\RE Revised OEFC

\RbP\Outlook\09. September\Backup\20170905-1 - Amortization of NUG Liability\NUG liability_estimated draw c
\RbP\Outlook\09. September\Backup\20170905-1 - Amortization of NUG Liability\NUG liability_estimated draw c

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\RbP\Outlook\09. September\Backup\20170905-1 - Amortization of NUG Liability\NUG liability_estimated draw c

ydro 2017\OEFC\RbP\Outlook\09. September\Backup\20170905-2 - 2016-17 Debt Guarantee Fee\2017 OEFC
ydro 2017\OEFC\RbP\Outlook\09. September\Backup\20170906-1 - OEFC Revenue Forecast for Board
ydro 2017\OEFC\RbP\Outlook\09. September\Backup\20170906-1 - OEFC Revenue Forecast for Board
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\RbP\Outlook\12. December\Backup\20171211-1 - Interest Numbers from FTD\OEFC forecast PRRT planning_
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Colour Codes

Formulas are in black text

Hard coded numbers are in blue text

References elsewhere are in purple

Green bold text with or without highlights mean updates required

Policies to follow when making updates to the Outlook

*** To quickly jump to the source numbers for a link, press "**Ctrl + [**"

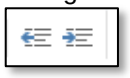
All new numbers must be fully sourced, and follow the colour codes above

Most numbers and text are Arial Size 10, unless it is a title

Add back up materials in a folder with the same numbers as in the 'Track Changes' tab

If there is a reason for italics, or other colours, or formatting make sure it is clear. Othe

Use indents to make things more clear to read



If numbers are taken from another tab they should ONLY be direct links, no calculation

Electricity Summary - (Budget17/On Deck) - Reflects Public Accounts/Financial Statem

OEFC - (Budget17/On Deck) - Reflects OEFC Annual Reports

*Due to slight discrepancies between Public Accounts reporting and OEFC Annual Rep

Outlook Updates Frequency

Frequency	Description	Tab
Monthly	OPG Net Income in-year forecast	OPG
Monthly	OPG PILs in-year forecast	OPG
Quarterly	ONFA Consolidation Adjustment	ONFA
Quarterly	OPG Cash vs Accrual Variance Account	Revenue (Risks)

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rwise expect it to be cleared

ı, adjustment should be done. Even if its just making a negative to a positive. Perform all the calculations on the

ıents

ɔorts, the numbers may not be identical

source tab then bring the number into the next tab. (Eg. Formulas like this become hard to troubleshoot ='Hydro

One'!AR29+'Hydro One'!AR31+'Hydro One'!AR32), let's avoid them.

	2017-18	2018-19	2019-20	2020-21
OPG net income	283	-	-	-
OPG PILs	95	-	-	-
Hydro One net income	(117)	(147)	(176)	(191)
Total	261	(147)	(176)	(191)

From: Bruno Amara
To: Ronald Kwan
Cc: John Kim
Subject: Electricity Outlook Update
Date: Thursday, February 15, 2018 6:39:28 PM
Attachments: Electricity Sector Outlook (2018 02 15)_v5.xlsm

Hi Ron

Please see attached our updated Electricity Sector Outlook.

This includes

- OPG 2018-2021 Business plan updates including the inclusion now of the proceeds in 2017-18 from Lakeview properties.
- Hydro One has also been updated to reflect year-end results for Hydro One. In particular 2017-18 is driven mainly by quarterly actual (the 2018 quarter is model projection. 2018-19 onward are also model projections.
- The outlook also incorporates the latest figures from SIFB wrt s. 50.3 and the debt OEF H1 debt paydown related to last May 2017 disposition.
- We also have updated IOD numbers from FTD today
- SPFB indicated they will updated power purchase/recovery outlook early next week.

We have added an additional year to the Outlook, 2021-22.

On risk table we added possible PILs transfer to municipalities. Note that this outlook has SD defeased as of 2021-22.

I have added a temporary worksheet showing the changes since the last Outlook distribution in January. The main changes related to OPG, particularly the 2017-18 increase only partly explained by inclusion of Lakeview. Note that the OPG business plan noted that 2017-18 included a $325 hit related to the later effective date. That is consistent with our estimate.

Thanks
Bruno

Bruno Amara
Sr. Manager, Financial and Regulatory Analysis
Electricity Finance Branch
Corporate and Electricity Finance Division
Ontario Financing Authority

Tel: 416-325-1489
Email: bruno.amara@ofina.on.ca

Electricity Sector Outlook
February 2018

Disclosure:

All information contained in this workbook is confidential and commercially sensitive

All projected numbers are estimates and subjected to change

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Please consult with OFA before sharing of information.

Commercially Sensitive and Confidential Advice to Cabinet for Consideration of Options for Discussion Purposes Only

Commercially Sensitive and Confidential Advice to Cabinet for Consideration of Options for Discussion Purposes Only

Electricity Sector Outlook
Including Line Items for Consolidation

Electricity Summary - On Deck

February 2018

			MOF Expense Items (consolidated)	**Current Outlook**			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**38**	Power Supply Contract Costs	(182)	(183)	(134)	(103)
Expense	**MOF (OEFC)**	**40**	Demand Management Support Costs	(10)	-	-	-
Expense	**MOF (OEFC)**	**41**	Provision for Electricity Sector	697	349	511	386
Expense	**MOF**	**17**	Provision for Electricity Sector	(697)	(349)	(511)	(386)
Expense	**MOF (OEFC)**	**42**	Other (Finance)	(6)	(7)	(7)	(7)
			Total MOF Expense	**(198)**	**(190)**	**(141)**	**(110)**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**7**	OPG Income	805	400	503	352
Revenue	**ENE**	**8**	OPG - ONFA and other Fair Value Adjustments	194	-	-	-
Revenue	**ENE**	**10**	HOI Income	346	353	412	438
Revenue		**11**	Brampton Income	-	-	-	-
Revenue	**MOF (OEFC)**	**26**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	530	387	531	535
Revenue	**MOF (OEFC)**	**29**	Electricity Debt Retirement Charge	623	-	-	-
Revenue	**MOF (OEFC)**	**30**	Power Supply Contract Recoveries	182	183	134	103
Revenue	**MOF (OEFC)**	**31**	Net Reduction of Power Purchase Contracts	74	41	30	28
Revenue	**MOF (OEFC)**	**34**	Miscellaneous	-	-	-	-
			Total MOF Revenue	**2,754**	**1,363**	**1,610**	**1,456**
			OFA IOD Expense				
			Public Debt Interest - Electricity Sector	(454)	(404)	(404)	(404)
			Interest on Debt	(472)	(468)	(473)	(402)
			Total OFA IOD Expense	**(926)**	**(872)**	**(877)**	**(806)**
			Impact on Surplus/Deficit	**1,631**	**302**	**592**	**540**
			check	-	-	-	-

Electricity Summary - Budget 17

For Discussion			MOF Expense Items (consolidated)	Plan			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**38**	Power Supply Contract Costs	(292)	(325)	(301)	(273)
Expense	**MOF (OEFC)**	**40**	Demand Management Support Costs	(10)	0	0	0
Expense	**MOF (OEFC)**	**41**	Provision for Electricity Sector	125	0	0	0
Expense	**MOF**	**17**	Provision for Electricity Sector	(125)	0	0	0
Expense	**MOF (OEFC)**	**42**	Other (Finance)	(6)	(6)	(6)	(6)
			Total MOF Expense	**(308)**	**(331)**	**(307)**	**(279)**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**7**	OPG Income	97	732	625	1,066
Revenue	**ENE**	**8**	OPG - ONFA and other Fair Value Adjustments	0	0	0	0
Revenue	**ENE**	**10**	HOI Income	520	562	603	652
			Brampton Income				
Revenue	**MOF (OEFC)**	**25**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	405	476	538	679
Revenue	**MOF (OEFC)**	**29**	Electricity Debt Retirement Charge	623	0	0	0
Revenue	**MOF (OEFC)**	**30**	Power Supply Contract Recoveries	292	325	301	273
Revenue	**MOF (OEFC)**	**31**	Net Reduction of Power Purchase Contracts	74	41	30	28
Revenue	**MOF (OEFC)**	**34**	Miscellaneous	0	0	0	0
			Total MOF Revenue	**2,011**	**2,136**	**2,098**	**2,697**
			OFA IOD Expense				
		17	Public Debt Interest - Electricity Sector	(492)	(492)	(492)	(492)
		36	Interest on Debt	(422)	(374)	(342)	(250)
			Total OFA IOD Expense	**(914)**	**(866)**	**(834)**	**(742)**
			Impact on Surplus/Deficit	**789**	**939**	**957**	**1,676**
			check	**-**	**-**	**-**	**-**

Electricity Summary - Change

			MOF Expense Items (consolidated)	Variance from Plan			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**69**	Power Supply Contract Costs	110	142	167	170
Expense	**MOF (OEFC)**	**71**	Demand Management Support Costs	0	0	0	0
Expense	**MOF (OEFC)**	**72**	Provision for Electricity Sector	572	349	511	386
Expense	**MOF**	**48**	Provision for Electricity Sector	(572)	(349)	(511)	(386)
Expense	**MOF (OEFC)**	**73**	Other (Finance)	0	(1)	(1)	(1)
			Total MOF Expense	**110**	**141**	**166**	**169**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**38**	OPG Income	708	(332)	(122)	(714)
Revenue	**ENE**	**39**	OPG - ONFA and other Fair Value Adjustments	194	0	0	0
Revenue	**ENE**	**41**	HOI Income	(173)	(209)	(191)	(214)
			Brampton Income	0	0	0	0
Revenue	**MOF (OEFC)**	**25**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	125	(89)	(7)	(143)
Revenue	**MOF (OEFC)**	**60**	Electricity Debt Retirement Charge	0	0	0	0
Revenue	**MOF (OEFC)**	**61**	Power Supply Contract Recoveries	(110)	(142)	(167)	(170)
Revenue	**MOF (OEFC)**	**62**	Net Reduction of Power Purchase Contracts	(0)	(0)	(0)	(0)
Revenue	**MOF (OEFC)**	**65**	Miscellaneous	0	0	0	0
			Total MOF Revenue	**743**	**(772)**	**(487)**	**(1,241)**
			OFA IOD Expense				
		17	Public Debt Interest - Electricity Sector	38	88	88	88
		36	Interest on Debt	(50)	(94)	(131)	(152)
			Total OFA IOD Expense	**(12)**	**(6)**	**(43)**	**(64)**
			Impact on Surplus/Deficit	**841**	**(637)**	**(364)**	**(1,136)**
			check	*-*	*-*	*-*	*-*

Track Changes in Surplus/Deficit

Date	Change ID#	Source	Tab
5/1/2017	20170501-1	Link	ONFA
5/1/2017	20170501-2	Link	Hydro One
5/1/2017	20170501-3	Link	Hydro One
5/1/2017	20170501-4	Link	Other Data
5/2/2017	20170502-1	Link	OPG
5/9/2017	20170509-1	Link	OPG
5/10/2017	20170510-1	Link	Hydro One
5/10/2017	20170510-2	Link	Other Data
5/12/2017	20170512-1	Link	Hydro One
5/15/2017	20170515-1	Link?	
5/15/2017	20170515-2	Link	OPG
5/17/2017	20170517-1	Link	Hydro One
5/17/2017	20170517-2	Link	ONFA
5/17/2017	20170517-3		
5/18/2017	20170518-1	Link	OPG
5/18/2017	20170518-2	Link	OPG
5/18/2017	20170518-3		
6/15/2017	20170615-1	Link	OPG
6/22/2017	20170622-1	Link	Hydro One
6/22/2017	20170622-2	Link	Hydro One
6/26/2017	20170626-1		
6/29/2017	20170629-1		

7/6/2017	20170706-1		
7/11/2017	20170711-1		
7/13/2017	20170713-1	Link	Provision
7/17/2017	20170717-1	Link	Revenue (Risks)
7/24/2017	20170724-1	Link	Revenue (Risks)
7/25/2017	20170725-1	Link	Revenue (Risks)
7/26/2017	20170726-1	Link	Revenue (Risks)
7/27/2017	20170727-1	Link	Revenue (Risks)
7/27/2017	20170727-2	Link	Revenue (Risks)
7/31/2017	20170731-1		
7/31/2017	20170731-2	Link	Hydro One
7/31/2017	20170731-3	Link	Other Data
8/11/2017	20170811-1	Link	OPG
8/15/2017	20170815-1		
8/15/2017	20170815-2		
8/15/2017	20170815-3		
8/15/2017	20170815-4		
8/15/2017	20170815-5		Other Data
8/15/2017	20170815-6		Other Data
8/15/2017	20170815-7		Other Data
8/15/2017	20170815-8		Other Data
8/15/2017	20170815-9		Other Data
8/15/2017	20170815-10		Other Data
8/17/2017	20170817-1	Link	Provision
8/17/2017	20170817-2	Link	Hydro One
8/18/2017	20170818-1	Link	Revenue (Risks)
8/22/2017	20170822-1	Link	OPG
8/25/2017	20170825-1		Hydro One
8/29/2017	20170829-1		Revenue (Risks)
8/31/2017	20170831-1		Revenue (Risks)
9/5/2017	20170905-1		Other Data
9/5/2017	20170905-2		Other Data
9/5/2017	20170905-3	Link	OPG

9/6/2017	20170906-1	Link	Other Data
9/6/2017	20170906-2	Link	Revenue (Risks)
9/8/2017	20170908-1	Link	Hydro One
9/8/2017	20170908-2	Link	OPG
9/11/2017			
9/12/2017			
9/13/2017			
9/21/2017			
9/22/2017			
10/2/2017			Hydro One
10/2/2017			
10/2/2017			
10/2/2017			
10/4/2017	20171004-1		OPG
10/4/2017	20171004-2		OPG
10/4/2017			
10/4/2017			
10/5/2017			
10/6/2017			
10/7/2017			
10/8/2017			
10/10/2017	20171010-1		Hydro One
10/10/2017			
10/10/2017			
10/11/2017	20171011-1		OPG
10/11/2017			
10/11/2017			
10/12/2017			OPG
10/12/2017			
10/12/2017			
10/12/2017			
10/18/2017	20171018-1		Hydro One
10/18/2017	20171018-1		Hydro One
10/18/2017	20171018-1		Hydro One
10/19/2017	20171019-1		Revenue (Risks)
10/19/2017	20171019-2		Revenue (Risks)
10/20/2017	20171020-1		Revenue (Risks)
10/20/2017	20171020-2		
10/20/2017	20171020-2		
10/20/2017	20171020-2		
10/20/2017	20171020-3		Revenue (Risks)
10/20/2017	20171020-4		OPG
10/20/2017	20171020-4		OPG
10/20/2017	20171020-4		OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017	20171114-1		Hydro One

11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017		Hydro One
11/14/2017		Hydro One
11/14/2017		Hydro One
11/30/2017	20171130-1	Revenue (Risks)
12/8/2017		Hydro One
12/11/2017	20171211-1	Other Data
12/11/2017	20171211-1	Other Data
12/22/2017	20171222-1	OPG
1/2/2018		Hydro One
1/2/2018		Hydro One
1/2/2018		Hydro One
1/2/2018	20180102-1	OPG
1/2/2018	20180102-1	OPG
1/2/2018	20180102-1	OPG
1/2/2018	20180102-2	OPG
1/2/2018	20180102-3	OPG
1/2/2018	20180102-3	Revenue (Risks)
1/2/2018	20180102-4	Revenue (Risks)
1/2/2018	20180102-5	Revenue (Risks)
1/2/2018	20180102-6	Revenue (Risks)
1/2/2018	20180102-7	Revenue (Risks)
1/2/2018	20180102-8	Revenue (Risks)
1/2/2018	20180102-9	OPG
1/2/2018	20180102-9	OPG
1/2/2018	20180102-9	OPG
1/2/2018	20180102-9	OPG
1/3/2018		OPG
1/3/2018		OPG
1/3/2018		OPG
1/3/2018		OPG
1/3/2018		Hydro One
1/3/2018		Hydro One
1/3/2018		Hydro One
1/4/2018	20180104-1	OPG
1/4/2018	20180104-1	OPG
1/4/2018	20180104-1	OPG
1/4/2018	20180104-1	OPG
1/4/2018	20180104-2	Other Data
1/4/2018	20180104-2	Other Data
1/5/2018		
1/5/2018		
1/5/2018		
1/5/2018		
1/5/2018		
1/5/2018		
1/5/2018		
1/8/2018		
1/8/2018		
1/8/2018		

1/16/2018		Other Data
1/23/2018		OPG
2/2/2018	20180202-1	OPG
		OPG
		OPG
	20180202-1	OPG
	20180202-1	OPG
	20180202-1	OPG
	20180202-1	OPG
		OPG
		OPG
		OPG
		OPG
		OPG
		OPG
2/13/2018		
2/13/2018		
2/13/2018		
2/13/2018		
2/13/2018		
2/13/2018		
2/15/2018	20180215-1	Hydro One
2/15/2018		
2/15/2018		

FOR EFB USE ONLY

Budget 2017 Outlook
Current Outlook
Change Since Budget

Description of Update
ONFA Update as of March 31 2017
s. 50.3 Update for 2016-17
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Debt Interest
OPG IFRS Risk in 2019-20
Revised OPG 2016-17 Net Income
Revised OPG 2016-17 Net Income
Revised OPG 2016-17 Net Income
tech change: slight update to assumed Prov share 70.05% from 70%
tech change: slight update to assumed Prov share 70.05% from 70%
tech change: slight update to assumed Prov share 70.05% from 70%
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
Updating H1 2016-17 Net Income for ESDI
Updating H1 2016-17 Net Income for ESDI
Updating H1 2016-17 Net Income for ESDI
Power Purchase Supply
H1 Model Forecasts - No Fiscal Update Resaving Data
Update Budget 2017 Tabs to reflect fiscal plan
Update OPG forecasted PILS to reflect sources
Update H1 2016-17 CIT
Re-inputting ONFA updates
Updating H1 Net Income to include Pref Shares in 16-17
Updating OPG Income Tax Expense for 2016-17
Updating OPG non-income tax PILs
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2017
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2018
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2019
Updating with actual OPG IFRS Adjustment 2016-17
Updating with actual OPG IFRS Adjustment 2016-17
Updating with actual OPG IFRS Adjustment 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
[NOT APPLIED] Updating H1 Brampton (Interim Adjustments)
Shifted H1 Brampton 2016-17 NI to the 2017-18
Removed H1 Brampton for 2016-17 (pending finals)
Removed H1 Brampton for 2016-17 (pending finals)
Removed H1 Brampton for 2016-17 (pending finals)

add prior-year adjustment for 2016-17

add prior-year adjustment for 2016-18
Reconfigured calculation of ESDI and MOF ESDI Expense
Reconfigured calculation of OPG 2017-18 Net Income
Backup for the Provincial Interest cost
Linking source for Revenue Risks Tab
New source for Revenue Risks Tab
Revenue Risks Tab - ROE Risks
Updating OEB Risk for OPG
OEB Staff Report - H1 Tx - Revenue Risks
OPG Pensions - Cash vs Accrual Deferral Accounts
Updating Links in Electricity Summary Change and OEFC Change
Preliminary estimate for Hydro One Brampton
Preliminary estimate for Hydro One Brampton
Preliminary estimate for Hydro One Brampton

Updating DRC for Actuals 2016-17 (Based on draft FS)
Updating PILs for 2016-17 Baced on Actuals
OPG: Non-ONFA Fair Value Adjustment
Round all Hydro One ownership assumptions to two decimal places
H1 Equity Adjustment rounding.
Round all Hydro One ownership assumptions to two decimal places
Round all Hydro One ownership assumptions to two decimal places
Revising source of ESDI, Dedicated Electricity Earnings
2016-17 - Update Power Supply Recoveries to actuals
2016-17 - Update Power Supply Recoveries to actuals
2016-17 - Updating Miscellaneous OEFC Revenue to Actuals
Adj: Exclude Bramton $15m add prior year adjustment +$3M
Adj: Exclude Bramton $15m add prior year adjustment +$3M
Public Accts: Updated IESO debt interest Interest On Debt, 2016-17
Public Accts: 2016-17 - Demand Management Support Costs Update
2017-18 - Demand Management Support Costs (no change)
Public Accts: 2016-17 - Updating Operating Expense in OEFC
Sourcing Provision for Electricity Sector from Actual Public Accounts
Revised 2016-17 Brampton Amount for Public Accounts
OPG Pensions - Cash vs Accrual Deferral Accounts (Revenue Risks Tab)
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
Reclassification
Reclassification
Reverting H1 Ownership change (undoing 20170518-3)
Reverting H1 Ownership change (undoing 20170518-3)
Reverting H1 Ownership change (undoing 20170518-3)
Updating Risks based on Hydro One Q2 Results Model
Avista Acquisition Risks
NUG Amortization Liability (sourcing amortization schedule)
2016-17 Actuals - Debt Guarantee Fee
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results

Interest Revenue for IESO and "Other"
OPG Revenue Risks from OEB Filings
Net income corrected for Preferred Shares
Net income corrected for Preferred Shares
Net income corrected for Preferred Shares
Made link edits to OPG sheet so that the "Net Income Before Tax" 2017-18 number is not a hardc
Updated PILs to include OPCD public accounts adjustment
Provision tab fix to pick up Hydro One preferred share net income
Provision tab fix to pick up Hydro One preferred share net income
FTD Update to OEFC Outlook (Sep 19, 2017) OPG Interest
FTD Update to OEFC Outlook (Sep 19, 2017) Other Interest
Update to Hydro One PILs from information in Transmission rate application material
OEB September 28, 2017 Hydro One decision and order impact - incl. rebasing
OEB September 28, 2017 Hydro One decision and order impact - incl. rebasing
OEB September 28, 2017 Hydro One decision and order impact - incl. rebasing
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Debenture Interest Costs - Removing from Revenue (Risks) and adding it ot H1 Model
Debenture Interest Costs - Removing from Revenue (Risks) and adding it ot H1 Model
Debenture Interest Costs - Removing from Revenue (Risks) and adding it ot H1 Model
Updated OPG Net Income and PILs based on monthly report (August 2017 results)
Updated OPG Net Income and PILs based on monthly report (August 2017 results)
Updated OPG Net Income and PILs based on monthly report (August 2017 results)
Correction to PILs on OPG sheet
Correction to PILs on OPG sheet
Correction to PILs on OPG sheet
Correction to PILs on OPG sheet
Switch to Direct from Model
Switch to Direct from Model
Switch to Direct from Model
Updating ROE Risks
Updating H1 Load Risks based on model output
Updating ONFA Risks for September 2017
Adjust OEB decision/rebasing to ~50% provincial ownership
Adjust OEB decision/rebasing to ~50% provincial ownership
Adjust OEB decision/rebasing to ~50% provincial ownership
Updating OPG
OPG IOD impact from GA Financing, FHP
OPG IOD impact from GA Financing, FHP
OPG IOD impact from GA Financing, FHP
Unpacking updated OPG Gain on sale (net income)
Unpacking updated OPG Gain on sale (net income)
Unpacking updated OPG Gain on sale (net income)
Unpack PILs related to HQ gain on sale
Updating IFRS Risk
Adjustment for lower Provincial share (from 70.1% to 50.9 2017-18 & 47.4% after)
Adjustment for lower Provincial share (from 70.1% to 50.9 2017-18 & 47.4% after)
Adjustment for lower Provincial share (from 70.1% to 50.9 2017-18 & 47.4% after)
November 1 and November 7 Hydro One model updates

November 1 and November 7 Hydro One model updates
November 1 and November 7 Hydro One model updates
Revise Hydro Model to reverse OEB tax decision ongoing annual impact
Revise Hydro Model to reverse OEB tax decision ongoing annual impact
Revise Hydro Model to reverse OEB tax decision ongoing annual impact
Undo allocation adjustment in H1 tab (now that provincial shares are updated)
Undo allocation adjustment in H1 tab (now that provincial shares are updated)
Undo allocation adjustment in H1 tab (now that provincial shares are updated)
Updating OPG Revenue Risks from rate application
Update Hydro One PILs (reverses update on line 119 whuich did not account fro Dx side)
Updating Debt Guarantee Fee
Updating OEFC Operating Expense
small changes - linking the net income numbers

Updated number of shares sold for First Nations (Dec 2017) sale
Updated number of shares sold for First Nations (Dec 2017) sale
Updated number of shares sold for First Nations (Dec 2017) sale
Implemented OEB's Dec 2017 payment amounts decision for OPG (CEFD Analysis)
Implemented OEB's Dec 2017 payment amounts decision for OPG (CEFD Analysis)
Implemented OEB's Dec 2017 payment amounts decision for OPG (CEFD Analysis)
Updated OPG Net Income (based on their Q3 update, Sep 30, 2017)
Updated OPG ONFA adjustment (up to Sep 30, 2017) in OPG tab (removed it from Risks table)
Removal of OPG ONFA Sep 2017 adjustment in Risks table
Included possible range (-50M to 50M) of impact for future OPG ONFA adjustment in the negative
Removal of negative regulatory risk: "OPG Switch from accrual based to cash based accounting f
Removal of negative regulatory risk: "Timing of OPG Rate Decision" from Risks table
Removal of negative regulatory risk: "OEB Staff Recommendations wrt OPG rate application(May
Removal of negative regulatory risk: "Nuclear Liabilities Cash vs. Accrual" from Risks table
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month
Updated estimates of NUG costs.
Updated estimates of NUG costs.
Unpacking OPG (Head Office sale)
Unpacking OPG (Head Office sale)
Unpacking OPG (Head Office sale)
Unpacking OPG (Head Office sale)
Unpacking Hydro One for AO (from 70.1% ownership to as of January 2018)
Unpacking Hydro One for AO (from 70.1% ownership to as of January 2018)
Unpacking Hydro One for AO (from 70.1% ownership to as of January 2018)
Update H1 allocations for additional shares (SIFB edits)
Update H1 allocations for additional shares (SIFB edits)
Update H1 allocations for additional shares (SIFB edits)

Updated (latest IOD) Debt Interest Expense line (OEFC on-deck tab) and OPG, IESO, and Other ONFA consolidation adjustment for Dec 2017

OPG 2018-2021 BP preliminary net income update
OPG 2018-2021 BP preliminary net income update
OPG 2018-2021 BP preliminary net income update
OPG 2018-2021 BP preliminary Income Tax PILs
OPG 2018-2021 BP preliminary GRC payable to OEFC update
OPG 2018-21 BP preliminary Property Tax Payable to OEFC update
Removal of net income from estimated gain from Lakeview sale, as it has not been realized yet
Removal of PILs from estimated gain from Lakeview sale, as it has not been realized yet
Removal of net income from estimated gain from Lakeview sale, as it has not been realized yet
Removal of net income from estimated gain from Lakeview sale, as it has not been realized yet
Remove EFB OEB impact estimate
Remove EFB OEB impact estimate
Remove EFB OEB impact estimate
Update with Board-approved net income
Update with Board-approved net income
Update with Board-approved net income
Remove reversal of Lakeview proceeds on net income (now included)
Remove reversal of Lakeview proceeds on net income (now included)
Remove reversal of Lakeview proceeds on net income (now included)
Remove reversal of Lakeview proceeds on PILs (now included)
Update with Board-approved PILs
Update OPG Fair Hydro Plan amounts from OPG Busdiness Plan 2018-2021
Update OPG Fair Hydro Plan amounts from OPG Busdiness Plan 2018-2022
Update OPG Fair Hydro Plan amounts from OPG Busdiness Plan 2018-2023
Remove Hydro One Debenture Cost from Outlook (now in Model)
Remove Hydro One Debenture Cost from Outlook (now in Model)
Remove Hydro One Debenture Cost from Outlook (now in Model)
Annual Report 2017 Hydro One Net Income Updates
Annual Report 2017 Hydro One Net Income Updates
Annual Report 2017 Hydro One Net Income Updates
Adjustment from using quarterly actuals
Adjustment from using quarterly actuals
Adjustment from using quarterly actuals
Updating Hydro One debt interest Costs
Updating Hydro One debt interest Costs
February 15, 2018 FTD Update\

This line show net impact of latest change. READ COMMENT

$ Millions

		2016-17	2017-18	2018-19	2019-20
		930	789	939	957
	File	915	1,631	302	592
		-15	841	-637	-364
	check	*0*	*0*	*0*	*0*
		Impacts by FY →			
Outlook line affected	**Expense / Reve**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
ONFA and other Fair Value Adjustments	Revenue	41.0	0.0	0.0	0.0
N/A		0.0	0.0	0.0	0.0
?		0.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		38.1		
Provision for Electricity Sector (MOF)	Expense		(38.1)		
Public Debt Interest - Electricity Sector	Expense	0.0	38.1	38.1	38.1
Interest on Debt	Expense	0.0	(69.1)	(79.1)	(75.1)
OPG Income	Expense	0.0	0.0	0.0	
OPG Income	Revenue	(2.0)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**(2.0)**			
Provision for Electricity Sector (MOF)	Expense	2.0			
HOI Income	Revenue	0.4			
Provision for Electricity Sector (OEFC)	Expense	0.4			
Provision for Electricity Sector (MOF)	Expense	(0.4)			
Public Debt Interest - Electricity Sector	Expense	1.7			
Provision for Electricity Sector (OEFC)	Expense	(1.7)			
Provision for Electricity Sector (MOF)	Expense	1.7			
Interest on Debt	Expense	(1.7)			
HOI Income	Revenue	(39.8)	0.0	0.0	(0.0)
Provision for Electricity Sector (OEFC)	Expense	**(39.8)**			
Provision for Electricity Sector (MOF)	Expense	39.8			
	Revenue	-	-	-	-
	Revenue	-	-	-	-
	n/a	-	-	-	-
		-	-	-	-
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	4.7	0.0	0.0	0.0
	Revenue	0.0	0.0	0.0	0.0
HOI Income	Revenue	18.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	7.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	8.0	9.0	12.0	3.5
HOI Income	Revenue	0.0	(141.5)	(181.4)	(194.9)
Provision for Electricity Sector (OEFC)	Expense		(141.5)		
Provision for Electricity Sector (MOF)	Expense		141.5		
OPG Income	Revenue	(3.0)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**(3.0)**			
Provision for Electricity Sector (MOF)	Expense	3.0			
HOI Income	Revenue	7.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**7.0**			
Provision for Electricity Sector (MOF)	Expense	(7.0)			
	Revenue	-	-	-	-
	Revenue	0.0	0.0	0.0	0.0
Brampton Income	Revenue	(14.7)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**(14.7)**			
Provision for Electricity Sector (MOF)	Expense	14.7			

Provision for Electricity Sector (OEFC)	Expense		3.2			
Provision for Electricity Sector (MOF)	Expense		(3.2)			
	Revenue	-	-	-	-	
		-	-	-	-	
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
Brampton Income	Revenue		15.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		**15.0**			
Provision for Electricity Sector (MOF)	Expense		(15.0)			
Provision for Electricity Sector (OEFC)	Expense		3.2			
Provision for Electricity Sector (MOF)	Expense		(3.2)			
Electricity Debt Retirement Charge	Revenue		(4.0)	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue		(29.0)	0.0	0.0	0.0
OPG Income	Revenue		(6.0)	0.0	0.0	0.0
HOI Income	Revenue		(0.0)	(0.0)	0.0	0.0
HOI Income	Revenue		(1.7)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense			(0.0)		
Provision for Electricity Sector (MOF)	Expense			0.0		
	Revenue		0.0	0.0	0.0	0.0
Power Supply Contract Recoveries	Revenue		99.0	0.0	0.0	0.0
Power Supply Contract Costs	Expense		(99.0)			
Miscellaneous	Revenue		14.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		(12.0)			
Provision for Electricity Sector (MOF)	Expense		12.0			
Interest on Debt	Expense		(3.0)	0.0	0.0	0.0
Demand Management Support Costs	Expense		1.8	0.0	0.0	0.0
			0.0	0.0	0.0	0.0
Other (Finance)	Expense		(1.0)	0.0	0.0	0.0
	Revenue	-	-	-	-	
Brampton Income	Revenue		3.0	0.0	0.0	0.0
			0.0	0.0	0.0	0.0
OPG Income	Revenue		0.0	85.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue			(6.0)		
Provision for Electricity Sector (OEFC)	Expense			**85.0**		
Provision for Electricity Sector (MOF)	Expense			(85.0)		
OPG Income	Revenue		6.0			
ONFA and other Fair Value Adjustments	Revenue		(6.0)			
HOI Income	Revenue		0.0	141.9	181.8	195.4
Provision for Electricity Sector (OEFC)	Expense			141.9		
Provision for Electricity Sector (MOF)	Expense			(141.9)		
	n/a		0.0	0.0	0.0	0.0
			0.0	0.0	0.0	0.0
Net Reduction of Power Purchase Contracts	Revenue		0.1	(0.1)	(0.1)	(0.1)
	Revenue		0.0	0.0	0.0	0.0
OPG Income	Revenue		0.0	16.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue			(1.0)		
Provision for Electricity Sector (OEFC)	Expense			**16.0**		
Provision for Electricity Sector (MOF)	Expense			(16.0)		

		0.0	0.0	0.0	0.0
	n/a	0.0	0.0	0.0	0.0
HOI Income	Revenue	0.0	5.3	5.3	5.3
Provision for Electricity Sector (OEFC)	Expense		(12.4)		
Provision for Electricity Sector (MOF)	Expense		12.4		
oded formula in the cell	n/a	0.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	(30.4)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		17.8		
Provision for Electricity Sector (MOF)	Expense		(17.8)		
Interest on Debt	Expense	(0.0)	1.0	(0.0)	1.0
Interest on Debt	Expense	0.0	15.0	15.0	5.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	0.0	(7.8)	(8.7)	(10.3)
HOI Income	Revenue	0.0	(47.4)	(54.0)	(54.0)
Provision for Electricity Sector (OEFC)	Expense	0.0	(47.4)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	47.4	0.0	0.0
OPG Income	Revenue	0.0	(61.0)	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	0.0	(21.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	(61.0)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	61.0	0.0	0.0
OPG Income	Revenue	0.0	(21.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	(21.0)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	21.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	0.0	21.0	0.0	0.0
HOI Income	Revenue	0.0	(23.6)	(27.4)	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	(23.6)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	23.6	0.0	0.0
OPG Income	Revenue	0.0	15.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	15.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	(15.0)	0.0	0.0
OPG Income	Revenue	0.0	21.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	0.0	(18.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	21.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	(21.0)	0.0	0.0
HOI Income	Revenue	0.0	(23.8)	(28.9)	(10.1)
Provision for Electricity Sector (OEFC)	Expense	0.0	(23.8)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	23.8	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
HOI Income	Revenue		16.1	26.7	20.6
Provision for Electricity Sector (OEFC)	Expense		16.1		
Provision for Electricity Sector (MOF)	Expense		(16.1)		
n/a	n/a	0.0	0.0	0.0	0.0
OPG Income	Revenue		(4.9)	(11.9)	(17.1)
Provision for Electricity Sector (OEFC)	Expense		(4.9)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		4.9	0.0	0.0
OPG Income	Revenue		283.0		
Provision for Electricity Sector (OEFC)	Expense		283.0		
Provision for Electricity Sector (MOF)	Expense		(283.0)		
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue		95.0		
OPG Income	Revenue		0.0	(475.0)	(500.0)
HOI Income	Revenue		(112.6)	(142.1)	(170.6)
Provision for Electricity Sector (OEFC)	Expense		(112.6)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		112.6	0.0	0.0
HOI Income	Revenue		(3.3)	(3.0)	(0.1)

Provision for Electricity Sector (OEFC)	Expense		(3.3)		
Provision for Electricity Sector (MOF)	Expense		3.3		
HOI Income	Revenue		14.7	14.4	12.9
Provision for Electricity Sector (OEFC)	Expense		14.7	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		(14.7)	0.0	0.0
HOI Income	Revenue		(16.1)	(26.7)	(20.6)
Provision for Electricity Sector (OEFC)	Expense		(16.1)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		16.1	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)		0.0	7.8	8.7	10.3
n/a	n/a	0.0	0.0	0.0	0.0
Other (Finance)			0.0	(1.0)	(1.0)
OPG Income	Revenue		0.0	0.0	0.0
HOI Income	Revenue		0.1	0.5	0.6
Provision for Electricity Sector (OEFC)	Expense		0.1	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		(0.1)	0.0	0.0
OPG Income	Revenue		(477.1)	(145.2)	(153.1)
Provision for Electricity Sector (OEFC)	Expense		(305.7)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		305.7	0.0	0.0
OPG Income	Revenue		39.0	0.0	0.0
OPG - ONFA and other Fair Value Adjustments	Revenue		171.5	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
OPG Income	Revenue		119.3	36.3	38.3
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue		(119.3)	(36.3)	(38.3)
Provision for Electricity Sector (OEFC)	Expense		0.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		0.0	0.0	0.0
OPG Income	Revenue		(283.0)	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue		(95.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		0.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		0.0	0.0	0.0
HOI Income	Revenue		116.8	147.1	176.1
Provision for Electricity Sector (OEFC)	Expense		0.0	0.0	80.3
Provision for Electricity Sector (MOF)	Expense		0.0	0.0	(80.3)
OPG Income	Revenue		37.5	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue		12.5	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		0.0	14.4	23.1
Provision for Electricity Sector (MOF)	Expense		0.0	(14.4)	(23.1)
Power Supply Contract Recoveries	Revenue		(109.9)	(142.1)	(166.7)
Power Supply Contract Costs	Expense		109.9	142.1	166.7
OPG Income	Revenue		283.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue		95.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		141.1	141.9	0.0
Provision for Electricity Sector (MOF)	Expense		(141.1)	(141.9)	0.0
HOI Income	Revenue		(116.8)	(147.1)	(176.1)
Provision for Electricity Sector (OEFC)	Expense		(116.8)	(147.1)	(103.4)
Provision for Electricity Sector (MOF)	Expense		116.8	147.1	103.4
HOI Income	Revenue		(0.0)	(0.2)	(0.2)
Provision for Electricity Sector (OEFC)	Expense		(0.0)	(0.2)	0.0
Provision for Electricity Sector (MOF)	Expense		0.0	0.2	0.0

Interest on Debt	Expense	(2.5)	8.0	(7.0)
OPG - ONFA and other Fair Value Adjustments	Revenue	22.5	0.0	0.0
OPG Income	Revenue	327.0	113.0	325.0
Provision for Electricity Sector (OEFC)	Expense	327.0	113.0	252.0
Provision for Electricity Sector (MOF)	Expense	(327.0)	(113.0)	(252.0)
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	54.0	(77.0)	7.0
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	(8.0)	(15.0)	(10.0)
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	(5.0)	(5.0)	(5.0)
OPG Income	Revenue	(185.0)	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	(65.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	(185.0)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	185.0	0.0	0.0
OPG Income	Revenue	427.1	145.2	153.1
Provision for Electricity Sector (OEFC)	Expense	427.1	145.2	153.1
Provision for Electricity Sector (MOF)	Expense	(427.1)	(145.2)	(153.1)
OPG Income	Revenue	11.0	4.0	2.0
Provision for Electricity Sector (OEFC)	Expense	11.0	4.0	2.0
Provision for Electricity Sector (MOF)	Expense	(11.0)	(4.0)	(2.0)
OPG Income	Revenue	185.0		
Provision for Electricity Sector (OEFC)	Expense	185.0		
Provision for Electricity Sector (MOF)	Expense	(185.0)		
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	65.0		
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	5.0	(4.0)	(2.0)
OPG Income	Revenue	(2.3)	37.5	67.7
Provision for Electricity Sector (OEFC)	Expense	(2.3)	37.5	67.7
Provision for Electricity Sector (MOF)	Expense	2.3	(37.5)	(67.7)
HOI Income	Revenue	17.1	18.6	0.0
Provision for Electricity Sector (OEFC)	Expense	17.1	18.6	0.0
Provision for Electricity Sector (MOF)	Expense	(17.1)	(18.6)	0.0
HOI Income	Revenue	8.4	7.7	24.4
Provision for Electricity Sector (OEFC)	Expense	8.4	7.7	24.4
Provision for Electricity Sector (MOF)	Expense	(8.4)	(7.7)	(24.4)
HOI Income	Revenue	(8.5)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	(8.5)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	8.5	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		50.4	50.4
Provision for Electricity Sector (MOF)	Expense		(50.4)	(50.4)
Interest on Debt	Expense	5.5	12.0	(5.0)
		0	***0***	***0***	***0***

2020-21
1,676
540
-1,136
0

2020-21	Further Explanation of Change and source of data
0.0	Regular quarterly ONFA Update
0.0	Benefit to OEFC under s.50.3: $411M gain, SIFB
0.0	Change to OEFC payment for interest costs of Debt for Equity Swap
38.1	Revised Provincial Debt Interest related to Hydro One Equity
(104.1)	From FTD, revised Debt Interest (net of revisions to Provincial and OPG debt interest)
0.0	Revised numbers from OEP with 2019-20 Risk
0.0	Updated numbers from OPG Q1 2017 FS
0.0	Updating H1 Net Income for actuals. Note does not update Brampton Income at this point. Will
-	No Change to numbers, just re-inputting data and saving sources
-	No Change to numbers, just re-inputting data and saving sources
-	No change to fiscal impact numbers. Deleting Budget 2016 and adding Budget 2017 fiscal imp
-	No Change to numbers, just re-inputting data and saving sources
0.0	Updated with CIT Numbers received from H1 as part of s.91.2 MB20 allocation from MOF
0.0	No Change to numbers, just re-inputting data and saving sources
0.0	Only included H1 Net Income - Common Shareholders before. Added preferred shareholder im
0.0	Updating OPG Income Tax Expense with info from OPG Monthly Presentation to Shareholder
1.8	Updating OPG GRC payable to OEFC and Proxy Property Tax from Answer back from OPG al
(210.6)	Based on H1 final offering and expected First Nations Sale by the end of 2017 (CY), with a wei
0.0	Based on EY analysis, and then applying fiscalization. Confirmation also received from OPCD.
0.0	Based on KPMG analysis, then fiscalization and other adjustments from OPCD.
-	**[NOT APPLIED, CALCULATIONS AND DATA LEFT ON THE FILE]** Used Brampton's Financ
0.0	Don't expect finalized 2016-17 data to become available in time for ESDI allocation. Will shift th
0.0	make decision on shifting when we know 2016-17 status.

-	No change to numbers. Just re-organizing spreadsheet. No backup data.
-	No change to numbers. Just re-organizing spreadsheet. No backup data.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided another scenario backup/source
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just updated the links to refer ot the delta between 2017 and On Deck
0.0	Adjustment to ESDI to include Hydro One Brampton
0.0	Finalizing 2016-17 DRC Based on Draft OEFC AR
0.0	Received actual PILs amounts from FTD with breakdown of source. Updated 2016-17 numbers
0.0	2016-17 - Non-ONFA Fair Value Adjustment
0.0	Round Hydro One ownership assumptions to 70.05% two decimal places to be consistent with
0.0	Revising Hydro One Amount for consistency with OPCD. Equity Adjustments
0.0	Updated Provision tab. Made two separate Provision amounts for ESDI in OEFC AR and Dedic
0.0	Updating Power Supply Recoveries to Public Accounts/OEFC AR actuals
0.0	Updating Miscellaneous to OEFC AR actuals
0.0	Updated 2016-17 Interest on Debt (IESO, OPG, Other (Net))
0.0	
0.0	2017-18 - Demand Management Support Costs (no change) - Linking correctly
0.0	2016-17 - Updating Operating Expense in OEFC and corresponding changes elsewhere and s
-	No change to numbers. Just re-organized spreadsheet
0.0	Revised H1 Brampton Net Income (for GBE Line only)
0.0	Revising for OPG's Q3 Finances
0.0	Revising OPG's Net Income for latest monthly report
211.1	Reverting ownership back to 70.05% from change 20170518-3. Will coordinate with other area
0.0	Updating Risks based on Hydro One Q2 Results Model
0.0	Updated two Risk components for the Avista Acquisition.
(0.0)	No significant changes, but used actual amortization liability schedule. Hence the rounding imp
0.0	Updating Debt Guarantee for actuals based on OEFC AR
0.0	Revising OPG's Net Income for latest monthly report

0.0	Linking interest revenue data for 2017-18 to 2020-21
0.0	OPG Revenue Risks from: OEB Staff Submission and OPG Updated Filings
5.3	Corrected Net income for 100% ownership in preferred shares and 70.05% in Commons Share
0.0	Updated the formula in the cell for 2017-18 Net Income Before Tax so that the numbers are no
0.0	Updated PILs to include OPCD public accounts adjustment
1.3	
5.0	
(12.2)	
(54.0)	
0.0	
0.0	
0.0	increase built into net income was $82m between NI and PILs
0.0	Remove $21m from PILs
0.0	expense impacts
0.0	expense impacts
0.0	need to also remove the $21m PILs built into OPG net incme
0.0	
0.0	
0.0	We removed $21m from PILs above, before having added it in (check is that lines 123 to 130 a
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
(13.0)	variances include: 2017-18 preferred vs common share fix, 2018-19 largely ROE change from
0.0	
0.0	
0.0	
0.0	
0.0	
21.6	
0.0	
(24.1)	
0.0	
0.0	**Distribution (October)**
(750.0)	
(185.3)	
0.0	
0.0	
(2.3)	

15.2	
0.0	
0.0	
(21.6)	
0.0	
0.0	
0.0	Updating OPG Rate application Revenue Risks based on revised calculations
12.2	
0.0	
(1.0)	Received Revised FTD Forecast
0.3	
0.7	
0.0	
0.0	
(180.7)	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	Removed based on Dec 2017 OEB decision
0.0	Removed based on Dec 2017 OEB decision
0.0	Removed based on Dec 2017 OEB decision
0.0	Removed based on Dec 2017 OEB decision
45.2	
(45.2)	
44.2	
(44.2)	
0.0	
0.0	
(44.2)	
44.2	
190.8	
311.7	
(311.7)	
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M
(170.7)	
170.7	
0.0	
0.0	
0.0	
0.0	
(190.8)	
(263.6)	
263.6	
(0.3)	
(0.5)	
0.5	**Distribution (January)**

0.4
0.0

(39.3)
33.7
(33.7)
(127.3)
(10.0)
(6.0)
0.0
0.0
0.0
0.0
180.7
180.7
(180.7)
3.0
3.0
(3.0)

(2.0)
96.5
96.5
(96.5)
0.0
0.0
0.0
19.2
19.2
(19.2)
0.0
0.0
0.0
50.4
(50.4)
(4.4)

0

Data Validation:

Options
Revenue (F
OPG
Hydro One
Provision

ONFA
Other Data

update once revised numbers are received.

acts

ıpact as well.

bout the BP
ghted average ownership for 2017-18. Also adjusted future net income attributed to the province.

ial Statements to produce an estimate. May require additional calculations.
ıis to 2017-18.

(from 2016 and On Deck)

s to reflect this.

OPCD.

:ated Earnings in Public Accounts.

ources.

s to ensure broadening change and reduction in net income happens concurrently in forecasts.

acts/changes.

es

t hardcoded directly

dd up to -$82m gain that we wanted to remove.

9.09% to 8.78% not previously captured.

Risks)

Electricity Sector Outlook

$ Millions

	Actual 2015-16	Interim 2016-17	Plan 2017-18	2018-19	2019-20	2020-21
On Deck Outlook as of March 2017						
Income from Investment in Government Business Enterprises						
OPG Income[1]	291	304	97	732	625	1,066
OPG - ONFA and other Fair Value Adjustments[2]	172	8	-	-	-	-
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	-
HOI Income[3]	236	516	520	562	603	652
Brampton Income	20	15	-	-	-	-
Total OPG and HOI Income	**719**	**842**	**617**	**1,294**	**1,229**	**1,717**
Other Fees and Licences	**127**	**122**	**102**	**91**	**88**	**81**
Electricity Expenses of the Province						
Provision for Electricity Sector[4]	(3)	(342)	(125)		-	-
Public Debt Interest - Electricity Sector	(520)	(492)	(492)	(492)	(492)	(492)
Subtotal	(523)	(834)	(617)	(492)	(492)	(492)
Public Debt Interest - Impact of ONFA						
Amortization of Deferred Revenue re profit on sale of H1 notes						
Total Electricity Expenses of the Province	**(523)**	**(834)**	**(617)**	**(492)**	**(492)**	**(492)**
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	3,228	373	405	476	538	679
Other Revenue						
Electricity Debt Retirement Charge[5]	859	625	623	-	-	-
Power Supply Contract Recoveries	875	739	292	325	301	273
Net Reduction of Power Purchase Contracts	172	129	74	41	30	28
Other Fees and Licences	(127)	(122)	(102)	(91)	(88)	(81)
Miscellaneous	9	-	-	-	-	-
Expenses						
Interest on Debt	(596)	(532)	(422)	(374)	(342)	(250)
Power Supply Contract Costs	(875)	(739)	(292)	(325)	(301)	(273)
Electricity Consumer Price Protection Fund	-	-	-	-	-	-
Demand Management Support Costs[6]	(8)	(10)	(10)	-	-	-
Provision for Electricity Sector	3	342	125	-	-	-
Other (Finance)	(7)	(6)	(6)	(6)	(6)	(6)
Total OEFC Income	**3,533**	**800**	**687**	**46**	**132**	**370**
Impact on Surplus/(Deficit)	**3,856**	**930**	**789**	**939**	**957**	**1,676**

Notes: The Hydro One net income outlook above (2016-17 to 2020-21) reflects the Province's 70% ownership share after the initial IPO in 2015 and the secondary offering in April 2016. At the time of 2017 Budget, net estimated fiscal impacts from future Hydro One offerings are reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

Notes:

1.OPG's 2016-17 outlook reflected its reported earnings. 2017-18 to 2019-20 reflects OPG's preliminary 2017-2019 business plan (as fiscalized by OPG). 2020-21 estimates are based on OPG's calendar year-based business plan projections. OPG net income also reflects IFRS adjustments fiscal impact decisions that were made centrally.

2. Provincial consolidation adjustments for unrealized earnings on the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds, as of the end of December 2016.

3. Hydro One 2016-17 income reflects its reported net income, adjusted for Hydro One IPO impacts. 2017-18 to 2020-21 projections are based on CEFD projections using the latest public information. The Hydro One net income outlook above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering as of 2017 Budget were reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial ONFA consolidation adjustments, less the interest on the Province's OPG/Hydro One debt payable to OEFC. The provision is currently assumed to end once the DRC ends on a legislated fixed end date of April 1, 2018.

5. Reflects April 23, 2014 announcement that DRC will be eliminated for residential users, after December 31, 2015. The end date of DRC for remaining users is legislated to be on April 1, 2018. Estimates are subject to change based on actual consumption.

6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Electricity Sector Outlook

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
On Deck Outlook as of February 2018						
Income from Investment in Government Business Enterprises						
OPG Income[1]	291	299	805	400	503	352
OPG - ONFA and other Fair Value Adjustments[2]	172	43	194	-	-	-
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	-
HOI Income[3]	236	500	346	353	412	438
Brampton Income	20	18	-	-	-	-
Total OPG and HOI Income	**719**	**860**	**1,345**	**753**	**915**	**790**
Other Fees and Licences (Debt Guarantee fee)	**127**	**122**	**102**	**99**	**98**	**91**
Electricity Expenses of the Province						
Provision for Electricity Sector[4]	-	(290)	(697)	(349)	(511)	(386)
Public Debt Interest - Electricity Sector	(520)	(514)	(454)	(404)	(404)	(404)
Subtotal	(520)	(803)	(1,151)	(753)	(915)	(790)
Public Debt Interest - Impact of ONFA						
Amortization of Deferred Revenue re profit on sale of H1 notes						
Total Electricity Expenses of the Province	**(520)**	**(803)**	**(1,151)**	**(753)**	**(915)**	**(790)**
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	3,247	334	530	387	531	535
Other Revenue						
Electricity Debt Retirement Charge[5]	859	621	623	-	-	-
Power Supply Contract Recoveries	875	838	182	183	134	103
Net Reduction of Power Purchase Contracts	172	129	74	41	30	28
Other Fees and Licences	(127)	(122)	(102)	(99)	(98)	(91)
Miscellaneous	9	14	-	-	-	-
Expenses						
Interest on Debt	(596)	(513)	(472)	(468)	(473)	(402)
Power Supply Contract Costs	(875)	(838)	(182)	(183)	(134)	(103)
Electricity Consumer Price Protection Fund	-	-	-	-	-	-
Demand Management Support Costs[6]	(8)	(8)	(10)	-	-	-
Provision for Electricity Sector	-	290	697	349	511	386
Other (Finance)	(7)	(7)	(6)	(7)	(7)	(7)
Total OEFC Income	**3,549**	**737**	**1,335**	**203**	**494**	**449**
Impact on Surplus/(Deficit)	**3,876**	**915**	**1,631**	**302**	**592**	**540**
variance to OEFC check	*(156)*	*(454)*	*(531)*	-	-	-

Notes:

1.OPG's 2017-18 to 2020-21 outlook reflects OPG's 2018-2021 Business Plan and Includes OPG head office properties sale proceeds and Lakeview property sale proceeds. 2021-22 estimates are based on OPG's calendar year-based business plan projections for 2021 and a CEFD projection for 2022. OPG net income also reflect projected IFRS adjustments as provided by OPCD at the time of the 2017 Budget. Note: all Asset Optimization transactions are re-categorised from Sales and Rentals in this Outlook.

2. Provincial consolidation adjustments for unrealized earnings on the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds, as of the end of September 2017.

3. Hydro One 2017-18 is based on actual Hydro One results for 2017 and CEFD projection for 2018. Quarterly earnings are adjusted for the provincial ownership share during the quarter. 2018-19 and onwards are CEFD projections using the latest public information and reflects the Province's ownership share following the May 2017 share disposition and including the First Nations sale in December 2017. Note: all Asset Optimization transactions are re-categorised from Sales and Rentals in this Outlook.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial ONFA consolidation adjustments, minus the interest on debt payable to OEFC. The provision is now assumed to continue after 2017-18 based on TB/MBC approval of the PRRT submission to continue ESDI payments to OEFC beyond 2017-18.

5. Reflects that DRC eliminated for residential users, after December 31, 2015. The end date of DRC for remaining users is legislated to be on April 1, 2018. Estimates are subject to change based on actual consumption.

6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Electricity Sector Change Since Budget	$ Millions					
($million)	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Changes from Budget 2017 as of February 2018						
Income from Investment in Government Business Enterprises						
OPG Income	(5)	708	(332)	(122)	(714)	2016-17 small decrease due to IFRS adjustment revision and OPG Net Income revision. 2017-18 increase is largely due to the re-categorization from Sales and Rentals to OPG net income proceeds from the sale of OPG head office and Lakeview properties. This accounts for $483M of the increase. Note that whicle the re-categorization itself is fiscally-neutral proceeds from property sales are $206M higher than projected at the time of the 2017 Budget. 2017-18 results are also boosted by lower expenses than assumed at the time of Budget 2017. Decrease in 2018-19 onward is due mainly to taking on projeceted IFRS adjustment impacts in those years as well as OEB Dec. 28, 2017 rate decision. The OEB Dec. 28, 2017 rate decision estimated impacts are allocated between OPG net income and PILs on a 75%/25% basis.
ONFA and other Fair Value Adjustments	35	194	-	-	-	Largely revision to ONFA fair value as of December 31, 2017
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	
HOI Income	(16)	(173)	(209)	(191)	(214)	2016-17 slight decrease from Budget 2017 Interim projection. 2017-18 onwards mainly reflects i) re-categorization from Sales and Rentals to Hydro One net income of the impact of a lower Provincial share of Hydro One net income from Hydro One share sales ii) impact of OEB Sep. 2017 decision on Hydro One transmission rates and iii) interest expense on Avitsa debentures (in 2017-18 and 2018-19).
Brampton Income	3.3					
Total OPG and HOI Income	**17**	**728.5**	**(541)**	**(314)**	**(928)**	
Other Fees and Licences	**-**	**-**	**8**	**10**	**10**	
Electricity Expenses of the Province						
Provision for Electricity Sector	53	(572)	(349)	(511)	(386)	**[NOTE: A positive number on this line indicates a decrease in the provision, while a negative number means an increase in provision expense.]** Changes to the Provision (ESDI) expense in 2017-18 mainly reflect higher OPG net income due to recategorisation from Sales and Rentals (see above). Change in out-years reflects TB/MBC approval in 2017-18 PRRT approval to continue Provision for the Electricity Sector (i.e., Electricity Sector Dedicated Income to OEFC) beyond 2017-18. 2017 Budget assumed previous policy whereby ESDI ended after 2017-18.
Public Debt Interest - Electricity Sector	(22)	38	88	88	88	2016-17 PDI at ($514m) was slightly larger than ($492m) projected at Interim. 2017-18 and 2018-19 and onward change reflects revised projections for Provincial debt interest as a result of debt pay downs related to Hydro One's April 2016 and April 2017 offerings, repectively.
Total Electricity Expenses of the Province	**31**	**(535)**	**(261)**	**(423)**	**(298)**	

Electricity Sector Change Since Budget	$ Millions					
($million)	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs)	(40)	125	(89)	(7)	(143)	2016-17 decrease largely due to an OPCD Public Accounts PILs adjustment related to reconciling between OPCD and OEFC net opening assets. OPG PILs also slightly lower than projected. 2017-18 increase is largely due to inclusion of PILs related to disposition of OPG headquarters and Lakeview properties. 2018-19 onward lower mainly due to lower OPG income tax PILs. Property tax componenst are close to Budget 2017.
Other Revenue						
Electricity Debt Retirement Charge	(4)	-	-	-	-	
Power Supply Contract Recoveries	99	(110)	(142)	(167)	(170)	Variance in 16-17 is largely due to retroactive payments that the OEFC made to certain non-utility generators (NUGs) with former Ontario Hydro power purchase agreement (PPA) contracts with OEFC. OEFC was required to make these payment following the dismissal by the Supreme Court of Canada of OEFC's application for leave to appeal a judgment of the Court of Appeal of Ontario on a 2015 court decision. Going-forward, variance is largely due to suspension or early termination of some NUG PPAs in response to the IESO's NUG curtailment initiative.
Net Reduction of Power Purchase Contracts	0.1	(0)	(0)	(0)	(0)	
Other Fees and Licences	-	-	(8)	(10)	(10)	
Revenue Pool Residual	-	-	-		-	
Miscellaneous	14	-	-	-	-	
Expenses						
Interest on Debt	19	(50)	(94)	(131)	(152)	2017-18 and onward reflects revised debt interest outlook net of revisions to OEFC interest revenue from OPG, Hyro One IESO and Province.
Power Supply Contract Costs	(99)	110	142	167	170	Same as Power supply contract recoveries above. Power supply contract costs are fully recovered by power supply contract recoveries.
Electricity Consumer Price Protection Fund	-	-	-	-	-	
Demand Management Support Costs	1.8	-	-	-	-	
Provision for Electricity Sector	(53)	572	349	511	386	see explanation above for "Provision for Electriocty Sector" (line 17)
Other (Finance)	(1.0)	-	(1)	(1)	(1)	
Total OEFC Income	**(63)**	**647**	**157**	**362**	**79**	
Impact on Surplus/(Deficit)[1]	**-15**	**841**	**-637**	**-364**	**-1,136**	Note: A significant component of the changes above affecting this net is from a fiscally-neutral recategorisation of revenue impacts from the Asset Optimisation (AO) initiative previously shown in Sales and Rentals in Budget 2017 for commercial confidentiality. The pure changes to non-AO electricity sector changes is significantly fiscally negative. IN 2018-19 ONWARD. See summary table below for breakdown of total change between these components.
Information: Breakdown of change between revenue and expense						
Total Revenue Impact	87	743	(772)	(487)	(1,241)	
Total Expenditure impact	101	(98)	(135)	(123)	(105)	

Electricity Sector Change Since Previous Distribution	$ Millions					
($million)	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Changes from Budget 2017 as of February 2018						
Income from Investment in Government Business Enterprises						
OPG Income	-	656	263	510	196	2017-18 mainly Lakeview +200 and OPG Provision and other improvements.
ONFA and other Fair Value Adjustments	-	22	-	-	-	
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	
HOI Income	-	17	26	24	19	
Brampton Income	-	-	-	-	-	
Total OPG and HOI Income	**-**	**695.5**	**290**	**534**	**215**	
	-	-	-	-	-	
Other Fees and Licences	**-**	**-**	**-**	**-**	**-**	
	-	-	-	-	-	
Electricity Expenses of the Province	-	-	-	-	-	
Provision for Electricity Sector	-	(673)	(340)	(511)	(338)	
Public Debt Interest - Electricity Sector	-	-	50	50	50	Update
Total Electricity Expenses of the Province	**-**	**(673)**	**(290)**	**(461)**	**(288)**	

Electricity Sector Change Since Previous Distribution	$ Millions					
($million)	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
	-	-	-	-	-	
OEFC Income	-	-	-	-	-	
Taxation Revenue	-	-	-	-	-	
Electricity Payments-in-Lieu of Taxes (PILs)	-	153	(65)	28	(100)	
						2017-18 mainly Lakeview +200 and OPG Provision and other improvements.
	-	-	-	-	-	
Other Revenue	-	-	-	-	-	
Electricity Debt Retirement Charge	-	-	-	-	-	
Power Supply Contract Recoveries	-	-	-	-	-	
Net Reduction of Power Purchase Contracts	-	-	-	-	-	
Other Fees and Licences	-	-	-	-	-	
Revenue Pool Residual	-	-	-	-	-	
Miscellaneous	-	-	-	-	-	
	-	-	-	-	-	
Expenses	-	-	-	-	-	
Interest on Debt	-	3	(30)	(62)	(54)	
Power Supply Contract Costs	-	-	-	-	-	
Electricity Consumer Price Protection Fund	-	-	-	-	-	
Demand Management Support Costs	-	-	-	-	-	
Provision for Electricity Sector	-	673	340	511	338	
Other (Finance)	-	-	-	-	-	
Total OEFC Income	**-**	**829**	**245**	**477**	**184**	
Impact on Surplus/(Deficit)[1]	**0**	**851**	**245**	**550**	**111**	
	-	-	-	-	-	
Information: Breakdown of change between revenue and expense						
Total Revenue Impact	-	848	225	562	115	
Total Expenditure impact	-	(3)	(20)	12	4	

Electricity Sector Outlook (PSAB)

Negative Revenue Risks	$ Millions				
($ millions)	**Plan**				
	2017-18	**2018-19**	**2019-20**	**2020-21**	**2021-22**
Generic					
OPG Generation Risk: Nuclear Reliability (-1.6 TWh)[1]	(120)	(120)	(120)	(120)	
1% decrease in Hydro One actual load[2]	(57)	(59)	(62)	(63)	
Lower OPG's Equity weighting & Return on Equity (ROE)[3]	(12)	(20)	(26)	(45)	
Lower Hydro One Return on Equity (ROE)[4]	(9)	(36)	(38)	(40)	
Regulatory					
Hydro One Distribution rate application[5]	(50)	(50)	(50)	(50)	
OPG Switch from accrual based to cash based accounting for pension and OPEB[6]	—	(600)			
Regulatory Risk - Timing of OPG Rate Decision[7]	—				
OEB Staff Recommendations wrt OPG rate application(May 2017)[8]	—				
Nuclear Liabilities Cash vs. Accrual[9]	—				
OEB decision on Hydro One tax recapture (if one-time write-down)[10]	(440)				
Accounting					
OPG IFRS Consolidation Risks[11]		—	—	—	
Other Risks					
ONFA adjustment decrease[12]	(100)				
Avista Acquisition - Termination fee		(49)			
PILs risk related to defesement of Stranded debt and potential wind down of OEFC[13]					(340)

Note: These risks do not reflect the impacts on electricity sector revenue and expense of reclassification of the Asset Optimization strategy o

1. OPG's market and generation risks related to nuclear reliability similar to the scenarios OPG developed for its sales margins to capture major market risk factors (e.g., natural gas prices, coal prices, foreign exchange, nuclear reliability) in its 2012 business plan. Currently, only the nuclear reliability risk is captured at the current regulated rate for OPG's nuclear generation.

2. Estimated revenue impact if Hydro One load for Transmission and Distribution is 1% lower than projected for all years in CEFD Hydro One Forecast. Based on the assumption a 1% increase in load is directly proportional to a 1% change in revenue requirements.

3. Risk range for Hydro One transmission and distribution reflects potential risk of lower ROE by 0.5% vs assumed ROEs in business plan along with reduced deemed debt to equity weighting of 55%/45% from the current 51%/49%.

4. Risk range for Hydro One transmission and distribution reflects potential risk of lower ROE by 0.5% vs assumed ROEs in CEFD Hydro One Forecast based on the most recent rate applications and forecasted ROE rates.

5. OEB is expected to make a decision on Hydro One's Distibution rate application for 2018 during the first half of 2018.

6. Previous risk removed shifted from 2017-18 to 2018-19. OEB's September 2017 Report, established accrual accounting method as default rate setting method to recover Pension and Other Pension Benefits (OPEBs) costs and recommended continuance of variance account tracking the difference between cash vs. accrual basis reporting for Pension and OPEB. This finding mitigates this risk. However, OEB December 28, OPG rate decision instructs OPG to submit request to dispose of Pension and OPEB deferral and variance account balances during 2018 for its 2019 payment application. OEB's final decision will be made at that time. Note, the impact of a decision could fall in 2019-20 depending on timing of the OEB decision.

7. **Previous risk removed with timing impact now reflected in OPG outlook.**. OEB December 28, decision and order provides an effective date for new rates of June 1, 2017. OPG's business plan assumed OEB decision would be effective as of January 1, 2017. OPG estimated an impact of -$60M for each month for which OEB decsion is not retroactive. The resulting $300M estimated impact has been included in the OPG outlook.

8. **Previous risk removed .** Estimated impact of OEB December 28the decision and order with respect to OPG rates is now reflected on the OPG Outlook.

9. **Previous risk removed.** Risk is related to potential switch to cash-basis accounting for regulated recovery of nuclear payment anmounts. OEB December 28, 2017 Decision and Order has deferred this issue to next OPG rate application in 2021 for 2022 to 2027 period.

10. The OEB's Sep. 28, 2017 ruling on Hydro One's Transmission rate application included direction on sharing, with ratepayers, tax savings related to the Hydro One IPO. Hydro One filed a Motion to Review this decision with the OEB and has also filed a court appeal. Hydro One's 2017 Q3 financial report notes that if the Motion to Review and appeal are unsuccesful the company would record a one-time write-down of $885 million (for transmission and distribution net income) reflecting the OEB decision. The risk above reflects this risk at teh Province's 49.9% average share allocation for 2017-18. Hydro One noted that timing for the Motion to Review and appeal is uncertain. It expects the OEB Review to start in Q1 but noted that it could run in to Q2.

11. **Previous risk figures removed.** OPCD provided IFRS impact estimates (largely related to OPG) at the time of Budget 2017. A portion of these were reflected in in OPG's and Hydro One's net income outlook at the time of the 2017. The current Electricity Outlook now reflects this additional IFRS risk. Table below outlines OPG IFRS Risks versus what is built into the 2017 Budget Fiscal Plan. The new IFRS adjustments figures are pending from OPG via Energy in the next few days.

	2017-18	**2018-19**	**2019-20**	**2020-21**
OPG IFRS Risk	(400)	(475)	(700)	(750)
Risks Built into Fiscal Plan at 2017 Budget	(400)	0	(200)	0
Additional Risks now picked up in this Electricity Outlook	0	(475)	(500)	(750)

Electricity Sector Outlook (PSAB)

Positive Revenue Risks				
($ millions)	**Plan**			
	2017-18	**2018-19**	**2019-20**	**2020-21**
Generic				
OPG Generation Risk: Nuclear Reliability (+1.1 TWh)[1]	85	85	85	85
1% increase in Hydro One actual load[2]	57	59	61	63
Higher OPG Return on Equity (ROE)[3]	6	22	19	33
Higher Hydro One Return on Equity (ROE)[4]	19	69	50	50
Regulatory				
Accounting				
Other Risks				
ONFA adjustment increase[5]	100			

r updates to AO strategy.

1. OPG's market and generation risks related to nuclear reliability similar to the scenarios OPG developed for its sales margins to capture major market risk factors (e.g., natural gas prices, coal prices, foreign exchange, nuclear reliability) in its 2012 business plan. Currently, only the nuclear reliability risk is captured at the current regulated rate for OPG's nuclear generation.

2. Estimated revenue impact if Hydro One load for Transmission and Distribution is 1% higher than projected for all years in CEFD Hydro One Forecast. Based on the assumption a 1% increase in load is directly proportional to a 1% change in revenue requirements.

3. Risk range for OPG reflects potential risk of higher ROE in 2018-2021 (for nuclear base) vs assumed ROE in OPG's 2016 business plan and corresponding rate application. Assumed ROE is 9.85%, respresenting recent in 2010.

4. Risk range for Hydro One transmission and distribution reflects potential risk of higher ROE vs assumed ROEs in the Hydro One CEFD Forecast for 2018-2021. Assumed ROE is 9.85%, representing recent high in 2010.

5. Reflects risk around the consolidation adjustment to OPG net income, whereby the realized portion of gains or losses of OPG's nuclear funds are added or subtracted from OPG net income. Currently $194M positive adjustment reflecting valuations as of December 31, 2017 is included in the OPG outlook. Given current market volatility the ONFA adjustment could change significantly by the end of the Province's fiscal year, March 31, 2018. The net debt adjustment to be included in the fiscal plan consistent with the December 31, 2017 valuations/reports would also be subject to the same type of volatility.

ONTARIO ELECTRICITY FINANCIAL CORPORATION
On Deck Outlook as of March 2017

$ Millions

	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Revenue						
Revenue Pool Residual						
Debt Retirement Charge	859	625	623	-	-	-
Payments-in-lieu of tax:						
OPG	268	302	315	366	408	537
Legacy Hydro One (Including Brampton)	2,929	7	2	2	2	2
Hydro One CIT dedicated to OEFC	3	20	20	22	23	25
MEUs	27	44	68	86	105	114
Total PILs & CIT dedicated to OEFC[1]	3,228	373	405	476	538	679
Interest :						
OPG	173	179	168	153	135	135
H1						
IESO	2	3	3	3	3	3
Province	520	492	492	492	492	492
Other	28	10	5	5	5	5
Total Interest	723	684	668	653	635	635
Power Supply Contract Recoveries	875	739	292	325	301	273
Amortization of NUG liability	172	129	74	41	30	28
Electricity sector dedicated income	3	342	525	-	-	-
Gain to OEFC under s. 50.3	172	-	-	-	-	-
Miscellaneous	9	-	-	-	-	-
	6,041	2,893	2,587	1,495	1,504	1,615
Expense						
Debt interest	1,319	1,216	1,090	1,027	977	885
Interest on nuclear risk funding						
Demand Management Support Costs	8	10	10	-	-	-
Amortization of deferred debt costs	-	-	-			
Power Supply Contract Costs	875	739	292	325	301	273
Debt Guarantee fee	127	122	102	91	88	81
Operating	7	6	6	6	6	6
	2,336	2,093	1,500	1,449	1,372	1,245
Excess (Deficiency) of Revenue over Expense	**3,705**	**800**	**1,087**	**46**	**132**	**370**
Prior period adjustment	87					
Stranded Debt - Year End	**4,393**	**3,593**	**2,506**	**2,460**	**2,328**	**1,958**

Note: All the Hydro One ownership broadening impacts, other than the ownership change from the initial IPO in 2015 and the secondary offering in April 2016, were reflected in Sales and Rentals as of the 2017 Budget.

ONTARIO ELECTRICITY FINANCIAL CORPORATION
On Deck Outlook as of February 2018 **$ Millions**

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Revenue						
Revenue Pool Residual						
Debt Retirement Charge	859	621	623	0	0	0
Payments-in-lieu of tax:						
OPG	268	224	440	277	401	394
Legacy Hydro One (Including Brampton)	2,929	4	2	2	2	2
Hydro One CIT dedicated to OEFC	3	25	20	22	23	25
MEUs	27	112	68	86	105	114
Total PILs & CIT dedicated to OEFC[1]	3,228	364	530	387	531	535
Interest :						
OPG	173	167	160	182	158	131
H1						
IESO	2	2	3	3	3	3
Province	520	514	454	404	404	404
Other	28	20	20	20	10	10
Total Interest	723	703	637	609	575	548
Power Supply Contract Recoveries	875	838	182	183	134	103
Amortization of NUG liability	172	129	74	41	30	28
Electricity sector dedicated income	3	302	697	349	511	386
Gain to OEFC under s. 50.3[2]	172	411	531	0	0	0
Miscellaneous	9	14	0	0	0	0
	6,041	3,382	3,275	1,568	1,781	1,600
Expense						
Debt interest	1,319	1,216	1,109	1,077	1,048	950
Interest on nuclear risk funding						
Demand Management Support Costs	8	8	10	0	0	0
Amortization of deferred debt costs	0	0	0			
Power Supply Contract Costs	875	838	182	183	134	103
Debt Guarantee fee	127	122	102	99	98	91
Operating	7	7	6	7	7	7
	2,336	2,191	1,409	1,366	1,287	1,151
Excess (Deficiency) of Revenue over Expense	3,705	**1,191**	**1,866**	**203**	**494**	**449**
Prior period adjustment	87					
Stranded Debt - Year End	4,393	**3,202**	**1,336**	**1,134**	**639**	**190**

1

Payments-in-lieu of tax:	2015-16 Public Accounts
OPG	290
Legacy Hydro One (Including Brampton)	2,941
Hydro One CIT dedicated to OEFC	0
MEUs	15
	3,247

2 **2017-18 value preliminary estimate, subject to change.**

ONTARIO ELECTRICITY FINANCIAL CORPORATION

Changes from Budget 2017 as of February 2018 **$ Millions**

	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Revenue						
Debt Retirement Charge	(4)	-	-	-	-	
Payments-in-lieu of tax:						
OPG	(78)	125	(89)	(7)	(143)	2016-17 decrease largely due to an OPCD Public Accounts PILs adjustment related to reconciling between OPCD and OEFC net opening assets. OPG PILs also slightly lower than projected. 2017-18 increase is largely due to inclusion of PILs related to disposition of OPG headquarters and Lakeview properties. 2018-19 onward lower mainly due to lower OPG income tax PILs. Property tax componenst are close to Budget 2017. .
Legacy Hydro One (Including Brampton)	(3)	-	-	-	-	
Hydro One CIT dedicated to OEFC	5	-	-	-	-	Adjustment based on updated information in Hydro One rate application
MEUs	68	-	-	-	-	Large increase in 2016-17 from $80M payment during transfer of H01 Brampton to new consolidated MEU Alectra.
Total PILs	(9)	125	(89)	(7)	(143)	
Interest :						
OPG	(12)	(8)	29	23	(4)	Update to OPG interest outlook (wrt interest on OEFC loan).
H1	-	-	-	-	-	
IESO	(1)	-	-	-	-	
Province	22	(38)	(88)	(88)	(88)	2016-17 PDI at ($514m) was slightly larger than ($492m) projected at Interim. 2017-18 and 2018-19 and onward change reflects revised projections for Provincial debt interest as a result of debt pay downs related to Hydro One's April 2016 and April 2017 offerings, repectively.
Other	10	15	15	5	5	
Total Interest	19	(31)	(44)	(60)	(87)	
Power Supply Contract Recoveries	99	(110)	(142)	(167)	(170)	Variance is largely due to retroactive payments that the OEFC made to certain non-utility-generators (NUGs) with former Ontario Hydro power purchase agreement contracts with OEFC. OEFC was required to make these payment following the dismissal by the Supreme Court of Canada of OEFC's application for leave to appeal a judgment of the Court of Appeal of Ontario on a 2015 court decision.
Amortization of NUG liability	0	(0)	(0)	(0)	(0)	
Electricity sector dedicated income	(41)	172	349	511	386	The decrease in OEFC ESDI in 2017-18 reflects i) the IFRS adjustment of $400 million in 2017-18 that was not reflected in the OEFC ESDI projection at the time of the 2017 Budget (Note the IFRS adjustment was reflected in OPG net income for the 2017 Budget fiscal plan) and ii) the lower OPG and Hydro One net income due to OEB's 2017 rate decisions. Changes to the Provision (ESDI) expense in 2017-18 mainly reflect higher OPG net income due to recategorisation from Sales and Rentals of proceeds from the sale of OPG headquarters properties and Lakeview properties. Th eincrease in 2018-19 onward reflects TB/MBC approval in 2017-18 PRRT approval to continue Provision for the Electricity Sector (i.e., Electricity Sector Dedicated Income to OEFC) beyond 2017-18. 2017 Budget assumed previous policy whereby ESDI ended after 2017-18.
Gain to OEFC under s. 50.3	411	531	-	-	-	
Miscellaneous	14	-	-	-	-	
	489	688	73	277	(15)	
Expense						
Debt interest	-	19	50	71	65	Revised outlook for OEFC debt interest outlook
Interest on nuclear risk funding	-	-	-	-	-	
Demand Management Support Costs	(2)	-	-	-	-	
Amortization of deferred debt costs	-	-	-	-	-	
Power Supply Contract Costs	99	(110)	(142)	(167)	(170)	Same as Power supply contract recoveries above. Power supply contract costs are fully recovered by power supply contract recoveries.
Debt Guarantee fee	-	-	8	10	10	
Operating	1	-	1	1	1	
	98	(91)	(83)	(85)	(94)	
Excess (Deficiency) of Revenue over Expense	**391**	**779**	**157**			
Stranded Debt - Year End	**3,202**	**1,336**	**1,134**	**639**	**190**	

Provision for Electricity Sector (Dedicated Electricity Earnings/Electricity Sector Dedicated Earnings)

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Income from Investment in Government Business Enterprises						
OPG Income	291	299	805	400	503	352
Hydro One Income[1]	232	501	346	353	412	438
Hydro One Brampton (if applied separately)		15				
Total Income	**523**	**815**	**1,151**	**753**	**915**	**790**
Public Debt Interest - Electricity Sector						
OPG			(300)	(300)	(300)	(300)
Hydro One[1]			(154)	(104)	(104)	(104)
Public Debt Interest - Electricity Sector (OEFC Interest revenue)	**(520)**	**(514)**	**(454)**	**(404)**	**(404)**	**(404)**
MOF Provision Expense (before adjustments)	**3**	**302**	**697**	**349**	**511**	**386**
Other Adjustments						
Prior-year Adjustment[2]		3				
Exclude Brampton[3]		(15)				
MOF Provision Expense (after other adjustments)	**0**	**290**	**697**	**349**	**511**	**386**
Cumulative Shortfall Adjustment						
Opening Balance	0	0	0	0	0	0
Deduction / (Addition)	0	0	0	0	0	0
Ending Balance	0	0	0	0	0	0
Dedicated Electricity Earnings (all adjustments) (Public Accounts)	**0**	**290**	**697**	**349**	**511**	**386**
Electricity Sector Dedicated Income (OEFC Annual Report)	**3**	**302**	**697**	**349**	**511**	**386**

Notes:

1. The Hydro One financials above now reflects the Provincial share allocation as of January 2018.

2. 2016-17 Adjustment was due to the discrepancy between the numbers in MOF expense in PA 2015-16 and OEFC Financials in 2015-16 due to timing issues. $3M adjustment rectifies this discrepancy

3. Brampton was excluded from the Ministry of Finance's ESDI allocation.

Ontario Power Generation

OPG Income - Budget 2017

$ Millions

	Actual	Interim	Plan				
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22
OPG Net Income After Tax (Adjusted)	291	304	97	732	625	1,066	
OPG Net Income After Tax	*291*	*379*	*480*	*678*	*726*	*913*	
Extraordinary Gains	-	-	-	-	-	-	
GA - OPG Trust Interest Revenue			*17*	*54*	*99*	*153*	
OPG IFRS consolidation risk picked up in Fiscal Plan		(75)	(400)		(200)		
ONFA and other Fair Value Adjustments	(75)	8					
ONFA Adjustments	-	8					
Other Fair Value Adjustments	(75)						

OPG PIL - Budget 2017

$ Millions

	Actual	Interim		
	2015-16	2016-17	2017-18	2018-19
Net Income Before Tax	383	396	572	867
Net Income After Tax (Adjusted)	291	304	97	732
Income Taxes	92	92	92	135
GRC: Payable to OEFC	198	196	205	212
Proxy Property Tax	16	14	18	19
Ontario Capital Tax	0	0	0	0
Total	**306**	**302**	**315**	**366**

OPG Income - January 2018

$ Millions

	Actual	Actual	Current Outlook				
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22
OPG Net Income	291	377	1,195	795	1,053	877	1,070
GA Financing - OPG Trust Interest Revenue[2]			10	80	150	225	225
OPG IFRS consolidation risk[3]		(78.00)	(400)	(475)	(700)	(750)	(750)
OPG Net Income (Adjusted before ONFA)	**291**	**299**	**805**	**400**	**503**	**352**	**545**
ONFA Adjustments	247	49	194				
Other Fair Value Adjustments	(75)	(6)					
ONFA and other Fair Value Adjustments	**172**	**43**	**194**				
OPG Net Income	**463**	**342**	**999**	**400**	**503**	**352**	**545**

OPG PIL - January 2018

$ Millions

	Actual	Actual		Cu
	2015-16	2016-17	2017-18	2018-19
Income Before Tax	383	308	1,026	454
OPG Net Income (Adjusted before ONFA)	**291**	299	805	400
OPG Income Tax (PILs)	92	9	221	54
GRC: Payable to OEFC	198	201	206	209
Proxy Property Tax to OEFC	16	14	13	14
Ontario Capital Tax	0	0	0	0
Total OPG PILs	**306**	**224**	**440**	**277**

1. OPG's May 2017 head office facilities sale impacts are re-categorized from Sales and Rentals to OPG net income and PILs in the current Electricity Outlook update. This update now also includes 2017-18 proceeds from the Lakeview properties sale.

2. This reflects interest earnings on GA financing costs which are consolidated back to Province

3. IFRS risk provided by OPCD as of 2017 Budget

Hydro One Ownership Calculation:		SOURCE:
Total number of shares outstanding[1]	595,000,000	1. Hydro One Ltd Annual Report 2015, pg 94 of PDF, pg 92 of the Report.
Additional Common Shares Issued since IPO	386,711	
IPO November 2015		
Initial Public Offering(2015)[2]	81,100,000	2. From news release: http://hydroone.mediaroom.com/2015-11-05-Hydro-One-Limited-Announces-Closing-of-IPO
Over allotment option (2015)[3]	8,150,000	3. From news release: http://hydroone.mediaroom.com/2015-11-12-Hydro-One-Limited-Announces-Closing-of-IPO-Over-Allotment-Option
Sales to PWU/SEP Trusts	5,646,340	
Total	94,896,340	
Province's remaining ownership, Nov 2015 (# Shares)	**500,103,660**	
Province's remaining ownership, Nov 2015 (%)	**84.05%**	
Secondary Offering April 2016		
Secondary Offering (2016)	72,434,800	4. Hydro One Ltd. Q2 Report, pg 1 http://www.hydroone.com/InvestorRelations/FinancialReporting/Documents/Hydro%20One%20Ltd%20Second%20Quarter%20
Over allotment option (2016)	10,865,200	
Total	83,300,000	
Province's remaining ownership, Apr 2016 (# Shares)	**416,803,660**	
Province's remaining ownership, Apr 2016 (%)	**70.05%**	
Final Offering May 2017		
Final Offering (2017)	120,000,000	Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by-the-Provin
Over allotment option (2017)	-	Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by-the-Provin
Total	120,000,000	
Province's remaining ownership, May 8, 2017 (# Shares)	296,803,660	Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by-the-Provin
Province's remaining ownership, May 8, 2017 (%)	**49.88%**	
First Nations Sale, closed on December 29, 2017	14,391,012	Source: http://www.S:\Users\CEF\Hydro 2018\OEFC\RbP\Outlook\01. January\Backup\20180103-0 - H1 First Nations Sales\
	2.4170865%	Source: https://news.ontario.ca/mei/en/2017/05/ontario-raises-28-billion-from-final-hydro-one-share-offering.html
Province's remaining onwership - post First Nations Sale (#Shares)	282,412,648	
Province's remaining onwership - post First Nations Sale (%)	**47.43%**	
Avista Impact (projected closing date 2nd half of 2018)		
Contingent Convertible Debenture	$1,540,000,000	
Conversion Price	$21	
Potential Dilution (# Shares)	71,962,617	
Revised Total number of shares outstanding	**666,962,617**	
Province's remaining onwership - post Avista Acquisition (#Shares)	282,412,648	
Province's remaining onwership - post Avista Aquisition (%)	**42.34%**	

Ownership Percentage in 2017-18 Fiscal Year	Number of Months	Percentage of Year
70.05%	1	8.3%
49.88%	8	66.7%
47.43%	3	25.0%
	12	
Average 2017-18 FY Ownership:	**51.0%**	

Ownership Percentage in 2018-19 Fiscal Year (assume Avista closing end of September 2018)	Number of Months	Percentage of Year
47.43%	6	50.0%
42.34%	6	50.0%
	12	
Average 2018-19 FY Ownership:	**44.9%**	

Ownership Percentage in 2019-20 Fiscal Year Onwards
42.34%

Accretive to earnings per share and cash flow for Hydro One in the first full year post closing
above is from Hydro One transaction overview. Check what this means for timing of additional shares and /or earnings.

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Hydro One Net Income and PILs

Hydro One Income - Budget 2017
($ millions)

	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Hydro One Net Income After Tax	685	737	742	802	862	931
Hydro One - Unrealized Gains Adjustment						

2016-17 to 2020-21 from CEFD Hydro One 2016 model.

Hydro One PIL - Budget 2017
($ millions)

	2015-16	2016-17	2017-18	2018-19
Net Income After Tax	685	737	742	802
Income Taxes PILs	132	160	181	205
Proxy Property Tax	2	2	2	2
Ontario Capital Tax	0	0	0	0
Total	**134**	**162**	**183**	**207**

Hydro One Income - December 2017
($ millions) **$ Millions**

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21	2021-22
Hydro One Net Income After Tax			662	706	831	885	943
Hydro One Net Income After Tax - Including Adjustments	670	680	662	706	831	885	943
Hydro One - Net Income Attributable to Preferred Shareholders	15	18	18	18	18	18	18
Hydro One - Unrealized Gains Adjustment							

Hydro One (100% Ownership)
($ millions) **$ Millions**

	Actual 2015-16	Actual 2016-17	2017-18	Cu 2018-19
Net Income After Tax - Common Shares	670	680	662	706
Net Income After Tax - Preferred Shares	15	18		
Income Taxes PILs	132	160	181	205
Proxy Property Tax	2	2	2	2
Ontario Capital Tax	0	0	0	0

Public Debt Interest and Section 50.3 payments

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Hydro One Public Debt Interest and Section 50.3 payments						
Government Annual Interest Costs - Hydro One	220	220	220	220	220	220
Reduction in Interest Costs due to Broadening[1]		(29)	(66)	(116)	(116)	(116)
Province Annual Interest Costs - Hydro One Debt	**220**	**191**	**154**	**104**	**104**	**104**
Province Annual Interest Cost - OPG Debt	300	300	300	300	300	300
Total Public Debt Interest	**520**	**514**	**454**	**404**	**404**	**404**

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Gain to OEFC under s. 50.3	172	411	531	0	0	0

1. The Hydro One reduction in interest costs above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering are currently reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

2020-21							
220	ID# (Track Cha	Fiscal Year	alue (Hardcode	Value (Linked)	Description	Source Details	Source (Link)
-116	20170501-2	2016-17	411,152,733	411,152,733	s 50.3 Gain for	Calculation provided by SIFB	
104	20170501-3	2016-17	29	29	Reduction in Int	Internal Calculation	
	20170501-3	2017-18	66	-116	Reduction in Int	Internal Calculation	
	20170501-3	n/a	220	220	Annual Interest	Internal Calculation	
300							
404							

2020-21	ID# (Track Cha	Fiscal Year	alue (Hardcode	Value (Linked)	Description	Source Details	Source (Link)
0	n/a	n/a	5126		($M) Provinces	OEFC 1999-2000 FS, pg 24	
	n/a	n/a	5.85%		Annual Interest	OEFC 1999-2000 FS, pg 26	
			299.871				

	OPG's Annual Interest Costs:		300	
20170713-1	2016-17	-513,768,361	Provincial interest cost for equity investment in OPG, H1 in 2016-17 Monthly Balances Sheet (from FTD) S:\Users\CEF\Hydro 2017\OEFC\RbP\Outlook\07. July\Backup\20170713-1\interest fr	
s. 50.3	531	531	S:\Users\CEF\Hydro 2018\OEFC\RbP\Outlook\02. February\Back-up files	

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PROVINCIAL CONSOLIDATION ADJUSTMENTS
Ontario Nuclear Funds Agreement

Adjustment for Change in OPG Reported Net Income

Adjustment for DSF Unrealized Earnings

Unrealized Earnings as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Bruce Variance Account Adjustment
OPG Net Income Adjustment

Adjustment for UFSF Unrealized Earnings

Unrealized Earnings as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Bruce Variance Account Adjustment
OPG Net Income Adjustment

Unrealized Earnings -- Fiscal YTD

Adjustment for Change in Due to Province

Adjustment for DSF Due to Province
Due to Province (cost basis) as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Change in Due to Province -- Fiscal YTD

Adjustment for UFSF Due to Province

Due to Province (cost basis) as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Change in Due to Province -- Fiscal YTD

Provincial Consolidation Adjustment

Other Data

	Actual 2016-17	2017-18
Debt Retirement Charge	621	0

	2016-17	2017-18
Power Supply Contract Recoveries	838	182

	2016-17	2017-18
Interest		
OPG	167	155
IESO	2	3
Other (Net)	20	20
Expense		
Debt interest	1216	1109

	Actual 2016-17	2017-18
MEU - PIL Income Tax	109.8	
MEU - PIL Property Tax	0.6	
MEU - GRC	1.2	
TOTAL MEU PILs	111.6	

	Actual 2016-17	2017-18
Miscellaneous/Other (OEFC FS)	14	
Demand Management Support Costs (IEI)	8	10
Operating [Expense]	7	6
Interest on nuclear risk funding	-	-
Amortization of deferred debt costs	-	-
Amortization of NUG liability	129	74
Debt Guarantee Fee	122	102

Expense (Electrictiy Summary Tab)		
Other (Finance)	-7	-6
Demand Management Support Costs (IEI)	-8	-10
Debt Guarantee Fee	(122)	(102)

Plan 2018-19	2019-20	2020-21	2020-21
0	0	0	0

Plan 2018-19	2019-20	2020-21	2020-21
183	134	103	103

Plan 2018-19	2019-20	2020-21	2020-21	
166	158	131	119	updated Feb 15, FTD
3	3	3	3	updated Feb 15, FTD
20	10	10	10	updated Feb 15, FTD
1077	1048	950	818	updated Feb 15, FTD

Plan 2018-19	2019-20	2020-21	2020-21

Plan 2018-19	2019-20	2020-21	2020-21
7	7	7	7
-	-	-	-
-	-	-	-
41	30	28	28
99	98	91	91
-7	-7	-7	-7
(99)	(98)	(91)	-91

ID# (Track Changes	Fiscal Year	Value (Hardcoded)	Value (Linked)
20170510-2	2016-17	$ 739,216,115	
20170510-2	2017-18	$ 291,629,707	
20170510-2	2018-19	$ 324,906,017	
20170510-2	2019-20	$ 300,648,570	
20170510-2	2020-21	$ 273,240,858	
20170501-4	2016-17	179	179
20170501-4	2017-18	169	169
20170501-4	2018-19	179	179
20170501-4	2019-20	175	175
20170501-4	2020-21	148	148
20170501-5	2016-17	1216	1,216
20170501-5	2017-18	1121	1,121
20170501-5	2018-19	1094	1,094
20170501-5	2019-20	1053	1,053
20170501-5	2020-21	963	963
20170731-3	2016-17	621	
20170811-1	2016-17	109.8	
20170811-1	2016-17	0.6	
20170811-1	2016-17	1.2	
20170815-5	2016-17	$ 838,000,000	
20170815-6	2016-17	$ 14,000,000	
20170815-8	2016-17	8	
20170815-9	2017-18	10	
20170815-10	2016-17	7	
20171211-2	2017-18	6	6
20171211-2	2018-19	7	7
20171211-2	2019-20	7	7
20171211-2	2020-21	7	7
20170815-7	2016-17	167	
20170815-7	2016-17	2	
20170815-7	2016-17	20	
20170815-7			

ID# (Track Changes	Fiscal Year	Value (Hardcoded)	Value (Linked)
20170905-1	2016-17	129	129
20170905-1	2017-18	74	74

20170905-1	2018-19	41	41
20170905-1	2019-20	30	30
20170905-1	2020-21	28	28
20170905-2	2016-17	122	
20170906-1	2017-18	3	3
20170906-1	2018-19	3	3
20170906-1	2019-20	3	3
20170906-1	2020-21	3	3
20170906-1	2017-18	20	5
20170906-1	2018-19	20	5
20170906-1	2019-20	10	5
20170906-1	2020-21	10	5
20171211-0	2017-18	1115	
20171211-0	2018-19	1089	
20171211-0	2019-20	1060	
20171211-0	2020-21	963	
20171211-1	2017-18	102	102
20171211-1	2018-19	99	99
20171211-1	2019-20	98	98
20171211-1	2020-21	91	91
20171211-1			
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20171211-1			
20171211-1			
20171211-1			
20171211-1			

ID# (Track Changes	Fiscal Year	Value (Hardcoded)	Value (Linked)
20180104-2	2017-18	$ 181,776,685	
20180104-2	2018-19	$ 182,785,215	
20180104-2	2019-20	$ 133,962,519	
20180104-2	2020-21	$ 102,554,665	

Description	Source Details	Source (Link)
The table below contains an updated preliminary N	SPFB Estimates, Email	
• The tables below provides both last year's submission for NUG costs by CEFD and this year's estimates (both of which exclude HST) based on the most recent NUG model.	SPFB Estimates, BN SPFB Estimates, BN SPFB Estimates, BN SPFB Estimates, BN	
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
Updating DRC from OEFC AR (Drafts)	2017 OEFC DRAFT FS	S:\Users\CEF\Hydro 2017\OEFC'
MEU - PIL Income Tax	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
MEU - PIL Property Tax	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
MEU - GRC	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
Updating to actuals	2017 OEFC AR	2017 OEFC Annual Report - Eng
Updating to actuals	2017 OEFC AR	2017 OEFC Annual Report - Eng
Updating to Actuals	2017 OEFC AR	S:\Users\CEF\Hydro 2017\OEFC'
OEFC 2017-18 IEI/Demand Management Suppor	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Operating Expense - Updating to Actuals	2017 OEFC AR	S:\Users\CEF\Hydro 2017\OEFC'
Revised Operating Expense from FTD Forecast	FTD - October PRRT	
OPG Interest Revenue - Actuals 2016-17	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
IESO Interest Revenue - Actuals 2016-17		
Other (Net) Interest Revenue - Actuals 2016-17		

Description	Source Details	Source (Link)
		S:\Users\CEF\Hydro 2017\OEFC'
	Amortization Schedule.	S:\Users\CEF\Hydro 2017\OEFC'

Sourcing the NUG liability amortization schedule.	Tab: Summary Fiscal Impact	S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Gurantee Fee - Updating to Actuals	2017 OEFC AR (pg 13 (	\\ofina.on.ca\ofadfs\Users\CEF\H
IESO Interest Revenue Plan	OEFC Revenue Forecast for Board - April 2017	\\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H
Other Interest Revenue Plan		\\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H
OEFC Debt Interest Expense (no change, just re-linking)	FTD - January 11	
OEFC Debt Guarantee Fee	FTD - October PRRT	S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC'

Description	Source Details	Source (Link)
Updated FY 2017-18 estimates of NUG costs	SPFB Estimates, BN	Power Purchases and Sales Fore
Updated FY 2017-18 estimates of NUG costs	SPFB Estimates, BN	Power Purchases and Sales Fore
Updated FY 2017-18 estimates of NUG costs	SPFB Estimates, BN	Power Purchases and Sales Fore
Updated FY 2017-18 estimates of NUG costs	SPFB Estimates, BN	Power Purchases and Sales Fore

\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
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\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board

\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board

\RbP\Outlook\07. July\Backup\20170731-3 - DRC Update\2017 OEFC Annual Report - English - DRAFT.PDF

\RbP\Outlook\08. August\Backup\20170811-1 - Updating PILs for 2016-17\OEFC 2016-17 Pils summary.pdf
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\RbP\Outlook\08. August\Backup\20170815-8 - 2016-17 Demand Management Support Costs (IEI)\2017 OEFC
\RbP\Outlook\08. August\Backup\20170815-9 - 2017-18 Demand Management Support Costs (IEI)\OEFC rever
\RbP\Outlook\08. August\Backup\20170815-10 - 2016-17 Operating (Expense)\2017 OEFC Annual Report - Enc

\RbP\Outlook\08. August\Backup\20170815-7 - 2016-17 Updated Interest on Debt Revenue\RE Revised OEFC

\RbP\Outlook\09. September\Backup\20170905-1 - Amortization of NUG Liability\NUG liability_estimated draw c
\RbP\Outlook\09. September\Backup\20170905-1 - Amortization of NUG Liability\NUG liability_estimated draw c

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ydro 2017\OEFC\RbP\Outlook\09. September\Backup\20170906-1 - OEFC Revenue Forecast for Board
ydro 2017\OEFC\RbP\Outlook\09. September\Backup\20170906-1 - OEFC Revenue Forecast for Board
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\RbP\Outlook\12. December\Backup\20171211-1 - Interest Numbers from FTD\OEFC forecast PRRT planning_
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lown_Mar15_if apply Jan1_Apr21.xls

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Colour Codes

Formulas are in black text

Hard coded numbers are in blue text

References elsewhere are in purple

Green bold text with or without highlights mean updates required

Policies to follow when making updates to the Outlook

*** To quickly jump to the source numbers for a link, press "**Ctrl + [**"

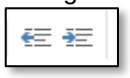
All new numbers must be fully sourced, and follow the colour codes above

Most numbers and text are Arial Size 10, unless it is a title

Add back up materials in a folder with the same numbers as in the 'Track Changes' tab

If there is a reason for italics, or other colours, or formatting make sure it is clear. Othe

Use indents to make things more clear to read



If numbers are taken from another tab they should ONLY be direct links, no calculation

Electricity Summary - (Budget17/On Deck) - Reflects Public Accounts/Financial Statem

OEFC - (Budget17/On Deck) - Reflects OEFC Annual Reports

*Due to slight discrepancies between Public Accounts reporting and OEFC Annual Rep

Outlook Updates Frequency

Frequency	Description	Tab
Monthly	OPG Net Income in-year forecast	OPG
Monthly	OPG PILs in-year forecast	OPG
Quarterly	ONFA Consolidation Adjustment	ONFA
Quarterly	OPG Cash vs Accrual Variance Account	Revenue (Risks)

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rwise expect it to be cleared

ı, adjustment should be done. Even if its just making a negative to a positive. Perform all the calculations on the

ıents

ɔorts, the numbers may not be identical

source tab then bring the number into the next tab. (Eg. Formulas like this become hard to troubleshoot ='Hydro

One'!AR29+'Hydro One'!AR31+'Hydro One'!AR32), let's avoid them.

From: Bruno Amara
To: John Kim; Ronald Kwan
Cc: Esther Jeon
Subject: Electricity Outlook
Date: Friday, February 23, 2018 9:01:13 AM
Attachments: Electricity Sector Outlook (2018 02 22)_v03_Markup2.xlsm

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Hi Ron, John

Attached is the revised electricity outlook. This is based on your edits. We have also pushed out the MEU recovery by one year as suggested. On cover sheet we added a Change from previous panel (line 97) to make clear to TBS, OEP the revisions they need to make to their ORBIT entries.

Esther will be using this to prepare the distribution copy which we hope to send out by 9:30. Let us know if any further comments.

Thanks
Bruno

Bruno Amara
Sr. Manager, Financial and Regulatory Analysis
Electricity Finance Branch
Corporate and Electricity Finance Division
Ontario Financing Authority

Tel: 416-325-1489
Email: bruno.amara@ofina.on.ca

Electricity Sector Outlook
February 2018

Disclosure:

All information contained in this workbook is confidential and commercially sensitive

All projected numbers are estimates and subjected to change

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Please consult with OFA before sharing of information.

Commercially Sensitive and Confidential Advice to Cabinet for Consideration of Options for Discussion Purposes Only

Commercially Sensitive and Confidential Advice to Cabinet for Consideration of Options for Discussion Purposes Only

Electricity Sector Outlook
Including Line Items for Consolidation

Electricity Summary - On Deck

February 2018

			MOF Expense Items (consolidated)	**Current Outlook**			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**38**	Power Supply Contract Costs	(182)	(183)	(134)	(103)
Expense	**MOF (OEFC)**	**40**	Demand Management Support Costs	(10)	-	-	-
Expense	**MOF (OEFC)**	**41**	Provision for Electricity Sector	797	449	736	711
Expense	**MOF**	**17**	Provision for Electricity Sector	(797)	(449)	(736)	(711)
Expense	**MOF (OEFC)**	**42**	Other (Finance)	(6)	(7)	(7)	(7)
			Total MOF Expense	**(198)**	**(190)**	**(141)**	**(110)**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**7**	OPG Income	905	500	728	677
Revenue	**ENE**	**8**	OPG - ONFA and other Fair Value Adjustments	194	-	-	-
Revenue	**ENE**	**10**	HOI Income	346	353	412	438
Revenue		**11**	Brampton Income	-	-	-	-
Revenue	**MOF (OEFC)**	**26**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	499	369	512	526
Revenue	**MOF (OEFC)**	**29**	Electricity Debt Retirement Charge	604	-	-	-
Revenue	**MOF (OEFC)**	**30**	Power Supply Contract Recoveries	182	183	134	103
Revenue	**MOF (OEFC)**	**31**	Net Reduction of Power Purchase Contracts	74	41	30	28
Revenue	**MOF (OEFC)**	**34**	Miscellaneous	-	-	-	-
			Total MOF Revenue	**2,804**	**1,445**	**1,816**	**1,772**
			OFA IOD Expense				
			Public Debt Interest - Electricity Sector	(454)	(404)	(404)	(404)
			Interest on Debt	(477)	(484)	(473)	(402)
			Total OFA IOD Expense	**(931)**	**(888)**	**(877)**	**(806)**
			Impact on Surplus/Deficit	**1,675**	**368**	**798**	**856**
			check	***(0)***	***(0)***	***(0)***	***(0)***

Electricity Summary - Budget 17

For Discussion			MOF Expense Items (consolidated)	Plan			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**38**	Power Supply Contract Costs	(292)	(325)	(301)	(273)
Expense	**MOF (OEFC)**	**40**	Demand Management Support Costs	(10)	0	0	0
Expense	**MOF (OEFC)**	**41**	Provision for Electricity Sector	125	0	0	0
Expense	**MOF**	**17**	Provision for Electricity Sector	(125)	0	0	0
Expense	**MOF (OEFC)**	**42**	Other (Finance)	(6)	(6)	(6)	(6)
			Total MOF Expense	**(308)**	**(331)**	**(307)**	**(279)**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**7**	OPG Income	97	732	625	1,066
Revenue	**ENE**	**8**	OPG - ONFA and other Fair Value Adjustments	0	0	0	0
Revenue	**ENE**	**10**	HOI Income	520	562	603	652
			Brampton Income				
Revenue	**MOF (OEFC)**	**25**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	405	476	538	679
Revenue	**MOF (OEFC)**	**29**	Electricity Debt Retirement Charge	623	0	0	0
Revenue	**MOF (OEFC)**	**30**	Power Supply Contract Recoveries	292	325	301	273
Revenue	**MOF (OEFC)**	**31**	Net Reduction of Power Purchase Contracts	74	41	30	28
Revenue	**MOF (OEFC)**	**34**	Miscellaneous	0	0	0	0
			Total MOF Revenue	**2,011**	**2,136**	**2,098**	**2,697**
			OFA IOD Expense				
		17	Public Debt Interest - Electricity Sector	(492)	(492)	(492)	(492)
		36	Interest on Debt	(422)	(374)	(342)	(250)
			Total OFA IOD Expense	**(914)**	**(866)**	**(834)**	**(742)**
			Impact on Surplus/Deficit	**789**	**939**	**957**	**1,676**
			check	**-**	**-**	**-**	**-**

Electricity Summary - Change

			MOF Expense Items (consolidated)	Variance from Plan			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**69**	Power Supply Contract Costs	110	142	167	170
Expense	**MOF (OEFC)**	**71**	Demand Management Support Costs	0	0	0	0
Expense	**MOF (OEFC)**	**72**	Provision for Electricity Sector	672	449	736	711
Expense	**MOF**	**48**	Provision for Electricity Sector	(672)	(449)	(736)	(711)
Expense	**MOF (OEFC)**	**73**	Other (Finance)	0	(1)	(1)	(1)
			Total MOF Expense	**110**	**141**	**166**	**169**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**38**	OPG Income	808	(232)	103	(389)
Revenue	**ENE**	**39**	OPG - ONFA and other Fair Value Adjustments	194	0	0	0
Revenue	**ENE**	**41**	HOI Income	(173)	(209)	(191)	(214)
			Brampton Income	0	0	0	0
Revenue	**MOF (OEFC)**	**25**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	93	(107)	(26)	(152)
Revenue	**MOF (OEFC)**	**60**	Electricity Debt Retirement Charge	(19)	0	0	0
Revenue	**MOF (OEFC)**	**61**	Power Supply Contract Recoveries	(110)	(142)	(167)	(170)
Revenue	**MOF (OEFC)**	**62**	Net Reduction of Power Purchase Contracts	(0)	(0)	(0)	(0)
Revenue	**MOF (OEFC)**	**65**	Miscellaneous	0	0	0	0
			Total MOF Revenue	**793**	**(690)**	**(281)**	**(925)**
			OFA IOD Expense				
		17	Public Debt Interest - Electricity Sector	38	88	88	88
		36	Interest on Debt	(55)	(110)	(131)	(152)
			Total OFA IOD Expense	**(17)**	**(22)**	**(43)**	**(64)**
			Impact on Surplus/Deficit	**886**	**(571)**	**(158)**	**(820)**
			check	***(0)***	***(0)***	***(0)***	***(0)***

Track Changes in Surplus/Deficit

Date	Change ID#	Source	Tab
5/1/2017	20170501-1	Link	ONFA
5/1/2017	20170501-2	Link	Hydro One
5/1/2017	20170501-3	Link	Hydro One
5/1/2017	20170501-4	Link	Other Data
5/2/2017	20170502-1	Link	OPG
5/9/2017	20170509-1	Link	OPG
5/10/2017	20170510-1	Link	Hydro One
5/10/2017	20170510-2	Link	Other Data
5/12/2017	20170512-1	Link	Hydro One
5/15/2017	20170515-1	Link?	
5/15/2017	20170515-2	Link	OPG
5/17/2017	20170517-1	Link	Hydro One
5/17/2017	20170517-2	Link	ONFA
5/17/2017	20170517-3		
5/18/2017	20170518-1	Link	OPG
5/18/2017	20170518-2	Link	OPG
5/18/2017	20170518-3		
6/15/2017	20170615-1	Link	OPG
6/22/2017	20170622-1	Link	Hydro One
6/22/2017	20170622-2	Link	Hydro One
6/26/2017	20170626-1		
6/29/2017	20170629-1		

7/6/2017	20170706-1		
7/11/2017	20170711-1		
7/13/2017	20170713-1	Link	Provision
7/17/2017	20170717-1	Link	Revenue (Risks)
7/24/2017	20170724-1	Link	Revenue (Risks)
7/25/2017	20170725-1	Link	Revenue (Risks)
7/26/2017	20170726-1	Link	Revenue (Risks)
7/27/2017	20170727-1	Link	Revenue (Risks)
7/27/2017	20170727-2	Link	Revenue (Risks)
7/31/2017	20170731-1		
7/31/2017	20170731-2	Link	Hydro One
7/31/2017	20170731-3	Link	Other Data
8/11/2017	20170811-1	Link	OPG
8/15/2017	20170815-1		
8/15/2017	20170815-2		
8/15/2017	20170815-3		
8/15/2017	20170815-4		
8/15/2017	20170815-5		Other Data
8/15/2017	20170815-6		Other Data
8/15/2017	20170815-7		Other Data
8/15/2017	20170815-8		Other Data
8/15/2017	20170815-9		Other Data
8/15/2017	20170815-10		Other Data
8/17/2017	20170817-1	Link	Provision
8/17/2017	20170817-2	Link	Hydro One
8/18/2017	20170818-1	Link	Revenue (Risks)
8/22/2017	20170822-1	Link	OPG
8/25/2017	20170825-1		Hydro One
8/29/2017	20170829-1		Revenue (Risks)
8/31/2017	20170831-1		Revenue (Risks)
9/5/2017	20170905-1		Other Data
9/5/2017	20170905-2		Other Data
9/5/2017	20170905-3	Link	OPG

9/6/2017	20170906-1	Link	Other Data
9/6/2017	20170906-2	Link	Revenue (Risks)
9/8/2017	20170908-1	Link	Hydro One
9/8/2017	20170908-2	Link	OPG
9/11/2017			
9/12/2017			
9/13/2017			
9/21/2017			
9/22/2017			
10/2/2017			Hydro One
10/2/2017			
10/2/2017			
10/2/2017			
10/4/2017	20171004-1		OPG
10/4/2017	20171004-2		OPG
10/4/2017			
10/4/2017			
10/5/2017			
10/6/2017			
10/7/2017			
10/8/2017			
10/10/2017	20171010-1		Hydro One
10/10/2017			
10/10/2017			
10/11/2017	20171011-1		OPG
10/11/2017			
10/11/2017			
10/12/2017			OPG
10/12/2017			
10/12/2017			
10/12/2017			
10/18/2017	20171018-1		Hydro One
10/18/2017	20171018-1		Hydro One
10/18/2017	20171018-1		Hydro One
10/19/2017	20171019-1		Revenue (Risks)
10/19/2017	20171019-2		Revenue (Risks)
10/20/2017	20171020-1		Revenue (Risks)
10/20/2017	20171020-2		
10/20/2017	20171020-2		
10/20/2017	20171020-2		
10/20/2017	20171020-3		Revenue (Risks)
10/20/2017	20171020-4		OPG
10/20/2017	20171020-4		OPG
10/20/2017	20171020-4		OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017	20171114-1		Hydro One

11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017		Hydro One
11/14/2017		Hydro One
11/14/2017		Hydro One
11/30/2017	20171130-1	Revenue (Risks)
12/8/2017		Hydro One
12/11/2017	20171211-1	Other Data
12/11/2017	20171211-1	Other Data
12/22/2017	20171222-1	OPG
1/2/2018		Hydro One
1/2/2018		Hydro One
1/2/2018		Hydro One
1/2/2018	20180102-1	OPG
1/2/2018	20180102-1	OPG
1/2/2018	20180102-1	OPG
1/2/2018	20180102-2	OPG
1/2/2018	20180102-3	OPG
1/2/2018	20180102-3	Revenue (Risks)
1/2/2018	20180102-4	Revenue (Risks)
1/2/2018	20180102-5	Revenue (Risks)
1/2/2018	20180102-6	Revenue (Risks)
1/2/2018	20180102-7	Revenue (Risks)
1/2/2018	20180102-8	Revenue (Risks)
1/2/2018	20180102-9	OPG
1/2/2018	20180102-9	OPG
1/2/2018	20180102-9	OPG
1/2/2018	20180102-9	OPG
1/3/2018		OPG
1/3/2018		OPG
1/3/2018		OPG
1/3/2018		OPG
1/3/2018		Hydro One
1/3/2018		Hydro One
1/3/2018		Hydro One
1/4/2018	20180104-1	OPG
1/4/2018	20180104-1	OPG
1/4/2018	20180104-1	OPG
1/4/2018	20180104-1	OPG
1/4/2018	20180104-2	Other Data
1/4/2018	20180104-2	Other Data
1/5/2018		
1/5/2018		
1/5/2018		
1/5/2018		
1/5/2018		
1/5/2018		
1/5/2018		
1/8/2018		
1/8/2018		
1/8/2018		
1/16/2018		Other Data

1/23/2018		OPG
2/2/2018	20180202-1	OPG
		OPG
		OPG
	20180202-1	OPG
	20180202-1	OPG
	20180202-1	OPG
	20180202-1	OPG
		OPG
		OPG
		OPG
		OPG
		OPG
		OPG
2/13/2018		
2/13/2018		
2/13/2018		
2/13/2018		
2/13/2018		
2/13/2018		
2/15/2018	20180215-1	Hydro One
2/15/2018		
2/15/2018		
2/22/2018	20180222-1	OPG
		OPG
		OPG

FOR EFB USE ONLY

Budget 2017 Outlook
Current Outlook
Change Since Budget

Description of Update
ONFA Update as of March 31 2017
s. 50.3 Update for 2016-17
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Debt Interest
OPG IFRS Risk in 2019-20
Revised OPG 2016-17 Net Income
Revised OPG 2016-17 Net Income
Revised OPG 2016-17 Net Income
tech change: slight update to assumed Prov share 70.05% from 70%
tech change: slight update to assumed Prov share 70.05% from 70%
tech change: slight update to assumed Prov share 70.05% from 70%
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
Updating H1 2016-17 Net Income for ESDI
Updating H1 2016-17 Net Income for ESDI
Updating H1 2016-17 Net Income for ESDI
Power Purchase Supply
H1 Model Forecasts - No Fiscal Update Resaving Data
Update Budget 2017 Tabs to reflect fiscal plan
Update OPG forecasted PILS to reflect sources
Update H1 2016-17 CIT
Re-inputting ONFA updates
Updating H1 Net Income to include Pref Shares in 16-17
Updating OPG Income Tax Expense for 2016-17
Updating OPG non-income tax PILs
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2017
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2018
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2019
Updating with actual OPG IFRS Adjustment 2016-17
Updating with actual OPG IFRS Adjustment 2016-17
Updating with actual OPG IFRS Adjustment 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
[NOT APPLIED] Updating H1 Brampton (Interim Adjustments)
Shifted H1 Brampton 2016-17 NI to the 2017-18
Removed H1 Brampton for 2016-17 (pending finals)
Removed H1 Brampton for 2016-17 (pending finals)
Removed H1 Brampton for 2016-17 (pending finals)

add prior-year adjustment for 2016-17

add prior-year adjustment for 2016-18
Reconfigured calculation of ESDI and MOF ESDI Expense
Reconfigured calculation of OPG 2017-18 Net Income
Backup for the Provincial Interest cost
Linking source for Revenue Risks Tab
New source for Revenue Risks Tab
Revenue Risks Tab - ROE Risks
Updating OEB Risk for OPG
OEB Staff Report - H1 Tx - Revenue Risks
OPG Pensions - Cash vs Accrual Deferral Accounts
Updating Links in Electricity Summary Change and OEFC Change
Preliminary estimate for Hydro One Brampton
Preliminary estimate for Hydro One Brampton
Preliminary estimate for Hydro One Brampton

Updating DRC for Actuals 2016-17 (Based on draft FS)
Updating PILs for 2016-17 Baced on Actuals
OPG: Non-ONFA Fair Value Adjustment
Round all Hydro One ownership assumptions to two decimal places
H1 Equity Adjustment rounding.
Round all Hydro One ownership assumptions to two decimal places
Round all Hydro One ownership assumptions to two decimal places
Revising source of ESDI, Dedicated Electricity Earnings
2016-17 - Update Power Supply Recoveries to actuals
2016-17 - Update Power Supply Recoveries to actuals
2016-17 - Updating Miscellaneous OEFC Revenue to Actuals
Adj: Exclude Bramton $15m add prior year adjustment +$3M
Adj: Exclude Bramton $15m add prior year adjustment +$3M
Public Accts: Updated IESO debt interest Interest On Debt, 2016-17
Public Accts: 2016-17 - Demand Management Support Costs Update
2017-18 - Demand Management Support Costs (no change)
Public Accts: 2016-17 - Updating Operating Expense in OEFC
Sourcing Provision for Electricity Sector from Actual Public Accounts
Revised 2016-17 Brampton Amount for Public Accounts
OPG Pensions - Cash vs Accrual Deferral Accounts (Revenue Risks Tab)
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
Reclassification
Reclassification
Reverting H1 Ownership change (undoing 20170518-3)
Reverting H1 Ownership change (undoing 20170518-3)
Reverting H1 Ownership change (undoing 20170518-3)
Updating Risks based on Hydro One Q2 Results Model
Avista Acquisition Risks
NUG Amortization Liability (sourcing amortization schedule)
2016-17 Actuals - Debt Guarantee Fee
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results

Interest Revenue for IESO and "Other"
OPG Revenue Risks from OEB Filings
Net income corrected for Preferred Shares
Net income corrected for Preferred Shares
Net income corrected for Preferred Shares
Made link edits to OPG sheet so that the "Net Income Before Tax" 2017-18 number is not a hardc
Updated PILs to include OPCD public accounts adjustment
Provision tab fix to pick up Hydro One preferred share net income
Provision tab fix to pick up Hydro One preferred share net income
FTD Update to OEFC Outlook (Sep 19, 2017) OPG Interest
FTD Update to OEFC Outlook (Sep 19, 2017) Other Interest
Update to Hydro One PILs from information in Transmission rate application material
OEB September 28, 2017 Hydro One decision and order impact - incl. rebasing
OEB September 28, 2017 Hydro One decision and order impact - incl. rebasing
OEB September 28, 2017 Hydro One decision and order impact - incl. rebasing
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Debenture Interest Costs - Removing from Revenue (Risks) and adding it ot H1 Model
Debenture Interest Costs - Removing from Revenue (Risks) and adding it ot H1 Model
Debenture Interest Costs - Removing from Revenue (Risks) and adding it ot H1 Model
Updated OPG Net Income and PILs based on monthly report (August 2017 results)
Updated OPG Net Income and PILs based on monthly report (August 2017 results)
Updated OPG Net Income and PILs based on monthly report (August 2017 results)
Correction to PILs on OPG sheet
Correction to PILs on OPG sheet
Correction to PILs on OPG sheet
Correction to PILs on OPG sheet
Switch to Direct from Model
Switch to Direct from Model
Switch to Direct from Model
Updating ROE Risks
Updating H1 Load Risks based on model output
Updating ONFA Risks for September 2017
Adjust OEB decision/rebasing to ~50% provincial ownership
Adjust OEB decision/rebasing to ~50% provincial ownership
Adjust OEB decision/rebasing to ~50% provincial ownership
Updating OPG
OPG IOD impact from GA Financing, FHP
OPG IOD impact from GA Financing, FHP
OPG IOD impact from GA Financing, FHP
Unpacking updated OPG Gain on sale (net income)
Unpacking updated OPG Gain on sale (net income)
Unpacking updated OPG Gain on sale (net income)
Unpack PILs related to HQ gain on sale
Updating IFRS Risk
Adjustment for lower Provincial share (from 70.1% to 50.9 2017-18 & 47.4% after)
Adjustment for lower Provincial share (from 70.1% to 50.9 2017-18 & 47.4% after)
Adjustment for lower Provincial share (from 70.1% to 50.9 2017-18 & 47.4% after)
November 1 and November 7 Hydro One model updates

November 1 and November 7 Hydro One model updates
November 1 and November 7 Hydro One model updates
Revise Hydro Model to reverse OEB tax decision ongoing annual impact
Revise Hydro Model to reverse OEB tax decision ongoing annual impact
Revise Hydro Model to reverse OEB tax decision ongoing annual impact
Undo allocation adjustment in H1 tab (now that provincial shares are updated)
Undo allocation adjustment in H1 tab (now that provincial shares are updated)
Undo allocation adjustment in H1 tab (now that provincial shares are updated)
Updating OPG Revenue Risks from rate application
Update Hydro One PILs (reverses update on line 119 whuich did not account fro Dx side)
Updating Debt Guarantee Fee
Updating OEFC Operating Expense
small changes - linking the net income numbers
Updated number of shares sold for First Nations (Dec 2017) sale
Updated number of shares sold for First Nations (Dec 2017) sale
Updated number of shares sold for First Nations (Dec 2017) sale
Implemented OEB's Dec 2017 payment amounts decision for OPG (CEFD Analysis)
Implemented OEB's Dec 2017 payment amounts decision for OPG (CEFD Analysis)
Implemented OEB's Dec 2017 payment amounts decision for OPG (CEFD Analysis)
Updated OPG Net Income (based on their Q3 update, Sep 30, 2017)
Updated OPG ONFA adjustment (up to Sep 30, 2017) in OPG tab (removed it from Risks table)
Removal of OPG ONFA Sep 2017 adjustment in Risks table
Included possible range (-50M to 50M) of impact for future OPG ONFA adjustment in the negative
Removal of negative regulatory risk: "OPG Switch from accrual based to cash based accounting f
Removal of negative regulatory risk: "Timing of OPG Rate Decision" from Risks table
Removal of negative regulatory risk: "OEB Staff Recommendations wrt OPG rate application(May
Removal of negative regulatory risk: "Nuclear Liabilities Cash vs. Accrual" from Risks table
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month
Updated estimates of NUG costs.
Updated estimates of NUG costs.
Unpacking OPG (Head Office sale)
Unpacking OPG (Head Office sale)
Unpacking OPG (Head Office sale)
Unpacking OPG (Head Office sale)
Unpacking Hydro One for AO (from 70.1% ownership to as of January 2018)
Unpacking Hydro One for AO (from 70.1% ownership to as of January 2018)
Unpacking Hydro One for AO (from 70.1% ownership to as of January 2018)
Update H1 allocations for additional shares (SIFB edits)
Update H1 allocations for additional shares (SIFB edits)
Update H1 allocations for additional shares (SIFB edits)
Updated (latest IOD) Debt Interest Expense line (OEFC on-deck tab) and OPG, IESO, and Other

ONFA consolidation adjustment for Dec 2017
OPG 2018-2021 BP preliminary net income update
OPG 2018-2021 BP preliminary net income update
OPG 2018-2021 BP preliminary net income update
OPG 2018-2021 BP preliminary Income Tax PILs
OPG 2018-2021 BP preliminary GRC payable to OEFC update
OPG 2018-21 BP preliminary Property Tax Payable to OEFC update
Removal of net income from estimated gain from Lakeview sale, as it has not been realized yet
Removal of PILs from estimated gain from Lakeview sale, as it has not been realized yet
Removal of net income from estimated gain from Lakeview sale, as it has not been realized yet
Removal of net income from estimated gain from Lakeview sale, as it has not been realized yet
Remove EFB OEB impact estimate
Remove EFB OEB impact estimate
Remove EFB OEB impact estimate
Update with Board-approved net income
Update with Board-approved net income
Update with Board-approved net income
Remove reversal of Lakeview proceeds on net income (now included)
Remove reversal of Lakeview proceeds on net income (now included)
Remove reversal of Lakeview proceeds on net income (now included)
Remove reversal of Lakeview proceeds on PILs (now included)
Update with Board-approved PILs
Update OPG Fair Hydro Plan amounts from OPG Busdiness Plan 2018-2021
Update OPG Fair Hydro Plan amounts from OPG Busdiness Plan 2018-2022
Update OPG Fair Hydro Plan amounts from OPG Busdiness Plan 2018-2023
Remove Hydro One Debenture Cost from Outlook (now in Model)
Remove Hydro One Debenture Cost from Outlook (now in Model)
Remove Hydro One Debenture Cost from Outlook (now in Model)
Annual Report 2017 Hydro One Net Income Updates
Annual Report 2017 Hydro One Net Income Updates
Annual Report 2017 Hydro One Net Income Updates
Adjustment from using quarterly actuals
Adjustment from using quarterly actuals
Adjustment from using quarterly actuals
Updating Hydro One debt interest Costs
Updating Hydro One debt interest Costs
February 15, 2018 FTD Update\
Update based on January 31, 2018 BSC material for OEFC YTD
Update from Hydro One Feb 16 (email to Gavin)
Update based on January 31, 2018 BSC material for OEFC YTD and Siva email
Updated OPG IFRS Impact
Updated OPG IFRS Impact
Updated OPG IFRS Impact
Rounding adjustment
Push recovery out one-year

This line show net impact of latest change. READ COMMENT

$ Millions

		2016-17	2017-18	2018-19	2019-20
		930	789	939	957
	File	915	1,675	368	798
		-15	886	-571	-158
	check	*0*	*0*	*0*	*0*
		Impacts by FY →			
Outlook line affected	**Expense / Rever**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
ONFA and other Fair Value Adjustments	Revenue	41.0	0.0	0.0	0.0
N/A		0.0	0.0	0.0	0.0
?		0.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		38.1		
Provision for Electricity Sector (MOF)	Expense		(38.1)		
Public Debt Interest - Electricity Sector	Expense	0.0	38.1	38.1	38.1
Interest on Debt	Expense	0.0	(69.1)	(79.1)	(75.1)
OPG Income	Expense	0.0	0.0	0.0	
OPG Income	Revenue	(2.0)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**(2.0)**			
Provision for Electricity Sector (MOF)	Expense	2.0			
HOI Income	Revenue	0.4			
Provision for Electricity Sector (OEFC)	Expense	0.4			
Provision for Electricity Sector (MOF)	Expense	(0.4)			
Public Debt Interest - Electricity Sector	Expense	1.7			
Provision for Electricity Sector (OEFC)	Expense	(1.7)			
Provision for Electricity Sector (MOF)	Expense	1.7			
Interest on Debt	Expense	(1.7)			
HOI Income	Revenue	(39.8)	0.0	0.0	(0.0)
Provision for Electricity Sector (OEFC)	Expense	**(39.8)**			
Provision for Electricity Sector (MOF)	Expense	39.8			
	Revenue	-	-	-	-
	Revenue	-	-	-	-
	n/a	-	-	-	-
		-	-	-	-
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	4.7	0.0	0.0	0.0
	Revenue	0.0	0.0	0.0	0.0
HOI Income	Revenue	18.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	7.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	8.0	9.0	12.0	3.5
HOI Income	Revenue	0.0	(141.5)	(181.4)	(194.9)
Provision for Electricity Sector (OEFC)	Expense		(141.5)		
Provision for Electricity Sector (MOF)	Expense		141.5		
OPG Income	Revenue	(3.0)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**(3.0)**			
Provision for Electricity Sector (MOF)	Expense	3.0			
HOI Income	Revenue	7.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**7.0**			
Provision for Electricity Sector (MOF)	Expense	(7.0)			
	Revenue	-	-	-	-
	Revenue	0.0	0.0	0.0	0.0
Brampton Income	Revenue	(14.7)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**(14.7)**			
Provision for Electricity Sector (MOF)	Expense	14.7			

Provision for Electricity Sector (OEFC)	Expense		3.2			
Provision for Electricity Sector (MOF)	Expense		(3.2)			
	Revenue	-	-	-	-	
		-	-	-	-	
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
Brampton Income	Revenue		15.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		**15.0**			
Provision for Electricity Sector (MOF)	Expense		(15.0)			
Provision for Electricity Sector (OEFC)	Expense		3.2			
Provision for Electricity Sector (MOF)	Expense		(3.2)			
Electricity Debt Retirement Charge	Revenue		(4.0)	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue		(29.0)	0.0	0.0	0.0
OPG Income	Revenue		(6.0)	0.0	0.0	0.0
HOI Income	Revenue		(0.0)	(0.0)	0.0	0.0
HOI Income	Revenue		(1.7)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense			(0.0)		
Provision for Electricity Sector (MOF)	Expense			0.0		
	Revenue		0.0	0.0	0.0	0.0
Power Supply Contract Recoveries	Revenue		99.0	0.0	0.0	0.0
Power Supply Contract Costs	Expense		(99.0)			
Miscellaneous	Revenue		14.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		(12.0)			
Provision for Electricity Sector (MOF)	Expense		12.0			
Interest on Debt	Expense		(3.0)	0.0	0.0	0.0
Demand Management Support Costs	Expense		1.8	0.0	0.0	0.0
			0.0	0.0	0.0	0.0
Other (Finance)	Expense		(1.0)	0.0	0.0	0.0
	Revenue	-	-	-	-	
Brampton Income	Revenue		3.0	0.0	0.0	0.0
			0.0	0.0	0.0	0.0
OPG Income	Revenue		0.0	85.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue			(6.0)		
Provision for Electricity Sector (OEFC)	Expense			**85.0**		
Provision for Electricity Sector (MOF)	Expense			(85.0)		
OPG Income	Revenue		6.0			
ONFA and other Fair Value Adjustments	Revenue		(6.0)			
HOI Income	Revenue		0.0	141.9	181.8	195.4
Provision for Electricity Sector (OEFC)	Expense			141.9		
Provision for Electricity Sector (MOF)	Expense			(141.9)		
	n/a		0.0	0.0	0.0	0.0
			0.0	0.0	0.0	0.0
Net Reduction of Power Purchase Contracts	Revenue		0.1	(0.1)	(0.1)	(0.1)
	Revenue		0.0	0.0	0.0	0.0
OPG Income	Revenue		0.0	16.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue			(1.0)		
Provision for Electricity Sector (OEFC)	Expense			**16.0**		
Provision for Electricity Sector (MOF)	Expense			(16.0)		

		0.0	0.0	0.0	0.0
	n/a	0.0	0.0	0.0	0.0
HOI Income	Revenue	0.0	5.3	5.3	5.3
Provision for Electricity Sector (OEFC)	Expense		(12.4)		
Provision for Electricity Sector (MOF)	Expense		12.4		
oded formula in the cell	n/a	0.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	(30.4)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		17.8		
Provision for Electricity Sector (MOF)	Expense		(17.8)		
Interest on Debt	Expense	(0.0)	1.0	(0.0)	1.0
Interest on Debt	Expense	0.0	15.0	15.0	5.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	0.0	(7.8)	(8.7)	(10.3)
HOI Income	Revenue	0.0	(47.4)	(54.0)	(54.0)
Provision for Electricity Sector (OEFC)	Expense	0.0	(47.4)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	47.4	0.0	0.0
OPG Income	Revenue	0.0	(61.0)	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	0.0	(21.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	(61.0)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	61.0	0.0	0.0
OPG Income	Revenue	0.0	(21.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	(21.0)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	21.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	0.0	21.0	0.0	0.0
HOI Income	Revenue	0.0	(23.6)	(27.4)	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	(23.6)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	23.6	0.0	0.0
OPG Income	Revenue	0.0	15.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	15.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	(15.0)	0.0	0.0
OPG Income	Revenue	0.0	21.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	0.0	(18.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	21.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	(21.0)	0.0	0.0
HOI Income	Revenue	0.0	(23.8)	(28.9)	(10.1)
Provision for Electricity Sector (OEFC)	Expense	0.0	(23.8)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	23.8	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
HOI Income	Revenue		16.1	26.7	20.6
Provision for Electricity Sector (OEFC)	Expense		16.1		
Provision for Electricity Sector (MOF)	Expense		(16.1)		
n/a	n/a	0.0	0.0	0.0	0.0
OPG Income	Revenue		(4.9)	(11.9)	(17.1)
Provision for Electricity Sector (OEFC)	Expense		(4.9)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		4.9	0.0	0.0
OPG Income	Revenue		283.0		
Provision for Electricity Sector (OEFC)	Expense		283.0		
Provision for Electricity Sector (MOF)	Expense		(283.0)		
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue		95.0		
OPG Income	Revenue		0.0	(475.0)	(500.0)
HOI Income	Revenue		(112.6)	(142.1)	(170.6)
Provision for Electricity Sector (OEFC)	Expense		(112.6)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		112.6	0.0	0.0
HOI Income	Revenue		(3.3)	(3.0)	(0.1)

Provision for Electricity Sector (OEFC)	Expense		(3.3)		
Provision for Electricity Sector (MOF)	Expense		3.3		
HOI Income	Revenue		14.7	14.4	12.9
Provision for Electricity Sector (OEFC)	Expense		14.7	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		(14.7)	0.0	0.0
HOI Income	Revenue		(16.1)	(26.7)	(20.6)
Provision for Electricity Sector (OEFC)	Expense		(16.1)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		16.1	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)		0.0	7.8	8.7	10.3
n/a	n/a	0.0	0.0	0.0	0.0
Other (Finance)			0.0	(1.0)	(1.0)
OPG Income	Revenue		0.0	0.0	0.0
HOI Income	Revenue		0.1	0.5	0.6
Provision for Electricity Sector (OEFC)	Expense		0.1	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		(0.1)	0.0	0.0
OPG Income	Revenue		(477.1)	(145.2)	(153.1)
Provision for Electricity Sector (OEFC)	Expense		(305.7)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		305.7	0.0	0.0
OPG Income	Revenue		39.0	0.0	0.0
OPG - ONFA and other Fair Value Adjustments	Revenue		171.5	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
OPG Income	Revenue		119.3	36.3	38.3
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue		(119.3)	(36.3)	(38.3)
Provision for Electricity Sector (OEFC)	Expense		0.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		0.0	0.0	0.0
OPG Income	Revenue		(283.0)	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue		(95.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		0.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		0.0	0.0	0.0
HOI Income	Revenue		116.8	147.1	176.1
Provision for Electricity Sector (OEFC)	Expense		0.0	0.0	80.3
Provision for Electricity Sector (MOF)	Expense		0.0	0.0	(80.3)
OPG Income	Revenue		37.5	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue		12.5	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		0.0	14.4	23.1
Provision for Electricity Sector (MOF)	Expense		0.0	(14.4)	(23.1)
Power Supply Contract Recoveries	Revenue		(109.9)	(142.1)	(166.7)
Power Supply Contract Costs	Expense		109.9	142.1	166.7
OPG Income	Revenue		283.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue		95.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		141.1	141.9	0.0
Provision for Electricity Sector (MOF)	Expense		(141.1)	(141.9)	0.0
HOI Income	Revenue		(116.8)	(147.1)	(176.1)
Provision for Electricity Sector (OEFC)	Expense		(116.8)	(147.1)	(103.4)
Provision for Electricity Sector (MOF)	Expense		116.8	147.1	103.4
HOI Income	Revenue		(0.0)	(0.2)	(0.2)
Provision for Electricity Sector (OEFC)	Expense		(0.0)	(0.2)	0.0
Provision for Electricity Sector (MOF)	Expense		0.0	0.2	0.0
Interest on Debt	Expense		(2.5)	8.0	(7.0)

OPG - ONFA and other Fair Value Adjustments	Revenue	22.5	0.0	0.0
OPG Income	Revenue	327.0	113.0	325.0
Provision for Electricity Sector (OEFC)	Expense	327.0	113.0	252.0
Provision for Electricity Sector (MOF)	Expense	(327.0)	(113.0)	(252.0)
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	54.0	(77.0)	7.0
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	(8.0)	(15.0)	(10.0)
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	(5.0)	(5.0)	(5.0)
OPG Income	Revenue	(185.0)	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	(65.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	(185.0)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	185.0	0.0	0.0
OPG Income	Revenue	427.1	145.2	153.1
Provision for Electricity Sector (OEFC)	Expense	427.1	145.2	153.1
Provision for Electricity Sector (MOF)	Expense	(427.1)	(145.2)	(153.1)
OPG Income	Revenue	11.0	4.0	2.0
Provision for Electricity Sector (OEFC)	Expense	11.0	4.0	2.0
Provision for Electricity Sector (MOF)	Expense	(11.0)	(4.0)	(2.0)
OPG Income	Revenue	185.0		
Provision for Electricity Sector (OEFC)	Expense	185.0		
Provision for Electricity Sector (MOF)	Expense	(185.0)		
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	65.0		
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	5.0	(4.0)	(2.0)
OPG Income	Revenue	(2.3)	37.5	67.7
Provision for Electricity Sector (OEFC)	Expense	(2.3)	37.5	67.7
Provision for Electricity Sector (MOF)	Expense	2.3	(37.5)	(67.7)
HOI Income	Revenue	17.1	18.6	0.0
Provision for Electricity Sector (OEFC)	Expense	17.1	18.6	0.0
Provision for Electricity Sector (MOF)	Expense	(17.1)	(18.6)	0.0
HOI Income	Revenue	8.4	7.7	24.4
Provision for Electricity Sector (OEFC)	Expense	8.4	7.7	24.4
Provision for Electricity Sector (MOF)	Expense	(8.4)	(7.7)	(24.4)
HOI Income	Revenue	(8.5)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	(8.5)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	8.5	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		50.4	50.4
Provision for Electricity Sector (MOF)	Expense		(50.4)	(50.4)
Interest on Debt	Expense	0.5	(4.0)	(5.0)
Electricity Debt Retirement Charge	Revenue	(19.0)	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	3.5	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	(35.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	100.0	100.0	225.0
Provision for Electricity Sector (MOF)	Expense	(100.0)	(100.0)	(225.0)
OPG Income	Revenue	100.0	100.0	225.0
		(0.0)	(0.0)	(0.0)
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	0.0	(18.0)	(19.0)

0	***0***	***0***	***0***

2020-21
1,676
856
-820
0

2020-21	Further Explanation of Change and source of data
0.0	Regular quarterly ONFA Update
0.0	Benefit to OEFC under s.50.3: $411M gain, SIFB
0.0	Change to OEFC payment for interest costs of Debt for Equity Swap
38.1	Revised Provincial Debt Interest related to Hydro One Equity
(104.1)	From FTD, revised Debt Interest (net of revisions to Provincial and OPG debt interest)
0.0	Revised numbers from OEP with 2019-20 Risk
0.0	Updated numbers from OPG Q1 2017 FS
0.0	Updating H1 Net Income for actuals. Note does not update Brampton Income at this point. Will
-	No Change to numbers, just re-inputting data and saving sources
-	No Change to numbers, just re-inputting data and saving sources
-	No change to fiscal impact numbers. Deleting Budget 2016 and adding Budget 2017 fiscal imp
-	No Change to numbers, just re-inputting data and saving sources
0.0	Updated with CIT Numbers received from H1 as part of s.91.2 MB20 allocation from MOF
0.0	No Change to numbers, just re-inputting data and saving sources
0.0	Only included H1 Net Income - Common Shareholders before. Added preferred shareholder im
0.0	Updating OPG Income Tax Expense with info from OPG Monthly Presentation to Shareholder
1.8	Updating OPG GRC payable to OEFC and Proxy Property Tax from Answer back from OPG al
(210.6)	Based on H1 final offering and expected First Nations Sale by the end of 2017 (CY), with a wei
0.0	Based on EY analysis, and then applying fiscalization. Confirmation also received from OPCD.
0.0	Based on KPMG analysis, then fiscalization and other adjustments from OPCD.
-	**[NOT APPLIED, CALCULATIONS AND DATA LEFT ON THE FILE]** Used Brampton's Financ
0.0	Don't expect finalized 2016-17 data to become available in time for ESDI allocation. Will shift th
0.0	make decision on shifting when we know 2016-17 status.

-	No change to numbers. Just re-organizing spreadsheet. No backup data.
-	No change to numbers. Just re-organizing spreadsheet. No backup data.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided another scenario backup/source
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just updated the links to refer ot the delta between 2017 and On Deck
0.0	Adjustment to ESDI to include Hydro One Brampton
0.0	Finalizing 2016-17 DRC Based on Draft OEFC AR
0.0	Received actual PILs amounts from FTD with breakdown of source. Updated 2016-17 numbers
0.0	2016-17 - Non-ONFA Fair Value Adjustment
0.0	Round Hydro One ownership assumptions to 70.05% two decimal places to be consistent with
0.0	Revising Hydro One Amount for consistency with OPCD. Equity Adjustments
0.0	Updated Provision tab. Made two separate Provision amounts for ESDI in OEFC AR and Dedic
0.0	Updating Power Supply Recoveries to Public Accounts/OEFC AR actuals
0.0	Updating Miscellaneous to OEFC AR actuals
0.0	Updated 2016-17 Interest on Debt (IESO, OPG, Other (Net))
0.0	
0.0	2017-18 - Demand Management Support Costs (no change) - Linking correctly
0.0	2016-17 - Updating Operating Expense in OEFC and corresponding changes elsewhere and s
-	No change to numbers. Just re-organized spreadsheet
0.0	Revised H1 Brampton Net Income (for GBE Line only)
0.0	Revising for OPG's Q3 Finances
0.0	Revising OPG's Net Income for latest monthly report
211.1	Reverting ownership back to 70.05% from change 20170518-3. Will coordinate with other area
0.0	Updating Risks based on Hydro One Q2 Results Model
0.0	Updated two Risk components for the Avista Acquisition.
(0.0)	No significant changes, but used actual amortization liability schedule. Hence the rounding imp
0.0	Updating Debt Guarantee for actuals based on OEFC AR
0.0	Revising OPG's Net Income for latest monthly report

0.0	Linking interest revenue data for 2017-18 to 2020-21
0.0	OPG Revenue Risks from: OEB Staff Submission and OPG Updated Filings
5.3	Corrected Net income for 100% ownership in preferred shares and 70.05% in Commons Share
0.0	Updated the formula in the cell for 2017-18 Net Income Before Tax so that the numbers are no
0.0	Updated PILs to include OPCD public accounts adjustment
1.3	
5.0	
(12.2)	
(54.0)	
0.0	
0.0	
0.0	increase built into net income was $82m between NI and PILs
0.0	Remove $21m from PILs
0.0	expense impacts
0.0	expense impacts
0.0	need to also remove the $21m PILs built into OPG net incme
0.0	
0.0	
0.0	We removed $21m from PILs above, before having added it in (check is that lines 123 to 130 a
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
(13.0)	variances include: 2017-18 preferred vs common share fix, 2018-19 largely ROE change from
0.0	
0.0	
0.0	
0.0	
0.0	
21.6	
0.0	
(24.1)	
0.0	
0.0	**Distribution (October)**
(750.0)	
(185.3)	
0.0	
0.0	
(2.3)	

15.2	
0.0	
0.0	
(21.6)	
0.0	
0.0	
0.0	Updating OPG Rate application Revenue Risks based on revised calculations
12.2	
0.0	
(1.0)	Received Revised FTD Forecast
0.3	
0.7	
0.0	
0.0	
(180.7)	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	Removed based on Dec 2017 OEB decision
0.0	Removed based on Dec 2017 OEB decision
0.0	Removed based on Dec 2017 OEB decision
0.0	Removed based on Dec 2017 OEB decision
45.2	
(45.2)	
44.2	
(44.2)	
0.0	
0.0	
(44.2)	
44.2	
190.8	
311.7	
(311.7)	
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M
(170.7)	
170.7	
0.0	
0.0	
0.0	
0.0	
(190.8)	
(263.6)	
263.6	
(0.3)	
(0.5)	
0.5	**Distribution (January)**
0.4	

0.0
(39.3)
33.7
(33.7)
(127.3)
(10.0)
(6.0)
0.0
0.0
0.0
0.0
180.7
180.7
(180.7)
3.0
3.0
(3.0)

(2.0)
96.5
96.5
(96.5)
0.0
0.0
0.0
19.2
19.2
(19.2)
0.0
0.0
0.0
50.4
(50.4)
(4.4)
0.0
0.0
0.0
325.0
(325.0)
325.0
(0.0)
(9.0)

0

Data Validation:

Options
Revenue (F
OPG
Hydro One
Provision

ONFA
Other Data

update once revised numbers are received.

acts

ıpact as well.

bout the BP
ghted average ownership for 2017-18. Also adjusted future net income attributed to the province.

ial Statements to produce an estimate. May require additional calculations.
ıis to 2017-18.

(from 2016 and On Deck)

s to reflect this.

OPCD.

:ated Earnings in Public Accounts.

ources.

s to ensure broadening change and reduction in net income happens concurrently in forecasts.

acts/changes.

es

t hardcoded directly

dd up to -$82m gain that we wanted to remove.

9.09% to 8.78% not previously captured.

Risks)

Electricity Sector Outlook

$ Millions

	Actual 2015-16	Interim 2016-17	Plan 2017-18	2018-19	2019-20	2020-21
On Deck Outlook as of March 2017						
Income from Investment in Government Business Enterprises						
OPG Income[1]	291	304	97	732	625	1,066
OPG - ONFA and other Fair Value Adjustments[2]	172	8	-	-	-	-
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	-
HOI Income[3]	236	516	520	562	603	652
Brampton Income	20	15	-	-	-	-
Total OPG and HOI Income	**719**	**842**	**617**	**1,294**	**1,229**	**1,717**
Other Fees and Licences	**127**	**122**	**102**	**91**	**88**	**81**
Electricity Expenses of the Province						
Provision for Electricity Sector[4]	(3)	(342)	(125)		-	-
Public Debt Interest - Electricity Sector	(520)	(492)	(492)	(492)	(492)	(492)
Subtotal	(523)	(834)	(617)	(492)	(492)	(492)
Public Debt Interest - Impact of ONFA						
Amortization of Deferred Revenue re profit on sale of H1 notes						
Total Electricity Expenses of the Province	**(523)**	**(834)**	**(617)**	**(492)**	**(492)**	**(492)**
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	3,228	373	405	476	538	679
Other Revenue						
Electricity Debt Retirement Charge[5]	859	625	623	-	-	-
Power Supply Contract Recoveries	875	739	292	325	301	273
Net Reduction of Power Purchase Contracts	172	129	74	41	30	28
Other Fees and Licences	(127)	(122)	(102)	(91)	(88)	(81)
Miscellaneous	9	-	-	-	-	-
Expenses						
Interest on Debt	(596)	(532)	(422)	(374)	(342)	(250)
Power Supply Contract Costs	(875)	(739)	(292)	(325)	(301)	(273)
Electricity Consumer Price Protection Fund	-	-	-	-	-	-
Demand Management Support Costs[6]	(8)	(10)	(10)	-	-	-
Provision for Electricity Sector	3	342	125	-	-	-
Other (Finance)	(7)	(6)	(6)	(6)	(6)	(6)
Total OEFC Income	**3,533**	**800**	**687**	**46**	**132**	**370**
Impact on Surplus/(Deficit)	**3,856**	**930**	**789**	**939**	**957**	**1,676**

Notes: The Hydro One net income outlook above (2016-17 to 2020-21) reflects the Province's 70% ownership share after the initial IPO in 2015 and the secondary offering in April 2016. At the time of 2017 Budget, net estimated fiscal impacts from future Hydro One offerings are reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

Notes:

1.OPG's 2016-17 outlook reflected its reported earnings. 2017-18 to 2019-20 reflects OPG's preliminary 2017-2019 business plan (as fiscalized by OPG). 2020-21 estimates are based on OPG's calendar year-based business plan projections. OPG net income also reflects IFRS adjustments fiscal impact decisions that were made centrally.

2. Provincial consolidation adjustments for unrealized earnings on the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds, as of the end of December 2016.

3. Hydro One 2016-17 income reflects its reported net income, adjusted for Hydro One IPO impacts. 2017-18 to 2020-21 projections are based on CEFD projections using the latest public information. The Hydro One net income outlook above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering as of 2017 Budget were reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial ONFA consolidation adjustments, less the interest on the Province's OPG/Hydro One debt payable to OEFC. The provision is currently assumed to end once the DRC ends on a legislated fixed end date of April 1, 2018.

5. Reflects April 23, 2014 announcement that DRC will be eliminated for residential users, after December 31, 2015. The end date of DRC for remaining users is legislated to be on April 1, 2018. Estimates are subject to change based on actual consumption.

6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Electricity Sector Outlook

$ Millions

	Actual 2014-15	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
On Deck Outlook as of February 2018							
Income from Investment in Government Business Enterprises							
OPG Income[1]	574	291	299	905	500	728	677
OPG - ONFA and other Fair Value Adjustments[2]	239	172	43	194	-	-	-
Hydro One - Unrealized Gains Adjustment	(8)	-	-	-	-	-	-
HOI Income[3]	741	236	500	346	353	412	438
Brampton Income		20	18	-	-	-	-
Total OPG and HOI Income	**1,546**	**719**	**860**	**1,445**	**853**	**1,140**	**1,115**
Other Fees and Licences (Debt Guarantee fee)	**131**	**127**	**122**	**102**	**99**	**98**	**91**
Electricity Expenses of the Province							
Provision for Electricity Sector[4]	(795)	-	(290)	(797)	(449)	(736)	(711)
Public Debt Interest - Electricity Sector	(520)	(520)	(514)	(454)	(404)	(404)	(404)
Subtotal	(1,315)	(520)	(803)	(1,251)	(853)	(1,140)	(1,115)
Public Debt Interest - Impact of ONFA							
Amortization of Deferred Revenue re profit on sale of H1 notes							
Total Electricity Expenses of the Province	**(1,315)**	**(520)**	**(803)**	**(1,251)**	**(853)**	**(1,140)**	**(1,115)**
OEFC Income							
Taxation Revenue							
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	180	3,247	334	499	369	512	526
Other Revenue							
Electricity Debt Retirement Charge[5]	956	859	621	604	-	-	-
Power Supply Contract Recoveries	950	875	838	182	183	134	103
Net Reduction of Power Purchase Contracts	217	172	129	74	41	30	28
Other Fees and Licences	(131)	(127)	(122)	(102)	(99)	(98)	(91)
Miscellaneous	9	9	14	-	-	-	-
Expenses							
Interest on Debt	(658)	(596)	(513)	(477)	(484)	(473)	(402)
Power Supply Contract Costs	(950)	(875)	(838)	(182)	(183)	(134)	(103)
Electricity Consumer Price Protection Fund	-	-	-	-	-	-	-
Demand Management Support Costs[6]	(9)	(8)	(8)	(10)	-	-	-
Provision for Electricity Sector	795	-	290	797	449	736	711
Other (Finance)	(6)	(7)	(7)	(6)	(7)	(7)	(7)
Total OEFC Income	**1,353**	**3,549**	**737**	**1,379**	**269**	**700**	**765**
Impact on Surplus/(Deficit)	**1,715**	**3,876**	**915**	**1,675**	**368**	**798**	**856**
variance to OEFC check		*(156)*	*(454)*	*(531)*	-	-	-

Notes:

1.OPG's 2017-18 to 2020-21 outlook reflects OPG's 2018-2021 Business Plan and Includes OPG head office properties sale proceeds and Lakeview property sale proceeds. 2021-22 estimates are based on OPG's calendar year-based business plan projections for 2021 and a CEFD projection for 2022. OPG net income also reflect projected IFRS adjustments as provided by OPCD at the time of the 2017 Budget. Note: all Asset Optimization transactions are re-categorised from Sales and Rentals in this Outlook.

2. Provincial consolidation adjustments for unrealized earnings on the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds, as of the end of September 2017.

3. Hydro One 2017-18 is based on actual Hydro One results for 2017 and CEFD projection for 2018. Quarterly earnings are adjusted for the provincial ownership share during the quarter. 2018-19 and onwards are CEFD projections using the latest public information and reflects the Province's ownership share following the May 2017 share disposition and including the First Nations sale in December 2017. Note: all Asset Optimization transactions are re-categorised from Sales and Rentals in this Outlook.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial ONFA consolidation adjustments, minus the interest on debt payable to OEFC. The provision is now assumed to continue after 2017-18 based on TB/MBC approval of the PRRT submission to continue ESDI payments to OEFC beyond 2017-18.

5. Reflects that DRC eliminated for residential users, after December 31, 2015. The end date of DRC for remaining users is legislated to be on April 1, 2018. Estimates are subject to change based on actual consumption.

6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Electricity Sector Change Since Budget	$ Millions					
($million)	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Changes from Budget 2017 as of February 2018						
Income from Investment in Government Business Enterprises						
OPG Income	(5)	808	(232)	103	(389)	2016-17 small decrease due to IFRS adjustment revision and OPG Net Income revision. 2017-18 increase is largely due to the re-categorization from Sales and Rentals to OPG net income proceeds from the completed sale of OPG head office properties and prospective sale of Lakeview lands. This accounts for $483M of the increase. Note that while the re-categorization itself is fiscally-neutral, net income impacts of the proceeds from property sales are $206M higher than projected at the time of the 2017 Budget. 2017-18 results are also boosted by lower projected IFRS adjustment (by $100M) for 2017-18 and lower OPG expenses than estimated at the time of Budget 2017. 2018-19 to 2020-21 chnages reflect the negative impact of higher projeceted IFRS adjustment impacts over that period partially offset by higher OPG net income in 2018-19 and 2020-21 and more than offset by higher OPG net income in 2019-20.
ONFA and other Fair Value Adjustments	35	194	-	-	-	Largely revision to ONFA fair value as of December 31, 2017
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	
HOI Income	(16)	(173)	(209)	(191)	(214)	2016-17 slight decrease from Budget 2017 Interim projection. 2017-18 onwards mainly reflects i) re-categorization from Sales and Rentals to Hydro One net income of the impact of a lower Provincial share of Hydro One net income from Hydro One share sales ii) impact of OEB Sep. 2017 decision on Hydro One transmission rates and iii) interest expense on Avitsa debentures (in 2017-18 and 2018-19).
Brampton Income	3.3					
Total OPG and HOI Income	**17**	**828.5**	**(441)**	**(89)**	**(603)**	
Other Fees and Licences	**-**	**-**	**8**	**10**	**10**	
Electricity Expenses of the Province						
Provision for Electricity Sector	53	(672)	(449)	(736)	(711)	**[NOTE: A positive number on this line indicates a decrease in the provision, while a negative number means an increase in provision expense.]** Changes to the Provision (ESDI) expense in 2017-18 mainly reflect higher OPG net income due to recategorisation from Sales and Rentals (see above). Change in out-years reflects TB/MBC approval in 2017-18 PRRT approval to continue Provision for the Electricity Sector (i.e., Electricity Sector Dedicated Income to OEFC) beyond 2017-18. 2017 Budget assumed previous policy whereby ESDI ended after 2017-18.
Public Debt Interest - Electricity Sector	(22)	38	88	88	88	2016-17 PDI at ($514m) was slightly larger than ($492m) projected at Interim. 2017-18 and 2018-19 and onward change reflects revised projections for Provincial debt interest as a result of debt pay downs related to Hydro One's April 2016 and April 2017 offerings, repectively.
Total Electricity Expenses of the Province	**31**	**(635)**	**(361)**	**(648)**	**(623)**	

Electricity Sector Change Since Budget	$ Millions					
($million)	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs)	(40)	93	(107)	(26)	(152)	2016-17 decrease largely due to an OPCD Public Accounts PILs adjustment related to reconciling between OPCD and OEFC net opening assets. OPG PILs also slightly lower than projected. 2017-18 increase is largely due to inclusion of PILs related to disposition of OPG headquarters and Lakeview properties. 2018-19 onward lower mainly due to lower OPG income tax PILs. Property tax components are close to Budget 2017.
Other Revenue						
Electricity Debt Retirement Charge	(4)	(19)	-	-	-	
Power Supply Contract Recoveries	99	(110)	(142)	(167)	(170)	Variance in 16-17 is largely due to retroactive payments that the OEFC made to certain non-utility generators (NUGs) with former Ontario Hydro power purchase agreement (PPA) contracts with OEFC. OEFC was required to make these payment following the dismissal by the Supreme Court of Canada of OEFC's application for leave to appeal a judgment of the Court of Appeal of Ontario on a 2015 court decision. Going-forward, variance is largely due to suspension or early termination of some NUG PPAs in response to the IESO's NUG curtailment initiative.
Net Reduction of Power Purchase Contracts	0.1	(0)	(0)	(0)	(0)	
Other Fees and Licences	-	-	(8)	(10)	(10)	
Revenue Pool Residual	-	-	-		-	
Miscellaneous	14	-	-	-	-	
Expenses						
Interest on Debt	19	(55)	(110)	(131)	(152)	2017-18 and onward reflects revised debt interest outlook net of revisions to OEFC interest revenue from OPG, Hyro One IESO and Province.
Power Supply Contract Costs	(99)	110	142	167	170	Same as Power supply contract recoveries above. Power supply contract costs are fully recovered by power supply contract recoveries.
Electricity Consumer Price Protection Fund	-	-	-	-	-	
Demand Management Support Costs	1.8	-	-	-	-	
Provision for Electricity Sector	(53)	672	449	736	711	see explanation above for "Provision for Electriocty Sector" (line 17)
Other (Finance)	(1.0)	-	(1)	(1)	(1)	
Total OEFC Income	**(63)**	**692**	**223**	**568**	**395**	
Impact on Surplus/(Deficit)[1]	**-15**	**886**	**-571**	**-158**	**-820**	Note: A significant component of the changes above affecting this net is from a fiscally-neutral recategorisation of revenue impacts from the Asset Optimisation (AO) initiative previously shown in Sales and Rentals in Budget 2017 for commercial confidentiality. The pure changes to non-AO electricity sector changes is significantly fiscally negative. IN 2018-19 ONWARD. See summary table below for breakdown of total change between these components.
Information: Breakdown of change between revenue and expense						
Total Revenue Impact	87	793	(690)	(281)	(925)	
Total Expenditure impact	101	(93)	(119)	(123)	(105)	

Electricity Sector Outlook (PSAB)

Negative Revenue Risks	$ Millions				
($ millions)	Plan				
	2017-18	2018-19	2019-20	2020-21	2021-22
Generic					
OPG Generation Risk: Nuclear Output (-1.6 TWh)[1]	(120)	(120)	(120)	(120)	(120)
1% decrease in Hydro One actual load[2]	(57)	(59)	(62)	(63)	(63)
Lower OPG's Equity weighting & Return on Equity (ROE)[3]	(12)	(20)	(26)	(45)	(45)
Lower Hydro One Return on Equity (ROE)[4]	(9)	(36)	(38)	(40)	(40)
Operations Maintainance & Administration (labour costs etc.)		0 - (100)	0 - (100)	0 - (100)	0 - (100)
ONFA adjsutment risk		(400) to 0	(400) to 0	(400) to 0	(400) to 0
Regulatory					
Hydro One Distribution rate application[5]	(50)	(50)	(50)	(50)	(50)
OPG Switch from accrual based to cash based accounting for pension and OPEB[6]	—	(600)			
Regulatory Risk - Timing of OPG Rate Decision[7]	—				
OEB Staff Recommendations wrt OPG rate application(May 2017)[8]	—				
Nuclear Liabilities Cash vs. Accrual[9]	—				
OEB decision on Hydro One tax recapture (if one-time write-down)[10]	(420)				
Accounting					
OPG IFRS Consolidation Risks[11]		—	—	—	
Other Risks					
ONFA adjustment decrease[12]	(100)				
Avista Acquisition - Termination fee		(49)			
PILs risk related to retirement of Stranded debt and potential wind down of OEFC[13]					(20)

Note: These risks do not reflect the impacts on electricity sector revenue and expense of reclassification of the Asset Optimization strategy

1. OPG's market and generation risks related to nuclear reliability similar to the scenarios OPG developed for its sales margins to capture major market risk factors (e.g., natural gas prices, coal prices, foreign exchange, nuclear reliability) in its 2012 business plan. Currently, only the nuclear reliability risk is captured at the current regulated rate for OPG's nuclear generation.

2. Estimated revenue impact if Hydro One load for Transmission and Distribution is 1% lower than projected for all years in CEFD Hydro One Forecast. Based on the assumption a 1% increase in load is directly proportional to a 1% change in revenue requirements.

3. Risk range for Hydro One transmission and distribution reflects potential risk of lower ROE by 0.5% vs assumed ROEs in business plan along with reduced deemed debt to equity weighting of 55%/45% from the current 51%/49%.

4. Risk range for Hydro One transmission and distribution reflects potential risk of lower ROE by 0.5% vs assumed ROEs in CEFD Hydro One Forecast based on the most recent rate applications and forecasted ROE rates.

5. OEB is expected to make a decision on Hydro One's Distibution rate application for 2018 during the first half of 2018.

6. Previous risk removed shifted from 2017-18 to 2018-19. OEB's September 2017 Report, established accrual accounting method as default rate setting method to recover Pension and Other Pension Benefits (OPEBs) costs and recommended continuance of variance account tracking the difference between cash vs. accrual basis reporting for Pension and OPEB. This finding mitigates this risk. However, OEB December 28, OPG rate decision instructs OPG to submit request to dispose of Pension and OPEB deferral and variance account balances during 2018 for its 2019 payment application. OEB's final decision will be made at that time. Note, the impact of a decision could fall in 2019-20 depending on timing of the OEB decision.

7. **Previous risk removed with timing impact now reflected in OPG outlook.**. OEB December 28, decision and order provides an effective date for new rates of June 1, 2017. OPG's business plan assumed OEB decision would be effective as of January 1, 2017. OPG estimated an impact of -$60M for each month for which OEB decsion is not retroactive. The resulting $300M estimated impact has been included in the OPG outlook.

8. **Previous risk removed .** Estimated impact of OEB December 28the decision and order with respect to OPG rates is now reflected on the OPG Outlook.

9. **Previous risk removed.** Risk is related to potential switch to cash-basis accounting for regulated recovery of nuclear payment anmounts. OEB December 28, 2017 Decision and Order has deferred this issue to next OPG rate application in 2021 for 2022 to 2027 period.

10. The OEB's Sep. 28, 2017 ruling on Hydro One's Transmission rate application included direction on sharing, with ratepayers, tax savings related to the Hydro One IPO. Hydro One filed a Motion to Review this decision with the OEB and has also filed a court appeal. Hydro One's 2017 Q3 financial report notes that if the Motion to Review and appeal are unsuccesful the company would record a one-time write-down of $885 million (for transmission and distribution net income) reflecting the OEB decision. The risk above reflects this risk at the Province's current 47.4% average share allocation. Hydro One noted that timing for the Motion to Review and appeal is uncertain. It expects the OEB Review to start in Q1 but noted that it could run in to Q2. As a result the impact could occur in 2018-19.

11. **Previous risk figures removed.** OPCD provided IFRS impact estimates (largely related to OPG) at the time of Budget 2017. A portion of these were reflected in in OPG's and Hydro One's net income outlook at the time of the 2017. The current Electricity Outlook now reflects this additional IFRS risk. Table below outlines OPG IFRS Risks versus what is built into the 2017 Budget Fiscal Plan. The new IFRS adjustments figures are pending from OPG via Energy in the next few days.

	2017-18	2018-19	2019-20	2020-21
OPG IFRS Risk	(400)	(475)	(700)	(750)
Risks Built into Fiscal Plan at 2017 Budget	(400)	0	(200)	0
Additional Risks now picked up in this Electricity Outlook	0	(475)	(500)	(750)

Electricity Sector Outlook (PSAB)

Positive Revenue Risks				
($ millions)	**Plan**			
	2017-18	**2018-19**	**2019-20**	**2020-21**
Generic				
OPG Generation Risk: Nuclear Output (+1.1 TWh)[1]	85	85	85	85
1% increase in Hydro One actual load[2]	57	59	61	63
Higher OPG Return on Equity (ROE)[3]	6	22	19	33
Higher Hydro One Return on Equity (ROE)[4]	19	69	50	50
ONFA adjsutment risk		0 to 400	0 to 400	0 to 400
Regulatory				
Accounting				
Other Risks				
ONFA adjustment increase[5]	100			

or updates to AO strategy.

1. OPG's market and generation risks related to nuclear reliability similar to the scenarios OPG developed for its sales margins to capture major market risk factors (e.g., natural gas prices, coal prices, foreign exchange, nuclear reliability) in its 2012 business plan. Currently, only the nuclear reliability risk is captured at the current regulated rate for OPG's nuclear generation.

2. Estimated revenue impact if Hydro One load for Transmission and Distribution is 1% higher than projected for all years in CEFD Hydro One Forecast. Based on the assumption a 1% increase in load is directly proportional to a 1% change in revenue requirements.

3. Risk range for OPG reflects potential risk of higher ROE in 2018-2021 (for nuclear base) vs assumed ROE in OPG's 2016 business plan and corresponding rate application. Assumed ROE is 9.85%, respresenting recent in 2010.

4. Risk range for Hydro One transmission and distribution reflects potential risk of higher ROE vs assumed ROEs in the Hydro One CEFD Forecast for 2018-2021. Assumed ROE is 9.85%, representing recent high in 2010.

5. Reflects risk around the consolidation adjustment to OPG net income, whereby the realized portion of gains or losses of OPG's nuclear funds are added or subtracted from OPG net income. Currently $194M positive adjustment reflecting valuations as of December 31, 2017 is included in the OPG outlook. Given current market volatility the ONFA adjustment could change significantly by the end of the Province's fiscal year, March 31, 2018. The net debt adjustment to be included in the fiscal plan consistent with the December 31, 2017 valuations/reports would also be subject to the same type of volatility.

ONTARIO ELECTRICITY FINANCIAL CORPORATION
On Deck Outlook as of March 2017

$ Millions

	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Revenue						
Revenue Pool Residual						
Debt Retirement Charge	859	625	623	-	-	-
Payments-in-lieu of tax:						
OPG	268	302	315	366	408	537
Legacy Hydro One (Including Brampton)	2,929	7	2	2	2	2
Hydro One CIT dedicated to OEFC	3	20	20	22	23	25
MEUs	27	44	68	86	105	114
Total PILs & CIT dedicated to OEFC[1]	3,228	373	405	476	538	679
Interest :						
OPG	173	179	168	153	135	135
H1						
IESO	2	3	3	3	3	3
Province	520	492	492	492	492	492
Other	28	10	5	5	5	5
Total Interest	723	684	668	653	635	635
Power Supply Contract Recoveries	875	739	292	325	301	273
Amortization of NUG liability	172	129	74	41	30	28
Electricity sector dedicated income	3	342	525	-	-	-
Gain to OEFC under s. 50.3	172	-	-	-	-	-
Miscellaneous	9	-	-	-	-	-
	6,041	2,893	2,587	1,495	1,504	1,615
Expense						
Debt interest	1,319	1,216	1,090	1,027	977	885
Interest on nuclear risk funding						
Demand Management Support Costs	8	10	10	-	-	-
Amortization of deferred debt costs	-	-	-			
Power Supply Contract Costs	875	739	292	325	301	273
Debt Guarantee fee	127	122	102	91	88	81
Operating	7	6	6	6	6	6
	2,336	2,093	1,500	1,449	1,372	1,245
Excess (Deficiency) of Revenue over Expense	**3,705**	**800**	**1,087**	**46**	**132**	**370**
Prior period adjustment	87					
Stranded Debt - Year End	**4,393**	**3,593**	**2,506**	**2,460**	**2,328**	**1,958**

Note: All the Hydro One ownership broadening impacts, other than the ownership change from the initial IPO in 2015 and the secondary offering in April 2016, were reflected in Sales and Rentals as of the 2017 Budget.

ONTARIO ELECTRICITY FINANCIAL CORPORATION
On Deck Outlook as of February 2018

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Revenue						
Revenue Pool Residual						
Debt Retirement Charge	859	621	604	0	0	0
Payments-in-lieu of tax:						
OPG	268	224	440	277	401	394
Legacy Hydro One (Including Brampton)	2,929	4	2	2	2	2
Hydro One CIT dedicated to OEFC	3	25	24	22	23	25
MEUs	27	112	33	68	86	105
Total PILs & CIT dedicated to OEFC[1]	3,228	364	499	369	512	526
Interest :						
OPG	173	167	155	166	158	131
H1						
IESO	2	2	3	3	3	3
Province	520	514	454	404	404	404
Other	28	20	20	20	10	10
Total Interest	723	703	632	593	575	548
Power Supply Contract Recoveries	875	838	182	183	134	103
Amortization of NUG liability	172	129	74	41	30	28
Electricity sector dedicated income	3	302	797	449	736	711
Gain to OEFC under s. 50.3[2]	172	411	531	0	0	0
Miscellaneous	9	14	0	0	0	0
	6,041	3,382	3,319	1,634	1,987	1,916
Expense						
Debt interest	1,319	1,216	1,109	1,077	1,048	950
Interest on nuclear risk funding						
Demand Management Support Costs	8	8	10	0	0	0
Amortization of deferred debt costs	0	0	0			
Power Supply Contract Costs	875	838	182	183	134	103
Debt Guarantee fee	127	122	102	99	98	91
Operating	7	7	6	7	7	7
	2,336	2,191	1,409	1,366	1,287	1,151
Excess (Deficiency) of Revenue over Expense	3,705	**1,191**	**1,911**	**269**	**700**	**765**
Prior period adjustment	87					
Stranded Debt - Year End	4,393	**3,202**	**1,292**	**1,023**	**323**	**(442)**

1

Payments-in-lieu of tax:	2015-16 Public Accounts
OPG	290
Legacy Hydro One (Including Brampton)	2,941
Hydro One CIT dedicated to OEFC	0
MEUs	15
	3,247

2 **2017-18 value preliminary estimate, subject to change.**

ONTARIO ELECTRICITY FINANCIAL CORPORATION

Changes from Budget 2017 as of February 2018 **$ Millions**

	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Revenue						
Debt Retirement Charge	(4)	(19)	-	-	-	
Payments-in-lieu of tax:						
OPG	(78)	125	(89)	(7)	(143)	2016-17 decrease largely due to an OPCD Public Accounts PILs adjustment related to reconciling between OPCD and OEFC net opening assets. OPG PILs also slightly lower than projected. 2017-18 increase is largely due to inclusion of PILs related to disposition of OPG headquarters and Lakeview properties. 2018-19 onward lower mainly due to lower OPG income tax PILs. Property tax componenst are close to Budget 2017. .
Legacy Hydro One (Including Brampton)	(3)	-	-	-	-	
Hydro One CIT dedicated to OEFC	5	3	-	-	-	Adjustment based on updated information in Hydro One rate application
MEUs	68	(35)	(18)	(19)	(9)	Large increase in 2016-17 from $80M payment during transfer of H01 Brampton to new consolidated MEU Alectra. Reduction in 17-18 based on YTD actual MEU PILs.
Total PILs	(9)	93	(107)	(26)	(152)	
Interest :						
OPG	(12)	(13)	13	23	(4)	Update to OPG interest outlook (wrt interest on OEFC loan).
H1	-	-	-	-	-	
IESO	(1)	-	-	-	-	
Province	22	(38)	(88)	(88)	(88)	2016-17 PDI at ($514m) was slightly larger than ($492m) projected at Interim. 2017-18 and 2018-19 and onward change reflects revised projections for Provincial debt interest as a result of debt pay downs related to Hydro One's April 2016 and May 2017 offerings, repectively.
Other	10	15	15	5	5	
Total Interest	19	(36)	(60)	(60)	(87)	
Power Supply Contract Recoveries	99	(110)	(142)	(167)	(170)	Variance in 16-17 is largely due to retroactive payments that the OEFC made to certain non-utility-generators (NUGs) with former Ontario Hydro power purchase agreement contracts with OEFC. OEFC was required to make these payment following the dismissal by the Supreme Court of Canada of OEFC's application for leave to appeal a judgment of the Court of Appeal of Ontario on a 2015 court decision. Going-forward, variance is largely due to suspension or early termination of some NUG PPAs in response to the IESO's NUG curtailment initiative.
Amortization of NUG liability	0	(0)	(0)	(0)	(0)	
Electricity sector dedicated income	(41)	272	449	736	711	The decrease in OEFC ESDI in 2016-17 reflects i) the IFRS adjustment of $400 million in 2017-18 that was not reflected in the OEFC ESDI projection at the time of the 2017 Budget (Note the IFRS adjustment was reflected in OPG net income for the 2017 Budget fiscal plan) and ii) the lower OPG and Hydro One net income due to OEB's 2017 rate decisions. Changes to the Provision (ESDI) expense in 2017-18 mainly reflect higher OPG net income due to recategorisation from Sales and Rentals of proceeds from the sale of OPG headquarters properties and Lakeview properties. Th eincrease in 2018-19 onward reflects TB/MBC approval in 2017-18 PRRT approval to continue Provision for the Electricity Sector (i.e., Electricity Sector Dedicated Income to OEFC) beyond 2017-18. 2017 Budget assumed previous policy whereby ESDI ended after 2017-18.
Gain to OEFC under s. 50.3	411	531	-	-	-	
Miscellaneous	14	-	-	-	-	
	489	732	139	483	301	
Expense						
Debt interest	-	19	50	71	65	Revised outlook for OEFC debt interest outlook
Interest on nuclear risk funding	-	-	-	-	-	
Demand Management Support Costs	(2)	-	-	-	-	
Amortization of deferred debt costs	-	-	-	-	-	
Power Supply Contract Costs	99	(110)	(142)	(167)	(170)	Same as Power supply contract recoveries above. Power supply contract costs are fully recovered by power supply contract recoveries.
Debt Guarantee fee	-	-	8	10	10	
Operating	1	-	1	1	1	
	98	(91)	(83)	(85)	(94)	
Excess (Deficiency) of Revenue over Expense	**391**	**823**	**223**	**568**	**395**	
Stranded Debt - Year End	**(391)**	**(1,214)**	**(1,437)**	**(2,005)**	**(2,400)**	

Provision for Electricity Sector (Dedicated Electricity Earnings/Electricity Sector Dedicated Earnings)

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Income from Investment in Government Business Enterprises						
OPG Income	291	299	905	500	728	677
Hydro One Income[1]	232	501	346	353	412	438
Hydro One Brampton (if applied separately)		15				
Total Income	**523**	**815**	**1,251**	**853**	**1,140**	**1,115**
Public Debt Interest - Electricity Sector						
OPG			(300)	(300)	(300)	(300)
Hydro One[1]			(154)	(104)	(104)	(104)
Public Debt Interest - Electricity Sector (OEFC Interest revenue)	**(520)**	**(514)**	**(454)**	**(404)**	**(404)**	**(404)**
MOF Provision Expense (before adjustments)	**3**	**302**	**797**	**449**	**736**	**711**
Other Adjustments						
Prior-year Adjustment[2]		3				
Exclude Brampton[3]		(15)				
MOF Provision Expense (after other adjustments)	**0**	**290**	**797**	**449**	**736**	**711**
Cumulative Shortfall Adjustment						
Opening Balance	0	0	0	0	0	0
Deduction / (Addition)	0	0	0	0	0	0
Ending Balance	0	0	0	0	0	0
Dedicated Electricity Earnings (all adjustments) (Public Accounts)	**0**	**290**	**797**	**449**	**736**	**711**
Electricity Sector Dedicated Income (OEFC Annual Report)	**3**	**302**	**797**	**449**	**736**	**711**

Notes:

1. The Hydro One financials above now reflects the Provincial share allocation as of January 2018.

2. 2016-17 Adjustment was due to the discrepancy between the numbers in MOF expense in PA 2015-16 and OEFC Financials in 2015-16 due to timing issues. $3M adjustment rectifies this discrepancy

3. Brampton was excluded from the Ministry of Finance's ESDI allocation.

Ontario Power Generation

OPG Income - Budget 2017

$ Millions

	Actual	Interim	Plan				
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22
OPG Net Income After Tax (Adjusted)	291	304	97	732	625	1,066	
OPG Net Income After Tax	*291*	*379*	*480*	*678*	*726*	*913*	
Extraordinary Gains	-	-	-	-	-	-	
GA - OPG Trust Interest Revenue			*17*	*54*	*99*	*153*	
OPG IFRS consolidation risk picked up in Fiscal Plan		(75)	(400)		(200)		
ONFA and other Fair Value Adjustments	(75)	8					
ONFA Adjustments	-	8					
Other Fair Value Adjustments	(75)						

OPG PIL - Budget 2017

$ Millions

	Actual	Interim		
	2015-16	2016-17	2017-18	2018-19
Net Income Before Tax	383	396	572	867
Net Income After Tax (Adjusted)	291	304	97	732
Income Taxes	92	92	92	135
GRC: Payable to OEFC	198	196	205	212
Proxy Property Tax	16	14	18	19
Ontario Capital Tax	0	0	0	0
Total	**306**	**302**	**315**	**366**

OPG Income - January 2018

$ Millions

	Actual	Actual	Current Outlook				
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22
OPG Net Income	291	377	1,195	795	1,053	877	1,070
GA Financing - OPG Trust Interest Revenue[2]			10	80	150	225	225
OPG IFRS consolidation risk[3]		(78.00)	(300)	(375)	(475)	(425)	(625)
OPG Net Income (Adjusted before ONFA)	**291**	**299**	**905**	**500**	**728**	**677**	**670**
ONFA Adjustments	247	49	194				
Other Fair Value Adjustments	(75)	(6)					
ONFA and other Fair Value Adjustments	**172**	**43**	**194**				
OPG Net Income	**463**	**342**	**1,099**	**500**	**728**	**677**	**670**

OPG PIL - January 2018

$ Millions

	Actual	Actual		Cu
	2015-16	2016-17	2017-18	2018-19
Income Before Tax	383	308	1,126	554
OPG Net Income (Adjusted before ONFA)	291	299	905	500
OPG Income Tax (PILs)	92	9	221	54
GRC: Payable to OEFC	198	201	206	209
Proxy Property Tax to OEFC	16	14	13	14
Ontario Capital Tax	0	0	0	0
Total OPG PILs	**306**	**224**	**440**	**277**

1. OPG's May 2017 head office facilities sale impacts are re-categorized from Sales and Rentals to OPG net income and PILs in the current Electricity Outlook update. This update now also includes 2017-18 proceeds from the Lakeview properties sale.

2. This reflects interest earnings on GA financing costs which are consolidated back to Province

3. IFRS risk provided by OPCD as of 2017 Budget

Hydro One Ownership Calculation:		SOURCE:
Total number of shares outstanding[1]	595,000,000	1. Hydro One Ltd Annual Report 2015, pg 94 of PDF, pg 92 of the Report.
Additional Common Shares Issued since IPO	386,711	
IPO November 2015		
Initial Public Offering(2015)[2]	81,100,000	2. From news release: http://hydroone.mediaroom.com/2015-11-05-Hydro-One-Limited-Announces-Closing-of-IPO
Over allotment option (2015)[3]	8,150,000	3. From news release: http://hydroone.mediaroom.com/2015-11-12-Hydro-One-Limited-Announces-Closing-of-IPO-Over-Allotment-Option
Sales to PWU/SEP Trusts	5,646,340	
Total	94,896,340	
Province's remaining ownership, Nov 2015 (# Shares)	**500,103,660**	
Province's remaining ownership, Nov 2015 (%)	**84.05%**	
Secondary Offering April 2016		
Secondary Offering (2016)	72,434,800	4. Hydro One Ltd. Q2 Report, pg 1 http://www.hydroone.com/InvestorRelations/FinancialReporting/Documents/Hydro%20One%20Ltd%20Second%20Quarter%20
Over allotment option (2016)	10,865,200	
Total	83,300,000	
Province's remaining ownership, Apr 2016 (# Shares)	**416,803,660**	
Province's remaining ownership, Apr 2016 (%)	**70.05%**	
Final Offering May 2017		
Final Offering (2017)	120,000,000	Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by-the-Provin
Over allotment option (2017)	-	Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by-the-Provin
Total	120,000,000	
Province's remaining ownership, May 8, 2017 (# Shares)	296,803,660	Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by-the-Provin
Province's remaining ownership, May 8, 2017 (%)	**49.88%**	
First Nations Sale, closed on December 29, 2017	14,391,012	Source: http://www.S:\Users\CEF\Hydro 2018\OEFC\RbP\Outlook\01. January\Backup\20180103-0 - H1 First Nations Sales\
	2.4170865%	Source: https://news.ontario.ca/mei/en/2017/05/ontario-raises-28-billion-from-final-hydro-one-share-offering.html
Province's remaining onwership - post First Nations Sale (#Shares)	282,412,648	
Province's remaining onwership - post First Nations Sale (%)	**47.43%**	
Avista Impact (projected closing date 2nd half of 2018)		
Contingent Convertible Debenture	$1,540,000,000	
Conversion Price	$21	
Potential Dilution (# Shares)	71,962,617	
Revised Total number of shares outstanding	**666,962,617**	
Province's remaining onwership - post Avista Acquisition (#Shares)	282,412,648	
Province's remaining onwership - post Avista Aquisition (%)	**42.34%**	

Ownership Percentage in 2017-18 Fiscal Year	Number of Months	Percentage of Year
70.05%	1	8.3%
49.88%	8	66.7%
47.43%	3	25.0%
	12	
Average 2017-18 FY Ownership:	**51.0%**	

Ownership Percentage in 2018-19 Fiscal Year (assume Avista closing end of September 2018)	Number of Months	Percentage of Year
47.43%	6	50.0%
42.34%	6	50.0%
	12	
Average 2018-19 FY Ownership:	**44.9%**	

Ownership Percentage in 2019-20 Fiscal Year Onwards
42.34%

Accretive to earnings per share and cash flow for Hydro One in the first full year post closing
above is from Hydro One transaction overview. Check what this means for timing of additional shares and /or earnings.

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Hydro One Net Income and PILs

Hydro One Income - Budget 2017
($ millions)

	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Hydro One Net Income After Tax	685	737	742	802	862	931
Hydro One - Unrealized Gains Adjustment						

2016-17 to 2020-21 from CEFD Hydro One 2016 model.

Hydro One PIL - Budget 2017
($ millions)

	2015-16	2016-17	2017-18	2018-19
Net Income After Tax	685	737	742	802
Income Taxes PILs	132	160	181	205
Proxy Property Tax	2	2	2	2
Ontario Capital Tax	0	0	0	0
Total	**134**	**162**	**183**	**207**

Hydro One Income - December 2017
($ millions) **$ Millions**

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21	2021-22
Hydro One Net Income After Tax			662	706	831	885	943
Hydro One Net Income After Tax - Including Adjustments	670	680	662	706	831	885	943
Hydro One - Net Income Attributable to Preferred Shareholders	15	18	18	18	18	18	18
Hydro One - Unrealized Gains Adjustment							

Hydro One (100% Ownership)
($ millions) **$ Millions**

	Actual 2015-16	Actual 2016-17	2017-18	Cu 2018-19
Net Income After Tax - Common Shares	670	680	662	706
Net Income After Tax - Preferred Shares	15	18		
Income Taxes PILs	132	160	181	205
Proxy Property Tax	2	2	2	2
Ontario Capital Tax	0	0	0	0

Public Debt Interest and Section 50.3 payments

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Hydro One Public Debt Interest and Section 50.3 payments						
Government Annual Interest Costs - Hydro One	220	220	220	220	220	220
Reduction in Interest Costs due to Broadening[1]		(29)	(66)	(116)	(116)	(116)
Province Annual Interest Costs - Hydro One Debt	**220**	**191**	**154**	**104**	**104**	**104**
Province Annual Interest Cost - OPG Debt	300	300	300	300	300	300
Total Public Debt Interest	**520**	**514**	**454**	**404**	**404**	**404**

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Gain to OEFC under s. 50.3	172	411	531	0	0	0

1. The Hydro One reduction in interest costs above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering are currently reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

2020-21							
220	ID# (Track Cha	Fiscal Year	alue (Hardcode	Value (Linked)	Description	Source Details	Source (Link)
-116	20170501-2	2016-17	411,152,733	411,152,733	s 50.3 Gain for	Calculation provided by SIFB	
104	20170501-3	2016-17	29	29	Reduction in Int	Internal Calculation	
	20170501-3	2017-18	66	-116	Reduction in Int	Internal Calculation	
	20170501-3	n/a	220	220	Annual Interest	Internal Calculation	
300							
404							

2020-21	ID# (Track Cha	Fiscal Year	alue (Hardcode	Value (Linked)	Description	Source Details	Source (Link)
0	n/a	n/a	5126		($M) Provinces	OEFC 1999-2000 FS, pg 24	
	n/a	n/a	5.85%		Annual Interest	OEFC 1999-2000 FS, pg 26	
			299.871				

	OPG's Annual Interest Costs:		300	
20170713-1	2016-17	-513,768,361	Provincial interest cost for equity investment in OPG, H1 in 2016-17 Monthly Balances Sheet (from FTD) S:\Users\CEF\Hydro 2017\OEFC\RbP\Outlook\07. July\Backup\20170713-1\interest fr	
s. 50.3	531	531	S:\Users\CEF\Hydro 2018\OEFC\RbP\Outlook\02. February\Back-up files	

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PROVINCIAL CONSOLIDATION ADJUSTMENTS
Ontario Nuclear Funds Agreement

Adjustment for Change in OPG Reported Net Income

Adjustment for DSF Unrealized Earnings

Unrealized Earnings as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Bruce Variance Account Adjustment
OPG Net Income Adjustment

Adjustment for UFSF Unrealized Earnings

Unrealized Earnings as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Bruce Variance Account Adjustment
OPG Net Income Adjustment

Unrealized Earnings -- Fiscal YTD

Adjustment for Change in Due to Province

Adjustment for DSF Due to Province
Due to Province (cost basis) as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Change in Due to Province -- Fiscal YTD

Adjustment for UFSF Due to Province

Due to Province (cost basis) as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Change in Due to Province -- Fiscal YTD

Provincial Consolidation Adjustment

Other Data

	Actual 2016-17	2017-18
Debt Retirement Charge	621	0

	2016-17	2017-18
Power Supply Contract Recoveries	838	182

	2016-17	2017-18
Interest		
OPG	167	155
IESO	2	3
Other (Net)	20	20
Expense		
Debt interest	1216	1109

	Actual 2016-17	2017-18
MEU - PIL Income Tax	109.8	
MEU - PIL Property Tax	0.6	
MEU - GRC	1.2	
TOTAL MEU PILs	111.6	

	Actual 2016-17	2017-18
Miscellaneous/Other (OEFC FS)	14	
Demand Management Support Costs (IEI)	8	10
Operating [Expense]	7	6
Interest on nuclear risk funding	-	-
Amortization of deferred debt costs	-	-
Amortization of NUG liability	129	74
Debt Guarantee Fee	122	102

Expense (Electrictiy Summary Tab)		
Other (Finance)	-7	-6
Demand Management Support Costs (IEI)	-8	-10
Debt Guarantee Fee	(122)	(102)

Plan 2018-19	2019-20	2020-21	2020-21
0	0	0	0

Plan 2018-19	2019-20	2020-21	2020-21
183	134	103	98

Plan 2018-19	2019-20	2020-21	2020-21	
166	158	131	119	updated Feb 15, FTD
3	3	3	3	updated Feb 15, FTD
20	10	10	10	updated Feb 15, FTD
1077	1048	950	818	updated Feb 15, FTD

Plan 2018-19	2019-20	2020-21	2020-21

Plan 2018-19	2019-20	2020-21	2020-21
7	7	7	7
-	-	-	-
-	-	-	-
41	30	28	28
99	98	91	91
-7	-7	-7	-7
(99)	(98)	(91)	-91

ID# (Track Changes	Fiscal Year	Value (Hardcoded)	Value (Linked)
20170510-2	2016-17	$ 739,216,115	
20170510-2	2017-18	$ 291,629,707	
20170510-2	2018-19	$ 324,906,017	
20170510-2	2019-20	$ 300,648,570	
20170510-2	2020-21	$ 273,240,858	
20170501-4	2016-17	179	179
20170501-4	2017-18	169	169
20170501-4	2018-19	179	179
20170501-4	2019-20	175	175
20170501-4	2020-21	148	148
20170501-5	2016-17	1216	1,216
20170501-5	2017-18	1121	1,121
20170501-5	2018-19	1094	1,094
20170501-5	2019-20	1053	1,053
20170501-5	2020-21	963	963
20170731-3	2016-17	621	
20170811-1	2016-17	109.8	
20170811-1	2016-17	0.6	
20170811-1	2016-17	1.2	
20170815-5	2016-17	$ 838,000,000	
20170815-6	2016-17	$ 14,000,000	
20170815-8	2016-17	8	
20170815-9	2017-18	10	
20170815-10	2016-17	7	
20171211-2	2017-18	6	6
20171211-2	2018-19	7	7
20171211-2	2019-20	7	7
20171211-2	2020-21	7	7
20170815-7	2016-17	167	
20170815-7	2016-17	2	
20170815-7	2016-17	20	
20170815-7			

ID# (Track Changes	Fiscal Year	Value (Hardcoded)	Value (Linked)
20170905-1	2016-17	129	129
20170905-1	2017-18	74	74

20170905-1	2018-19	41	41
20170905-1	2019-20	30	30
20170905-1	2020-21	28	28
20170905-2	2016-17	122	
20170906-1	2017-18	3	3
20170906-1	2018-19	3	3
20170906-1	2019-20	3	3
20170906-1	2020-21	3	3
20170906-1	2017-18	20	5
20170906-1	2018-19	20	5
20170906-1	2019-20	10	5
20170906-1	2020-21	10	5
20171211-0	2017-18	1115	
20171211-0	2018-19	1089	
20171211-0	2019-20	1060	
20171211-0	2020-21	963	
20171211-1	2017-18	102	102
20171211-1	2018-19	99	99
20171211-1	2019-20	98	98
20171211-1	2020-21	91	91
20171211-1			
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20180104-2	2017-18	$ 181,776,685	
20180104-2	2018-19	$ 182,785,215	
20180104-2	2019-20	$ 133,962,519	
20180104-2	2020-21	$ 102,554,665	
	2021-22	$ 98,255,464	

Description	Source Details	Source (Link)
The table below contains an updated preliminary N	SPFB Estimates, Email	
• The tables below provides both last year's submission for NUG costs by CEFD and this year's estimates (both of which exclude HST) based on the most recent NUG model.	SPFB Estimates, BN SPFB Estimates, BN SPFB Estimates, BN SPFB Estimates, BN	
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
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OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
Updating DRC from OEFC AR (Drafts)	2017 OEFC DRAFT FS	S:\Users\CEF\Hydro 2017\OEFC'
MEU - PIL Income Tax	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
MEU - PIL Property Tax	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
MEU - GRC	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
Updating to actuals	2017 OEFC AR	2017 OEFC Annual Report - Eng
Updating to actuals	2017 OEFC AR	2017 OEFC Annual Report - Eng
Updating to Actuals	2017 OEFC AR	S:\Users\CEF\Hydro 2017\OEFC'
OEFC 2017-18 IEI/Demand Management Suppor	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Operating Expense - Updating to Actuals	2017 OEFC AR	S:\Users\CEF\Hydro 2017\OEFC'
Revised Operating Expense from FTD Forecast	FTD - October PRRT	
OPG Interest Revenue - Actuals 2016-17	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
IESO Interest Revenue - Actuals 2016-17		
Other (Net) Interest Revenue - Actuals 2016-17		

Description	Source Details	Source (Link)
		S:\Users\CEF\Hydro 2017\OEFC'
	Amortization Schedule.	S:\Users\CEF\Hydro 2017\OEFC'

Sourcing the NUG liability amortization schedule.	Tab: Summary Fiscal Impact	S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Gurantee Fee - Updating to Actuals	2017 OEFC AR (pg 13 (	\\ofina.on.ca\ofadfs\Users\CEF\H
IESO Interest Revenue Plan	OEFC Revenue Forecast for Board - April 2017	\\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H
Other Interest Revenue Plan		\\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H
OEFC Debt Interest Expense (no change, just re-linking)	FTD - January 11	
OEFC Debt Guarantee Fee	FTD - October PRRT	S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC'

Description	Source Details	Source (Link)
Updated FY 2017-18 estimates of NUG costs	SPFB Estimates, BN	Power Purchases and Sales Fore
Updated FY 2017-18 estimates of NUG costs	SPFB Estimates, BN	Power Purchases and Sales Fore
Updated FY 2017-18 estimates of NUG costs	SPFB Estimates, BN	Power Purchases and Sales Fore
Updated FY 2017-18 estimates of NUG costs	SPFB Estimates, BN	Power Purchases and Sales Fore

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Colour Codes

Formulas are in black text

Hard coded numbers are in blue text

References elsewhere are in purple

Green bold text with or without highlights mean updates required

Policies to follow when making updates to the Outlook

*** To quickly jump to the source numbers for a link, press "**Ctrl + [**"

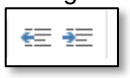
All new numbers must be fully sourced, and follow the colour codes above

Most numbers and text are Arial Size 10, unless it is a title

Add back up materials in a folder with the same numbers as in the 'Track Changes' tab

If there is a reason for italics, or other colours, or formatting make sure it is clear. Othe

Use indents to make things more clear to read



If numbers are taken from another tab they should ONLY be direct links, no calculation

Electricity Summary - (Budget17/On Deck) - Reflects Public Accounts/Financial Statem

OEFC - (Budget17/On Deck) - Reflects OEFC Annual Reports

*Due to slight discrepancies between Public Accounts reporting and OEFC Annual Rep

Outlook Updates Frequency

Frequency	Description	Tab
Monthly	OPG Net Income in-year forecast	OPG
Monthly	OPG PILs in-year forecast	OPG
Quarterly	ONFA Consolidation Adjustment	ONFA
Quarterly	OPG Cash vs Accrual Variance Account	Revenue (Risks)

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ı, adjustment should be done. Even if its just making a negative to a positive. Perform all the calculations on the

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source tab then bring the number into the next tab. (Eg. Formulas like this become hard to troubleshoot ='Hydro

One'!AR29+'Hydro One'!AR31+'Hydro One'!AR32), let's avoid them.

From:	Ken Kandeepan
To:	Scott Nelms (ENERGY)
Cc:	Ronald Kwan; Carlos Yep; Graham Monroe; Mike Manning; James Devine; Veinot, Cindy (TBS)
Subject:	FHP - OPG Performance Fee
Date:	Wednesday, July 05, 2017 11:59:10 AM

Hi Scott

I am writing this to you as an FYI since there may be some push back from OPG. I am cc'ing Cindy as well given the accounting implications raised by OPG. As you may be aware, OPG provided us with the proposed methodology for computing the performance fee. Both the benchmark and the actual include the 44% debt issued by OPG to the Trust which is in turn fully funded by the Province's equity injection.

Given that there are no capital market decision-making associated with this component of the debt, we are reluctant to sign off on OPG's methodology in its current form. OPG is not particularly happy with our response and posits that the accounting treatment requires a performance fee. While I agree that the E&Y opinion does refer to a performance fee I am a little doubtful that E&Y specified that all of the debt should be part of the computation. I have requested that OPG provide me with any specific reference by E&Y on the performance fee methodology. If E&Y does require that the benchmark and actual include the total debt issuance, we can reconsider our stance.

Finally, the performance fee methodology computes the fee for a particular year by applying the difference between the benchmark and the actual on the 5% that is borrowed by OPG. We requested and obtained confirmation that the performance fee will be limited to new borrowings by OPG and not apply to any refinancing. OPG finds this acceptable and it also ensures that the performance fee will be capped at $1.2 million or so per annum.

Thanks

Ken k

From:	Bruno Amara
To:	Ronald Kwan
Cc:	Darren Scanlan; Francisco Chinchon; John Kim; Usman Zahid
Subject:	FW: 2018-02-16- OPG 2018-21 Business Plan Review-EFBv5.pptx
Date:	Wednesday, March 21, 2018 2:12:59 PM
Attachments:	2018-02-16- OPG 2018-21 Business Plan Review-CEFDv2.pptx

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Hi Ron

Attached is Energy's slide deck on the OPG 18-21 BP for approval by TB/MBC. EFB and SIFB have reviewed an made a few comments.

Thanks
Bruno

Ontario

MINISTRY OF
ENERGY

Ontario Power Generation 2018-2021 Business Plan

March 2018

Ministry Request

- The Ministry of ENERGY is requesting that Treasury Board/Management Board of Cabinet (TB/MBC):

    1. NOTE the receipt of OPG's 2018-2021 Business Plan.

    2. NOTE that the Minister of Energy will provide concurrence with OPG's Business Plan.

Purpose

- As required by the Memorandum of Agreement (MOA) between Ontario Power Generation and the Minister of Energy, OPG provided its Business Plan for 2018-2021 to the Ministry of Energy on February 12, 2018 for concurrence.
- The Minister's concurrence requires presentation of OPG's business plan before TB/MBC.
- Ministry of Energy staff have reviewed this plan in the context of key government priorities and recommend that TB provide approval.
- The Ministry of Energy review and analysis of OPG's business plan is supported by the Corporate and Electricity Finance Division of the Ontario Financing Authority (OFA).
- The following presentation identifies the key aspects of the business plan and how they interrelate.

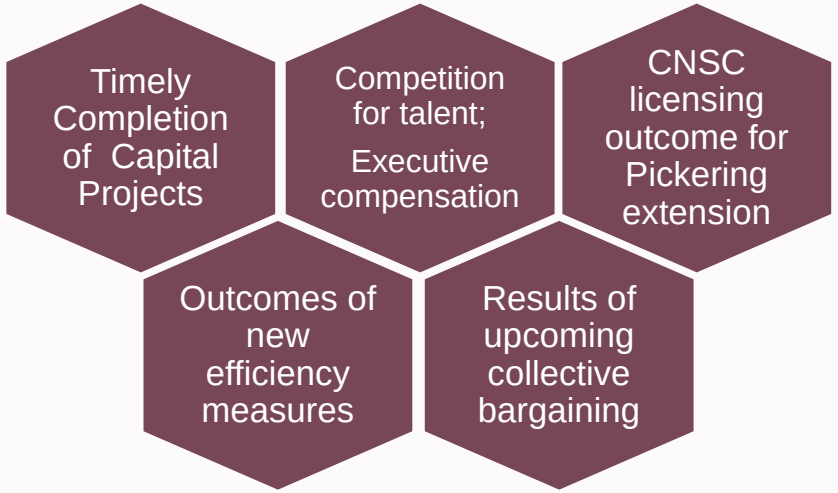
Overview

Business Plan Elements

- The 2018-2021 Business Plan covers an important time for OPG for several reasons:

Business Plan Risks

- Achieving financial performance targets is contingent on positive outcomes in a number of areas:



OPG's ability to manage these elements & risks will determine if it is improves return to the Province and limits ratepayer costs.

Elements of Business Plan

1. **Electricity Production**
   - ❖ Higher than approved production improves financial performance through increased revenue.
   - ❖ Affected by capital projects (e.g., refurb) and Pickering Extension.

2. **Production Costs**
   - ❖ Cost targets fluctuate due to outages, water conditions and efficiency initiatives.
   - ❖ Pickering's cost performance expected to improve relative to previous plan.

3. **Capital Projects**
   - ❖ Timely completion impacts production and project costs
   - ❖ Darlington Refurbishment on track- Unit 2 online in 2020.

4. **Operating Costs & Compensation**
   - ❖ Strategies to increase efficiencies and savings improve financial performance
   - ❖ Subject to collective bargaining that will take place in 2018.

5. **Fair Hydro Plan**
   - Adds ~$6 billion in debt by 2021; Provincial equity doubles by end of plan.
   - Generates net income for OPG ($465 million over 4 years)

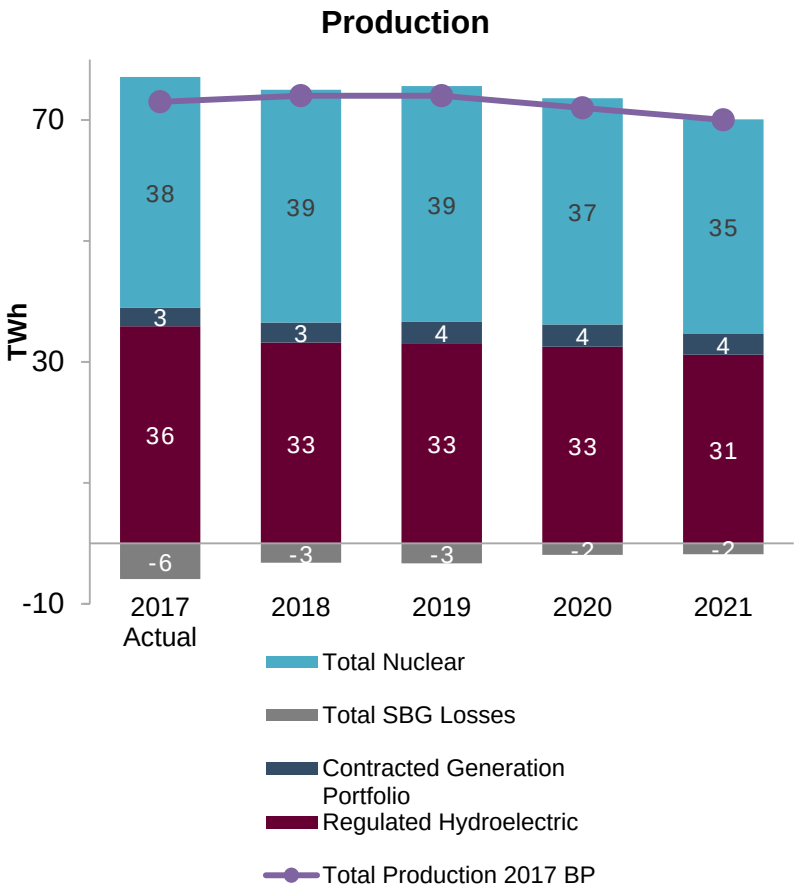
6. **Business Development**
   - Increase revenue through modest hydro expansion, solar, nuclear services & low-carbon technology.
   - Long-term need for new business lines outside of province

7. **Financial Performance**
   - ❖ Performance impacts Province's fiscal position Total Shareholder Return expected to improve over previous plans.

Electricity Production

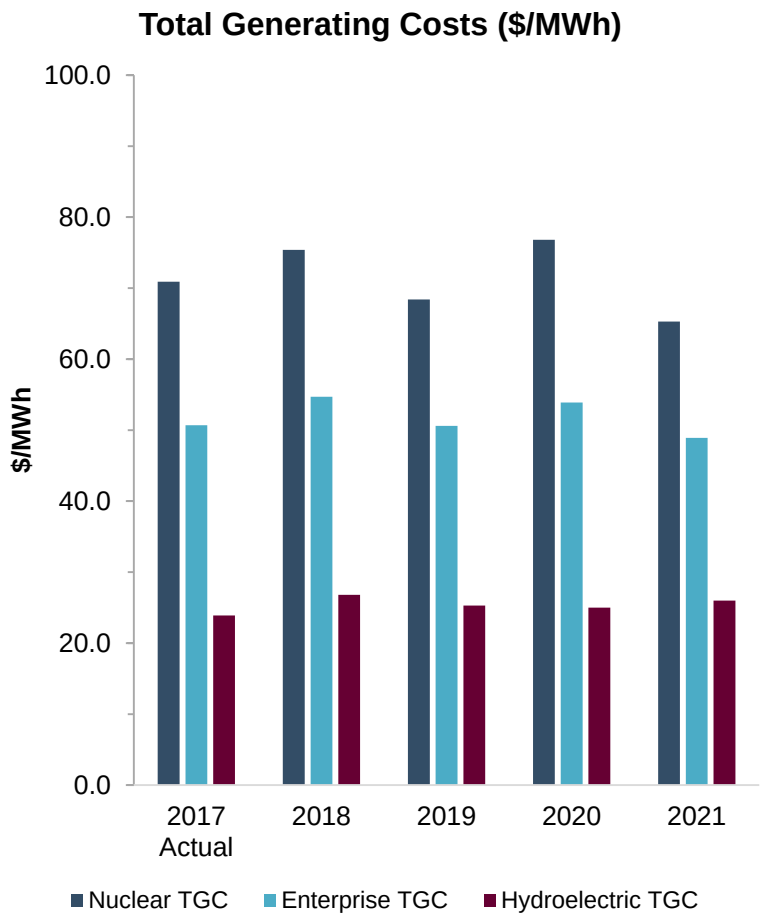
- ❖ Production increases improve financial performance through increased revenue.
- ❖ Forecasts affected by capital projects (e.g., Darlington Refurbishment); Pickering extension and efficiency strategies.

- The plan forecasts a total increase of 5.4 TWh compared to the last business plan.
- Increases are driven by higher production at Pickering Generating Station.
  - OPG will increase time between routine outages, allowing units to run longer.
  - Other reliability improvements reduce Pickering's 'forced loss rate'- (i.e., losses from unplanned shutdowns.)
- The forecasts assume CNSC will grant Pickering license extension to 2024.
- Production decreases in 2020 when Darlington Unit 2 returns to service and Unit 3 is taken offline. There is also a lengthy planned outage at Pickering.
- The current Thunder Bay biomass energy supply agreement expires in January 2020. The station may participate in a future capacity auction.



Cost of Production

- ❖ Cost targets fluctuate due to outages, water conditions and efficiency initiatives.
- ❖ Pickering's cost performance expected to improve relative to previous plan.



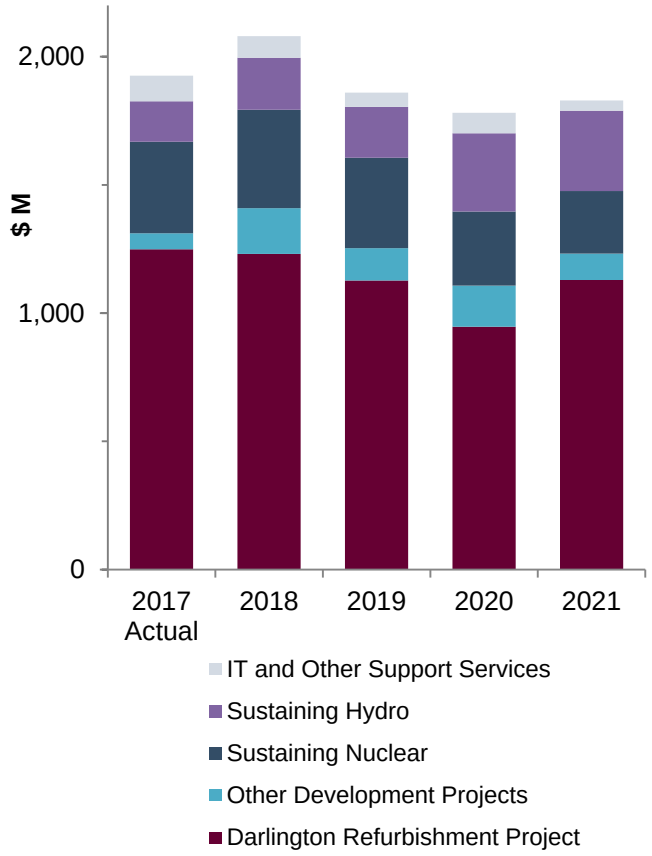
- Total Generating Cost (TGC) per MWh is OPG's measure of operational cost effectiveness.
  - TGC is a performance metric for executive compensation
  - Darlington Generating Station's TGC performance will be how OPG measures the long-term success of its OPG25 restructuring initiative.
- TGC targets fluctuate due to nuclear outages, efficiency initiatives and surplus-baseload generation adjustments due to high water levels.
- The production and cost forecasts are consistent with its OEB rate application. The set rates through 2021 provide planning stability.
  - If OPG exceeds production forecasts, it generates additional revenue. It must absorb costs if production is lower than forecast.

Capital Projects

- ❖ Timely completion impacts production output and costs.
- ❖ Costs deemed imprudent for regulated projects negatively impact financial performance

- The plan includes $4.4 billion in capital expenditures for the Darlington Refurbishment project (DRP). Unit 2 is planned for return to service in early 2020.
- The plan includes $105 million in capital expenditures for the Heavy Water Storage(D2O) project, an enabling sub-project for the DRP that previously experienced delays and cost overruns (note: overall refurbishment has remained within budget and schedule).
- In its rate decision, OEB confirmed it will take a holistic view to assessing DRP costs, evaluating overall project performance against approved budget rather than an individual sub-project basis.
- Other capital expenditures include:
  - Ranney Falls re-development (2019 completion)
  - Nanticoke Solar (2019 completion)
  - Beck generating station upgrades (2022 completion)
  - Other sustaining capital (Hydro unit overhauls; equipment upgrades)
- The plan accelerates capital expenditures for OPG's digital transformation in support of improved efficiency.

Total Capital Expenditures



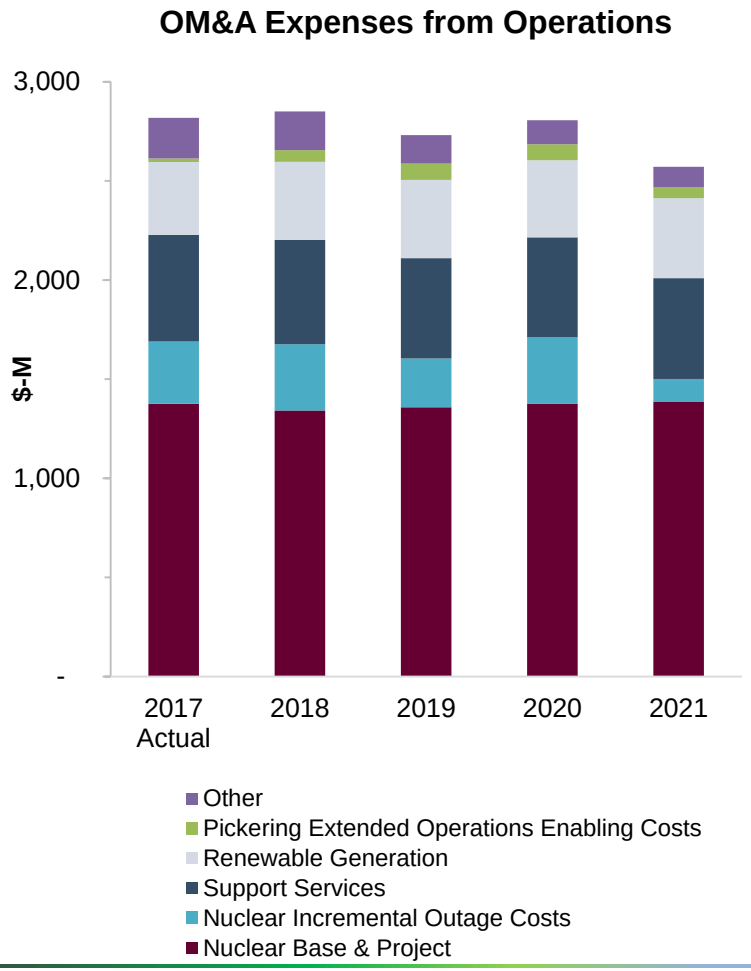
Operating Costs (OM&A)

- ❖ Incremental efficiencies/savings improve financial performance
- ❖ OEB Decision reduces OM&A / compensation

- The plan targets a total decrease in OM&A expenditures of $600 million over four years. Annual spending decreases by $280 million in 2021 compared to 2018.
- The reductions will be achieved through new processes, technology upgrades and reducing nuclear plant outage frequencies.

OPG25 Initiative

- OPG25 is a plan to restructure OPG due to the closure of Pickering in 2024.
- The objective of OPG25 is to ensure operations remain cost-effective and that OPG is positioned for growth.
- The long-term target for the plan is having Darlington operate in the top-quartile for total generating costs.
- The initiative includes a staffing transition work stream, making interaction with unions critical.
- The 2018-21 business plan's cost reductions will help move OPG towards achieving the total target reductions post Pickering operations.

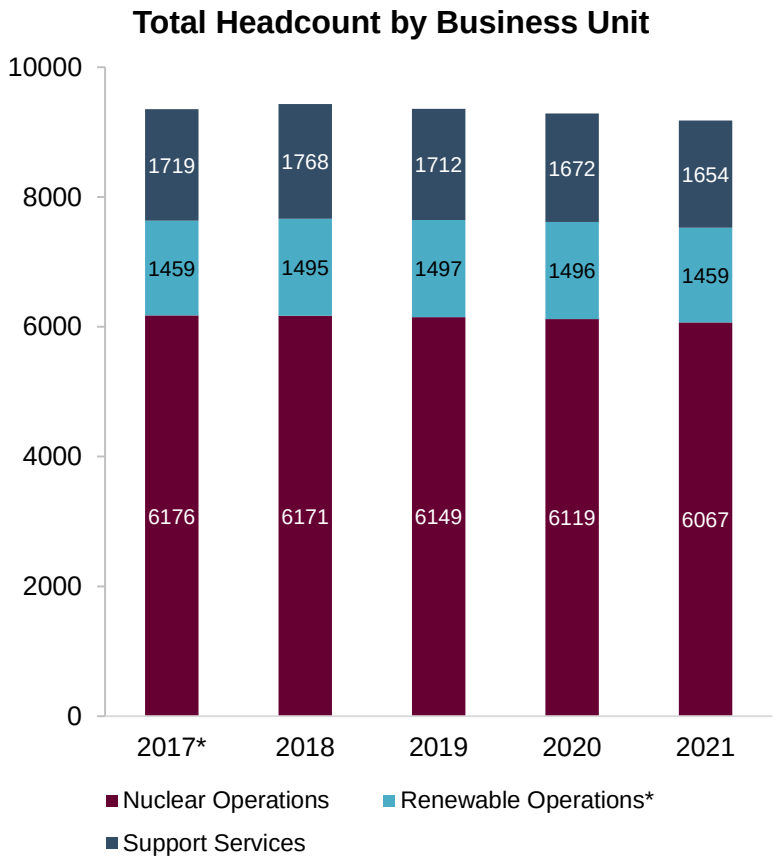


Compensation

Collective Bargaining

- ❖ Collective agreements expire in 2018.
- ❖ Results of collective bargaining will impact efficiency and cost-optimization initiatives.

- Collective bargaining impacts OPG's ability to reduce OM&A. Most employees belong to either the Power Workers Union (PWU) or Society of Energy Professionals (Society).
- Collective agreements with Society & PWU expire in 2018. Negotiated outcomes will impact OPG's ability to meet the plan's savings forecasts. Through collective bargaining, OPG hopes to:
  - Manage wage increases
  - Reduce future workforce costs including pension and benefits
  - Ensure future staff capability
  - Reduce downsizing costs resulting from Pickering closure*
- The plan identifies an accounting risk related to Pickering downsizing costs materializing prior to the next OEB rate application. This would affect net income in the year the costs were recognized.



Compensation

Executive Compensation

- ❖ Executive compensation program implemented in January 2017
- ❖ Compensation program benchmarks against comparator organizations

- OPG implemented an Executive Compensation Program in 2017 compliant with *O.Reg 304/16.*
- The program is designed to provide compensation that is at the 50th percentile of the market and focused on at-risk, performance based pay.
- In 2017, TB/MBC approved exemptions allowing OPG to compare against private sector and international companies.
- Overall compensation for all management group staff increases at 2% based on assumed inflation each year in the plan.
- Short-term incentives are based on individual performance and the corporate scorecard. Strong performance on the scorecard led to increases in executive incentives in 2017.
- Corporate scorecard measures for 2018 include:

2016-2018 executive medium-term incentive performance metrics
(on 3-year cycle ending 2018)

- **Return on Equity**
- **Total Generating Cost**
- **Darlington Refurbishment Major Milestones**

Social License: Total Recordable Injury Frequency; no significant events impacting OPG's reputation

Financial Strength: Earnings Before Tax (excluding the Nuclear Waste Management segment), Plan Operating OM&A Expenses.

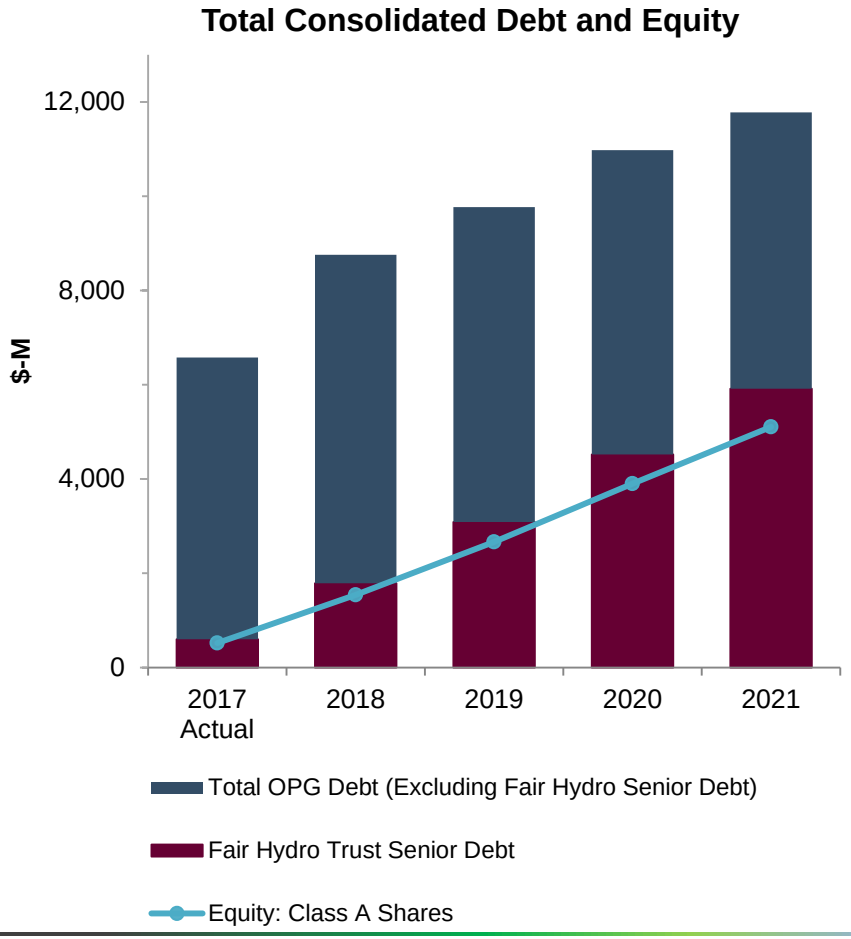
Operational Excellence: Total OPG production adjusted for Surplus Baseload Generation

Project Excellence: DRP costs and schedule; Peter Sutherlands Sr. Generating Station, and total in-service capital

Fair Hydro Plan

- ❖ FHP is managing the deferral of a portion of Global Adjustment (GA) costs.
- ❖ OPG earns revenue and incurs debt; Provincial equity in OPG doubles by 2021.
- ❖ While a new source of revenue for OPG, revenue is paid by Ontario ratepayers.

- In 2017, OPG began its role as OFHP Financial Services Manager (FSM).
- The Fair Hydro Trust contributes to increasing amounts of net income, growing from $10 million in 2018 to $225 million in 2021.
  - This reflects the spread earned on the equity contributions from the Province to fund 44% of OPG's financing of the Trust.
- As the Province provides more funding to facilitate asset purchases in exchange for shares in the company, the government's equity increases, lowering ROE.
- The Fair Hydro Trust external senior debt is projected to increase to $5.9 billion by 2021.



Business Development

- ❖ OPG hopes to grow its business and increase revenue through modest hydro expansion, solar, nuclear services & low-carbon technology.
- ❖ Long-term need for new business lines outside of province.

- OPG hopes to grow its business by investing in commercial innovation, project development and asset acquisition.
- The business plan references organic and non-organic investments:
  - Organic investments are in-house project development of generation and energy products in Ontario. The plan allocates incremental capital funding of ~$200 million for organic investments.
  - Non-organic investments are new opportunities in Ontario. These investments are not included in the plan, however, OPG forecasts up to $3 billion would be available for such investments.

Business Development investment categories:

Innovation & Services
OPG will consider investing in near commercial emerging technologies

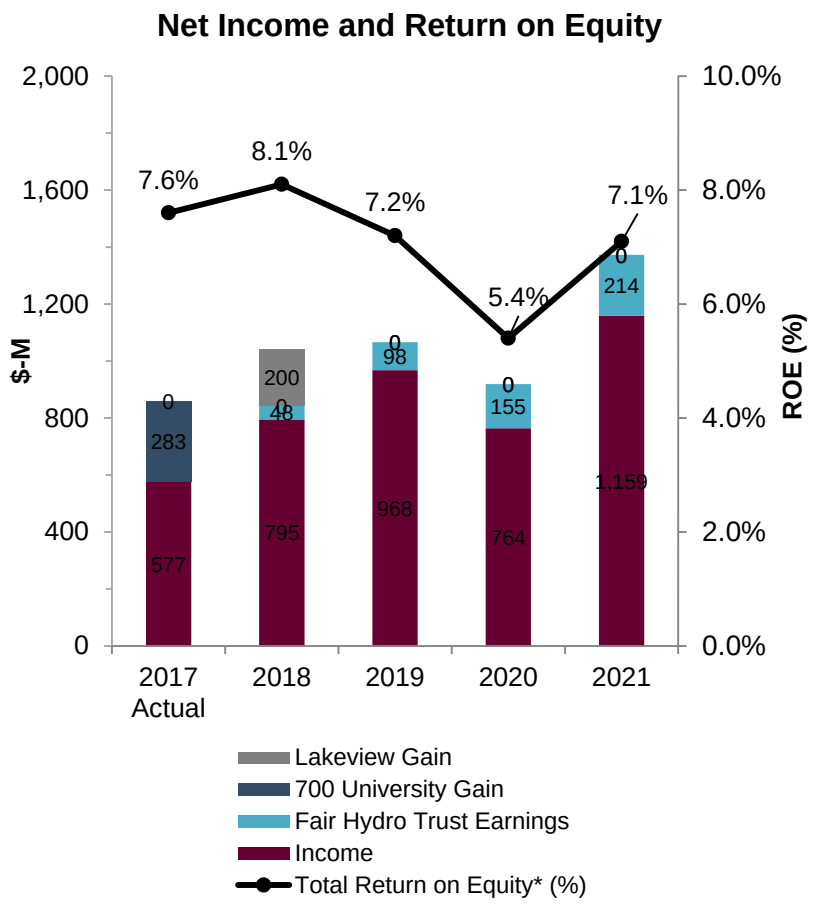
Acquisition and Development
OPG will develop assets and consider acquisitions in Ontario and other North American markets

- As the Shareholder, the Province may need to provide approvals for certain investments (e.g., development and acquisitions).
  - The Ministry of Energy plans to develop a policy framework to guide these approvals.

Financial Performance

Business Plan Results as presented by OPG

- ❖ Plan forecasts total net income to reach $1.37 billion in 2021, from $860 million in 2017
- ❖ OEB Decision provides rate stability over the planning period.



- OPG shareholder return (Net income + PILS) are consolidated to the Province.
- The plan reflects the Ontario Energy Board's (OEB) December 2017 Decision on OPG's regulated rates through 2021, providing stability in the planning period.
- Return on Equity (excluding impact of Fair Hydro Trust) increases from 5.3% in 2017 to 8.1% in 2021. ROE is a performance metric for executive compensation.
- Should OPG fail to meet targets for production, operating cost reductions or capital expenditures, net income improvements may not materialize.
- Net income in 2017/18 is impacted by one-time asset sales (Head Office and Lakeview), ~~which~~ with net proceeds ~~will be~~ credited to the Trillium Trust.

Financial Performance

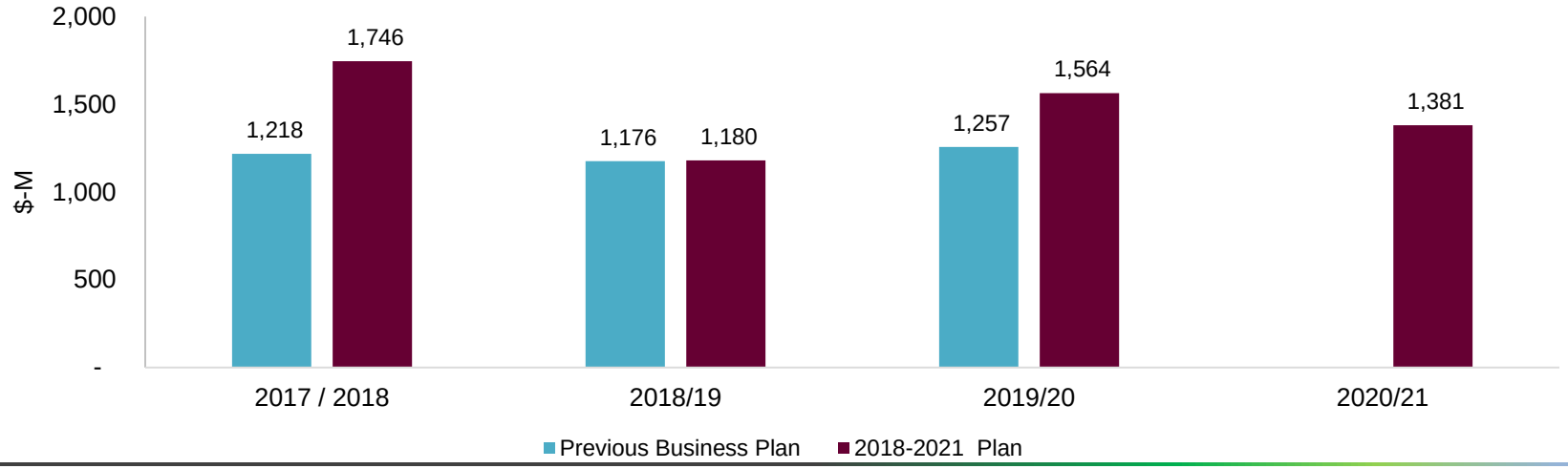
2018-21 Business Plan compared to previous plan

- ❖ Improved net income and shareholder return over previous plans.
- ❖ Projections impacted by efficiency measures and one-time real estate gains.

- The plan's total shareholder return is higher than last year's 2017-19 business plan.
- The financial performance reflects increased efficiency leading to revenue increases from higher production and lower operating costs
- The plan assumes the sale of Lakeview will be complete in 2017/18, resulting in $200M in net income and $70 million in PILS. The sale was not included in last year's plan.
  - OPG closed the sale of the ~~has a purchase agreement for~~ Lakeview site~~, anticipated to close~~ in March, 2018.

Total Shareholder Return

2018-21 BP vs. Previous Business Plan



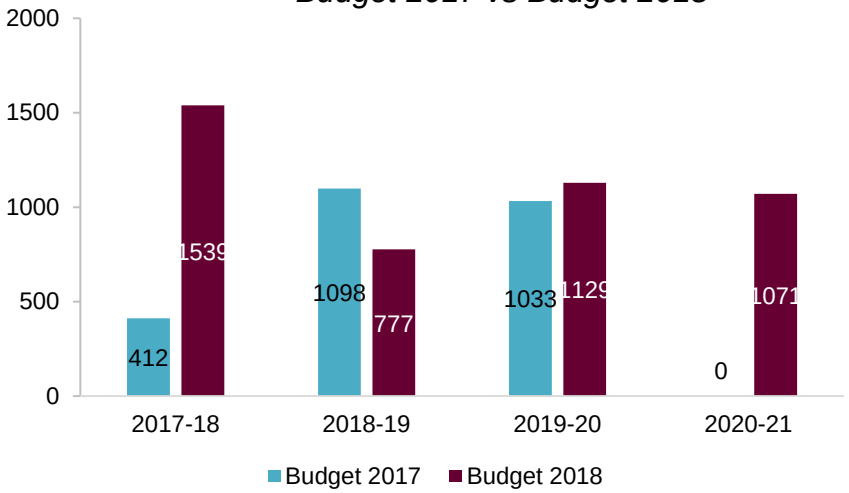
Financial Performance:[OFA to review]

Impacts to Province

- The Ministry of Finance and Treasury Board Secretariat are responsible for the fiscal consolidation of OPG's financials on the Province's financial statements which may include accounting adjustments.
- Budget 2018 reflects the impacts of OPG's 2018-2021 Business Plan

- When OPG's financials are consolidated into the Province's financials, some adjustments are required
  - **IFRS:** OPG uses US GAAP accounting standards for financial reporting. The Province consolidates OPG's results using International Financial Reporting Standards (IFRS).
  - **Fair Hydro Income:** While OPG separates out this income in its Business Plan, OPG's Financial Services Manger revenue is added to OPG net income when consolidated.

Total OPG Revenues to the Province
Budget 2017 vs Budget 2018



2017/18 positive variance due to:
- $646M for real estate sales included as OPG revenue in Budget 2018,. In Budget 2017, ~~not in Budget 2017 as~~ projected OPG real estate revenues ~~those revenues~~ were included in the Sales and Rentals line.
- Positive ONFA Adjustments included in Budget 2018 not in Budget 2017
- Lower IFRS adjustment in Budget 2018 than Budget 2017

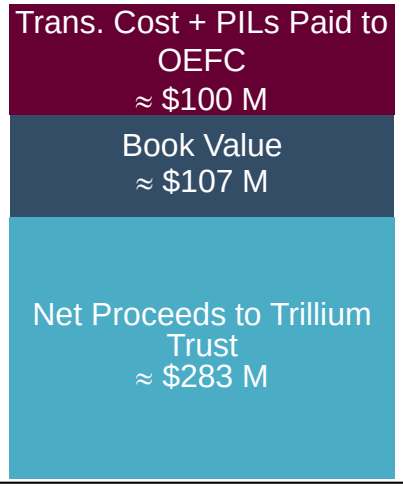
2018/19 negative variance due to:
- Negative IFRS adjustment included in Budget 2018

Financial Performance

Contribution to the Trillium Trust

- Net proceeds from the sale of OPG's ~~its~~ Head Office (700 University) and Lakeview site are paid by OPG to the CRF and credited to the Trillium Trust.
- The Province ~~will~~ has received a dividend payment from OPG for the OPG Head Office Sale. OPG will be required to pay the net proceeds from the Lakeview sale once a Trillium Trust regulation is filed.~~gains on these sales.~~
- The Head Office sale closed in April 2017. Lakeview ~~expected to~~ closed in March, 2018.

Head Office: ~~Designated~~ Net Proceeds to Trillium Trust from OPG



- Shareholder Declaration & Resolution received: December 2015
- Sale closed: April 2017
- Amount credited to Trillium Trust: Mar 2018

Lakeview: Estimated Net Proceeds to Trillium Trust from OPG

- Shareholder Declaration & Resolution received: June 2016
- ~~Expected~~ Sale closed: March 2018
- Regulation required to prescribe amounts to Trillium trust

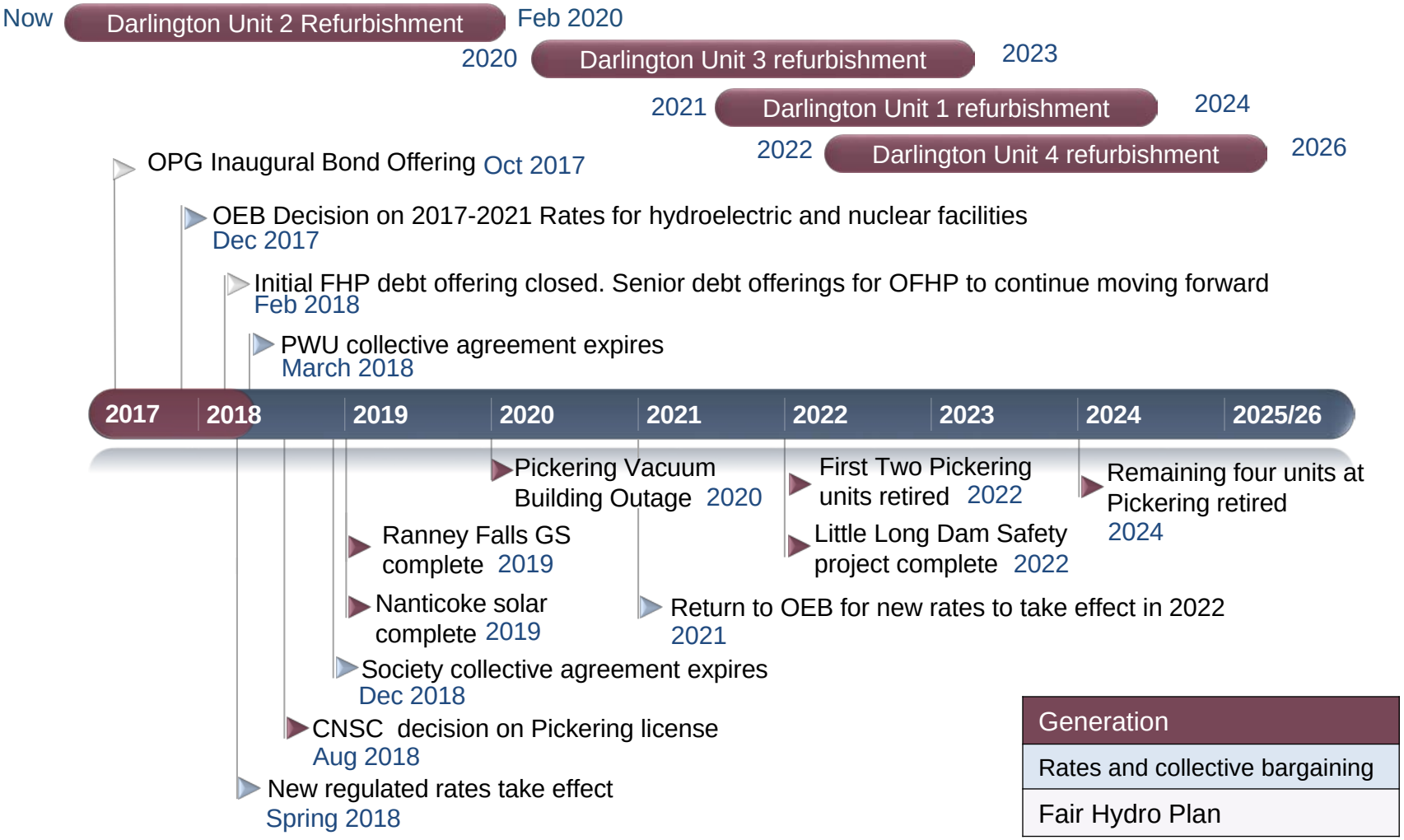
Considerations

- Based on these materials, ENERGY is seeking approval to provide OPG with business plan concurrence.
- At this point OPG has rate stability through the planning period and has demonstrated success in key projects including Darlington refurbishment. The plan is in line with government expectations on reducing costs in order to drive value for Ontario ratepayers and the Province, as Shareholder.
- OPG identified risks that the Ministry will continue to monitor. These include
  - Meeting efficiency targets for cost-savings and production.
  - Successful collective bargaining negotiations with PWU and Society; and
  - Completion of capital projects on budget and schedule
- OPG will continue to seek new business opportunities within Ontario and other jurisdictions. OPG will seek comfort from the Province for any new acquisitions.
- OPG will consider investing in near-commercial emerging technologies, acquisitions and development.

Appendix

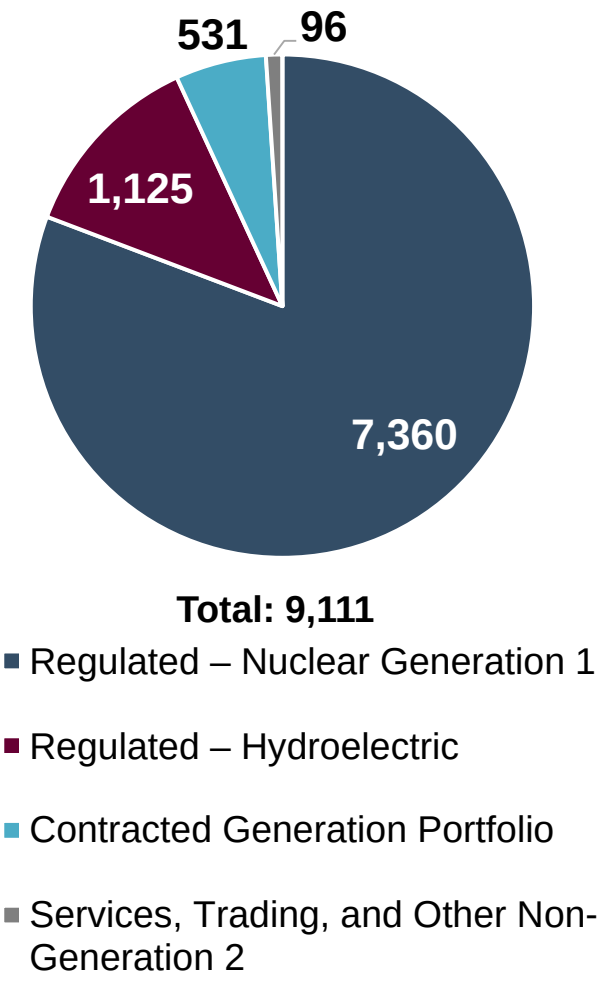
Timeline

- Outcomes from the Business Plan are impacted by the following events:



Company Profile

2017 Average Full-Time Employees

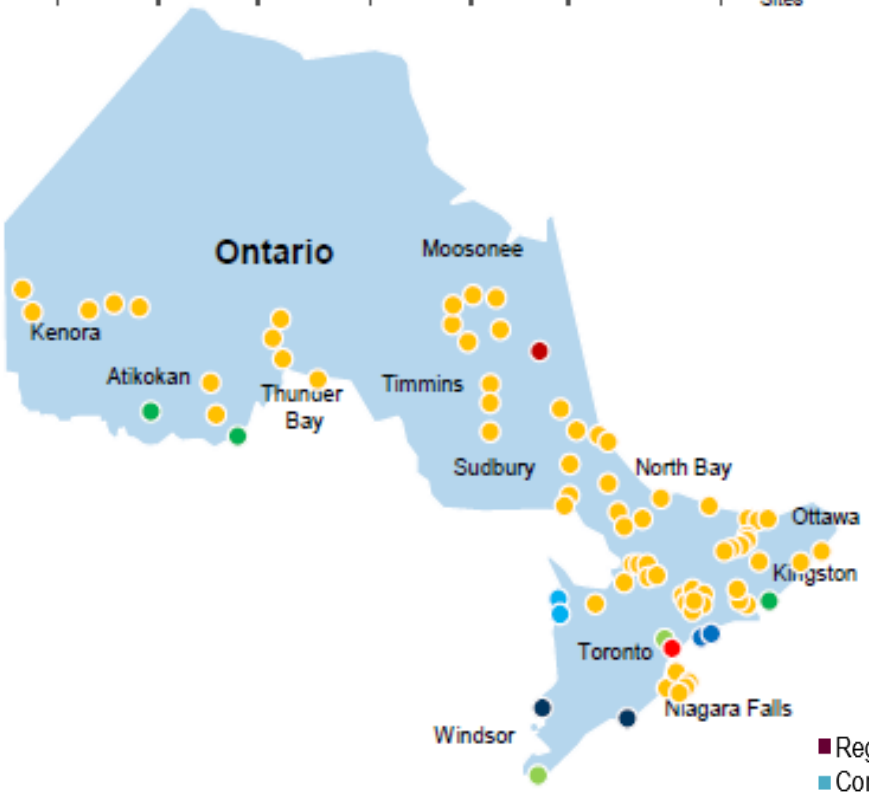


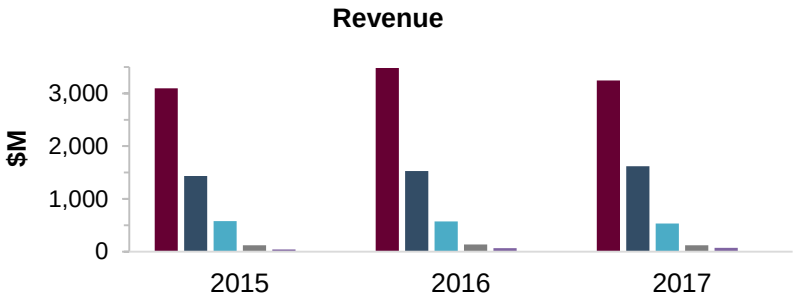
- Majority of OPG's employees are represented by one of two unions:
  1. The Power Workers' Union (PWU); and
  2. The Society.
- The PWU includes most workers below the level of first line manager
- The Society includes supervisors, professional engineers, scientists and other professionals.
- Construction work is performed through 19 craft unions.

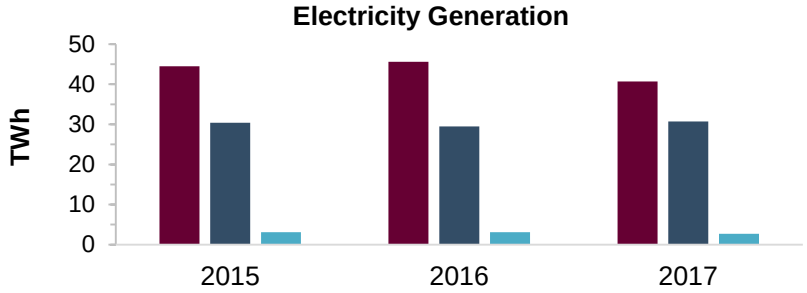
Company Profile

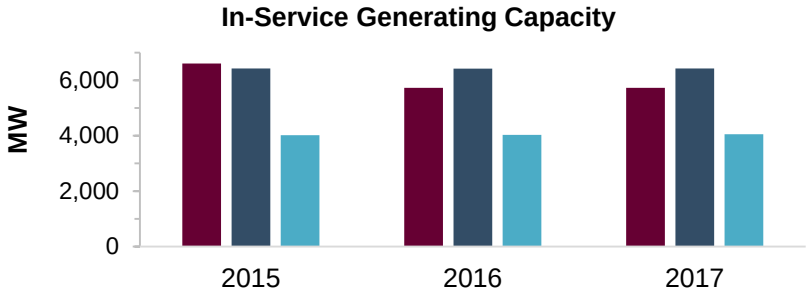
Map of OPG Generating Stations:

2	2	3	2	65	1	1	2
Nuclear Stations	Leased Nuclear Stations	Thermal Stations	Co-Owned Gas-Fired Stations	Hydro-electric Stations	Wind Power Turbine	Hydroelectric Project Under Construction [1]	Brownfield Coal Generation Sites









- Regulated – Nuclear Generation
- Regulated – Hydroelectric
- Contracted Generation Portfolio 1
- Regulated – Nuclear Waste Management
- Services, Trading, and Other Non-Generation

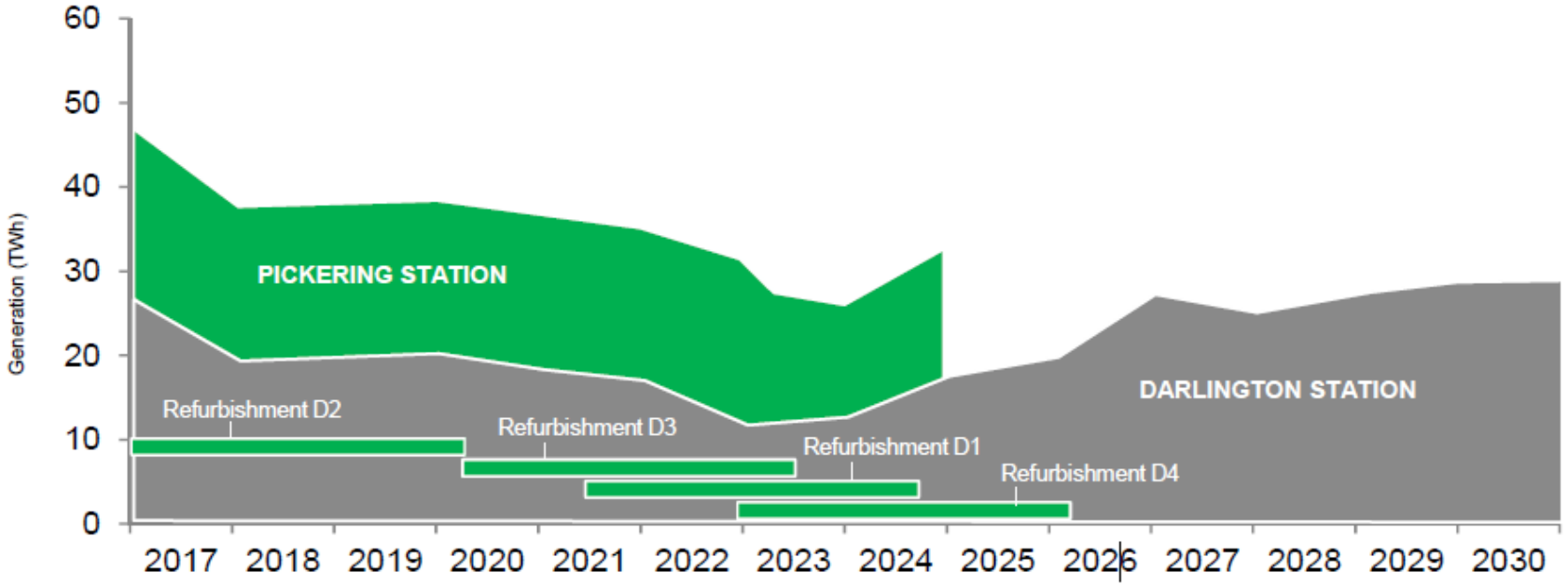
Key Projects: Nuclear

1. Pickering Extension

- OPG is continuing work to extend operations of the Pickering GS to 2024. It is currently licensed to operate to 2020.
- OPG has applied for a license renewal from the CNSC. The ruling is expected in August 2018.

2. Darlington Refurbishment

- OPG is refurbishing the Darlington Nuclear station to extend the operating life of the station by 30 years.
- Status: tracking on schedule and budget.
- Total Budget: $12.8 billion.



Source: OPG Initial Public Debt Program, 2017

Key Projects: Renewables

Biomass

1. Atikokan

Capacity: 205 MW

Converted from coal in 2014

Capex: ~$170M

2. Thunder Bay

Capacity: 153 MW

Converted from coal in 2014

Indigenous Relations

OPG's corporate governance includes an Indigenous Relations policy to help build and develop mutually beneficial working relationships with Indigenous communities proximate to the Company's present and future operations.

Renewables

Hydroelectric

1. Peter Sutherland Sr.

Capacity: 28 MW

Completed: March 2017

Capex: <$300M

2. Lower Mattagami

Capacity: 438 MW

Completed: 2014

Capex: $2.5BN

Solar

1. Nanticoke Solar

Project partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation to build the new facility.

Capacity: 44 MW

Commenced: Q4 2017

Expected completion: 2019

Role of OFHP Financial Services Manager

- In June 2017, the Province enacted the *Ontario Fair Hydro Plan Act, 2017* in order to ensure the costs and benefits associated with the Province's clean energy initiatives are allocated fairly between present and future electricity consumers.
    - The policy goals of the Act are being achieved through the refinancing of a portion of the Global Adjustment (GA).
    - OPG was appointed Financial Services Manager (FSM) under the Act.

- OPG's duties as FSM include:
    - Establishing one or more financing entities to incur funding obligations. OPG established the Fair Hydro Trust in 2017.
    - Preparing a financing plan to evaluate how and when funding obligations should be incurred.
    - Administering investment assets purchased from IESO
    - Determining the monthly clean energy adjustment for each reference period
    - Establishing and charging fees to recover costs, expenditures and earn a return
    - Seeking best available terms for incurrence of a funding obligation
    - Fulfilling various reporting requirements

Board of directors

- OPG's Board of Directors is made up of 14 individuals. Each Director holds office until he or she resigns or a successor is elected or appointed:

Director	Role	Appointed
1. Bernard Lord	Chair	November 2013
2. Jeffrey Lyash	President and CEO of OPG	August 2015
3. William Coley	Director	January 2013
4. Elisabeth DeMarco	Director	April 2014
5. Jean Paul Gladu	Director	November 2015
6. John Herron	Director	November 2013
7. Ani Hotoyan-Joly	Director	March 2017
8. Wendy Kei	Director	March 2017
9. M. George Lewis	Director	February 2005
10. Margaret Mulligan	Director	December 2005
11. Yezdi Pavri	Director	September 2015
12. Gerry Phillips	Director	January 2013
13. Jim Reinsch	Director	August 2015
14. James Sheppard	Director	March 2017

Compensation

2017 Statement of Executive Compensation

- OPG exceeded many of the measures in its Corporate Scorecard, impacting incentive payments.
- Scorecard is based on a predetermined scale of Threshold/Business Plan/Stretch targets (i.e., low/medium/high) and given a weighting. The scorecard is summarized below.

Category	**Performance Measure**	**Threshold Target**	**Business Plan Target**	**Stretch Target**	**2017 Results**	**Score (0 to 1.5)**
Social Licence	All Injury rate (AIR)	0.49	0.37	0.31	0.48	0.54
	Addressing Safety Focus Areas	CEO assessed target			1.5	1.46
	No significant impacts to OPG's reputation					
Financial Strength	Earnings Before Taxes, ($M)	675	875	1075	1296	1.50
	OM&A Expenses ($M)	2675	2550	2425	2474	1.30
Operational Excellence	Production (TWh)	70.3	72.4	74.6	78.1	1.50
Project Excellence	Refurbishment Project Cost – 2017 actual expenditures ($M) as a percentage of approved 2017 budget	100%	97.50%	95%	120%	0.00
	Refurbishment Unit 2 Critical Path Execution – Commencement of Feeder cabinet removal (Milestone	05-Aug-17	26-Jul-17	28-Jun-17	22-Jun-17	1.50
	Refurbishment Unit 2 Critical Path Execution: Progress of Critical path on Dec 31, 2017	All Bellows Severed	50% End Fitting Removed	400 Pressure Tubes Removed	45% of End Fittings Removed	0.95
	Pump Generating Station: In service	06-01-2017	04-01-2017	03-01-2017	02-04-2017	1.50
	Peter Sutherland Generating Station: Both Units in service	10-19-2017	06-30-2017	04-30-2017	03-31-2017	1.50
	Total In-service Capital -	$578 (+/- 10% to +/- to 15%)	$578 (+/- 3% to +/- 10%)	$578 (to +/- 3%)	$625 (+8%)	1.00
	Total Weighted Score[1]					**1.19**

Exceeded Stretch Target
Exceeded BP Target
Below BP Target
Below Threshold

From:	John Kim
To:	Ronald Kwan
Subject:	FW: Draft Fees Regulation
Date:	Wednesday, September 27, 2017 3:50:57 PM

Fyi, went back with some minor comments.

From: John Kim
Sent: Wednesday, September 27, 2017 3:43 PM
To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>; Mike Manning <Mike.Manning@ofina.on.ca>; James Devine <James.Devine@ofina.on.ca>
Cc: Carlos Yep <Carlos.Yep@ofina.on.ca>
Subject: RE: Draft Fees Regulation

Some minor comments. All under Base Fee section.

I'd convey that the compromise of 5bps is still generous more explicitly. I think that was Jim's comment. The rest of the comments imply it but could be useful. "10bps is high. We would recommend a compromise of 5bps to start, which we feel is still generous and to be reviewed in a year."

Where it says "This is consistent with the actual fees paid by OPG and the Province…", consider adding "also" to imply that it is referring to the 1-2bps for passive fixed income funds.

"From a significant economics of the financing entity,…" I wasn't quite sure what this is trying to say. Could be just me.

From: Ken Kandeepan
Sent: Wednesday, September 27, 2017 2:54 PM
To: Mike Manning <Mike.Manning@ofina.on.ca>; James Devine <James.Devine@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>
Cc: Carlos Yep <Carlos.Yep@ofina.on.ca>
Subject: RE: Draft Fees Regulation

Hi Mike at al

Pls see the draft email back to Scott Nelms, all credit to Carlos. Mike you may want to send it to Scott with cc's to the usual suspects, if you have any logistical issues, I am happy to do so, I will wait until 4.30 and if I don't hear from you will send it out.

Thanks

Ken k

From: Carlos Yep

Sent: Wednesday, September 27, 2017 2:43 PM
To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
Subject: FW: Draft Fees Regulation
Importance: High

Ken
Here are some thoughts …

Base Fee: 10bps is high. We recommend a compromise of 5bps to be reviewed in a year.
As background, market investment manager fees are 1-2bps for passive fixed income funds.
This is consistent with the actual fees paid by OPG and Province to co-manage the nuclear fund's index fixed income funds. The index funds require constant rebalancing by the investment manager.

From a significant economics of the financing entity, OPG is getting 44% equity investment from the Province at 0% cost and lending the funds as subordinated debt at a forecasted yield of around 5%. Ie. For each $2.5B of Global Asset X 44% equity injection would contribute $55million net revenue to OPG for each of 10 years and would be a reduced amounts for the following 30 years as the Global Asset is paid down.

Variable Fee: We recommend going back to the original proposal of "… not more than plus/minus 1% … on the net annual funding obligation …"
That means deleting column 1 and item 2 of the table.

Pass through costs: Pass through costs as outlined in the draft regulations appear reasonable. As suggested in Scott's email including tighter language that prevents any OPG costs from being passed through makes sense. As further due diligence it may be advisable for the for the Financing Entity as part of its annual audit or a separate assurance audit to have the external auditors opine whether the actual pass through costs of the Financing Entity in each fiscal year is in accordance with the regulations.

From: Mike Manning
Sent: Tuesday, September 26, 2017 1:53 PM
To: James Devine <James.Devine@ofina.on.ca>; Carlos Yep <Carlos.Yep@ofina.on.ca>
Cc: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
Subject: FW: Draft Fees Regulation
Importance: High

I was talking to Ken Kandeepan, and he was talking about arranging a meeting for as early as tomorrow.

Mike

From: Nelms, Scott (MOF) [mailto:Scott.Nelms@ontario.ca]
Sent: Tuesday, September 26, 2017 12:18 PM
To: Gadi Mayman <Gadi.Mayman@ofina.on.ca>
Cc: Steen Hume (CAB) <Steen.Hume@ontario.ca>; Mike Manning <Mike.Manning@ofina.on.ca>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Subject: Draft Fees Regulation
Importance: High

Hi Gadi,

I hope NYC is going well and you are finding air conditioning.

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- The draft reg outlines a base fee as well as a variable fee.
    - The base fee is provided monthly at an annual rate of 10-basis points for the first two years (we had this initially set at one year but Torys' markup changes this to two years). After 2019, the base fee is provided at an annual rate of 8 basis points should the funding obligations exceed $10B. Does this seem reasonable?
  - The variable fee structure seems consistent with previous discussions (5 basis point fee provided on the spread). Do you think this makes sense?
  - It would also be helpful if the OFA could let us know if the method for calculating the monthly funding obligation is reasonable.
- With respect to costs, our understanding is that these sorts of costs are typically a pass through; can the OFA confirm? The Torys markup removes OEB oversight on costs but we are wondering if there should be a role for the OFA in reviewing / providing oversight in this regard?
  - Also, do the costs they've outlined seem reasonable? In particular, LSB is wondering whether this leaves the door open for OPG to pass through any overhead costs (i.e. should we be explicit about excluding them)?
- On timing, the draft reg currently contemplates a fee application by OPG every two years regardless of what interest rates are in the market. Do we think this is fair or should the application occur annually? (Note that until new fees are established, the old fees are still in effect).

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Date:	Wednesday, September 27, 2017 3:19:54 PM

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From: Ronald Kwan
To: Ken Kandeepan; John Kim
Subject: FW: Draft Fees Regulation
Date: Tuesday, September 26, 2017 12:23:23 PM
Attachments: Blackline_24180663v1 - 24180663v3.pdf
Importance: High

Hi Ken, John,

Have you reviewed this? Comments?

Ron

From: Nelms, Scott (MOF) [mailto:Scott.Nelms@ontario.ca]
Sent: September-26-17 12:18
To: Gadi Mayman <Gadi.Mayman@ofina.on.ca>
Cc: Steen Hume (CAB) <Steen.Hume@ontario.ca>; Mike Manning <Mike.Manning@ofina.on.ca>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
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- The draft reg outlines a base fee as well as a variable fee.
    - The base fee is provided monthly at an annual rate of 10-basis points for the first two years (we had this initially set at one year but Torys' markup changes this to two years). After 2019, the base fee is provided at an annual rate of 8 basis points should the funding obligations exceed $10B. Does this seem reasonable?
  - The variable fee structure seems consistent with previous discussions (5 basis point fee provided on the spread). Do you think this makes sense?
  - It would also be helpful if the OFA could let us know if the method for calculating the monthly funding obligation is reasonable.
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  - Also, do the costs they've outlined seem reasonable? In particular, LSB is wondering whether this leaves the door open for OPG to pass through any overhead costs (i.e.

should we be explicit about excluding them)?

- On timing, the draft reg currently contemplates a fee application by OPG every two years regardless of what interest rates are in the market. Do we think this is fair or should the application occur annually? (Note that until new fees are established, the old fees are still in effect).

In terms of next steps, OPG would like to get a draft to their Board in time for the meeting on Friday. ENERGY LSB is hoping for comments by tomorrow. I don't think we need anything too detailed or formal, but a quick sniff test would be useful to ensure we are on the right track.

Thanks for your help,
Scott

CONFIDENTIAL
FOR DISCUSSION PURPOSES ONLY

ONTARIO REGULATION

made under the

ONTARIO FAIR HYDRO PLAN ACT, 2017

FEES

Definitions

1. (1) In this Regulation,

"average monthly funding obligation" means, in respect of a month, the amount determined in accordance with subsection (2);

"average annual funding obligation" means, in respect of a year, the sum of the average monthly funding obligations for the year;

"comparison fees" means ~~typical fees~~**market comparable fees, expressed as a per annum percentage rate,** charged by ~~[service providers?~~**asset** managers~~?]~~ ~~in Ontario~~ **in Canada and any other jurisdiction as may be determined by the Board** for services that are similar to the services provided by the Financial ~~Service Manger~~**Services Manager** under the Act in terms of,

(a) the type of services provided, being services in respect of funds including securitization vehicles, pension funds, other investment funds, hedge funds and other similar funds ~~in Ontario~~,

(b) the scope of the services provided, ~~and~~

(c) the level of the services provided**, and**

(d) the amount of assets under management;

"forecast interest rate" means, in respect of each tranche of funding obligations, an interest rate forecast to be applicable to such tranche of funding obligations after taking into account (i) the interest rate for debt of or guaranteed by the Province of Ontario with a corresponding term or duration, (ii) the estimated credit spread for such tranche of funding obligations with a comparable term and based on the type of instrument and risk of the issuer, and (iii) anticipated fees and commissions expected to be payable in connection with the issuance of such tranche of funding obligations.

"net annual funding obligation" means, in respect of a year, the sum of the principal amounts of funding obligations incurred by financing entities in a year~~, other than any refinancing~~;

(2) For the purposes of determining the average monthly funding obligation for a month, the following formula applies:

$$(A + B) / 2$$

Where,

A = the sum of the balances**, as** at **12:00 am on** the ~~start~~**first calendar day** of the month**,** of the principal amount of all **outstanding** funding obligations ~~incurred by~~**for all** financing entities,

2

B = the sum of the balances**, as** at **11:59 pm on** the ~~end~~**last calendar day** of the month**,** of the principal amount of all **outstanding** funding obligations ~~incurred by~~**for all** financing entities.

Fees that may be established, charged

2. (1) For the purposes of subsection 19 (3) of the Act, the fees established and charged by the Financial Services Manager may be charged to financing entities in relation to **the management and administration of financing entities and the investment asset, including in relation to** funding obligations incurred or that are planned to be incurred by the financing entities.

(2) A fee mentioned in subsection (1) shall be comprised of a base fee calculated under section [3, 4 or 5], as the case may be, and a variable fee calculated under section [6].

(3) ~~For the purposes of subsection 19 (3) of the Act, fees may be~~**Out-of-pocket costs and expenses of the financing entities incurred by the Financial Services Manager on behalf of the financing entities and for which the Financial Services Manager is entitled to reimbursement under a** management agreement with **such financing entity shall not constitute a fee** established and charged by the Financial Services Manager ~~to financing entities for the recovery of costs and expenditures, as provided for in section 7.~~**under subsection 19(3)**

of the Act.[1] The costs and expenditures of the financing entities referred to in this subsection (3) may include costs and expenditures in respect of the following:

1. Underwriters or selling agents for funding obligations**;**

2. **Banking fees, including structuring fees or work fees;**

3. Fees of issuing and paying agents for funding obligations**;**

4. **Fees of trustees;**

5. Fees incurred in the preparation of financial statements, financial reports, compliance certificates and tax returns**;**

6. Fees of legal counsel**;**

7. **Rating agency fees; and**

8. Filing or registration fees.

(4) The Financial Services Manager shall not establish or charge any fees to financing entities other than those provided for under this ~~R~~egulation.

Base fee, 2018 and 2019

3. Subject to section 5.1, the base fee for a month in the ~~year~~**calendar years** 2018 **and 2019** shall be calculated using the following formula:

$$(0.1 \times B) / 12$$

Where,

B = the average monthly funding obligation for the preceding month.

Base fee, after ~~2018,~~2019, average annual funding obligation greater than $10 billion

4. (1) This section applies for the purpose of calculating the base fee for a month in any year following ~~2018~~**2019** if the average annual funding obligation for the preceding year was greater than $10 billion.

[1] These represent third party costs and expenses of the financing entity, not part of the fees that OPG is charging the financing entity. From time to time, OPG may have to pay these upfront costs on behalf of financing entities but they will be a pass-through cost for which OPG would simply be reimbursed by the financing entity. Other than OPG's fees, the costs and expenditures of financing entities are not subject to OEB review under the Act but rather are recoverable as expenses through the CEA (and through IESO during the moratorium). Subsection (3) in this draft was added for greater certainty to ensure there was no misunderstanding.

(2) Subject to section 5.1, the base fee for the month shall be calculated using the following formula:

$$(0.08 \times B) / 12$$

Where,

B = the average monthly funding obligation for the preceding month.

Base fee, after ~~2018,~~2019, average annual funding obligation $10 billion or less

5. (1) This section applies for the purpose of calculating the base fee for a month in any year following ~~2018~~2019 if the average annual funding obligation for the preceding year was equal to or less than $10 billion.

(2) Subject to section 5.1, the base fee for the month shall be calculated using the following formula:

$$(0.1 \times B) / 12$$

Where,

4

B = the average monthly funding obligation for the preceding month.

Board review of base fee

5.1 If the Board, after reviewing a submission in respect of a proposed base fee by the Financial Services Manager under section 9, is of the view that applying the applicable formula set out in section 3, 4 or 5 results in a base fee that is inconsistent with prevailing comparison fees, the Board may refuse to approve the proposed fee. If the Board refuses to approve the proposed base fee submitted by the Financial Services Manager under section 9, the Board shall provide its reasons for such refusal and ~~may~~ make recommendations to the Financial Services Manager regarding the determination of a base fee that is consistent with comparison fees~~.~~ and based on the methodology used in the formulas set out in section 3, 4 and 5.

Variable fee

6. (1) Subject to subsection (2) and section 6.1, the variable fee for a year shall be the sum of the amounts of each tranche of net annual funding obligations for the year, calculated by using the following formula~~:~~ (which in respect of individual tranches may result in a negative number):

$$(A \times (B - C)) \times 0.05$$

Where,

A = the principal amount of the tranche,

B= the forecast interest rate for the tranche, as determined by the Financial Services Manager before the start of the year, based on the term of the tranche, and

C = the actual interest rate for the tranche.

(2) If the circumstances set out in Column 1 of the following Table apply in a year, the variable fee payable for a year is subject to the rules set out opposite the circumstances in Column 2 of the Table:

Item	Column 1 Circumstances	Column 2 Rules
1.	The average annual funding obligations are $10 billion or less.	The variable fee payable for the year shall not be more than 1 per cent of the amount that is 5 per cent of the net annual funding obligation for the year. The variable fee payable for the year shall not be less than -1per cent of the amount that is 5 per cent of the net annual funding obligation.
2.	The average annual funding obligations are greater than $10 billion.	The variable fee payable for the year shall not be more than 2 per cent of the amount that is 5 per cent of the net annual funding obligation for the year. The variable fee payable for the year shall not be less than -2 per cent of the amount that is 5 per cent of the net annual funding obligation for the year.

Board review of variable fee 5

6.1 If the Board, after reviewing a submission in respect of a proposed variable fee by the Financial Services Manager under section 9, is of the view that the forecast interest rate used for the purposes of the formula set out in subsection 6 (1) is ~~[unreasonable]~~**not consistent with market comparable forecast interest rates**, the Board may refuse to approve the proposed fee**. If the Board refuses to approve the proposed variable fee submitted by the** Financial Services Manager **under section 9, the Board shall provide its reasons for such refusal** and ~~may~~ make recommendations to the Financial Services Manager regarding the forecast interest rate that is ~~reasonable.~~**consistent with market comparable forecast interest rates.**

~~**Fees for costs and expenditures**~~

~~**7.** (1) The Financial Services Manager may establish and charge fees for the recovery from a financing entity of any costs and expenditures incurred in connection with the Financial Services Manager's duties under the Act in relation to the financing entity or under any management agreement with the financing entity.~~

~~(2) The costs and expenditures referred to in subsection (1) may include costs and expenditures in respect of the following:~~

~~1. Underwriters or selling agents for funding obligations.~~

~~2. Banking fees.~~

3. ~~Fees of issuing and paying agents for funding obligations.~~

4. ~~Fees of trustees.~~

5. ~~Fees incurred in the preparation of financial statements, financial reports, compliance certificates and tax returns.~~

6. ~~Fees of legal counsel.~~

7. ~~Filing or registration fees.~~

8. ~~Fees of any third party independent consultants required to be retained under the Act.~~

~~**Board review of fees for costs, expenditures**~~

~~**7.1** If the Board, after reviewing a submission in respect of a proposed fee for costs and expenditures by the Financial Services Manager under section 9, is of the view that the proposed fee is in respect of costs and expenses that were [not prudently incurred, or not incurred in relation to funding obligations incurred or that are planned to be incurred by financing entities], the Board may refuse to approve the proposed fee or a portion of the proposed fee and may make recommendations to the Financial Services Manager regarding the proposed fee.~~

Charging of fees

8. (1) In charging fees, the Financial Services Manager shall provide for,

(a) the base fee for a month to be payable within **[x]** days after the end of the month; and

(b) the variable fee for a year to be payable in the following calendar year in twelve equal monthly instalments that coincide with the payment of the base fee for each month.

(2) If the variable fee is a negative amount, it shall be deducted from the base fee payable in the following calendar year in twelve equal monthly instalments.

(3) Where there is more than one financing entity, the portion of the fees allocated to and payable by a financing entity shall be based on its proportionate share of the average principal amount of funding obligations for the applicable period.

Submissions to Board re fees

9. (1) The Financial Services Manager shall make submissions to the Board in respect of the fees proposed to be charged under section ~~5.1, 6.1~~**5.1** and ~~7.1~~**6.1.**

(2) The first submission **for proposed fees to be charged for a two year period commencing in 2018** shall be made no later than [October 31, 2017].

(3) ~~The submission for each calendar year starting with 2019~~**Submissions for proposed fees to be charged for a two year period commencing in 2020 and for every two year period thereafter** shall be made no later than [120 days] before the start of the **applicable two** year **period**.

(4**) Submissions to amend the proposed fees for a month in any year following approval of the proposed fees for any two year period may be made from time to time but no more frequently than once in any 12 month period and no later than 120 days before the start of the year in which such fees are proposed to be effective.**

(5) If the Board makes recommendations as described in section ~~5.1, 6.1~~**5.1** or ~~7.1,~~**6.1,** the Financial Services Manager shall submit to the Board,

(a) a revised proposed fee that takes into consideration the recommendations of the Board, and in the case of the base fee is consistent with comparison fees;

(b~~)~~ ~~a description of the methodology that the Financial Services Manager has applied to determine the revised proposed fee;~~

(~~c~~) in the case of the base fee, details concerning the comparison fees that the Financial Services Manager considered; **and**

(~~d~~**c**) in the case of the variable fee, a description of the methodology that the Financial Services Manager has applied to determine forecast interest rates in respect of tranches of the net annual funding obligations~~; and~~**.**

(~~e) in the case of a proposed fee for costs and expenditures by the Financial Services Manager, the rationale for the costs and expenditures having been [prudently incurred, and having been incurred in relation to funding obligations incurred or that are planned to be incurred by financing entities]~~ **6) Until the Board has approved the fees in respect of any two year period, the fees approved for the prior two year period shall remain in effect.**

Board approval, general

10. (1) ~~The Board may approve a proposed fee submitted by the Financial Services Manager or refuse to approve and refer the proposed fee back to the Financial Services Manager with the Board's recommendations.~~

~~[OLC Note: As noted by ENE LSB, there is some redundancy at the moment between section 10 and sections 5.1 and 6.1. This matter will be addressed in a subsequent draft when we have settled the Board approval process for each of the various scenarios (e.g. base fee; variable fee; costs/expenditures fee).]~~

~~(2) The Board may specify in its approval that a fee payable in respect of any period beginning on or after July 1, 2017.~~(3) For the purpose of determining whether to approve a proposed fee~~,~~ **described in section 5.1 or 6.1,**

(a) the Board shall consider the information provided by the Financial Service Manager in its submission relating to the proposed fee~~.~~**; and**

(~~4) For the purpose of determining whether to approve a proposed fee,~~ **b)** the Board may consider advice provided by the Ontario Financing Authority [with respect to comparison fees, annual rates and forecast interest rates].

[OLC Note re DEFERRAL ACCOUNT:
1. You included the following instruction that would require the FSM to establish a deferral account -- what is the authority for imposing this requirement? Recall that in subs. 34 (1) of the Act, the Board is given authority to require that the FSM maintain specific accounts.

2. ENE LSB note: *Necessity of this provision to be discussion with the OEB given that fees will be recovered as a financing entity expense through the Fair Hydro program and not as part of the fees to be approved by the Board.*]

[If needed, deferral provision could be along the following lines: The Financial Services Manager shall establish a deferral account in connection with subsection 19 (3) of the Act that records costs incurred by the Financial Services Manager in providing services referred to in section 1 during the period from July 1, 2017 to the day before the date of the Board's first order under subsection 19 (3) of the Act.]

[OLC Note re FINANCE AMOUNT: You included the following instruction, but I think this more properly belongs somewhere in section 5 of O. Reg. 206/17? In fact, are these fees not already covered in that section (perhaps under "financing entity expenses"?). Please confirm: *Fees established by the Financial Services Manager and approved by the Board, and any applicable taxes on such fees, shall be included in the definition of "expenses" for the purposes of determining finance amounts under the Act.*]

[Notes Re: Determining Fees:

(1) An alternative approach involves the Board approving the initial base fee and variable fee, with any changes to those fees being triggered by the FSM submitting to the Board proposed amendments to those fees (or the Board triggering a review on its own initiative (not more than once per year). However, because interest rates (and hence forecast interest rates) change over time (and can change even within a year), consider whether variable B of the variable fee should be approved annually. Similarly, because trends for "market comparable fees charged by service providers for similar services" change over time, consider whether variable A of the base fee should be approved annually.]

(2) Once every three years after the Board has approved the fees submitted by the Financial Services Manager under section 3, or more frequently if the Board requires but not more frequently than annually, the Board may require the Financial Services Manager to engage, on behalf of and at the cost of the financing entities, a third-party independent consultant to review and advise as to the appropriate benchmarks and range of values for [annual rates?] used for the purpose of determining the base fee and forecast interest rates used for the purposes of determining the variable fee and shall give due consideration to such advice.]

Commencement

x. This Regulation comes into force on the day it is filed.

Document comparison by Workshare Compare on September-23-17 6:39:45 PM

Input:	
Document 1 ID	interwovenSite://INVENTORYS1/TorysAtWork/24180663/1
Description	#24180663v1<TorysAtWork> - Fair Hydro Fee Regs (Torys Comments)
Document 2 ID	interwovenSite://INVENTORYS1/TorysAtWork/24180663/3
Description	#24180663v3<TorysAtWork> - Fair Hydro Fee Regs (Torys Comments)
Rendering set	Firm_Standard

Legend:	
Insertion	
~~Deletion~~	
~~Moved from~~	
Moved to	
Style change	
Format change	
~~Moved deletion~~	
Inserted cell	
Deleted cell	
Moved cell	
Split/Merged cell	
Padding cell	

Statistics:	
	Count
Insertions	70
Deletions	58
Moved from	8
Moved to	8
Style change	0
Format changed	0
Total changes	144

From: John Kim
To: Ronald Kwan
Subject: FW: Draft Fees Regulation
Date: Wednesday, September 27, 2017 3:51:09 PM

Fyi.

From: Anna Strathy
Sent: Wednesday, September 27, 2017 3:47 PM
To: Mike Manning <Mike.Manning@ofina.on.ca>; James Devine <James.Devine@ofina.on.ca>; Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>; Carlos Yep <Carlos.Yep@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>
Subject: RE: Draft Fees Regulation

Hi All,

I briefed Gadi on our call discussion this morning – he's comfortable with the proposed approach of going back at 5, with the caveats that it is at the higher end of market norms and should be evaluated by an independent expert within the first year of the program.

That said, he was also under the impression that the number/fees had already been agreed to. Had something changed between a few weeks ago and now? I'm sure Ken/Mike could clarify tomorrow – feel free to pop by his office.

Thanks, Anna

From: Gadi Mayman
Sent: Tuesday, September 26, 2017 2:15 PM
To: Scott Nelms (ENERGY) <Scott.Nelms@ontario.ca>
Cc: Steen Hume (CAB) <Steen.Hume@ontario.ca>; Mike Manning <Mike.Manning@ofina.on.ca>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>; Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
Subject: Re: Draft Fees Regulation

Thanks, Scott. I understand that there are a few items in here that are a little different than what we'd expected, so we'll get back to you with our consolidated OFA response tomorrow.

Regards,
Gadi

On Sep 26, 2017, at 12:18 PM, Nelms, Scott (MOF) <Scott.Nelms@ontario.ca> wrote:

> Hi Gadi,
>
> I hope NYC is going well and you are finding air conditioning.
>
> We have been working with Steen's team and Energy legal on a draft of the fees

regulation for OPG Trust and OFHP. As we progress through this, there are some elements of the regulation that we were hoping you and the OFA team might be able to consider (please see attached a black line for your reference):

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- On timing, the draft reg currently contemplates a fee application by OPG every two years regardless of what interest rates are in the market. Do we think this is fair or should the application occur annually? (Note that until new fees are established, the old fees are still in effect).

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Thanks for your help,
Scott

<Blackline_24180663v1 - 24180663v3.pdf>

From:	John Kim
To:	Bruno Amara; Shajee Kathirgamanathan; Gavin He
Cc:	Ronald Kwan; Usman Zahid
Subject:	FW: Draft OPG Business Plan TB Sub
Date:	Tuesday, March 20, 2018 11:50:15 AM
Attachments:	2018-02-16- OPG 2018-21 Business Plan Review - clean.pptx
Importance:	High

Could we review? For end of day?

Energy is asking us not to share externally.

From: Talwar, Shruti (ENERGY) [mailto:Shruti.Talwar@ontario.ca]
Sent: Tuesday, March 20, 2018 11:47 AM
To: John Kim <John.Kim@ofina.on.ca>
Cc: Graham Young (MOI) <Graham.Young@ontario.ca>; Sud, Manu (ENERGY) <Manu.Sud@ontario.ca>
Subject: Draft OPG Business Plan TB Sub
Importance: High

John,

As discussed, we are scheduled for Treasury Board on April 10. Please see the attached draft presentation.

If you can take a look and provide your comments for end of day tomorrow (March 21) that would be great. We have specifically flagged the fiscal impact slide for your review, but feedback on other pieces are welcome.

FYI, I am also sharing this draft concurrently with OPG for their review.

Thanks,
Shruti

Shruti Talwar
Director, Strategic Policy and Analytics Branch
Strategic, Network and Agency Policy Division
Ontario Ministry of Energy
416.325-8698
shruti.talwar@ontario.ca

Ontario

MINISTRY OF
ENERGY

Ontario Power Generation 2018-2021 Business Plan

March 2018

Ministry Request

- The Ministry of ENERGY is requesting that Treasury Board/Management Board of Cabinet (TB/MBC):

    1. NOTE the receipt of OPG's 2018-2021 Business Plan.

    2. NOTE that the Minister of Energy will provide concurrence with OPG's Business Plan.

Purpose

- As required by the Memorandum of Agreement (MOA) between Ontario Power Generation and the Minister of Energy, OPG provided its Business Plan for 2018-2021 to the Ministry of Energy on February 12, 2018 for concurrence.
- The Minister's concurrence requires presentation of OPG's business plan before TB/MBC.
- Ministry of Energy staff have reviewed this plan in the context of key government priorities and recommend that TB provide approval.
- The Ministry of Energy review and analysis of OPG's business plan is supported by the Corporate and Electricity Finance Division of the Ontario Financing Authority (OFA).
- The following presentation identifies the key aspects of the business plan and how they interrelate.

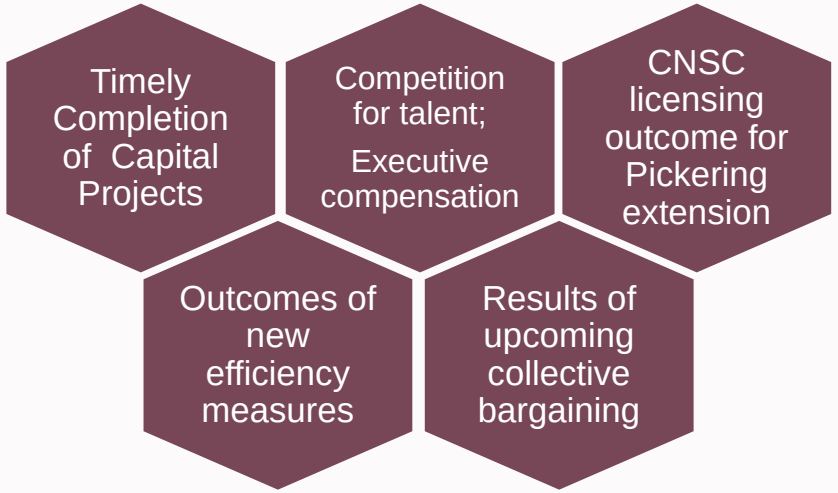
Overview

Business Plan Elements

- The 2018-2021 Business Plan covers an important time for OPG for several reasons:

Business Plan Risks

- Achieving financial performance targets is contingent on positive outcomes in a number of areas:



OPG's ability to manage these elements & risks will determine if it is improves return to the Province and limits ratepayer costs.

Elements of Business Plan

1. **Electricity Production**
   - ❖ Higher than approved production improves financial performance through increased revenue.
   - ❖ Affected by capital projects (e.g., refurb) and Pickering Extension.

2. **Production Costs**
   - ❖ Cost targets fluctuate due to outages, water conditions and efficiency initiatives.
   - ❖ Pickering's cost performance expected to improve relative to previous plan.

3. **Capital Projects**
   - ❖ Timely completion impacts production and project costs
   - ❖ Darlington Refurbishment on track- Unit 2 online in 2020.

4. **Operating Costs & Compensation**
   - ❖ Strategies to increase efficiencies and savings improve financial performance
   - ❖ Subject to collective bargaining that will take place in 2018.

5. **Fair Hydro Plan**
   - Adds ~$6 billion in debt by 2021; Provincial equity doubles by end of plan.
   - Generates net income for OPG ($465 million over 4 years)

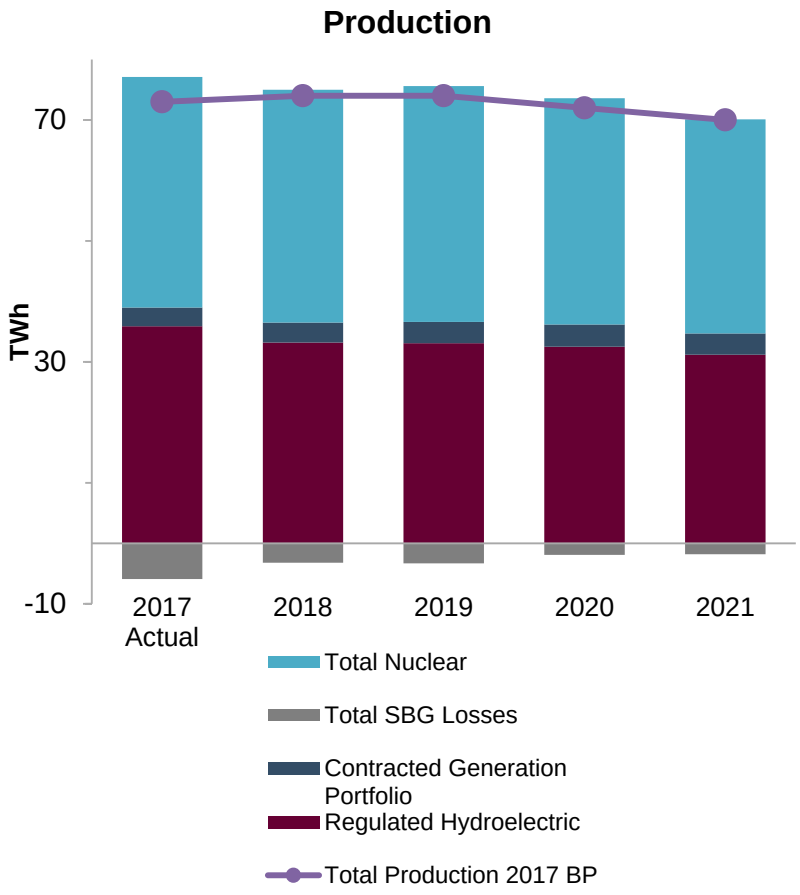
6. **Business Development**
   - Increase revenue through modest hydro expansion, solar, nuclear services & low-carbon technology.
   - Long-term need for new business lines outside of province

7. **Financial Performance**
   - ❖ Performance impacts Province's fiscal position Total Shareholder Return expected to improve over previous plans.

Electricity Production

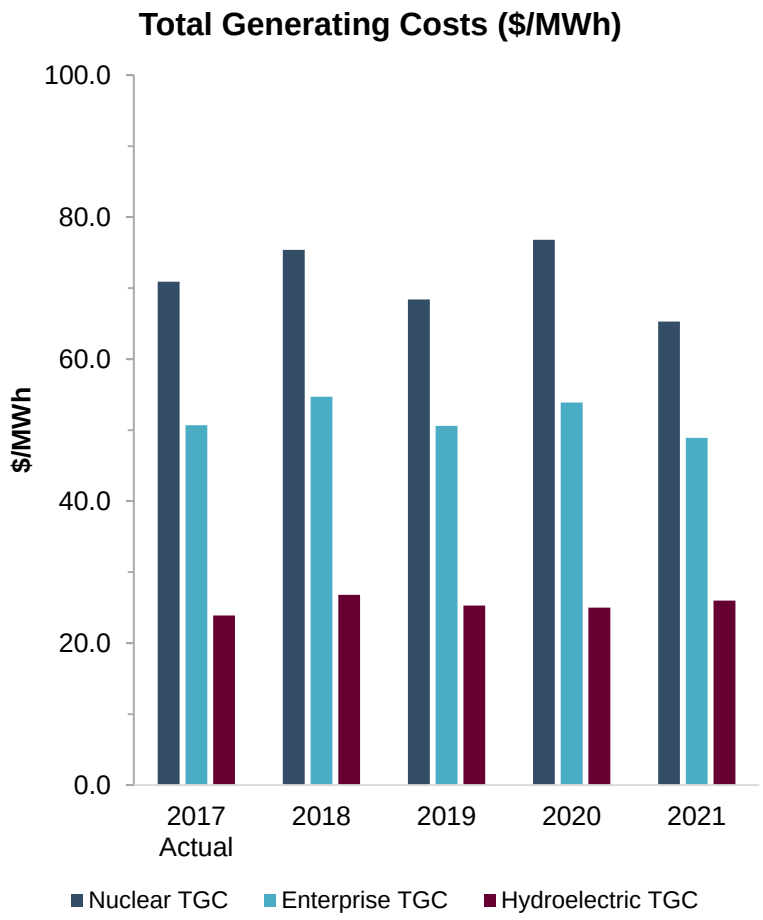
- ❖ Production increases improve financial performance through increased revenue.
- ❖ Forecasts affected by capital projects (e.g., Darlington Refurbishment); Pickering extension and efficiency strategies.

- The plan forecasts a total increase of 5.4 TWh compared to the last business plan.
- Increases are driven by higher production at Pickering Generating Station.
  - OPG will increase time between routine outages, allowing units to run longer.
  - Other reliability improvements reduce Pickering's 'forced loss rate'- (i.e., losses from unplanned shutdowns.)
- The forecasts assume CNSC will grant Pickering license extension to 2024.
- Production decreases in 2020 when Darlington Unit 2 returns to service and Unit 3 is taken offline. There is also a lengthy planned outage at Pickering.
- The current Thunder Bay biomass energy supply agreement expires in January 2020. The station may participate in a future capacity auction



Cost of Production

- ❖ Cost targets fluctuate due to outages, water conditions and efficiency initiatives.
- ❖ Pickering's cost performance expected to improve relative to previous plan.



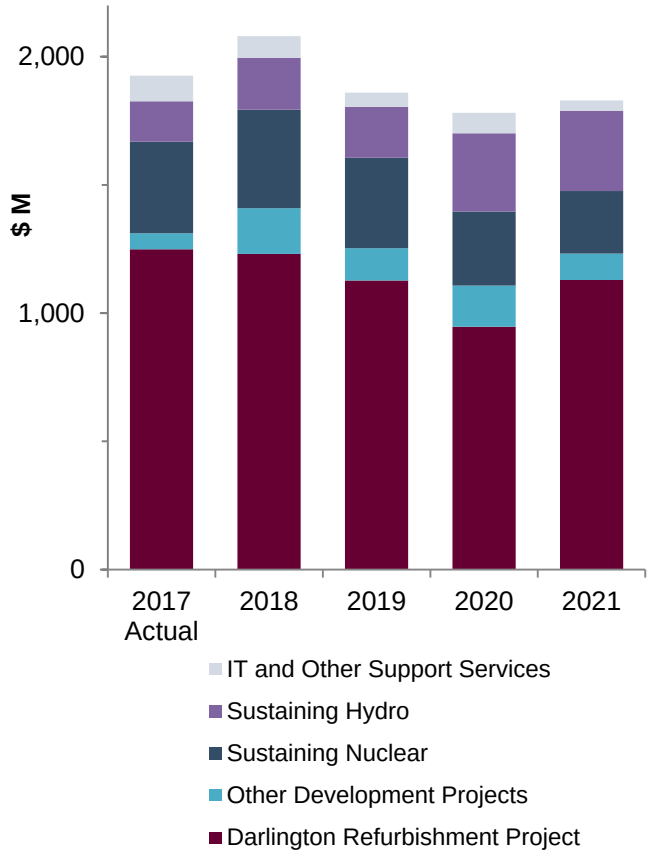
- Total Generating Cost (TGC) per MWh is OPG's measure of operational cost effectiveness.
  - TGC is a performance metric for executive compensation
  - Darlington Generating Station's TGC performance will be how OPG measures the long-term success of its OPG25 restructuring initiative.
- TGC targets fluctuate due to nuclear outages, efficiency initiatives and surplus-baseload generation adjustments due to high water levels.
- The production and cost forecasts are consistent with its OEB rate application. The set rates through 2021 provide planning stability.
  - If OPG exceeds production forecasts, it generates additional revenue. It must absorb costs if production is lower than forecast.

Capital Projects

- ❖ Timely completion impacts production output and costs.
- ❖ Costs deemed imprudent for regulated projects negatively impact financial performance

- The plan includes $4.4 billion in capital expenditures for the Darlington Refurbishment project (DRP). Unit 2 is planned for return to service in early 2020.
- The plan includes $105 million in capital expenditures for the Heavy Water Storage(D2O) project, an enabling sub-project for the DRP that previously experienced delays and cost overruns (note: overall refurbishment has remained within budget and schedule).
- In its rate decision, OEB confirmed it will take a holistic view to assessing DRP costs, evaluating overall project performance against approved budget rather than an individual sub-project basis.
- Other capital expenditures include:
  - Ranney Falls re-development (2019 completion)
  - Nanticoke Solar (2019 completion)
  - Beck generating station upgrades (2022 completion)
  - Other sustaining capital (Hydro unit overhauls; equipment upgrades)
- The plan accelerates capital expenditures for OPG's digital transformation in support of improved efficiency.

Total Capital Expenditures



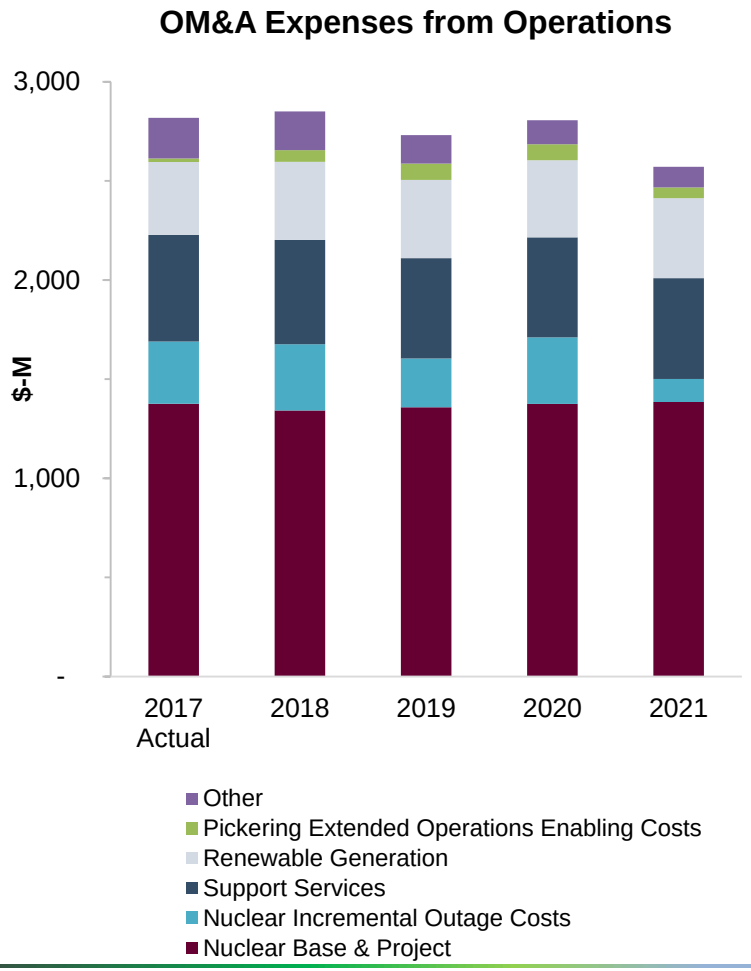
Operating Costs (OM&A)

- ❖ Incremental efficiencies/savings improve financial performance
- ❖ OEB Decision reduces OM&A / compensation

- The plan targets a total decrease in OM&A expenditures of $600 million over four years. Annual spending decreases by $280 million in 2021 compared to 2018.
- The reductions will be achieved through new processes, technology upgrades and reducing nuclear plant outage frequencies.

OPG25 Initiative

- OPG25 is a plan to restructure OPG due to the closure of Pickering in 2024.
- The objective of OPG25 is to ensure operations remain cost-effective and that OPG is positioned for growth.
- The long-term target for the plan is having Darlington operate in the top-quartile for total generating costs.
- The initiative includes a staffing transition work stream, making interaction with unions critical.
- The 2018-21 business plan's cost reductions will help move OPG towards achieving the total target reductions post Pickering operations.

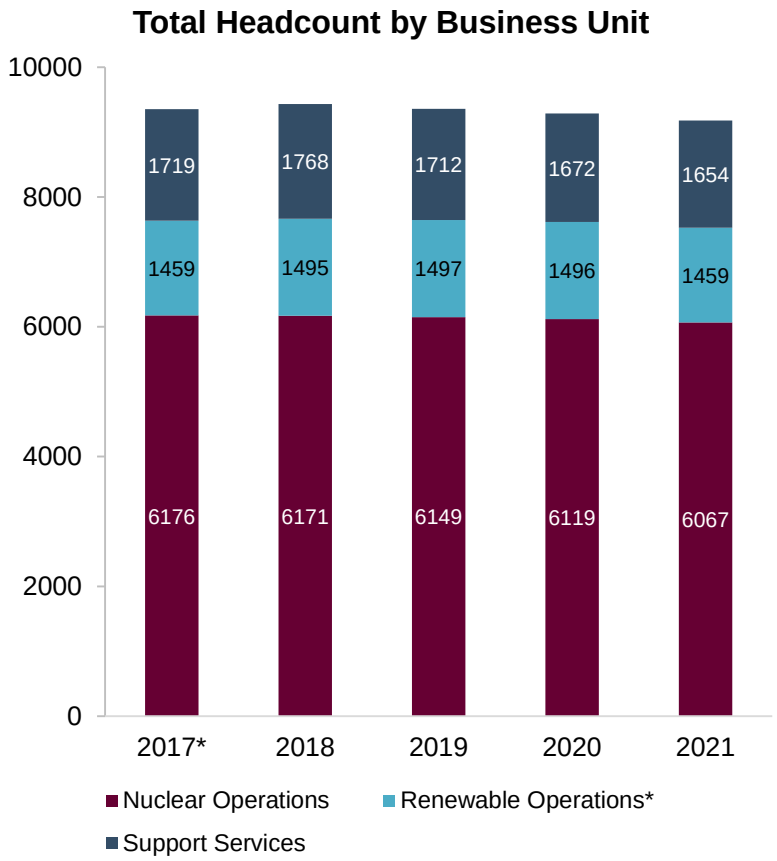


Compensation

Collective Bargaining

- ❖ Collective agreements expire in 2018.
- ❖ Results of collective bargaining will impact efficiency and cost-optimization initiatives.

- Collective bargaining impacts OPG's ability to reduce OM&A. Most employees belong to either the Power Workers Union (PWU) or Society of Energy Professionals (Society).
- Collective agreements with Society & PWU expire in 2018. Negotiated outcomes will impact OPG's ability to meet the plan's savings forecasts. Through collective bargaining, OPG hopes to:
  - Manage wage increases
  - Reduce future workforce costs including pension and benefits
  - Ensure future staff capability
  - Reduce downsizing costs resulting from Pickering closure*
- The plan identifies an accounting risk related to Pickering downsizing costs materializing prior to the next OEB rate application. This would affect net income in the year the costs were recognized.



Compensation

Executive Compensation

- ❖ Executive compensation program implemented in January 2017
- ❖ Compensation program benchmarks against comparator organizations

- OPG implemented an Executive Compensation Program in 2017 compliant with *O.Reg 304/16.*
- The program is designed to provide compensation that is at the 50th percentile of the market and focused on at-risk, performance based pay.
- In 2017, TB/MBC approved exemptions allowing OPG to compare against private sector and international companies.
- Overall compensation for all management group staff increases at 2% based on assumed inflation each year in the plan.
- Short-term incentives are based on individual performance and the corporate scorecard. Strong performance on the scorecard led to increases in executive incentives in 2017.
- Corporate scorecard measures for 2018 include:

2016-2018 executive medium-term incentive performance metrics
(on 3-year cycle ending 2018)

- **Return on Equity**
- **Total Generating Cost**
- **Darlington Refurbishment Major Milestones**

Social License: Total Recordable Injury Frequency; no significant events impacting OPG's reputation

Financial Strength: Earnings Before Tax (excluding the Nuclear Waste Management segment), Plan Operating OM&A Expenses.

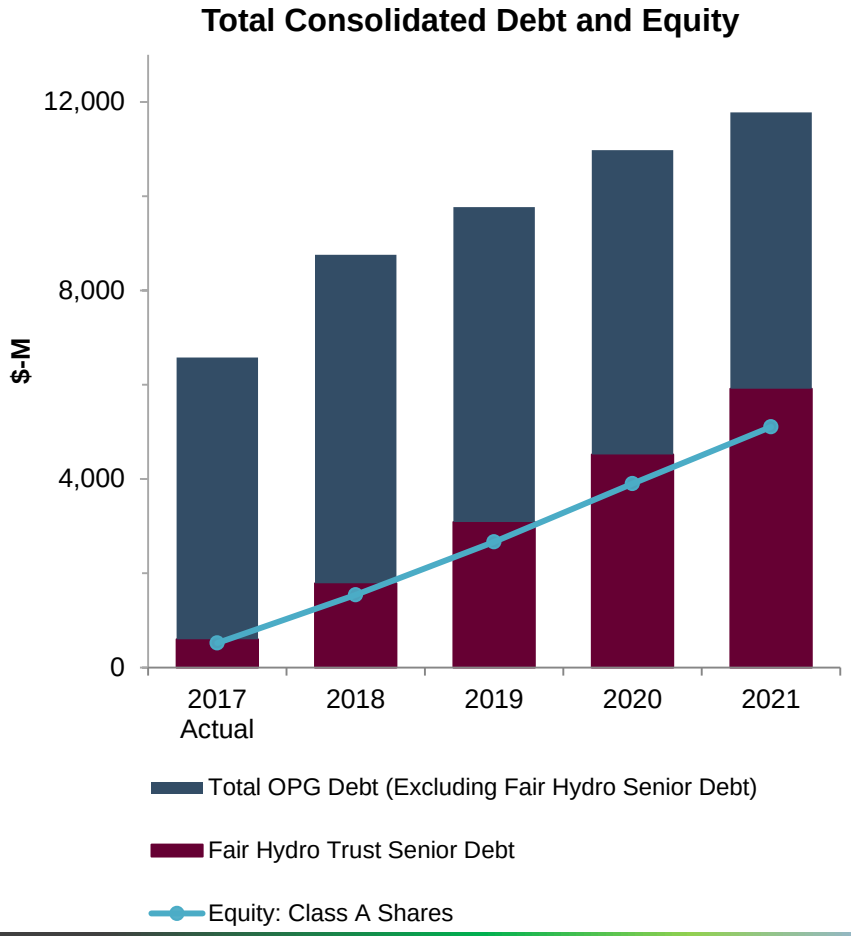
Operational Excellence: Total OPG production adjusted for Surplus Baseload Generation

Project Excellence: DRP costs and schedule; Peter Sutherlands Sr. Generating Station, and total in-service capital

Fair Hydro Plan

- ❖ FHP is managing the deferral of a portion of Global Adjustment (GA) costs.
- ❖ OPG earns revenue and incurs debt; Provincial equity in OPG doubles by 2021.
- ❖ While a new source of revenue for OPG, revenue is paid by Ontario ratepayers.

- In 2017, OPG began its role as OFHP Financial Services Manager (FSM).
- The Fair Hydro Trust contributes to increasing amounts of net income, growing from $10 million in 2018 to $225 million in 2021.
  - This reflects the spread earned on the equity contributions from the Province to fund 44% of OPG's financing of the Trust.
- As the Province provides more funding to facilitate asset purchases in exchange for shares in the company, the government's equity increases, lowering ROE.
- The Fair Hydro Trust external senior debt is projected to increase to $5.9 billion by 2021.



Business Development

- ❖ OPG hopes to grow its business and increase revenue through modest hydro expansion, solar, nuclear services & low-carbon technology.
- ❖ Long-term need for new business lines outside of province.

- OPG hopes to grow its business by investing in commercial innovation, project development and asset acquisition.
- The business plan references organic and non-organic investments:
  - Organic investments are in-house project development of generation and energy products in Ontario. The plan allocates incremental capital funding of ~$200 million for organic investments.
  - Non-organic investments are new opportunities in Ontario. These investments are not included in the plan, however, OPG forecasts up to $3 billion would be available for such investments.

Business Development investment categories:

Innovation & Services
OPG will consider investing in near commercial emerging technologies

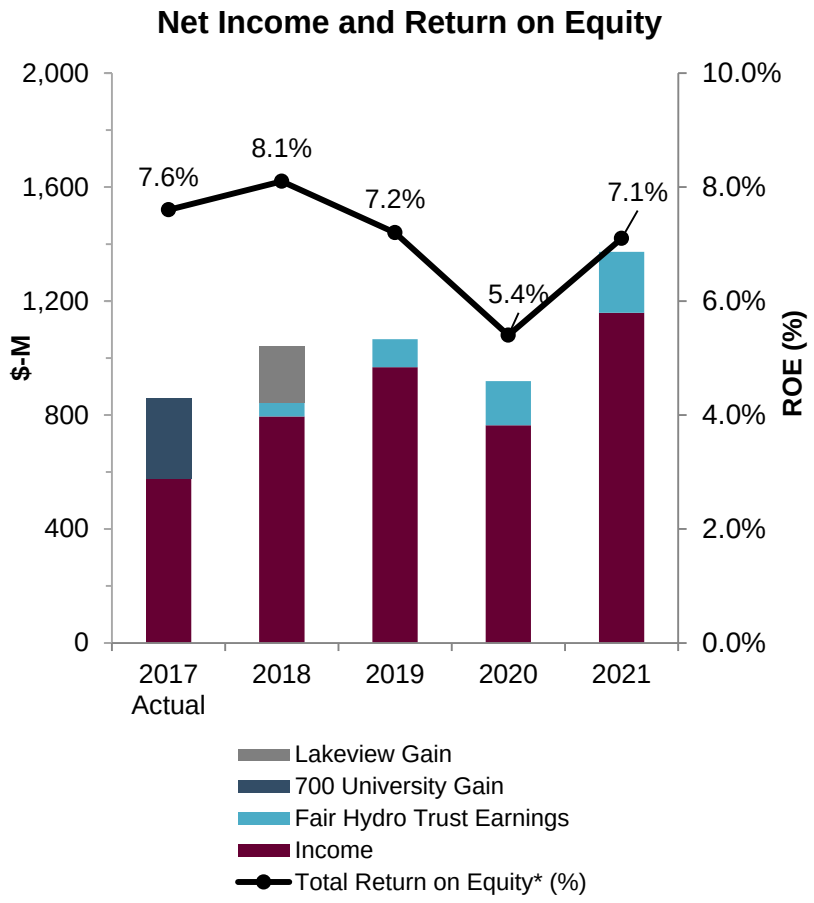
Acquisition and Development
OPG will develop assets and consider acquisitions in Ontario and other North American markets

- As the Shareholder, the Province may need to provide approvals for certain investments (e.g., development and acquisitions).
  - The Ministry of Energy plans to develop a policy framework to guide these approvals.

Financial Performance

Business Plan Results as presented by OPG

- ❖ Plan forecasts total net income to reach $1.37 billion in 2021, from $860 million in 2017
- ❖ OEB Decision provides rate stability over the planning period.



- OPG shareholder return (Net income + PILS) are consolidated to the Province.
- The plan reflects the Ontario Energy Board's (OEB) December 2017 Decision on OPG's regulated rates through 2021, providing stability in the planning period.
- Return on Equity (excluding impact of Fair Hydro Trust) increases from 5.3% in 2017 to 8.1% in 2021. ROE is a performance metric for executive compensation.
- Should OPG fail to meet targets for production, operating cost reductions or capital expenditures, net income improvements may not materialize.
- Net income in 2017/18 is impacted by one-time asset sales (Head Office and Lakeview), which will be credited to the Trillium Trust.

Financial Performance

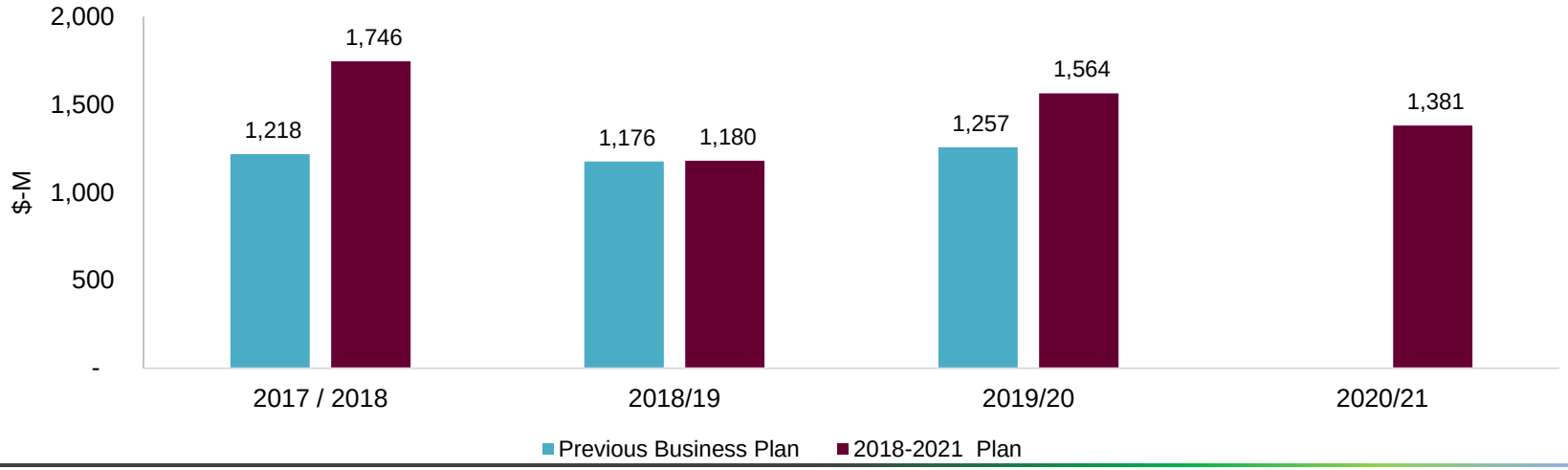
2018-21 Business Plan compared to previous plan

- ❖ Improved net income and shareholder return over previous plans.
- ❖ Projections impacted by efficiency measures and one-time real estate gains.

- The plan's total shareholder return is higher than last year's 2017-19 business plan.
- The financial performance reflects increased efficiency leading to revenue increases from higher production and lower operating costs
- The plan assumes the sale of Lakeview will be complete in 2017/18, resulting in $200M in net income and $70 million in PILS. The sale was not included in last year's plan.
  - OPG has a purchase agreement for Lakeview site, anticipated to close in March, 2018.

Total Shareholder Return

2018-21 BP vs. Previous Business Plan



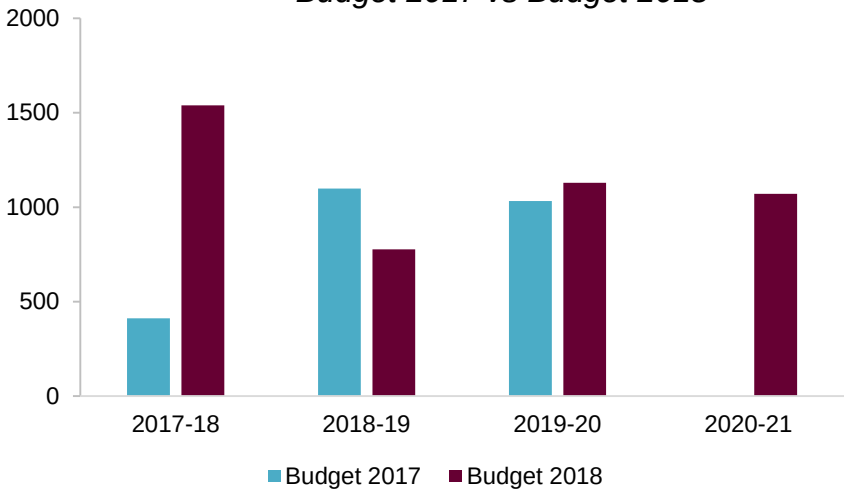
Financial Performance:[OFA to review]

Impacts to Province

- The Ministry of Finance and Treasury Board Secretariat are responsible for the fiscal consolidation of OPG's financials on the Province's financial statements which may include accounting adjustments.
- Budget 2018 reflects the impacts of OPG's 2018-2021 Business Plan

- When OPG's financials are consolidated into the Province's financials, some adjustments are required
  - **IFRS:** OPG uses US GAAP accounting standards for financial reporting. The Province consolidates OPG's results using International Financial Reporting Standards (IFRS).
  - **Fair Hydro Income:** While OPG separates out this income in its Business Plan, OPG's Financial Services Manger revenue is added to OPG net income when consolidated.

Total OPG Revenues to the Province
Budget 2017 vs Budget 2018



2017/18 positive variance due to:
- $646M for real estate sales included in Budget 2018, not in Budget 2017.
- Positive ONFA Adjustments included in Budget 2018 not in Budget 2017
- Lower IFRS adjustment in Budget 2018 than Budget 2017

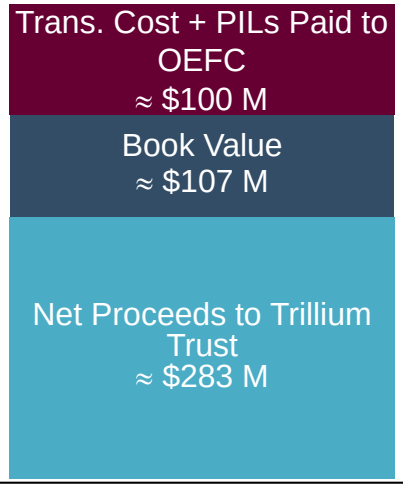
2018/19 negative variance due to:
- Negative IFRS adjustment included in Budget 2018

Financial Performance

Contribution to the Trillium Trust

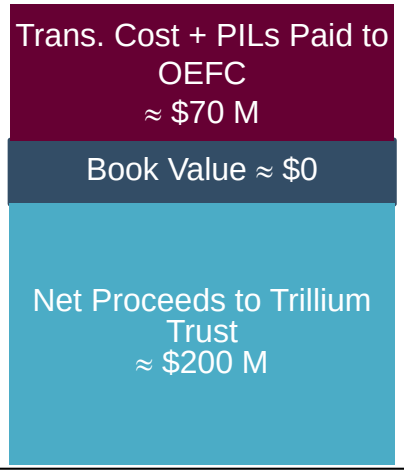
- Net proceeds from the sale of OPG's its Head Office (700 University) and Lakeview site are paid to the CRF and credited to the Trillium Trust.
- The Province will receive a dividend payment from OPG for the gains on these sales.
- The Head Office sale closed in April 2017. Lakeview expected to close in 2018.

Head Office: Designated Proceeds to Trillium Trust from OPG



- Shareholder Declaration & Resolution received: December 2015
- Sale closed: April 2017
- Amount credited to Trillium Trust: Mar 2018

Lakeview: Estimated Proceeds to Trillium Trust from OPG



- Shareholder Declaration & Resolution received: June 2016
- Expected sale: March 2018
- Regulation required to prescribe amounts to Trillium trust

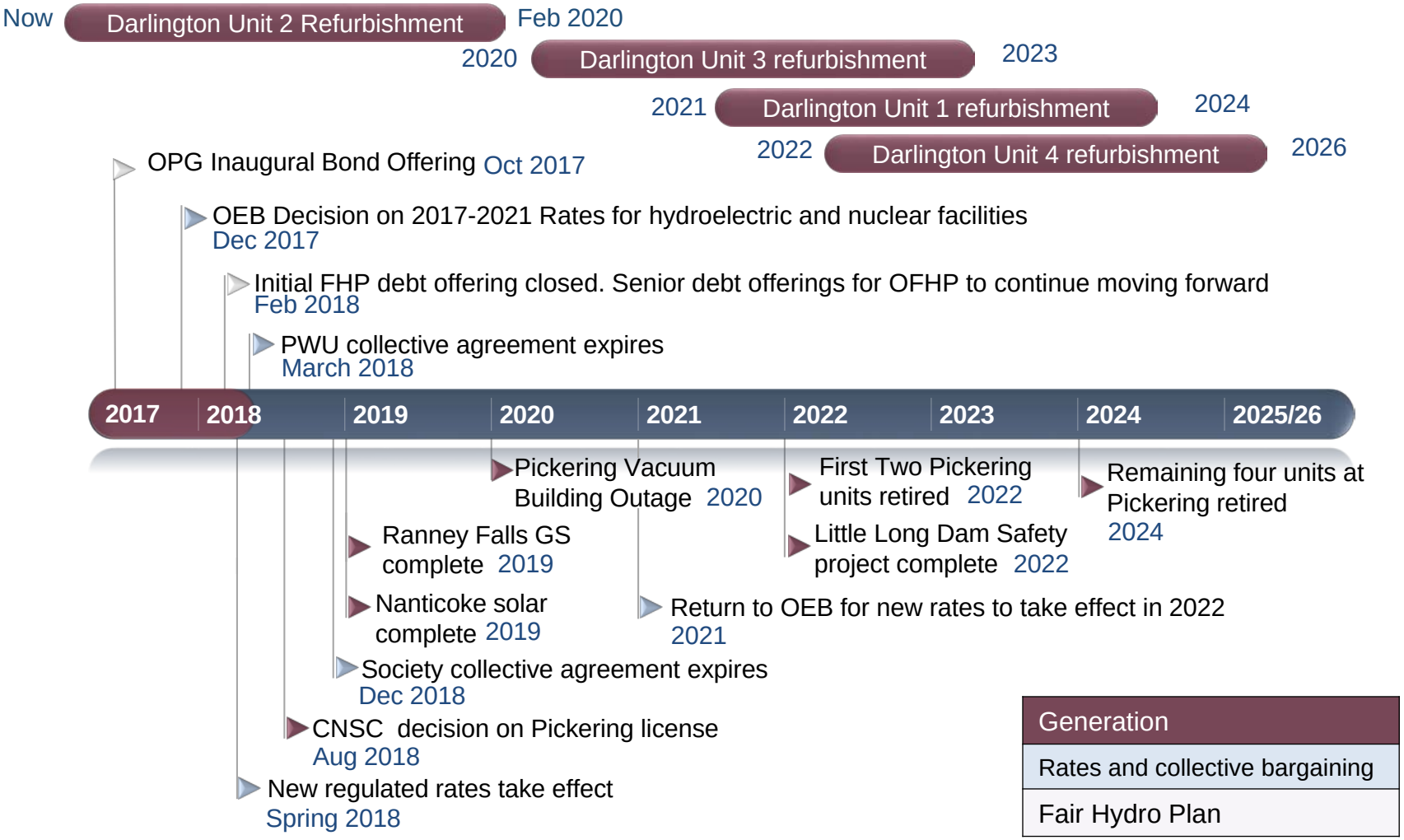
Considerations

- Based on these materials, ENERGY is seeking approval to provide OPG with business plan concurrence.
- At this point OPG has rate stability through the planning period and has demonstrated success in key projects including Darlington refurbishment. The plan is in line with government expectations on reducing costs in order to drive value for Ontario ratepayers and the Province, as Shareholder.
- OPG identified risks that the Ministry will continue to monitor. These include
  - Meeting efficiency targets for cost-savings and production.
  - Successful collective bargaining negotiations with PWU and Society; and
  - Completion of capital projects on budget and schedule
- OPG will continue to seek new business opportunities within Ontario and other jurisdictions. OPG will seek comfort from the Province for any new acquisitions.
- OPG will consider investing in near-commercial emerging technologies, acquisitions and development.

Appendix

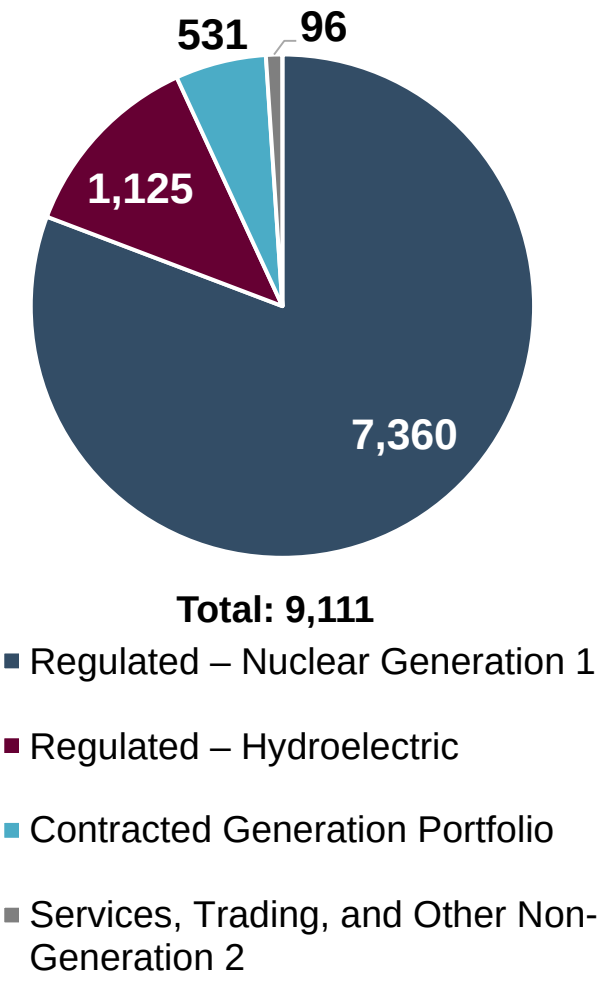
Timeline

- Outcomes from the Business Plan are impacted by the following events:



Company Profile

2017 Average Full-Time Employees

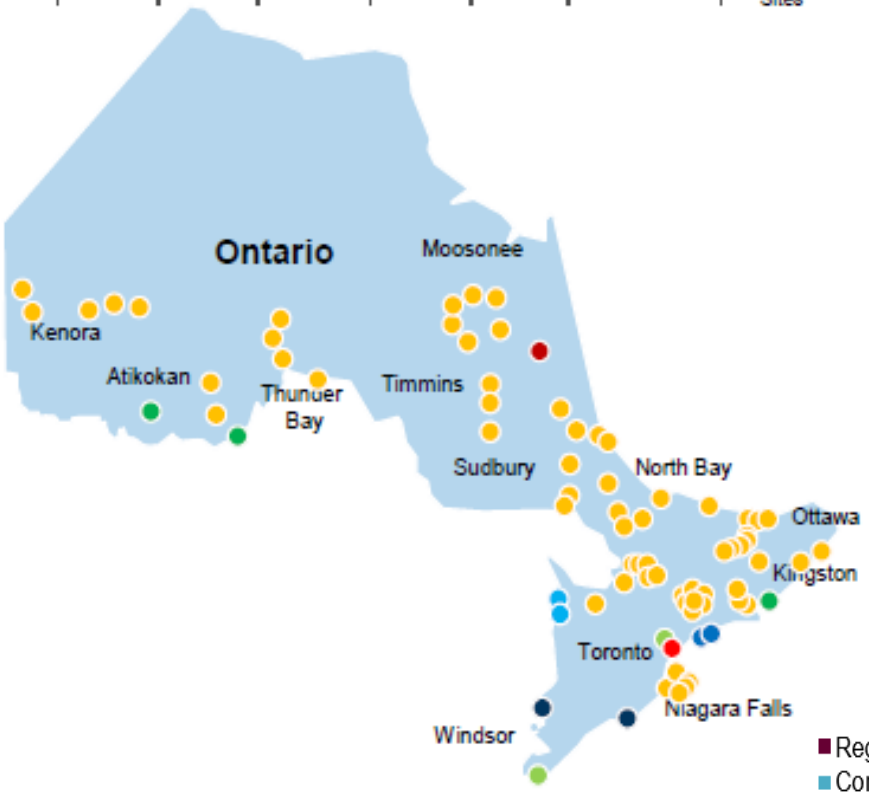


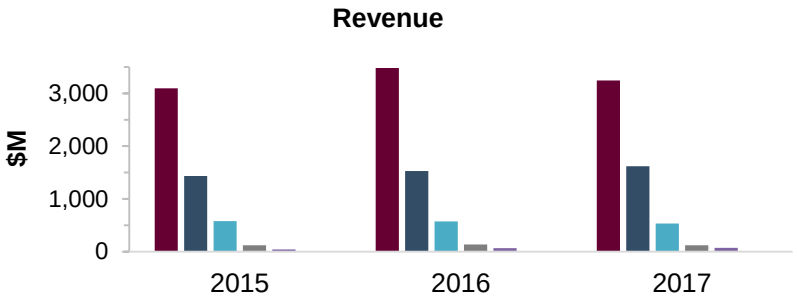
- Majority of OPG's employees are represented by one of two unions:
  1. The Power Workers' Union (PWU); and
  2. The Society.
- The PWU includes most workers below the level of first line manager
- The Society includes supervisors, professional engineers, scientists and other professionals.
- Construction work is performed through 19 craft unions.

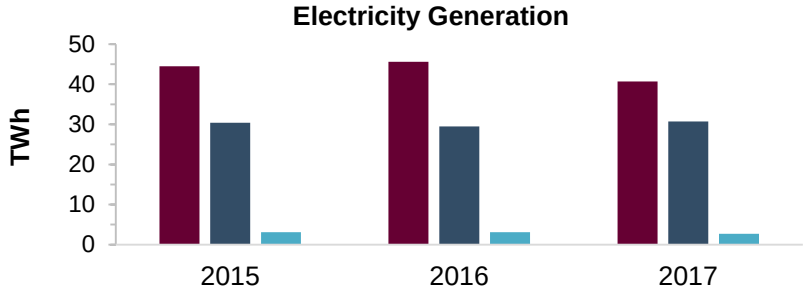
Company Profile

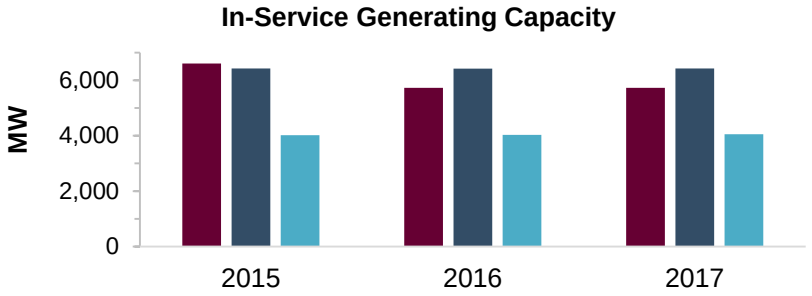
Map of OPG Generating Stations:

2	2	3	2	65	1	1	2
Nuclear Stations	Leased Nuclear Stations	Thermal Stations	Co-Owned Gas-Fired Stations	Hydro-electric Stations	Wind Power Turbine	Hydroelectric Project Under Construction [1]	Brownfield Coal Generation Sites









- Regulated – Nuclear Generation
- Regulated – Hydroelectric
- Contracted Generation Portfolio 1
- Regulated – Nuclear Waste Management
- Services, Trading, and Other Non-Generation

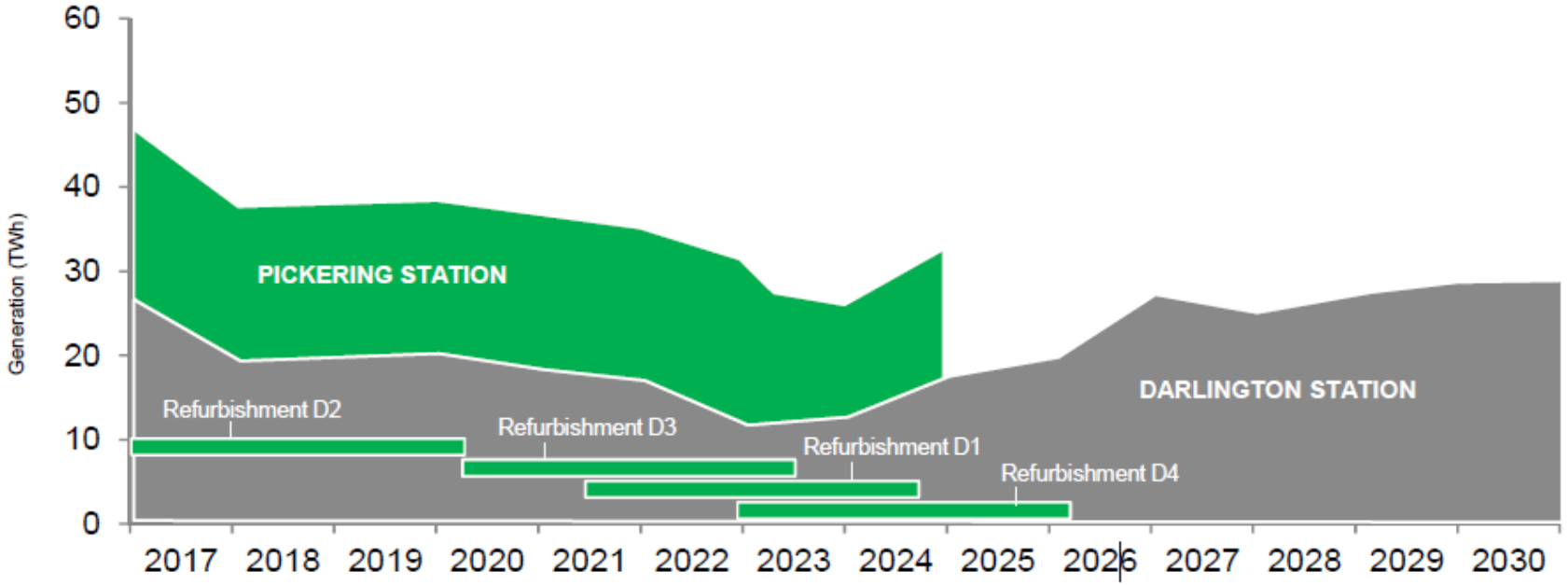
Key Projects: Nuclear

1. Pickering Extension

- OPG is continuing work to extend operations of the Pickering GS to 2024. It is currently licensed to operate to 2020.
- OPG has applied for a license renewal from the CNSC. The ruling is expected in August 2018.

2. Darlington Refurbishment

- OPG is refurbishing the Darlington Nuclear station to extend the operating life of the station by 30 years.
- Status: tracking on schedule and budget.
- Total Budget: $12.8 billion.



Source: OPG Initial Public Debt Program, 2017

Key Projects: Renewables

Biomass

1. Atikokan

Capacity: 205 MW

Converted from coal in 2014

Capex: ~$170M

2. Thunder Bay

Capacity: 153 MW

Converted from coal in 2014

Indigenous Relations

OPG's corporate governance includes an Indigenous Relations policy to help build and develop mutually beneficial working relationships with Indigenous communities proximate to the Company's present and future operations.

Renewables

Hydroelectric

1. Peter Sutherland Sr.

Capacity: 28 MW

Completed: March 2017

Capex: <$300M

2. Lower Mattagami

Capacity: 438 MW

Completed: 2014

Capex: $2.5BN

Solar

1. Nanticoke Solar

Project partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation to build the new facility.

Capacity: 44 MW

Commenced: Q4 2017

Expected completion: 2019

Role of OFHP Financial Services Manager

- In June 2017, the Province enacted the *Ontario Fair Hydro Plan Act, 2017* in order to ensure the costs and benefits associated with the Province's clean energy initiatives are allocated fairly between present and future electricity consumers.
    - The policy goals of the Act are being achieved through the refinancing of a portion of the Global Adjustment (GA).
    - OPG was appointed Financial Services Manager (FSM) under the Act.

- OPG's duties as FSM include:
    - Establishing one or more financing entities to incur funding obligations. OPG established the Fair Hydro Trust in 2017.
    - Preparing a financing plan to evaluate how and when funding obligations should be incurred.
    - Administering investment assets purchased from IESO
    - Determining the monthly clean energy adjustment for each reference period
    - Establishing and charging fees to recover costs, expenditures and earn a return
    - Seeking best available terms for incurrence of a funding obligation
    - Fulfilling various reporting requirements

Board of directors

- OPG's Board of Directors is made up of 14 individuals. Each Director holds office until he or she resigns or a successor is elected or appointed:

Director	Role	Appointed
1. Bernard Lord	Chair	November 2013
2. Jeffrey Lyash	President and CEO of OPG	August 2015
3. William Coley	Director	January 2013
4. Elisabeth DeMarco	Director	April 2014
5. Jean Paul Gladu	Director	November 2015
6. John Herron	Director	November 2013
7. Ani Hotoyan-Joly	Director	March 2017
8. Wendy Kei	Director	March 2017
9. M. George Lewis	Director	February 2005
10. Margaret Mulligan	Director	December 2005
11. Yezdi Pavri	Director	September 2015
12. Gerry Phillips	Director	January 2013
13. Jim Reinsch	Director	August 2015
14. James Sheppard	Director	March 2017

Compensation

2017 Statement of Executive Compensation

- OPG exceeded many of the measures in its Corporate Scorecard, impacting incentive payments.
- Scorecard is based on a predetermined scale of Threshold/Business Plan/Stretch targets (i.e., low/medium/high) and given a weighting. The scorecard is summarized below.

Category	**Performance Measure**	**Threshold Target**	**Business Plan Target**	**Stretch Target**	**2017 Results**	**Score (0 to 1.5)**
Social Licence	All Injury rate (AIR)	0.49	0.37	0.31	0.48	0.54
	Addressing Safety Focus Areas	CEO assessed target			1.5	1.46
	No significant impacts to OPG's reputation					
Financial Strength	Earnings Before Taxes, ($M)	675	875	1075	1296	1.50
	OM&A Expenses ($M)	2675	2550	2425	2474	1.30
Operational Excellence	Production (TWh)	70.3	72.4	74.6	78.1	1.50
Project Excellence	Refurbishment Project Cost – 2017 actual expenditures ($M) as a percentage of approved 2017 budget	100%	97.50%	95%	120%	0.00
	Refurbishment Unit 2 Critical Path Execution – Commencement of Feeder cabinet removal (Milestone	05-Aug-17	26-Jul-17	28-Jun-17	22-Jun-17	1.50
	Refurbishment Unit 2 Critical Path Execution: Progress of Critical path on Dec 31, 2017	All Bellows Severed	50% End Fitting Removed	400 Pressure Tubes Removed	45% of End Fittings Removed	0.95
	Pump Generating Station: In service	06-01-2017	04-01-2017	03-01-2017	02-04-2017	1.50
	Peter Sutherland Generating Station: Both Units in service	10-19-2017	06-30-2017	04-30-2017	03-31-2017	1.50
	Total In-service Capital -	$578 (+/- 10% to +/- to 15%)	$578 (+/- 3% to +/- 10%)	$578 (to +/- 3%)	$625 (+8%)	1.00
	Total Weighted Score[1]					**1.19**

Exceeded Stretch Target
Exceeded BP Target
Below BP Target
Below Threshold

From: Ken Kandeepan
To: Gadi Mayman
Cc: Lynsey Wynberg; Ronald Kwan; Mike Manning
Subject: FW: EXTERNAL - RE: OEFC Funding of the Global Adjustment Deferral
Date: Thursday, February 16, 2017 9:04:04 AM

Hi Gadi

I suggest that we respond as follows: pls let me know if you have any changes

Hi John

Gadi and others spent considerable time last night discussing the equity injection option and we are unclear as to how the Province will be made whole from a fiscal perspective. I suggest that you proceed with fleshing out this option and once we have all the details a decision can be made as to its viability.

Thanks

Ken k

-----Original Message-----
From: LEE John -TREASURY [mailto:john.s.lee@opg.com]
Sent: Thursday, February 16, 2017 8:28 AM
To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
Cc: Veinot, Cindy (TBS) <Cindy.Veinot@ontario.ca>; Nadine Petsche (MOF) <Nadine.Petsche@ontario.ca>; RYFA Ken -TREASURY <ken.ryfa@opg.com>; CHENG Alec -FIN & C CTRL <alec.cheng@opg.com>
Subject: RE: EXTERNAL - RE: OEFC Funding of the Global Adjustment Deferral

Ken:

Have you had any confirmation from Gadi on the approach. As you know time is of the essence, as a result we are proceeding with discussions with the external auditors this morning to brief them on the approach and get their thoughts on the accounting implications and what needs to be done from a structuring perspective to ensure that the varying objectives can be met. Please advise ASAP.

John

-----Original Message-----
From: Ken Kandeepan [mailto:Ken.Kandeepan@ofina.on.ca]
Sent: Wednesday, February 15, 2017 6:37 PM
To: LEE John -TREASURY
Cc: Veinot, Cindy (TBS); Nadine Petsche (MOF); RYFA Ken -TREASURY; CHENG Alec -FIN & C CTRL
Subject: Re: EXTERNAL - RE: OEFC Funding of the Global Adjustment Deferral

Thanks John, it seems that what you are saying is OPG's net income will increase, all else being equal, by the amount of the interest relating to the equity injection.

In which case upon consolidation there will be no fiscal impact to the Province.

As you work through the options this needs to be fleshed out since the Trust will be consolidated with OPG we need to understand how OPG will show a net interest income.

Thanks

Ken k

> On Feb 15, 2017, at 6:28 PM, LEE John -TREASURY <john.s.lee@opg.com> wrote:
>
> Ken:
> To clarify the expectation is that equity injected into OPG which is on-lend to the Trust would result in net interest income that would roll up to the Province and this would cover the interest expense for the associated debt at the Province. The dividend comment was meant to describe mechanism on how to get cash to the province.
>
> John
>
> -----Original Message-----
> From: Ken Kandeepan [mailto:Ken.Kandeepan@ofina.on.ca]
> Sent: Wednesday, February 15, 2017 5:51 PM
> To: LEE John -TREASURY; 'Veinot, Cindy (TBS)'
> Cc: Nadine Petsche (MOF)
> Subject: RE: EXTERNAL - RE: OEFC Funding of the Global Adjustment Deferral
>
> Hi John and Cindy
>
> I just realized that in the event of an equity injection by the Province to OPG for a maximum of 49%, will as we discussed, have no impact on the Province's net debt.
>
> Unfortunately there will be an IOD impact. John, I remember you mentioning that OPG will increase the dividends it pays to the Province by an amount equivalent to the interest on the equity injection to date, however, that will only provide a cash and not a fiscal offset.
>
> The only way a fiscal offset can be provided is if OPG's net income increases by an amount equal to the increase in the Province's IOD (all else being equal). In which case the Province will be fiscally whole upon consolidation.
>
> But I am not sure that going to happen since the Trust will not contribute to OPG's bottom line, or at least that's my understanding.
>
> As such the potential fiscal impact from the increased IOD may be an issue for the Province re this option. In any event I will check with Gadi and circle back.
>
> Thanks
>
> Ken k
>
> -----Original Message-----
> From: HAHN PARKER Janet -TREASURY [mailto:j.hahnparker@opg.com]
> Sent: Wednesday, February 15, 2017 4:50 PM
> To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
> Cc: LEE John -TREASURY <john.s.lee@opg.com>; 'Veinot, Cindy (TBS)' <Cindy.Veinot@ontario.ca>
> Subject: RE: EXTERNAL - RE: OEFC Funding of the Global Adjustment Deferral
>
> Thank you. Will do.
>
> -----Original Message-----
> From: Ken Kandeepan [mailto:Ken.Kandeepan@ofina.on.ca]
> Sent: Wednesday, February 15, 2017 4:49 PM
> To: HAHN PARKER Janet -TREASURY
> Cc: LEE John -TREASURY; 'Veinot, Cindy (TBS)'
> Subject: RE: EXTERNAL - RE: OEFC Funding of the Global Adjustment Deferral
>
> Cindy is free now if you can set up the call.
>

> Thanks
>
> Ken k
>
> -----Original Message-----
> From: HAHN PARKER Janet -TREASURY [mailto:j.hahnparker@opg.com]
> Sent: Wednesday, February 15, 2017 3:43 PM
> To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
> Cc: LEE John -TREASURY <john.s.lee@opg.com>
> Subject: RE: EXTERNAL - RE: OEFC Funding of the Global Adjustment Deferral
>
> Thank you.
> This is of utmost importance. Please advise soonest.
> Janet
>
> -----Original Message-----
> From: Ken Kandeepan [mailto:Ken.Kandeepan@ofina.on.ca]
> Sent: Wednesday, February 15, 2017 3:37 PM
> To: HAHN PARKER Janet -TREASURY
> Cc: LEE John -TREASURY
> Subject: RE: EXTERNAL - RE: OEFC Funding of the Global Adjustment Deferral
>
> My apologies for the delay, unfortunately I am yet to hear back from Cindy, will let you know as soon as I do.
>
> Thanks
>
> Ken K
>
> -----Original Message-----
> From: HAHN PARKER Janet -TREASURY [mailto:j.hahnparker@opg.com]
> Sent: Wednesday, February 15, 2017 1:57 PM
> To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
> Cc: LEE John -TREASURY <john.s.lee@opg.com>
> Subject: RE: EXTERNAL - RE: OEFC Funding of the Global Adjustment Deferral
>
> Ken,
>
> Please advise on this call. Timing is important.
> A prompt response would be most appreciated,
>
> Thank you,
> Janet Hahn Parker
>
> 416 592-6749
> j.hahnparker@opg.com
>
> -----Original Message-----
> From: Ken Kandeepan [mailto:Ken.Kandeepan@ofina.on.ca]
> Sent: Wednesday, February 15, 2017 9:30 AM
> To: LEE John -TREASURY
> Cc: CHENG Alec -FIN & C CTRL; RYFA Ken -TREASURY; LIU Sheen -TREASURY; HAHN PARKER Janet -TREASURY
> Subject: EXTERNAL - RE: OEFC Funding of the Global Adjustment Deferral
>
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>

> Thanks John for the quick response, I have forwarded your email to Cindy, since her presence and/or Nadine's is essential if we are having a conference call, will get back to you as soon as I hear from her.
>
>
> Ken K
>
> -----Original Message-----
> From: LEE John -TREASURY [mailto:john.s.lee@opg.com]
> Sent: Wednesday, February 15, 2017 9:09 AM
> To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
> Cc: CHENG Alec -FIN & C CTRL <alec.cheng@opg.com>; RYFA Ken -TREASURY <ken.ryfa@opg.com>; LIU Sheen -TREASURY <sheen.liu@opg.com>; HAHN PARKER Janet -TREASURY <j.hahnparker@opg.com>
> Subject: RE: OEFC Funding of the Global Adjustment Deferral
>
> Ken:
>
> Got your voice message with respect to your proposal to have OEFC fund the Global Adjustment deferral indirectly by lending to OPG and having OPG subsequently lend to a Financing Trust. I agree that this would be the simplest funding mechanism. However since the key objective for the Province to avoid having to recognize the debt and writeoff the Global Adjustment deferral OPG must maintain Government Business Entity (GBE) status. In order to remain a GBE, we must be able to "in the normal course of its operations, maintain its operations and meet its liabilities from revenue received from sources outside of the government reporting entity." I understanding from Alec Cheng (OPG accounting) who was on yesterday accounting call with Nadine (Controllers Office) that OPG GBE status would be put at high risk under the proposed scheme due to the proposed quantum of lending from the OEFC. Our accounting group along with Treasury will be performing some further assessment on this but it may be worth arranging another call with you and your accounting group to layout the issues since the Province seems to be driven by very tight and uncertain timelines and I want everyone to be up to speed.
>
> We can make ourselves available for a call this morning. Please advise.
>
>
> John
>
>
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From: Ken Kandeepan
To: Ronald Kwan; Mike Manning
Subject: FW: EXTERNAL - RE: OEFC Funding of the Global Adjustment Deferral
Date: Thursday, February 16, 2017 9:33:12 AM

Sorry should have cc'ed you, hopefully there will be clarification from OPG sooner rather than later.

Thanks

Ken k

-----Original Message-----
From: Ken Kandeepan
Sent: Thursday, February 16, 2017 9:19 AM
To: 'LEE John -TREASURY' <john.s.lee@opg.com>
Cc: Veinot, Cindy (TBS) <Cindy.Veinot@ontario.ca>; Nadine Petsche (MOF) <Nadine.Petsche@ontario.ca>; RYFA Ken -TREASURY <ken.ryfa@opg.com>; CHENG Alec -FIN & C CTRL <alec.cheng@opg.com>
Subject: RE: EXTERNAL - RE: OEFC Funding of the Global Adjustment Deferral

Hi John

Gadi and others spent considerable time last night discussing the equity injection option and we are unclear as to how the Province will be made whole from a fiscal perspective. I suggest that you proceed with fleshing out this option and once we have all the details a decision can be made as to its viability. Naturally, pls include details on the external borrowing for the 51%; will the borrowing be conducted by OPG, the Trust, etc.

Thanks

Ken k

-----Original Message-----
From: LEE John -TREASURY [mailto:john.s.lee@opg.com]
Sent: Thursday, February 16, 2017 8:28 AM
To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
Cc: Veinot, Cindy (TBS) <Cindy.Veinot@ontario.ca>; Nadine Petsche (MOF) <Nadine.Petsche@ontario.ca>; RYFA Ken -TREASURY <ken.ryfa@opg.com>; CHENG Alec -FIN & C CTRL <alec.cheng@opg.com>
Subject: RE: EXTERNAL - RE: OEFC Funding of the Global Adjustment Deferral

Ken:

Have you had any confirmation from Gadi on the approach. As you know time is of the essence, as a result we are proceeding with discussions with the external auditors this morning to brief them on the approach and get their thoughts on the accounting implications and what needs to be done from a structuring perspective to ensure that the varying objectives can be met. Please advise ASAP.

John

-----Original Message-----
From: Ken Kandeepan [mailto:Ken.Kandeepan@ofina.on.ca]
Sent: Wednesday, February 15, 2017 6:37 PM
To: LEE John -TREASURY
Cc: Veinot, Cindy (TBS); Nadine Petsche (MOF); RYFA Ken -TREASURY; CHENG Alec -FIN & C CTRL
Subject: Re: EXTERNAL - RE: OEFC Funding of the Global Adjustment Deferral

Thanks John, it seems that what you are saying is OPG's net income will increase, all else being equal, by the amount of the interest relating to the equity injection.

In which case upon consolidation there will be no fiscal impact to the Province.

As you work through the options this needs to be fleshed out since the Trust will be consolidated with OPG we need to understand how OPG will show a net interest income.

Thanks

Ken k

> On Feb 15, 2017, at 6:28 PM, LEE John -TREASURY <john.s.lee@opg.com> wrote:
>
> Ken:
> To clarify the expectation is that equity injected into OPG which is on-lend to the Trust would result in net interest income that would roll up to the Province and this would cover the interest expense for the associated debt at the Province. The dividend comment was meant to describe mechanism on how to get cash to the province.
>
> John
>
> -----Original Message-----
> From: Ken Kandeepan [mailto:Ken.Kandeepan@ofina.on.ca]
> Sent: Wednesday, February 15, 2017 5:51 PM
> To: LEE John -TREASURY; 'Veinot, Cindy (TBS)'
> Cc: Nadine Petsche (MOF)
> Subject: RE: EXTERNAL - RE: OEFC Funding of the Global Adjustment Deferral
>
> Hi John and Cindy
>
> I just realized that in the event of an equity injection by the Province to OPG for a maximum of 49%, will as we discussed, have no impact on the Province's net debt.
>
> Unfortunately there will be an IOD impact. John, I remember you mentioning that OPG will increase the dividends it pays to the Province by an amount equivalent to the interest on the equity injection to date, however, that will only provide a cash and not a fiscal offset.
>
> The only way a fiscal offset can be provided is if OPG's net income increases by an amount equal to the increase in the Province's IOD (all else being equal). In which case the Province will be fiscally whole upon consolidation.
>
> But I am not sure that going to happen since the Trust will not contribute to OPG's bottom line, or at least that's my understanding.
>
> As such the potential fiscal impact from the increased IOD may be an issue for the Province re this option. In any event I will check with Gadi and circle back.
>
> Thanks
>
> Ken k
>
> -----Original Message-----
> From: HAHN PARKER Janet -TREASURY [mailto:j.hahnparker@opg.com]
> Sent: Wednesday, February 15, 2017 4:50 PM
> To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
> Cc: LEE John -TREASURY <john.s.lee@opg.com>; 'Veinot, Cindy (TBS)' <Cindy.Veinot@ontario.ca>
> Subject: RE: EXTERNAL - RE: OEFC Funding of the Global Adjustment Deferral
>

> Thank you. Will do.
>
> -----Original Message-----
> From: Ken Kandeepan [mailto:Ken.Kandeepan@ofina.on.ca]
> Sent: Wednesday, February 15, 2017 4:49 PM
> To: HAHN PARKER Janet -TREASURY
> Cc: LEE John -TREASURY; 'Veinot, Cindy (TBS)'
> Subject: RE: EXTERNAL - RE: OEFC Funding of the Global Adjustment Deferral
>
> Cindy is free now if you can set up the call.
>
> Thanks
>
> Ken k
>
> -----Original Message-----
> From: HAHN PARKER Janet -TREASURY [mailto:j.hahnparker@opg.com]
> Sent: Wednesday, February 15, 2017 3:43 PM
> To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
> Cc: LEE John -TREASURY <john.s.lee@opg.com>
> Subject: RE: EXTERNAL - RE: OEFC Funding of the Global Adjustment Deferral
>
> Thank you.
> This is of utmost importance. Please advise soonest.
> Janet
>
> -----Original Message-----
> From: Ken Kandeepan [mailto:Ken.Kandeepan@ofina.on.ca]
> Sent: Wednesday, February 15, 2017 3:37 PM
> To: HAHN PARKER Janet -TREASURY
> Cc: LEE John -TREASURY
> Subject: RE: EXTERNAL - RE: OEFC Funding of the Global Adjustment Deferral
>
> My apologies for the delay, unfortunately I am yet to hear back from Cindy, will let you know as soon as I do.
>
> Thanks
>
> Ken K
>
> -----Original Message-----
> From: HAHN PARKER Janet -TREASURY [mailto:j.hahnparker@opg.com]
> Sent: Wednesday, February 15, 2017 1:57 PM
> To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
> Cc: LEE John -TREASURY <john.s.lee@opg.com>
> Subject: RE: EXTERNAL - RE: OEFC Funding of the Global Adjustment Deferral
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> Ken,
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> Please advise on this call. Timing is important.
> A prompt response would be most appreciated,
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> Thank you,
> Janet Hahn Parker
>
> 416 592-6749
> j.hahnparker@opg.com
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> Sent: Wednesday, February 15, 2017 9:30 AM
> To: LEE John -TREASURY
> Cc: CHENG Alec -FIN & C CTRL; RYFA Ken -TREASURY; LIU Sheen -TREASURY; HAHN PARKER Janet -TREASURY
> Subject: EXTERNAL - RE: OEFC Funding of the Global Adjustment Deferral
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> Ken K
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> Sent: Wednesday, February 15, 2017 9:09 AM
> To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
> Cc: CHENG Alec -FIN & C CTRL <alec.cheng@opg.com>; RYFA Ken -TREASURY <ken.ryfa@opg.com>; LIU Sheen -TREASURY <sheen.liu@opg.com>; HAHN PARKER Janet -TREASURY <j.hahnparker@opg.com>
> Subject: RE: OEFC Funding of the Global Adjustment Deferral
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> John
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From: Carlos Yep
To: Mike Manning; James Devine; Ken Kandeepan; John Psinas; John Kim; Ronald Kwan
Subject: FW: EXTERNAL – FHP Questions - Funding Profile
Date: Thursday, February 15, 2018 12:52:02 PM

FYI

From: RYFA Ken -TREASURY [mailto:ken.ryfa@opg.com]
Sent: Wednesday, February 07, 2018 12:19 PM
To: Talwar, Shruti (ENERGY) <Shruti.Talwar@ontario.ca>; Carlos Yep <Carlos.Yep@ofina.on.ca>
Cc: Graham Young (MOI) <Graham.Young@ontario.ca>; LADAK Lubna -TREASURY <lubna.ladak@opg.com>; LIU Sheen -TREASURY <sheen.liu@opg.com>; GO Matthew -TREASURY <matthew.go@opg.com>
Subject: RE: EXTERNAL – FHP Questions

Shruti,
Now that the FHT has issued term debt the funding composition is starting to get more complicated. To help understand this below is a summary of the overall funding in the FHT which is now split between warehouse funding and term funding:

			Term debt takeout		
Warehouse Funding		Initial Balance	(980,392,156.86)	Ending Balance	
Senior debt	B=51% x A	601,290,000.00	(500,000,000.00)	101,290,000.00	51%
Subordinated	39/51 X B	459,810,000.00	(382,353,000.00)	77,457,000.00	39%
Junior subordinated	10/51 X B	117,900,000.00	(98,040,000.00)	19,860,000.00	10%
		1,179,000,000.00	(980,393,000.00)	198,607,000.00	
Term Debt Funding					
Senior debt	51.00%		500,000,000.00	500,000,000.00	51%
Subordinated	39.00%		382,353,000.00	382,353,000.00	39%
Junior subordinated	10.00%		98,040,000.00	98,040,000.00	10%
		-	980,393,000.00	980,393,000.00	
Total Funding					
Senior debt	51.00%	601,290,000.00	-	601,290,000.00	51%
Subordinated	39.00%	459,810,000.00	-	459,810,000.00	39%
Junior subordinated	10.00%	117,900,000.00	-	117,900,000.00	10%
		1,179,000,000.00	-	1,179,000,000.00	

1) The equity injection in December was used to fund the subordinated warehouse notes not the term notes. The warehouse notes have a base rate representing all-in funding costs of the senior warehouse notes per s 2.03(b). This funding cost is variable so any rate provided will only apply to a particular period. The December rate was approximately 2.5%. Per s 2.04(b)(i) & (c)(i) the applicable spread for sub and jr sub of this issuance was set at 0.10%.

   The sub and jr sub term notes that correspond to the senior term notes priced yesterday are different. The actual rates are still under review for the sub and jr sub which should be finalized soon.

2) Yes, next equity injection is likely March but could be February as well. For March transaction we would clear out as much of the IESO variance account as possible most of which is reflected in the February month end balance.

Hope this helps.
Thanks,
Ken

From: Talwar, Shruti (ENERGY) [mailto:Shruti.Talwar@ontario.ca]
Sent: Wednesday, February 07, 2018 11:25 AM
To: RYFA Ken -TREASURY <ken.ryfa@opg.com>; Yep, Carlos (OFA) <Carlos.Yep@ofina.on.ca>
Cc: Young, Graham (ENERGY) <Graham.Young@ontario.ca>
Subject: EXTERNAL – FHP Questions

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Hi Ken, Carlos,

Hope you are both well.

I have a couple of questions re: equity injection. They may be both for Ken, but Carlos may be useful to loop you in as well.

1) Can you please provide the interest rate for suboardinate and jr. suboardinate term notes for the transaction that closed on Dec 20, 2017. Per the interest protocol agreement, the interest rate is the 'applicable base rate' (defined in S 2.03) and 'applicable spread' (defined in S 2.04). Section 2.06 of the protocol notes the sharing of this information with ENERGY and OFA. We need this information as soon as possible.

2) What is the timing for the next equity injection? Are you thinking it will be as of the regulatory asset balance as at Feb 28, 2018? In which case, could we expect a request in early March? As you know, the transaction needs to close before March 31 to align with our approved allocations from Treasury Board.

Thank you. Feel free to give me a call with any questions.
Shruti

Shruti Talwar
Director, Strategic Policy and Analytics Branch
Strategic, Network and Agency Policy Division
Ontario Ministry of Energy
416.325-8698
shruti.talwar@ontario.ca

From:	John Kim
To:	Gavin He
Cc:	Ronald Kwan; Shajee Kathirgamanathan; Bruno Amara
Subject:	FW: EXTERNAL – RE: Fair Hydro Plan Protocol Agreement - Subordinated and Junior Subordinated Debt
Date:	Thursday, November 30, 2017 8:22:37 AM
Attachments:	Interest Protocol Agreement (OPG 11-29).doc

Pls. take a look.

From: Carlos Yep
Sent: Thursday, November 30, 2017 8:22 AM
To: John Kim <John.Kim@ofina.on.ca>; James Devine <James.Devine@ofina.on.ca>; John Psinas <John.Psinas@ofina.on.ca>
Subject: FW: EXTERNAL – RE: Fair Hydro Plan Protocol Agreement - Subordinated and Junior Subordinated Debt

FYI

From: LIU Sheen -TREASURY [mailto:sheen.liu@opg.com]
Sent: Wednesday, November 29, 2017 6:07 PM
To: Carlos Yep <Carlos.Yep@ofina.on.ca>
Cc: MCAULEY Tyler -LAWDIV <tyler.mcauley@opg.com>; PRESTON Stuart -TREASURY <stuart.preston@opg.com>; LEE John -TREASURY <john.s.lee@opg.com>; Mike Manning <Mike.Manning@ofina.on.ca>; Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
Subject: RE: EXTERNAL – RE: Fair Hydro Plan Protocol Agreement - Subordinated and Junior Subordinated Debt

Carlos,

Attached for your review please find the draft "Sub Debt Pricing Protocol Agreement", based on the term sheet you've commented on. Please let us know if you have any comments.

Thanks

Sheen

From: Carlos Yep [mailto:Carlos.Yep@ofina.on.ca]
Sent: Monday, November 27, 2017 3:10 PM
To: LIU Sheen -TREASURY <sheen.liu@opg.com>
Subject: RE: EXTERNAL – RE: Fair Hydro Plan Protocol Agreement - Subordinated and Junior Subordinated Debt

Sheen
The only change that I have is in section

Applicable Spread: "Applicable Spread" means the addition spread in basis points …

Regards
Carlos

From: LIU Sheen -TREASURY [mailto:sheen.liu@opg.com]
Sent: Wednesday, November 22, 2017 4:39 PM
To: Carlos Yep <Carlos.Yep@ofina.on.ca>
Subject: RE: EXTERNAL – RE: Fair Hydro Plan Protocol Agreement - Subordinated and Junior Subordinated Debt

For term debt, the process will be similar to our corporate debt spread, i.e. dealers provide indicative spread on a weekly basis (I believe OFA is copied on those emails as well), even though OPG does not issue debt on a weekly basis. This will provide us with a good sense of market conditions, etc.

For senior debt issuance, you are correct, probably quarterly, depending on the accumulated amount of deferral assets.

Sheen

From: Carlos Yep [mailto:Carlos.Yep@ofina.on.ca]
Sent: Wednesday, November 22, 2017 4:31 PM
To: LIU Sheen -TREASURY <sheen.liu@opg.com>
Subject: RE: EXTERNAL – RE: Fair Hydro Plan Protocol Agreement - Subordinated and Junior Subordinated Debt

Sheen
For the term debt, do you still need spreads "no less frequently than weekly"?
What is the projected frequency of issuing senior debt – quarterly?
C

From: LIU Sheen -TREASURY [mailto:sheen.liu@opg.com]
Sent: Wednesday, November 22, 2017 4:27 PM
To: Carlos Yep <Carlos.Yep@ofina.on.ca>
Subject: RE: EXTERNAL – RE: Fair Hydro Plan Protocol Agreement - Subordinated and Junior Subordinated Debt

Ok please give me a call if you'd like to discuss

From: Carlos Yep [mailto:Carlos.Yep@ofina.on.ca]
Sent: Wednesday, November 22, 2017 3:41 PM
To: LIU Sheen -TREASURY <sheen.liu@opg.com>
Subject: RE: EXTERNAL – RE: Fair Hydro Plan Protocol Agreement - Subordinated and Junior Subordinated Debt

Sheen
I have not discussed with Mike or Jim yet
C

From: LIU Sheen -TREASURY [mailto:sheen.liu@opg.com]
Sent: Wednesday, November 22, 2017 3:30 PM
To: Carlos Yep <Carlos.Yep@ofina.on.ca>
Subject: RE: EXTERNAL – RE: Fair Hydro Plan Protocol Agreement - Subordinated and Junior Subordinated Debt

Carlos – I left a v-message with you as I've realized that you might find the warehouse pricing different as discussed previously. The reason is that based on the Warehouse Facility Agreement re the senior tranche we are working on with dealers, the way it is to be charged includes various fees, such as upfront fees, standby fees, program fees (CP + adder), etc. The facility is committed by dealers and the Global Adjustments deferral assets will be part of banks' ABCP Trust assets pool, through which CP will be issued.

Please give me a call if you'd like to go through the details and rationale.

Sheen
4165922458

From: LIU Sheen -TREASURY
Sent: Wednesday, November 22, 2017 9:56 AM
To: 'Carlos Yep' <Carlos.Yep@ofina.on.ca>
Cc: MCAULEY Tyler -LAWDIV <tyler.mcauley@opg.com>; PRESTON Stuart -TREASURY <stuart.preston@opg.com>; Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>; LEE John -TREASURY <john.s.lee@opg.com>; Mike Manning <Mike.Manning@ofina.on.ca>
Subject: RE: EXTERNAL – RE: Fair Hydro Plan Protocol Agreement - Subordinated and Junior Subordinated Debt

Carlos,

Attached please find the revised summary term sheet re Protocol Agreement which incorporated your suggestions/comments. Please review and let us know if you have further comments.

Thanks

Sheen

From: Carlos Yep [mailto:Carlos.Yep@ofina.on.ca]
Sent: Thursday, November 16, 2017 12:49 PM
To: LIU Sheen -TREASURY <sheen.liu@opg.com>
Subject: RE: EXTERNAL – RE: Fair Hydro Plan Protocol Agreement - Subordinated and Junior

Subordinated Debt

Sheen
Thanks
Carlos

From: LIU Sheen -TREASURY [mailto:sheen.liu@opg.com]
Sent: Thursday, November 16, 2017 11:31 AM
To: Carlos Yep <Carlos.Yep@ofina.on.ca>
Cc: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>; Mike Manning <Mike.Manning@ofina.on.ca>; James Devine <James.Devine@ofina.on.ca>; PRESTON Stuart -TREASURY <stuart.preston@opg.com>; LEE John -TREASURY <john.s.lee@opg.com>
Subject: RE: EXTERNAL – RE: Fair Hydro Plan Protocol Agreement - Subordinated and Junior Subordinated Debt

Hi Carlos,

To expedite the process, we agree with your suggestion re short term funding, as per our last conversation , i.e. one single spread will be used for both sub and junior sub debt unless junior sub drops to non-investment grade, in which case additional 100bps will be added to junior sub for pricing purpose.

For long term funding, we are in agreement with your approach suggested below.

Thanks

Sheen

From: Carlos Yep [mailto:Carlos.Yep@ofina.on.ca]
Sent: Wednesday, November 15, 2017 3:44 PM
To: LIU Sheen -TREASURY <sheen.liu@opg.com>
Cc: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>; Mike Manning <Mike.Manning@ofina.on.ca>; James Devine <James.Devine@ofina.on.ca>
Subject: EXTERNAL – RE: Fair Hydro Plan Protocol Agreement - Subordinated and Junior Subordinated Debt

*** Exercise caution. This is an EXTERNAL email. DO NOT open attachments or click links from unknown senders or unexpected email. ***

Hi Sheen
There are 2 main simplifying comments that start by eliminating the need for the full pricing grid solely based on credit rating from BBB to AAA.

1)For the short term funding, it would be more efficient to use one single spread rather than

multiple spreads for subordinated and junior subordinated.

2)For long term funding, there are no comparable issuers of subordinated & junior subordinated debt issues. Dealers can provide estimates for the subordinated and junior subordinated spreads for each tenor based on the specific characteristics of the Financing Trust.

Please call if you have any questions or would like to discuss further.

Regards
Carlos

From: LIU Sheen -TREASURY [mailto:sheen.liu@opg.com]
Sent: Tuesday, November 07, 2017 1:23 PM
To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
Cc: PRESTON Stuart -TREASURY <stuart.preston@opg.com>; MCAULEY Tyler -LAWDIV <tyler.mcauley@opg.com>
Subject: Fair Hydro Plan Protocol Agreement

Ken,

As you're aware we are currently working on drafting the Protocol Agreement re Sub Debt under the Fair Hydro Plan. Attached for you review please find the key terms re the Agreement, including procedure for advance, as well as price setting, etc. Please let us know if you have any comments/thoughts.

Please be advised that FHP financing will include both a short term warehouse facility (ABCP conduit) and term debt.

Thanks

Sheen

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conversion to hard copy or other use of this communication is strictly prohibited. If you are not the intended recipient and have received this message in error, please notify me by return e-mail and delete this message from your system. Ontario Power Generation Inc.

Subordinated Debt Pricing Protocol Agreement

THIS AGREEMENT is made as of •, 2017

BETWEEN

ONTARIO POWER GENERATION INC., a corporation incorporated under the laws of Ontario ("**OPG**"), solely in its capacity as financial services manager (the "**FSM**") of the Fair Hydro Trust (the "**Issuer**"), a trust existing under the laws of the Province of Ontario

- and -

HER MAJESTY THE QUEEN IN RIGHT OF ONTARIO, (the "**Province**") as represented by the Minister of Energy

WHEREAS the Issuer and BNY Trust Company of Canada entered into that certain trust indenture (as supplemented from time to time, the "**Trust Indenture**") dated ■, 2017;

AND WHEREAS pursuant to the Trust Indenture the Issuer may issue, from time to time, certain Subordinated Notes and Junior Subordinated Notes;

AND WHEREAS the FSM and the Province have agreed to establish herein the procedures for establishing the interest rate applicable to each Series of Subordinated Notes and Junior Subordinated Notes where such Notes are to be issued only to OPG or its Affiliates;

NOW THEREFORE, in consideration of the premises and the covenants and agreements herein contained, the parties agree as follows:

ARTICLE 1 - INTERPRETATION

1.01 Definitions

In this Agreement, unless something in the subject matter or context is inconsistent therewith terms used herein have the meanings ascribed in the Trust Indenture. In addition, the following terms shall have the following meanings:

(a) "**Applicable Spread**" has the meaning ascribed to such term in section 2.04(c);

(b) "**Base Rate**" has the meaning ascribed to such term in section 2.03(a) or (b), as applicable;

(c) "**Junior Subordinated Term Note**" means a Junior Subordinated Note that is not incurred pursuant to a Warehouse Facility Agreement;

(d) "**Junior Subordinated Warehouse Note**" means a Junior Subordinated Note that is incurred pursuant to a Warehouse Facility Agreement;

(e) "**Subordinated Term Note**" means a Subordinated Note that is not incurred pursuant to a Warehouse Facility Agreement; and

(f) "**Subordinated Warehouse Note**" means a Subordinated Note that is incurred pursuant to a Warehouse Facility Agreement.

1.02 **Headings**

The division of this Agreement into Articles and Sections and the insertion of headings are for convenience of reference only and do not affect the construction or interpretation of this Agreement. The terms "hereof", "hereunder" and similar expressions refer to this Agreement and not to any particular Article, Section or other portion hereof.

ARTICLE 2 - INTEREST RATE PROTOCOLS

2.01 **Interest Rate Protocols**

The interest rate applicable to each Series of Subordinated Notes and Junior Subordinated Notes that are issued only to OPG or its Affiliates shall be established by the FSM in accordance with the procedures set out herein.

2.02 **Composite Interest Rate**

For any Series of Subordinated Notes or Junior Subordinated Notes that are issued only to OPG or its Affiliates, the interest rate shall be the aggregate of the applicable Base Rate and the Applicable Spread.

2.03 **Base Rate**

(a) For Subordinated Term Notes and Junior Subordinated Term Notes, the "Base Rate" shall be an annual rate of interest comprised of the applicable yield for the Benchmark Government of Canada bonds listed at the time and with the same term as that of the Series of Subordinated Notes or Series of Junior Subordinated Notes, as applicable. In the event that there are no such Benchmark Government of Canada bonds listed at the time of issuance, the applicable Base Rate of interest shall be established by interpolating on a straight line basis the terms of the two Benchmark Government of Canada bonds that are closest to the term of the applicable Series of Subordinated Term Notes or Series of Junior Subordinated Term Notes, as applicable, one being for a longer term and the other being for a shorter term; and

(b) For Subordinated Warehouse Notes and Junior Subordinated Warehouse Notes, the "Base Rate" shall be an annual interest rate equal to the all-in funding costs under the related Warehouse Obligations, expressed as a rate per annum, as

determined by the FSM acting reasonably, or at any time when there are no Warehouse Obligations outstanding the "Base Rate" shall be the average of the posted "prime rate of interest" published by the five largest Canadian banks at such time.

2.04 **Applicable Spread**

(a) Prior to the issuance of any new Subordinated Term Notes or Junior Subordinated Term Notes, the FSM will solicit from at least five investment dealers in Canada, a survey of indicative spreads over the applicable Base Rate (collectively, the "**Indicative Spreads**" and each an "**Indicative Spread**") applicable to capital market debt issuances having features comparable to each of the proposed Series of Subordinated Term Notes and Junior Subordinated Term Notes, having regard to the expected credit rating and tenor. Such solicitation of Indicative Spreads shall occur on the pricing date of the applicable Series of Subordinated Term Notes and Junior Subordinated Term Notes and may, at the FSM's option, also occur on other dates selected by the FSM provided that no such date is more than **one week** prior to the pricing date. The Applicable Spread for Subordinated Term Notes or Junior Subordinated Term Notes, as applicable, will be the simple average of the respective Indicative Spreads after excluding the highest and the lowest Indicative Spread for each day (not more than one week prior to the pricing date) that Indicative Spreads were provided;

(b) For Subordinated Warehouse Notes the FSM will solicit from time to time, but no less frequently than on an annual basis, from at least five investment dealers in Canada, a survey of Indicative Spreads over the applicable Base Rate applicable to commercial paper issuances having features comparable to the Subordinated Warehouse Notes including credit rating and tenor. The Applicable Spread for Subordinated Warehouse Notes will be the simple average of the respective Indicative Spreads, after excluding the highest and the lowest Indicative Spread;

(c) The Applicable Spread for Junior Subordinated Warehouse Notes shall be equal to the Applicable Spread derived from Section 2.04(b) for the Subordinated Warehouse Notes, provided the Junior Subordinated Term Notes are rated Investment Grade. If the Junior Subordinated Term Notes are rated below Investment Grade, the Applicable Spread for the Junior Subordinated Warehouse Notes will equal to the Applicable Spread for the Subordinated Warehouse Notes plus 100 bps.

For the purposes of this section "Investment Grade" means an "approved rating" from at least one "designated rating organization" (as such terms are defined for securities law purposes).

2.05 **Credit Ratings**

In order to facilitate the survey of Indicative Spreads, the FSM will solicit from time to time, from an approved rating organization (as such term is defined for securities laws

purposes), a credit rating, which may include a shadow rating, for the Subordinated Notes and the Junior Subordinated Notes.

ARTICLE 3 - GENERAL

3.01 Benefit of the Agreement

This Agreement will enure to the benefit of and be binding upon the respective successors and permitted assigns of the parties.

3.02 Entire Agreement

This Agreement constitutes the entire agreement between the parties with respect to the subject matter hereof and cancel and supersede any prior understandings and agreements between the parties with respect thereto. There are no representations, warranties, terms, conditions, undertakings or collateral agreements, express, implied or statutory, between the parties other than as expressly set forth in this Agreement.

3.03 Assignment, Amendments and Waivers

No assignment or amendment to this Agreement will be valid or binding unless set forth in writing and duly executed by all of the parties. No waiver of any breach of any provision of this Agreement will be effective or binding unless made in writing and signed by the party purporting to give the same and, unless otherwise provided in the written waiver, will be limited to the specific breach waived.

3.04 Severability

If any provision of this Agreement is determined to be invalid or unenforceable in whole or in part, such invalidity or unenforceability will attach only to such provision or part thereof and the remaining part of such provision and all other provisions hereof will continue in full force and effect.

3.05 Governing Law

This Agreement is governed by and will be construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein. For the purpose of all legal proceedings this Agreement will be deemed to have been performed in the Province of Ontario and the courts of the Province of Ontario will have exclusive jurisdiction to entertain any action arising under this Agreement. The parties hereby attorn to the exclusive jurisdiction of the courts of the Province of Ontario.

3.06 Counterparts

This Agreement may be executed in any number of counterparts, each of which will be deemed to be an original and all of which taken together will be deemed to constitute one and the same instrument.

3.07 **Electronic Execution**

Any party may deliver an executed signature page to this Agreement by electronic transmission and such delivery will be as effective as delivery of a manually executed copy of the Agreement by such party.

[SIGNATURE PAGES FOLLOW]

IN WITNESS WHEREOF the parties have executed this Agreement.

ONTARIO POWER GENERATION INC.
solely in its capacity as Financial Services Manager of the Fair Hydro Trust

Per: _____
Ken Hartwick
Chief Financial Officer and Senior Vice President

Per: _____
John Lee
Vice President- Treasurer

HER MAJESTY THE QUEEN IN RIGHT OF ONTARIO, as represented by the Minister of Energy

Per: _____
[Name]
[Position]

From: Bruno Amara
To: Ronald Kwan; John Kim
Subject: FW: Electricity Outlook Update
Date: Thursday, March 23, 2017 5:40:06 PM

Hi Ron, John

Per our discussion, we had confirmed amongst EFB, Risk Control, OB, OEP treatment of the IOD expense related to Province's GA financing. This IOD was added to OPG net income and was also included in IOD expense. See yellow highlights below. Confirmation from Alex Krass and Gavin's email further below confirming pick up in OPG net income.

Bruno

From: Alexander Kraas
Sent: Thursday, March 16, 2017 12:45 PM
To: 'Inglis, Liane (MOF)' <Liane.Inglis@ontario.ca>; Teshome Amare (MOF) <Teshome.Amare@ontario.ca>; Gavin He <Gavin.He@ofina.on.ca>
Cc: Bruno Amara <Bruno.Amara@ofina.on.ca>; Stephen Taylor (MOF) <Stephen.Taylor@ontario.ca>
Subject: RE: Electricity Outlook Update

The Province is expected to borrow to fund the GA smoothing. The cost of this borrowing is included in IOD.

The trust/OPG are expected to be reimbursed for the cost of this borrowing. This interest revenue is not included in IOD since the trust/OPG is not consolidated on a "line-by-line" basis, but partially offsets the increase in IOD caused by borrowing for the initiative.

From: Inglis, Liane (MOF) [mailto:Liane.Inglis@ontario.ca]
Sent: Thursday, March 16, 2017 12:21 PM
To: Teshome Amare (MOF) <Teshome.Amare@ontario.ca>; Gavin He <Gavin.He@ofina.on.ca>
Cc: Bruno Amara <Bruno.Amara@ofina.on.ca>; Stephen Taylor (MOF) <Stephen.Taylor@ontario.ca>; Alexander Kraas <Alexander.Kraas@ofina.on.ca>
Subject: RE: Electricity Outlook Update

Hi All – the IOD number Teshome attached is currently in the forecast. We added it manually at the time of the last rollup (March 5th). Gavin, I think what you're saying is that this is that this was the right call. I've included Alex as we are currently confirming this with OFA as well.

The timing on this is a bit out of synch as MOF was asked to build in the fiscal impact of GA smoothing on March 5th, but – and please correct me if I'm wrong - GA smoothing is included in the latest electricity sector update. So, I would just like to confirm – the fiscal impact that emma sent out Monday (attached) includes GA smoothing. However, GA smoothing was fiscally neutral (increase to revenue offset by increase to IOD expense), so the Monday number still reflects the total fiscal impact that we will be picking up in the plan (all on the revenue side).

Thanks everyone. Sorry for so much back and forth on this, I just want to make sure I'm on the same page as the rest of you.

Best,

Liane

From: Amare, Teshome (MOF)
Sent: March 16, 2017 12:10 PM
To: Gavin He
Cc: Bruno Amara; Taylor, Stephen (MOF); Inglis, Liane (MOF)
Subject: RE: Electricity Outlook Update

Thank you Gavin.

Please follow-up with the OFA accounting group to make a corresponding entry .

For your follow-up, I attached an email communication we received prior to your electricity update to capture IOD on top of OPG's net income – which we no longer need to do as your final version of electricity tracks it under OPG net income

Thanks again
Teshome

From: Gavin He [mailto:Gavin.He@ofina.on.ca]
Sent: March 16, 2017 12:03 PM
To: Amare, Teshome (MOF)
Cc: Bruno Amara; Taylor, Stephen (MOF)
Subject: RE: Electricity Outlook Update

Hi Teshome,

Sorry for the delay in getting back to you.

Yes, in our Outlook file, IOD is included as part of OPG's net income. However, there should be a corresponding entry in the IOD numbers provided from our OFA accounting group.

Hope that helps and please let me know if you have any other questions.

Thanks,
Gavin He

From: Amare, Teshome (MOF) [mailto:Teshome.Amare@ontario.ca]
Sent: Thursday, March 16, 2017 11:39 AM
To: Gavin He <Gavin.He@ofina.on.ca>

Cc: Bruno Amara <Bruno.Amara@ofina.on.ca>; Stephen Taylor (MOF) <Stephen.Taylor@ontario.ca>
Subject: FW: Electricity Outlook Update

Hi Gavin,

I like to reconfirm whether IOD is included in OPG's net income. In our teleconference, I remember Bruno mentioning that it is included in the OPG net income. However, your file name says no IOD.

Please confirm.

Thanks
Teshome

From: Gavin He [mailto:Gavin.He@ofina.on.ca]
Sent: March 8, 2017 4:35 PM
To: Taylor, Stephen (MOF); Amare, Teshome (MOF); Inglis, Liane (MOF); Lindquist, Emma (MOF); Luk, Sandy (TBS); Raashid, Sohaeb (TBS); Scanlan, Darren (OFA)
Cc: Kim, John (OFA); Bruno Amara; Salman Qadir; Adam Prokop; Chinchon, Francisco (OFA); Esmail, Selena (MOF)
Subject: RE: Electricity Outlook Update

Hi all,

Please find attached the latest approved Outlook heading into the Document process. We will set up a brief meeting to go through the Outlook tomorrow.

Also, as requested from the previous conversation, we have added a cover sheet in the Outlook.

The attachment is password protected with the internal Document password.

Thanks,
Gavin He

From: Gavin He
Sent: Monday, February 06, 2017 4:44 PM
To: Bruno Amara (MOF) <Bruno.Amara@ontario.ca>; Teshome Amare (MOF) <Teshome.Amare@ontario.ca>; 'Liane.Inglis@ontario.ca' <Liane.Inglis@ontario.ca>; Emma Lindquist (MOF) <Emma.Lindquist@ontario.ca>; Sandy Luk (MOHLTC) <Sandy.Luk@ontario.ca>; Sohaeb Raashid (MOI) <Sohaeb.Raashid@ontario.ca>; Darren Scanlan <Darren.Scanlan@ofina.on.ca>
Cc: John Kim <John.Kim@ofina.on.ca>; Salman Qadir <Salman.Qadir@ofina.on.ca>; Adam Prokop <Adam.Prokop@ofina.on.ca>; Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>; Selena Esmail (MOF) <Selena.Esmail@ontario.ca>
Subject: Electricity Outlook Update

Hi all,

Hope you are doing well! Please find attached the latest approved Outlook heading into the Document season.

We understand that the Q3 Finance is in the works, but please note that this Outlook update is NOT intended for the Q3 Finance update.

The attachment is password protected with the internal Document password. Please let us know if you have any questions.

Best regards,

Gavin He
Corporate and Electricity Finance Division
Ontario Financing Authority
416-325-0924 | Gavin.He@ofina.on.ca

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From:	Usman Zahid
To:	Ronald Kwan
Cc:	John Kim; Bruno Amara; Shajee Kathirgamanathan; Gavin He
Subject:	FW: FES Items for Today
Date:	Friday, November 10, 2017 10:52:07 AM
Attachments:	1. Electricity Sector Outlook (2017 10 20v3)_Sent.pdf 2. OFHP supporting data for OFA_v0.1.pdf

Hi Ron,

Attached are two items for inclusion into the TB/MBC Binder. The first item is a PDF version of the Electricity Sector Outlook (similar to what was submitted previously). The second item is information on the financing of FHP. EFB have said they are open to omitting the second item if appropriate.

Regards,
Usman

From: Shajee Kathirgamanathan
Sent: Friday, November 10, 2017 10:37 AM
To: Usman Zahid <Usman.Zahid@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>
Subject: RE: FES Items for Today

Hi Usman,

Please find attached the two documents for inclusions into EFB's portion of the TB Binder.

1) PDF'ed version of the Electricity Sector Outlook. Similar to what we submitted last time
2) Information we received on the financing of the Fair Hydro Plan. We didn't use this information per se, so we're open to omitting it should it be decided to exclude.

Files saved here:
S:\Users\CEF\Hydro 2017\FES\TB Binder\EFB

Thanks,
Shajee

Shajee Kathirgamanathan
Office: 416-325-1402 | Mobile: 647-294-3359
shajee.kathirgamanathan@ofina.on.ca

From: Usman Zahid
Sent: Friday, November 10, 2017 9:33 AM
To: John Kim <John.Kim@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>

Subject: FES Items for Today

Hi All,

TB/MBC Binder Materials: Due by noon, please get to Ron ASAP.

Placemats: Due at 2pm, please get in right after TB/MBC binder Materials.

Regards,
Usman

Electricity Sector Outlook
October 2017

Disclosure:

All information contained in this workbook is confidential and commercially sensitive

All projected numbers are estimates and subjected to change

This workbook and all information or analysis contained in it is property of the Ontario Financing Authority.
Please consult with OFA before sharing of information.

Commercially Sensitive and Confidential Advice to Cabinet for Consideration of Options for Discussion Purposes Only

Electricity Sector Outlook
Including Line Items for Consolidation

Electricity Summary - On Deck

			MOF Expense Items (consolidated)	Current Outlook			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**38**	Power Supply Contract Costs	(292)	(325)	(301)	(273)
Expense	**MOF (OEFC)**	**40**	Demand Management Support Costs	(10)	-	-	-
Expense	**MOF (OEFC)**	**41**	Provision for Electricity Sector	140	-	-	-
Expense	**MOF**	**17**	Provision for Electricity Sector	(140)	-	-	-
Expense	**MOF (OEFC)**	**42**	Other (Finance)	(6)	(6)	(6)	(6)
			Total MOF Expense	**(308)**	**(331)**	**(307)**	**(279)**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**7**	OPG Income	147	720	608	1,041
Revenue	**ENE**	**8**	OPG - ONFA and other Fair Value Adjustments	-	-	-	-
Revenue	**ENE**	**10**	HOI Income	447	484	566	612
Revenue		**11**	Brampton Income	-	-	-	-
Revenue	**MOF (OEFC)**	**26**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	381	479	531	668
Revenue	**MOF (OEFC)**	**29**	Electricity Debt Retirement Charge	623	-	-	-
Revenue	**MOF (OEFC)**	**30**	Power Supply Contract Recoveries	292	325	301	273
Revenue	**MOF (OEFC)**	**31**	Net Reduction of Power Purchase Contracts	74	41	30	28
Revenue	**MOF (OEFC)**	**34**	Miscellaneous	-	-	-	-
			Total MOF Revenue	**1,964**	**2,049**	**2,036**	**2,623**
			OFA IOD Expense				
			Public Debt Interest - Electricity Sector	(454)	(454)	(454)	(454)
			Interest on Debt	(475)	(438)	(411)	(348)
			Total OFA IOD Expense	**(929)**	**(892)**	**(865)**	**(802)**
			Impact on Surplus/Deficit	**727**	**826**	**864**	**1,542**
			check	**-**	**-**	**-**	**-**

Electricity Summary - Budget 17

	For Discussion		MOF Expense Items (consolidated)	Plan			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**38**	Power Supply Contract Costs	(292)	(325)	(301)	(273)
Expense	**MOF (OEFC)**	**40**	Demand Management Support Costs	(10)	0	0	0
Expense	**MOF (OEFC)**	**41**	Provision for Electricity Sector	125	0	0	0
Expense	**MOF**	**17**	Provision for Electricity Sector	(125)	0	0	0
Expense	**MOF (OEFC)**	**42**	Other (Finance)	(6)	(6)	(6)	(6)
			Total MOF Expense	**(308)**	**(331)**	**(307)**	**(279)**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**7**	OPG Income	97	732	625	1,066
Revenue	**ENE**	**8**	OPG - ONFA and other Fair Value Adjustments	0	0	0	0
Revenue	**ENE**	**10**	HOI Income	520	562	603	652
			Brampton Income				
Revenue	**MOF (OEFC)**	**25**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	405	476	538	679
Revenue	**MOF (OEFC)**	**29**	Electricity Debt Retirement Charge	623	0	0	0
Revenue	**MOF (OEFC)**	**30**	Power Supply Contract Recoveries	292	325	301	273
Revenue	**MOF (OEFC)**	**31**	Net Reduction of Power Purchase Contracts	74	41	30	28
Revenue	**MOF (OEFC)**	**34**	Miscellaneous	0	0	0	0
			Total MOF Revenue	**2,011**	**2,136**	**2,098**	**2,697**
			OFA IOD Expense				
		17	Public Debt Interest - Electricity Sector	(492)	(492)	(492)	(492)
		36	Interest on Debt	(422)	(374)	(342)	(250)
			Total OFA IOD Expense	**(914)**	**(866)**	**(834)**	**(742)**
			Impact on Surplus/Deficit	**789**	**939**	**957**	**1,676**
			check	**-**	**-**	**-**	**-**

Electricity Summary - Change

			MOF Expense Items (consolidated)	Variance from Plan			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**69**	Power Supply Contract Costs	0	0	0	(0)
Expense	**MOF (OEFC)**	**71**	Demand Management Support Costs	0	0	0	0
Expense	**MOF (OEFC)**	**72**	Provision for Electricity Sector	15	0	0	0
Expense	**MOF**	**48**	Provision for Electricity Sector	(15)	0	0	0
Expense	**MOF (OEFC)**	**73**	Other (Finance)	0	0	0	0
			Total MOF Expense	**0**	**0**	**0**	**(0)**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**38**	OPG Income	50	(12)	(17)	(24)
Revenue	**ENE**	**39**	OPG - ONFA and other Fair Value Adjustments	0	0	0	0
Revenue	**ENE**	**41**	HOI Income	(73)	(78)	(38)	(40)
			Brampton Income	0	0	0	0
Revenue	**MOF (OEFC)**	**25**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	(24)	3	(7)	(10)
Revenue	**MOF (OEFC)**	**60**	Electricity Debt Retirement Charge	0	0	0	0
Revenue	**MOF (OEFC)**	**61**	Power Supply Contract Recoveries	(0)	(0)	(0)	0
Revenue	**MOF (OEFC)**	**62**	Net Reduction of Power Purchase Contracts	(0)	(0)	(0)	(0)
Revenue	**MOF (OEFC)**	**65**	Miscellaneous	0	0	0	0
			Total MOF Revenue	**(47)**	**(87)**	**(62)**	**(74)**
			OFA IOD Expense				
		17	Public Debt Interest - Electricity Sector	38	38	38	38
		36	Interest on Debt	(53)	(64)	(69)	(98)
			Total OFA IOD Expense	**(15)**	**(26)**	**(31)**	**(60)**
			Impact on Surplus/Deficit	**(62)**	**(113)**	**(93)**	**(134)**
			check	***-***	***0***	***(0)***	***(0)***

Electricity Sector Outlook	$ Millions					
	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
On Deck Outlook as of March 2017						
Income from Investment in Government Business Enterprises						
OPG Income[1]	291	304	97	732	625	1,066
OPG - ONFA and other Fair Value Adjustments[2]	172	8	-	-	-	-
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	-
HOI Income[3]	236	516	520	562	603	652
Brampton Income	20	15	-	-	-	-
Total OPG and HOI Income	**719**	**842**	**617**	**1,294**	**1,229**	**1,717**
Other Fees and Licences	**127**	**122**	**102**	**91**	**88**	**81**
Electricity Expenses of the Province						
Provision for Electricity Sector[4]	(3)	(342)	(125)		-	-
Public Debt Interest - Electricity Sector	(520)	(492)	(492)	(492)	(492)	(492)
Subtotal	(523)	(834)	(617)	(492)	(492)	(492)
Public Debt Interest - Impact of ONFA						
Amortization of Deferred Revenue re profit on sale of H1 notes						
Total Electricity Expenses of the Province	**(523)**	**(834)**	**(617)**	**(492)**	**(492)**	**(492)**
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	3,228	373	405	476	538	679
Other Revenue						
Electricity Debt Retirement Charge[5]	859	625	623	-	-	-
Power Supply Contract Recoveries	875	739	292	325	301	273
Net Reduction of Power Purchase Contracts	172	129	74	41	30	28
Other Fees and Licences	(127)	(122)	(102)	(91)	(88)	(81)
Miscellaneous	9	-	-	-	-	-
Expenses						
Interest on Debt	(596)	(532)	(422)	(374)	(342)	(250)
Power Supply Contract Costs	(875)	(739)	(292)	(325)	(301)	(273)
Electricity Consumer Price Protection Fund	-	-	-	-	-	-
Demand Management Support Costs[6]	(8)	(10)	(10)	-	-	-
Provision for Electricity Sector	3	342	125	-	-	-
Other (Finance)	(7)	(6)	(6)	(6)	(6)	(6)
Total OEFC Income	**3,533**	**800**	**687**	**46**	**132**	**370**
Impact on Surplus/(Deficit)	**3,856**	**930**	**789**	**939**	**957**	**1,676**

Notes: The Hydro One net income outlook above (2016-17 to 2020-21) reflects the Province's current 70% ownership share, after the initial IPO in 2015 [and the secondary offering in April 2016]. Net estimated fiscal impacts from future Hydro One offerings are reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

Notes:

1.OPG's 2016-17 outlook reflected its reported earnings. 2017-18 outlook reflects OPG's latest monthly update. Out-years reflect OPG's preliminary 2017-19 business plan and long-term outlook to 2019-20 (as fiscalized by OPG). 2020-21 estimates are based on OPG's calendar year-based business plan projections and as fiscalized by CEFD staff.

2. Provincial consolidation adjustments for unrealized earnings on the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds, as of the end of December 2016.

3. Hydro One 2016-17 income reflects its reported net income, adjusted for Hydro One IPO impacts. 2017-18 to 2020-21 projections are based on CEFD projections using the latest public information. The Hydro One net income outlook above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering are currently reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial ONFA consolidation adjustments, minus the interest on debt payable to OEFC. The provision is currently assumed to end once the DRC ends on a legislated fixed end date of April 1, 2018.

5. Reflects April 23, 2014 announcement that DRC will be eliminated for residential users, after December 31, 2015. The end date of DRC for remaining users is legislated to be on April 1, 2018. Estimates are subject to change based on actual consumption.

6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Electricity Sector Outlook

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
On Deck Outlook as of October 2017						
Income from Investment in Government Business Enterprises						
OPG Income[1]	291	299	147	720	608	1,041
OPG - ONFA and other Fair Value Adjustments[2]	172	43	-	-	-	-
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	-
HOI Income[3]	236	500	447	484	566	612
Brampton Income	20	18	-	-	-	-
Total OPG and HOI Income	**719**	**860**	**594**	**1,204**	**1,174**	**1,654**
Other Fees and Licences (Debt Guarantee fee)	**127**	**122**	**102**	**91**	**88**	**81**
Electricity Expenses of the Province						
Provision for Electricity Sector[4]	-	(290)	(140)			
Public Debt Interest - Electricity Sector	(520)	(514)	(454)	(454)	(454)	(454)
Subtotal	(520)	(803)	(594)	(454)	(454)	(454)
Public Debt Interest - Impact of ONFA						
Amortization of Deferred Revenue re profit on sale of H1 notes						
Total Electricity Expenses of the Province	**(520)**	**(803)**	**(594)**	**(454)**	**(454)**	**(454)**
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	3,247	334	381	479	531	668
Other Revenue						
Electricity Debt Retirement Charge[5]	859	621	623	-	-	-
Power Supply Contract Recoveries	875	838	292	325	301	273
Net Reduction of Power Purchase Contracts	172	129	74	41	30	28
Other Fees and Licences	(127)	(122)	(102)	(91)	(88)	(81)
Miscellaneous	9	14	-	-	-	-
Expenses						
Interest on Debt	(596)	(513)	(475)	(438)	(411)	(348)
Power Supply Contract Costs	(875)	(838)	(292)	(325)	(301)	(273)
Electricity Consumer Price Protection Fund	-	-	-	-	-	-
Demand Management Support Costs[6]	(8)	(8)	(10)	-	-	-
Provision for Electricity Sector	-	290	140	-	-	-
Other (Finance)	(7)	(7)	(6)	(6)	(6)	(6)
Total OEFC Income	**3,549**	**737**	**625**	**(15)**	**56**	**261**
Impact on Surplus/(Deficit)	**3,876**	**915**	**727**	**826**	**864**	**1,542**
variance to OEFC check	*(156)*	*(454)*	*(550)*	*-*	*0*	*-*

Notes:

1.OPG's 2016-17 outlook reflected its reported earnings. 2017-18 outlook reflects OPG's latest monthly update. Out-years reflect OPG's preliminary 2017-19 business plan and long-term outlook to 2019-20 (as fiscalized by OPG). 2020-21 estimates are based on OPG's calendar year-based business plan projections and as fiscalized by CEFD staff.

2. Provincial consolidation adjustments for unrealized earnings on the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds, as of the end of December 2016.

3. Hydro One 2016-17 income reflects its reported net income, adjusted for Hydro One IPO impacts. 2017-18 to 2020-21 projections are based on CEFD projections using the latest public information. The Hydro One net income outlook above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering are currently reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial ONFA consolidation adjustments, minus the interest on debt payable to OEFC. The provision is currently assumed to end once the DRC ends on a legislated fixed end date of April 1, 2018.

5. Reflects April 23, 2014 announcement that DRC will be eliminated for residential users, after December 31, 2015. The end date of DRC for remaining users is legislated to be on April 1, 2018. Estimates are subject to change based on actual consumption.

6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Electricity Sector Change Since Budget

$ Millions

($million)	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Changes from Budget 2017 as of October 2017						
Income from Investment in Government Business Enterprises						
OPG Income	(5)	50	(12)	(17)	(24)	2016-17 small decrease due to IFRS adjustment revision and OPG Net Income revision. 2017-18 increase mainly due to deferral of Pickering Unit 6 planned outage to Jan 18, deferral of sale of land at Hearn site from Q1 2017 to later in 2017, partially offsdet by lower gropss margin.
ONFA and other Fair Value Adjustments	35	-	-	-	-	Largely revision to ONFA fair value as of March 31, 2017
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	
HOI Income	(16)	(73)	(78)	(38)	(40)	2016-17 slight decrease from Budget 2017 Interim projection. 2017-18 onwards reflects impacts of OEB decision on Hydro One rates, interest expense on Avitsa debentures (in 2017-18 and 2018-19) and update to Hydro One model update based on Hydro One Q2 results.
Brampton Income	3.3					
Total OPG and HOI Income	**17**	**(22.9)**	**(90)**	**(55)**	**(64)**	
Other Fees and Licences	**-**	**-**	**-**	**-**	**-**	
Electricity Expenses of the Province						
Provision for Electricity Sector	53	(15)	-	-	-	Changes in the Proviision (ESDI) expense reflect net changes in the outlook for Public Debt Interest, and OPG and HOI net income (excludinging ONFA adjustments).
Public Debt Interest - Electricity Sector	(22)	38	38	38	38	2016-17 PDI at ($514m) was slightly larger than ($492m) projected at Interim. 2017-18 change reflects revised projections for Provincial debt interest related to Hydro equity.
Total Electricity Expenses of the Province	**31**	**23**	**38**	**38**	**38**	
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs)	(40)	(24)	3	(7)	(10)	2016-17 decrease largely due to an OPCD Public Accounts PILs adjustment related to reconciling between OPCD and OEFC net opening assets. OPG PILs also slightly lower than projected.
Other Revenue						
Electricity Debt Retirement Charge	(4)	-	-	-	-	
Power Supply Contract Recoveries	99	(0)	(0)	(0)	0	Variance is largely due to retroactive payments that the OEFC made to certain non-utility-generato (NUGs) with former Ontario Hydro power purchase agreement contracts with OEFC. OEFC was required to make these payment following the dismissal by the Supreme Court of Canada of OEFC's application for leave to appeal a judgment of the Court of Appeal of Ontario on a 2015 co decision.
Net Reduction of Power Purchase Contracts	0.1	(0)	(0)	(0)	(0)	
Other Fees and Licences	-	-	-	-	-	
Revenue Pool Residual	-	-	-	-	-	
Miscellaneous	14	-	-	-	-	Higher than projected at Interim.
Expenses						
Interest on Debt	19	(53)	(64)	(69)	(98)	2016-17 higher than projected at Interim. 2017-18 reflects revised debt interest outlook net of revisions to OEFC interest revenue from OPG and Province.
Power Supply Contract Costs	(99)	0	0	0	(0)	Same as Power supply contract recoveries above. Power supply contract costs are fully recovered by power supply contract recoveries.
Electricity Consumer Price Protection Fund	-	-	-	-	-	
Demand Management Support Costs	1.8	-	-	-	-	
Provision for Electricity Sector	(53)	15	-	-	-	Changes in the Proviision (ESDI) expense (negative expense or revenue to OEFC) reflect net changes in the outlook for Public Debt Interest, and OPG and HOI net income (excludinging ONFA adjustments).
Other (Finance)	(1.0)	-	-	-	-	
Total OEFC Income	**(63)**	**(62)**	**(61)**	**(76)**	**(108)**	
Impact on Surplus/(Deficit)	**(14.6)**	**(62)**	**(113)**	**(93)**	**(134)**	

Information: Breakdown of change between revenue and expense

Total Revenue Impact	87	(47)	(87)	(62)	(74)	
Total Expenditure impact	101	15	26	31	60	

Electricity Sector Outlook (PSAB)

Negative Revenue Risks	$ Millions			
($ millions)	Plan			
	2017-18	2018-19	2019-20	2020-21
Generic				
OPG Generation Risk: Nuclear Reliability (-1.6 TWh)[1]	(120)	(120)	(120)	(120)
1% decrease in Hydro One actual load[2]	(57)	(59)	(62)	(63)
Lower OPG's Equity weighting & Return on Equity (ROE)[3]	(12)	(20)	(26)	(45)
Lower Hydro One Return on Equity (ROE)[4]	(9)	(36)	(38)	(40)
Regulatory				
Hydro One Distribution rate application[5]	(50)	(50)	(50)	(50)
OPG Switch from accrual based to cash based accounting for pension and OPEB[6]	(600)			
Regulatory Risk - Timing of Rate Decision[7]	(540)			
OEB Staff Recommendations wrt OPG rate application(May 2017)[8]	(175)	(143)	(151)	(175)
Nuclear Liabilities Cash vs. Accrual[9]	(450)	(450)	(450)	(450)
OEB decision on Hydro One tax recapture (if one-time write-down)[10]	(251)			
Accounting				
Net OPG IFRS Consolidation Risks - Scenario 1b: 15 year historical, update discount rate each year.[11]	-	(475)	(500)	(750)
Other Risks				
Avista Acquisition - Termination fee		(103)		

Note: These risks do not reflect the impacts on electricity sector revenue and expense of reclassification of the Asset Optimi

1. OPG's market and generation risks related to nuclear reliability similar to the scenarios OPG developed for its sales margins to capture major market risk factors (e.g., natural gas prices, coal prices, foreign exchange, nuclear reliability) in its 2012 business plan. Currently, only the nuclear reliability risk is captured at the current regulated rate for OPG's nuclear generation.

2. Estimated revenue impact if Hydro One load for Transmission and Distribution is 1% lower than projected for all years in CEFD Hydro One Forecast. Based on the assumption a 1% increase in load is directly proportional to a 1% change in revenue requirements.

3. Risk range for Hydro One transmission and distribution reflects potential risk of lower ROE by 0.5% vs assumed ROEs in business plan along with reduced deemed debt to equity weighting of 55%/45% from the current 51%/49%.

4. Risk range for Hydro One transmission and distribution reflects potential risk of lower ROE by 0.5% vs assumed ROEs in CEFD Hydro One Forecast based on the most recent rate applications and forecasted ROE rates.

5. OEB is expected to make a decision on Hydro One's Distibution rate application for 2018 during the first half of 2018.

6. The OEB directed a switch to cash-based accounting for years 2014 and 2015. However, the OEB also directed OPG to track the difference between cash based and accrual based accounting in a deferral account, while a generic proceeding is underway for all OEB-regulated electric and gas utilities. OEB September 2017 Report, recommends continuance of variance account which would mitigate this risk. However, the final decision (expected in Fall 2017) will be with the OEB Board.

7. Risk refelects OPG impact if the OEB rate rulings are applied as of the final decision date rather than retroactive to January 1, 2017 . OPG's business plan assumed OEB decision would be effective as of January 1, 2017. OPG estimated an impact of -$60M for each month for which OEB decsion is not retroactive.

8. Reflects OEB staff report (May 2017) reccomendations with respect to OPG's rate application. (Inlcudes OPG rate application updates).

9. Risk refelects impact of OEB decision that OPG switch to cash-basis accounting for regulated recovery of nuclear payment anmounts. OEB staff report (May 2017) appears to mitigate this risk as it makes no decision and recommends revisiting this issue in 5 years at next OEB application.

10. The OEB's Sep. 28, 2017 ruling on Hydro One's Transmission rate application included direction on sharing, with ratepayers, tax savings related to the Hydro One IPO. The estimated annual ongoing impact of this is factored into the current outlook. This risk reflects the impact if a decision is made by Hydro One that the impact of the ruling has to be accounted for as an immediate one-time write-down.
Note: Corresponding Positive Revenue Risks would also need to be incorporated for 2018-19 to 2020-21 if this risk is to be recognized. The risk reflect ther roughly 50% proncial ownership pending recategorization from teh AO Sales and Rentals outlook.

11. OPCD provided IFRS impact estimates at the time of Budget 2017. A portion of these were reflected in in OPG's and Hydro One's net inc0me outlook. The Risk above reflect the impacts iof IFRS not refelcted in the Budget 2017 fiscal plan.
Table below outlines OPG IFRS Risks versus what is built into the Fiscal Plan.

	2017-18	2018-19	2019-20	2020-21
OPG IFRS Risk	(400)	(475)	(700)	(750)
Risks Built into Fiscal Plan	(400)	0	(200)	0
Additional Risks to be picked up	0	(475)	(500)	(750)

Electricity Sector Outlook (PSAB)

Positive Revenue Risks				
($ millions)	**Plan**			
	2017-18	**2018-19**	**2019-20**	**2020-21**
Generic				
OPG Generation Risk: Nuclear Reliability (+1.1 TWh)[1]	85	85	85	85
1% increase in Hydro One actual load[2]	57	59	61	63
Higher OPG Return on Equity (ROE)[3]	6	22	19	33
Higher Hydro One Return on Equity (ROE)[4]	19	69	50	50
Regulatory				
Hydro One Motion to Review OEB Transmission ruling[5]	40	54	41	43
OEB decision on Hydro One tax recapture (if one-time write-down)[6]		6	7	10
Other Risks				
ONFA adjustment increase (as of September 2017 Q3)[7]	171			

zation strategy or updates to AO strategy.

1. OPG's market and generation risks related to nuclear reliability similar to the scenarios OPG developed for its sales margins to capture major market risk factors (e.g., natural gas prices, coal prices, foreign exchange, nuclear reliability) in its 2012 business plan. Currently, only the nuclear reliability risk is captured at the current regulated rate for OPG's nuclear generation.

2. Estimated revenue impact if Hydro One load for Transmission and Distribution is 1% higher than projected for all years in CEFD Hydro One Forecast. Based on the assumption a 1% increase in load is directly proportional to a 1% change in revenue requirements.

3. Risk range for OPG reflects potential risk of higher ROE in 2018-2021 (for nuclear base) vs assumed ROE in OPG's 2016 business plan and corresponding rate application. Assumed ROE is 9.85%, respresenting recent in 2010.

4. Risk range for Hydro One transmission and distribution reflects potential risk of higher ROE vs assumed ROEs in the Hydro One CEFD Forecast for 2018-2021. Assumed ROE is 9.85%, representing recent high in 2010.

5. On October 18, 2017, Hydro One filed a Notice of Motion to Review and vary the Decision and Order dated September 28, 2017. Upside risks based on Hydro One's motions to vary the OEB decision.

6. The OEB's Sep. 28, 2017 ruling on Hydro One's Transmission rate application included direction on sharing, with ratepayers, tax savings related to the Hydro One IPO. The estimated annual ongoing impact of this is factored into the current outlook. This risk reflects the impact if a decision is made by Hydro One that the impact of the ruling has to be accounted for as an immediate one-time write-down.
Note: Corresponding Negative Revenue Risks would also need to be incorporated for 2017-18 if this risk is to be recognized

7. Reflects consolidation adjustment to OPG net income, whereby the realized portion of gains or losses of OPG's nuclear funds are added or subtracted from OPG net income.

ONTARIO ELECTRICITY FINANCIAL CORPORATION

On Deck Outlook as of March 2017

$ Millions

	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Revenue						
Revenue Pool Residual						
Debt Retirement Charge	859	625	623	-	-	-
Payments-in-lieu of tax:						
OPG	268	302	315	366	408	537
Legacy Hydro One (Including Brampton)	2,929	7	2	2	2	2
Hydro One CIT dedicated to OEFC	3	20	20	22	23	25
MEUs	27	44	68	86	105	114
Total PILs & CIT dedicated to OEFC[1]	3,228	373	405	476	538	679
Interest :						
OPG	173	179	168	153	135	135
H1						
IESO	2	3	3	3	3	3
Province	520	492	492	492	492	492
Other	28	10	5	5	5	5
Total Interest	723	684	668	653	635	635
Power Supply Contract Recoveries	875	739	292	325	301	273
Amortization of NUG liability	172	129	74	41	30	28
Electricity sector dedicated income	3	342	525	-	-	-
Gain to OEFC under s. 50.3	172	-	-	-	-	-
Miscellaneous	9	-	-	-	-	-
	6,041	2,893	2,587	1,495	1,504	1,615
Expense						
Debt interest	1,319	1,216	1,090	1,027	977	885
Interest on nuclear risk funding						
Demand Management Support Costs	8	10	10	-	-	-
Amortization of deferred debt costs	-	-	-			
Power Supply Contract Costs	875	739	292	325	301	273
Debt Guarantee fee	127	122	102	91	88	81
Operating	7	6	6	6	6	6
	2,336	2,093	1,500	1,449	1,372	1,245
Excess (Deficiency) of Revenue over Expense	**3,705**	**800**	**1,087**	**46**	**132**	**370**
Prior period adjustment	87					
Stranded Debt - Year End	**4,393**	**3,593**	**2,506**	**2,460**	**2,328**	**1,958**

Note: All the Hydro One ownership broadening impacts, other than the ownership change from the initial IPO in 2015 [and the secondary offering in April 2016], are in the asset optimisation line (Sales and Rentals) and not in the current Outlook file.

ONTARIO ELECTRICITY FINANCIAL CORPORATION

On Deck Outlook as of October 2017 **$ Millions**

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Revenue						
Revenue Pool Residual						
Debt Retirement Charge	859	621	623	0	0	0
Payments-in-lieu of tax:						
OPG	268	224	299	378	411	539
Legacy Hydro One (Including Brampton)	2,929	4	2	2	2	2
Hydro One CIT dedicated to OEFC	3	25	12	13	13	13
MEUs	27	112	68	86	105	114
Total PILs & CIT dedicated to OEFC[1]	3,228	364	381	479	531	668
Interest :						
OPG	173	167	169	179	175	148
H1						
IESO	2	2	3	3	3	3
Province	520	514	454	454	454	454
Other	28	20	20	20	10	10
Total Interest	723	703	646	656	642	615
Power Supply Contract Recoveries	875	838	292	325	301	273
Amortization of NUG liability	172	129	74	41	30	28
Electricity sector dedicated income	3	302	140	0	0	0
Gain to OEFC under s. 50.3[2]	172	411	550	0	0	0
Miscellaneous	9	14	0	0	0	0
	6,041	3,382	2,706	1,501	1,504	1,585
Expense						
Debt interest	1,319	1,216	1,121	1,094	1,053	963
Interest on nuclear risk funding						
Demand Management Support Costs	8	8	10	0	0	0
Amortization of deferred debt costs	0	0	0			
Power Supply Contract Costs	875	838	292	325	301	273
Debt Guarantee fee	127	122	102	91	88	81
Operating	7	7	6	6	6	6
	2,336	2,191	1,531	1,516	1,448	1,323
Excess (Deficiency) of Revenue over Expense	3,705	**1,191**	**1,175**	**(15)**	**56**	**261**
Prior period adjustment	87					
Stranded Debt - Year End	4,393	**3,202**	**2,027**	**2,042**	**1,985**	**1,724**

1

Payments-in-lieu of tax:	2015-16 Public Accounts
OPG	290
Legacy Hydro One (Including Brampton)	2,941
Hydro One CIT dedicated to OEFC	0
MEUs	15
	3,247

2 **2017-18 value preliminary estimate, subject to change.**

ONTARIO ELECTRICITY FINANCIAL CORPORATION

Changes from Budget 2017 as of October 2017 **$ Millions**

	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Revenue						
Debt Retirement Charge	(4)	-	-	-	-	
Payments-in-lieu of tax:						
OPG	(78)	(16)	12	4	2	2016-17 variance is largely due to method of reporting OPG PILs by OEFC and OPG.
Legacy Hydro One (Including Brampton)	(3)	-	-	-	-	
Hydro One CIT dedicated to OEFC	5	(8)	(9)	(10)	(12)	Adjustment based on updated information in Hydro One rate application
MEUs	68	-	-	-	-	Large increase in 2016-17 from $80M payment during transfer of H01 Brampton to new consolidated MEU Alectra.
Total PILs	(9)	(24)	3	(7)	(10)	
Interest :						
OPG	(12)	1	26	40	13	Update to OPG interest outlook (wrt interest on OEFC loan).
H1	-	-	-	-	-	
IESO	(1)	-	-	-	-	
Province	22	(38)	(38)	(38)	(38)	2016-17 PDI at ($514m) was slightly larger than ($492m) projected at Interim. 2017-18 change reflects revised projections for Provincial debt interest related to Hydro equity.
Other	10	15	15	5	5	
Total Interest	19	(22)	3	7	(20)	
Power Supply Contract Recoveries	99	(0)	(0)	(0)	0	Variance is largely due to retroactive payments that the OEFC made to certain non-utility-generators (NUGs) with former Ontario Hydro power purchase agreement contracts with OEFC. OEFC was required to make these payment following the dismissal by the Supreme Court of Canada of OEFC's application for leave to appeal a judgment of the Court of Appeal of Ontario on a 2015 court decision.
Amortization of NUG liability	0	(0)	(0)	(0)	(0)	
Electricity sector dedicated income	(41)	(385)	-	-	-	Changes to ESDI (offset ny MoF Provision expense) largely reflect combined revisions to OPG and Hydro One net income and revisions to public debt intetest.
Gain to OEFC under s. 50.3	411	550	-	-	-	
Miscellaneous	14	-	-	-	-	
	489	119	6	(0)	(30)	
Expense						
Debt interest	-	31	67	76	78	Revised outlook for OEFC debt interest outlook
Interest on nuclear risk funding	-	-	-	-	-	
Demand Management Support Costs	(2)	-	-	-	-	
Amortization of deferred debt costs	-	-	-	-	-	
Power Supply Contract Costs	99	(0)	(0)	(0)	0	Same as Power supply contract recoveries above. Power supply contract costs are fully recovered by power supply contract recoveries.
Debt Guarantee fee	-	-	-	-	-	
Operating	1	-	-	-	-	
	98	31	67	76	78	
Excess (Deficiency) of Revenue over Expense	**391**	**88**	**(61)**			
Stranded Debt - Year End	**3,202**	**2,027**	**2,042**	**1,985**	**1,724**	

Provision for Electricity Sector (Dedicated Electricity Earnings/Electricity Sector Dedicated Earnings)

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Income from Investment in Government Business Enterprises						
OPG Income	291	299	147	720	608	1,041
Hydro One Income[1]	232	501	447	484	566	612
Hydro One Brampton (if applied separately)		15				
Total Income	**523**	**815**	**594**	**1,204**	**1,174**	**1,654**
Public Debt Interest - Electricity Sector						
OPG			(300)	(300)	(300)	(300)
Hydro One[1]			(154)	(154)	(154)	(154)
Public Debt Interest - Electricity Sector (OEFC Interest revenue)	**(520)**	**(514)**	**(454)**	**(454)**	**(454)**	**(454)**
MOF Provision Expense (before adjustments)	**3**	**302**	**140**	**750**	**720**	**1,199**
Other Adjustments						
Prior-year Adjustment[2]		3				
Exclude Brampton[3]		(15)				
MOF Provision Expense (after other adjustments)	**0**	**290**	**140**	**750**	**720**	**1,199**
Cumulative Shortfall Adjustment						
Opening Balance	0	0	0	0	0	0
Deduction / (Addition)	0	0	0	0	0	0
Ending Balance	0	0	0	0	0	0
Dedicated Electricity Earnings (all adjustments) (Public Accounts)	**0**	**290**	**140**	**750**	**720**	**1,199**
Electricity Sector Dedicated Income (OEFC Annual Report)	**3**	**302**	**140**			

Notes:

1. The Hydro One financials above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering are currently reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

2. 2016-17 Adjustment was due to the discrepancy between the numbers in MOF expense in PA 2015-16 and OEFC Financials in 2015-16 due to timing issues. $3M adjustment rectifies this discrepancy

3. Brampton was excluded from the Ministry of Finance's ESDI allocation.

Ontario Power Generation

OPG Income - Budget 2017

$ Millions

	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
OPG Net Income After Tax (Adjusted)	291	304	97	732	625	1,066
OPG Net Income After Tax	*291*	*379*	*480*	*678*	*726*	*913*
Extraordinary Gains	-	-	-	-	-	-
GA - OPG Trust Interest Revenue			*17*	*54*	*99*	*153*
OPG IFRS consolidation risk picked up in Fiscal Plan		(75)	(400)		(200)	
ONFA and other Fair Value Adjustments	(75)	8				
ONFA Adjustments	-	8				
Other Fair Value Adjustments	(75)					

OPG PIL - Budget 2017

$ Millions

	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Net Income Before Tax	383	396	572	867	795	1364
Net Income After Tax (Adjusted)	291	304	97	732	625	1066
Income Taxes	92	92	92	135	170	298
GRC: Payable to OEFC	198	196	205	212	219	220
Proxy Property Tax	16	14	18	19	19	19
Ontario Capital Tax	0	0	0	0	0	0
Total	**306**	**302**	**315**	**366**	**408**	**537**

OPG Income - October 2017

$ Millions

	Actual	Actual	Current Outlook			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
OPG Net Income	291	377	818	678	726	913
Adjustment for OPG HQ gain on sale[1]			(283)			
Extraordinary Gains	0	0	0	0	0	0
GA Financing - OPG Trust Interest Revenue[2]			12	42	82	128
OPG IFRS consolidation risk reflected in Fiscal Plan[3]		(78.00)	(400)		(200)	
OPG Net Income (Adjusted before ONFA)	**291**	**299**	**147**	**720**	**608**	**1,041**
ONFA Adjustments	247	49				
Other Fair Value Adjustments	(75)	(6)				
ONFA and other Fair Value Adjustments	**172**	**43**				
OPG Net Income	**463**	**342**	**147**	**720**	**608**	**1,041**

OPG PIL - August 2017

$ Millions

	Actual	Actual	Current Outlook			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Income Before Tax	383	308	684	855	778	1340
OPG Net Income (Adjusted before ONFA)	291	299	147	720	608	1041
OPG Income Tax (PILs)	92	9	162	135	170	298
Tax adjustment for OPG HQ gain on sale[1]			(95)			
GRC: Payable to OEFC	198	201	214	224	222	222
Proxy Property Tax to OEFC	16	14	18	19	19	19
Ontario Capital Tax	0	0	0	0	0	0
Total OPG PILs	**306**	**224**	**299**	**378**	**411**	**539**

1. As part of Asset Optimization Plan the projected proceeds are currently reported in OEP/MoF Sales and Rentals line. To be re-categorized after the transaction is completed and in coordination with OEP and SIFB.
2. This reflects interest earnings on GA financing costs which are consolidated back to Province
3. See Risks tab for IFRS impacts that were not reflected in Fiscal Plan, and table below.

	2017-18	2018-19	2019-20	2020-21
OPG IFRS Risk	(400)	(475)	(700)	(750)
Risks Built into Fiscal Plan	(400)	0	(200)	0
Additional Risks to be picked up	0	(475)	(500)	(750)

Hydro One Net Income and PILs

Hydro One Income - Budget 2017
($ millions)

	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Hydro One Net Income After Tax	685	737	742	802	862	931
Hydro One - Unrealized Gains Adjustment						

2016-17 to 2020-21 from CEFD Hydro One 2016 model.

Hydro One PIL - Budget 2017
($ millions)

	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Net Income After Tax	685	737	742	802	862	931
Income Taxes PILs	132	160	181	205	212	225
Proxy Property Tax	2	2	2	2	2	2
Ontario Capital Tax	0	0	0	0	0	0
Total	**134**	**162**	**183**	**207**	**214**	**227**

Hydro One (Post IPO Scenario) - Budget 2017
($ millions)

	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Assumed Provincial share		70.0%	70.0%	70.0%	70.0%	70.0%
Hydro One Net Income	236	516	520	562	603	652
Brampton Net Income	20	15				
Hydro One PILs		0	0	0	0	0
Hydro One CIT	3	20	20	22	23	25
Brampton PILs		5				
Proxy Property Tax		2	2	2	2	2
Total	**2886**	**27**	**22**	**24**	**25**	**27**

Hydro One Income - October 2017
($ millions) — $ Millions

	Actual	Actual	Current Outlook			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Hydro One Net Income After Tax			623	666	753	818
Debenture Costs Impacts (After Tax)			(34)	(39)		
Hydro One Net Income After Tax - Including Adjustments	670	680	589	627	753	818
Hydro One - Net Income Attributable to Preferred Shareholders	15	18				
Hydro One - Unrealized Gains Adjustment						

2017-18 to 2020-21 from CEFD Hydro One 2016 model.

Hydro One (100% Ownership)
($ millions) — $ Millions

	Actual	Actual	Current Outlook			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Net Income After Tax - Common Shares	670	680	589	627	753	818
Net Income After Tax - Preferred Shares	15	18				
Income Taxes PILs	132	160	181	205	212	225
Proxy Property Tax	2	2	2	2	2	2
Ontario Capital Tax	0	0	0	0	0	0
Total	**134**	**162**	**183**	**207**	**214**	**227**

Hydro One (Post IPO Scenario) - March 2017
$ Millions

	Actual	Actual	Current Outlook			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Assumed Provincial share		70.1%	70.1%	70.1%	70.1%	70.1%
Net Income After Tax - Common Shares	670	680	589	627	753	818
Net Income After Tax - Preferred Shares	15	18	18	18	18	18
adjustment for lower Provincial share		(204)	(177)	(188)	(225)	(245)
Hydro one IPO-related and other adjustments*	(449)					
Hydro One IFRS Adjustment to Province		7				
OPCD adjustment for Equity advances		(2)				
Adjust OEB decision/rebasing to ~50% provincial ownership**			16	27	21	22
Hydro One - Unrealized Gains Adjustment						
Total Hydro One Income - Province	**236**	**500**	**447**	**484**	**566**	**612**
Brampton Net Income - For Provision/ESDI	20	15				
other adjustments	(24)	2				
Combined Income for ESDI	232	501	447	484	566	612
Brampton Net Income - Public Accounts	**20**	**18**				
Hydro One PILs		2				
Proxy Property Tax		2	2	2	2	2
Brampton PILs						
Hydro One CIT	3	25	12	13	13	13
Total H1 PILs (incl. CIT)		29	14	15	15	15
Total H1 PILs (excl CIT)		4	2	2	2	2
Total	**2,886**	**29**	**14**	**15**	**15**	**15**

* Hydro one IPO-related and other adjustments	2015-16
Deferred Tax Asset (Post IPO Portion)- 100%	(2,619)
Deferred Tax Asset (Pre IPO Portion) - 100%	(191)
Deferred Tax Asset - Province	2,392
Loss of H1 Net Income	(50)
Consolidation adjustment	19

** An adjustment is made for OEB decision and rebasing impacts to show them at about 50% Provincial allocation, pending recategorization of AO amounts from Sales and Rentals.

Hydro One 2015-16 Net Income Estimation (USGAAP) ($M)

Q2 2015[1]	Q3 2015[2]	Q4 2015[1]	Q1 2016[2]	Fiscal Year 2015-16
131	188	143	208	**670**
	9		6	**15**

2016	Q1 2017	cal Year 2016-17
721	167	**680**
19	5	**18**

2015-16 PILs Estimation (Accounting Numbers)	Exc. B	Inc. B
2015 Income Tax	105	105
Q1 2016 Income Tax	33	33
Q1 2015 Income Tax	(45)	(45)
Income Taxes PILs	93	93
Departure Tax	2,600	2,600
Additional PILs	191	191
Brampton PILs	(4)	
Proxy Property Tax	2	2
Total	**2882**	**2886**

Public Debt Interest and Section 50.3 payments

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Hydro One Public Debt Interest and Section 50.3 payments						
Government Annual Interest Costs - Hydro One	220	220	220	220	220	220
Reduction in Interest Costs due to Broadening[1]		(29)	(66)	(66)	(66)	(66)
Province Annual Interest Costs - Hydro One Debt	**220**	**191**	**154**	**154**	**154**	**154**
Province Annual Interest Cost - OPG Debt	300	300	300	300	300	300
Total Public Debt Interest	**520**	**514**	**454**	**454**	**454**	**454**

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Gain to OEFC under s. 50.3	172	411	550	0	0	0

1. The Hydro One reduction in interest costs above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering are currently reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

PROVINCIAL CONSOLIDATION ADJUSTMENTS
Ontario Nuclear Funds Agreement

	2015-16	2016-17	2017-18
Adjustment for Change in OPG Reported Net Income			
Adjustment for DSF Unrealized Earnings			
Unrealized Earnings as at beginning of year	0	0	
Unrealized Earnings as at fiscal year end / latest quarter	(175)	0	
Bruce Variance Account Adjustment	(82)	0	
OPG Net Income Adjustment	(93)	0	
Adjustment for UFSF Unrealized Earnings			
Unrealized Earnings as at beginning of year	0	0	
Unrealized Earnings as at fiscal year end / latest quarter	(82)	56	
Bruce Variance Account Adjustment	(42)	28	
OPG Net Income Adjustment	(40)	28	
Unrealized Earnings -- Fiscal YTD	**(133)**	**28**	
Adjustment for Change in Due to Province			
Adjustment for DSF Due to Province			
Due to Province (cost basis) as at beginning of year	0	39	
Unrealized Earnings as at fiscal year end / latest quarter	39	79	
Change in Due to Province -- Fiscal YTD	**39**	**40**	
Adjustment for UFSF Due to Province			
Due to Province (cost basis) as at beginning of year	295	370	
Unrealized Earnings as at fiscal year end / latest quarter	370	407	
Change in Due to Province -- Fiscal YTD	**75**	**37**	
Provincial Consolidation Adjustment	**247**	**49**	

Other Data

	Actual	Plan			
	2016-17	2017-18	2018-19	2019-20	2020-21
Debt Retirement Charge	621	0	0	0	0

	Plan				
	2016-17	2017-18	2018-19	2019-20	2020-21
Power Supply Contract Recoveries	838	292	325	301	273

	Plan				
	2016-17	2017-18	2018-19	2019-20	2020-21
Interest					
OPG	167	169	179	175	148
IESO	2	3	3	3	3
Other (Net)	20	20	20	10	10
Expense					
Debt interest	1216	1121	1094	1053	963

	Actual	Plan			
	2016-17	2017-18	2018-19	2019-20	2020-21
MEU - PIL Income Tax	109.8				
MEU - PIL Property Tax	0.6				
MEU - GRC	1.2				
TOTAL MEU PILs	111.6				

	Actual	Plan			
	2016-17	2017-18	2018-19	2019-20	2020-21
Miscellaneous/Other (OEFC FS)	14				
Demand Management Support Costs (IEI)	8	10			
Operating [Expense]	7	6	6	6	6
Interest on nuclear risk funding	-	-	-	-	-
Amortization of deferred debt costs	-	-	-	-	-
Amortization of NUG liability	129	74	41	30	28
Debt Guarantee Fee	122				

Expense (Electrictiy Summary Tab)					
Other (Finance)	-7	-6	-6	-6	-6
Demand Management Support Costs (IEI)	-8	-10			
Debt Guarantee Fee	(122)				

OFHP debt and interest projections, by calendar year

$ nominal million	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
FAA w/ Interest, Fees, Readjustment Principle Recovery, Readjustment*	- 1,396	- 2,189	- 2,296	- 2,414	- 2,204	- 1,700	- 1,050	- 492	- 61	79	129	354	714	1,251	1,188	1,348	1,419	1,901	2,087	2,128	2,062	2,099	1,796	1,527	1,392	1,379	1,310	1,341	1,357	1,526	2,034
Interest Paid	32	116	225	343	466	577	667	733	778	814	851	883	896	888	872	854	830	791	736	673	607	540	475	420	372	326	279	231	179	121	45
Closing Debt Balance	1,428	3,734	6,254	9,011	11,681	13,958	15,674	16,899	17,677	18,491	19,342	19,904	19,904	19,541	19,226	18,732	18,143	17,033	15,682	14,227	12,773	11,214	9,893	8,786	7,766	6,713	5,682	4,571	3,394	1,989	0

*Delta between IESO GA cost forecast and Total GA paid by ratepayer, inclusive of interest
Notes: model assumes interest rate of 4.5% and data is exclusive of OPG financing fees

Date: October 19, 2017
Source: Ministry of Energy

From: Usman Zahid
To: Ronald Kwan
Subject: FW: FES Items for Today
Date: Friday, November 10, 2017 11:51:53 AM
Attachments: 1. Electricity Sector Outlook (2017 10 20v3)_Sent.pdf
2. OFHP supporting data for OFA_v0.1.pdf

Hi Ron,

Just a reminder on this, we need to get it in soon.

BudSec is working on the Table of Contents for Current Issue Notes submitted. The statement is available, I will go down to frost to review the statement shortly.

Regards,
Usman

From: Usman Zahid
Sent: Friday, November 10, 2017 10:52 AM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: John Kim <John.Kim@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>
Subject: FW: FES Items for Today

Hi Ron,

Attached are two items for inclusion into the TB/MBC Binder. The first item is a PDF version of the Electricity Sector Outlook (similar to what was submitted previously). The second item is information on the financing of FHP. EFB have said they are open to omitting the second item if appropriate.

Regards,
Usman

From: Shajee Kathirgamanathan
Sent: Friday, November 10, 2017 10:37 AM
To: Usman Zahid <Usman.Zahid@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>
Subject: RE: FES Items for Today

Hi Usman,

Please find attached the two documents for inclusions into EFB's portion of the TB Binder.

1) PDF'ed version of the Electricity Sector Outlook. Similar to what we submitted last time
2) Information we received on the financing of the Fair Hydro Plan. We didn't use this

information per se, so we're open to omitting it should it be decided to exclude.

Files saved here:
S:\Users\CEF\Hydro 2017\FES\TB Binder\EFB

Thanks,
Shajee

Shajee Kathirgamanathan
Office: 416-325-1402 | Mobile: 647-294-3359
shajee.kathirgamanathan@ofina.on.ca

From: Usman Zahid
Sent: Friday, November 10, 2017 9:33 AM
To: John Kim <John.Kim@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>
Subject: FES Items for Today

Hi All,

TB/MBC Binder Materials: Due by noon, please get to Ron ASAP.

Placemats: Due at 2pm, please get in right after TB/MBC binder Materials.

Regards,
Usman

Electricity Sector Outlook
October 2017

Disclosure:

All information contained in this workbook is confidential and commercially sensitive

All projected numbers are estimates and subjected to change

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Please consult with OFA before sharing of information.

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Electricity Sector Outlook
Including Line Items for Consolidation

Electricity Summary - On Deck

			MOF Expense Items (consolidated)	Current Outlook			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**38**	Power Supply Contract Costs	(292)	(325)	(301)	(273)
Expense	**MOF (OEFC)**	**40**	Demand Management Support Costs	(10)	-	-	-
Expense	**MOF (OEFC)**	**41**	Provision for Electricity Sector	140	-	-	-
Expense	**MOF**	**17**	Provision for Electricity Sector	(140)	-	-	-
Expense	**MOF (OEFC)**	**42**	Other (Finance)	(6)	(6)	(6)	(6)
			Total MOF Expense	**(308)**	**(331)**	**(307)**	**(279)**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**7**	OPG Income	147	720	608	1,041
Revenue	**ENE**	**8**	OPG - ONFA and other Fair Value Adjustments	-	-	-	-
Revenue	**ENE**	**10**	HOI Income	447	484	566	612
Revenue		**11**	Brampton Income	-	-	-	-
Revenue	**MOF (OEFC)**	**26**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	381	479	531	668
Revenue	**MOF (OEFC)**	**29**	Electricity Debt Retirement Charge	623	-	-	-
Revenue	**MOF (OEFC)**	**30**	Power Supply Contract Recoveries	292	325	301	273
Revenue	**MOF (OEFC)**	**31**	Net Reduction of Power Purchase Contracts	74	41	30	28
Revenue	**MOF (OEFC)**	**34**	Miscellaneous	-	-	-	-
			Total MOF Revenue	**1,964**	**2,049**	**2,036**	**2,623**
			OFA IOD Expense				
			Public Debt Interest - Electricity Sector	(454)	(454)	(454)	(454)
			Interest on Debt	(475)	(438)	(411)	(348)
			Total OFA IOD Expense	**(929)**	**(892)**	**(865)**	**(802)**
			Impact on Surplus/Deficit	**727**	**826**	**864**	**1,542**
			check	**-**	**-**	**-**	**-**

Electricity Summary - Budget 17

	For Discussion		MOF Expense Items (consolidated)	Plan			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**38**	Power Supply Contract Costs	(292)	(325)	(301)	(273)
Expense	**MOF (OEFC)**	**40**	Demand Management Support Costs	(10)	0	0	0
Expense	**MOF (OEFC)**	**41**	Provision for Electricity Sector	125	0	0	0
Expense	**MOF**	**17**	Provision for Electricity Sector	(125)	0	0	0
Expense	**MOF (OEFC)**	**42**	Other (Finance)	(6)	(6)	(6)	(6)
			Total MOF Expense	**(308)**	**(331)**	**(307)**	**(279)**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**7**	OPG Income	97	732	625	1,066
Revenue	**ENE**	**8**	OPG - ONFA and other Fair Value Adjustments	0	0	0	0
Revenue	**ENE**	**10**	HOI Income	520	562	603	652
			Brampton Income				
Revenue	**MOF (OEFC)**	**25**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	405	476	538	679
Revenue	**MOF (OEFC)**	**29**	Electricity Debt Retirement Charge	623	0	0	0
Revenue	**MOF (OEFC)**	**30**	Power Supply Contract Recoveries	292	325	301	273
Revenue	**MOF (OEFC)**	**31**	Net Reduction of Power Purchase Contracts	74	41	30	28
Revenue	**MOF (OEFC)**	**34**	Miscellaneous	0	0	0	0
			Total MOF Revenue	**2,011**	**2,136**	**2,098**	**2,697**
			OFA IOD Expense				
		17	Public Debt Interest - Electricity Sector	(492)	(492)	(492)	(492)
		36	Interest on Debt	(422)	(374)	(342)	(250)
			Total OFA IOD Expense	**(914)**	**(866)**	**(834)**	**(742)**
			Impact on Surplus/Deficit	**789**	**939**	**957**	**1,676**
			check	**-**	**-**	**-**	**-**

Electricity Summary - Change

			MOF Expense Items (consolidated)	Variance from Plan			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**69**	Power Supply Contract Costs	0	0	0	(0)
Expense	**MOF (OEFC)**	**71**	Demand Management Support Costs	0	0	0	0
Expense	**MOF (OEFC)**	**72**	Provision for Electricity Sector	15	0	0	0
Expense	**MOF**	**48**	Provision for Electricity Sector	(15)	0	0	0
Expense	**MOF (OEFC)**	**73**	Other (Finance)	0	0	0	0
			Total MOF Expense	**0**	**0**	**0**	**(0)**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**38**	OPG Income	50	(12)	(17)	(24)
Revenue	**ENE**	**39**	OPG - ONFA and other Fair Value Adjustments	0	0	0	0
Revenue	**ENE**	**41**	HOI Income	(73)	(78)	(38)	(40)
			Brampton Income	0	0	0	0
Revenue	**MOF (OEFC)**	**25**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	(24)	3	(7)	(10)
Revenue	**MOF (OEFC)**	**60**	Electricity Debt Retirement Charge	0	0	0	0
Revenue	**MOF (OEFC)**	**61**	Power Supply Contract Recoveries	(0)	(0)	(0)	0
Revenue	**MOF (OEFC)**	**62**	Net Reduction of Power Purchase Contracts	(0)	(0)	(0)	(0)
Revenue	**MOF (OEFC)**	**65**	Miscellaneous	0	0	0	0
			Total MOF Revenue	**(47)**	**(87)**	**(62)**	**(74)**
			OFA IOD Expense				
		17	Public Debt Interest - Electricity Sector	38	38	38	38
		36	Interest on Debt	(53)	(64)	(69)	(98)
			Total OFA IOD Expense	**(15)**	**(26)**	**(31)**	**(60)**
			Impact on Surplus/Deficit	**(62)**	**(113)**	**(93)**	**(134)**
			check	***-***	***0***	***(0)***	***(0)***

Electricity Sector Outlook	$ Millions					
	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
On Deck Outlook as of March 2017						
Income from Investment in Government Business Enterprises						
OPG Income[1]	291	304	97	732	625	1,066
OPG - ONFA and other Fair Value Adjustments[2]	172	8	-	-	-	-
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	-
HOI Income[3]	236	516	520	562	603	652
Brampton Income	20	15	-	-	-	-
Total OPG and HOI Income	**719**	**842**	**617**	**1,294**	**1,229**	**1,717**
Other Fees and Licences	**127**	**122**	**102**	**91**	**88**	**81**
Electricity Expenses of the Province						
Provision for Electricity Sector[4]	(3)	(342)	(125)		-	-
Public Debt Interest - Electricity Sector	(520)	(492)	(492)	(492)	(492)	(492)
Subtotal	(523)	(834)	(617)	(492)	(492)	(492)
Public Debt Interest - Impact of ONFA						
Amortization of Deferred Revenue re profit on sale of H1 notes						
Total Electricity Expenses of the Province	**(523)**	**(834)**	**(617)**	**(492)**	**(492)**	**(492)**
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	3,228	373	405	476	538	679
Other Revenue						
Electricity Debt Retirement Charge[5]	859	625	623	-	-	-
Power Supply Contract Recoveries	875	739	292	325	301	273
Net Reduction of Power Purchase Contracts	172	129	74	41	30	28
Other Fees and Licences	(127)	(122)	(102)	(91)	(88)	(81)
Miscellaneous	9	-	-	-	-	-
Expenses						
Interest on Debt	(596)	(532)	(422)	(374)	(342)	(250)
Power Supply Contract Costs	(875)	(739)	(292)	(325)	(301)	(273)
Electricity Consumer Price Protection Fund	-	-	-	-	-	-
Demand Management Support Costs[6]	(8)	(10)	(10)	-	-	-
Provision for Electricity Sector	3	342	125	-	-	-
Other (Finance)	(7)	(6)	(6)	(6)	(6)	(6)
Total OEFC Income	**3,533**	**800**	**687**	**46**	**132**	**370**
Impact on Surplus/(Deficit)	**3,856**	**930**	**789**	**939**	**957**	**1,676**

Notes: The Hydro One net income outlook above (2016-17 to 2020-21) reflects the Province's current 70% ownership share, after the initial IPO in 2015 [and the secondary offering in April 2016]. Net estimated fiscal impacts from future Hydro One offerings are reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

Notes:

1.OPG's 2016-17 outlook reflected its reported earnings. 2017-18 outlook reflects OPG's latest monthly update. Out-years reflect OPG's preliminary 2017-19 business plan and long-term outlook to 2019-20 (as fiscalized by OPG). 2020-21 estimates are based on OPG's calendar year-based business plan projections and as fiscalized by CEFD staff.

2. Provincial consolidation adjustments for unrealized earnings on the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds, as of the end of December 2016.

3. Hydro One 2016-17 income reflects its reported net income, adjusted for Hydro One IPO impacts. 2017-18 to 2020-21 projections are based on CEFD projections using the latest public information. The Hydro One net income outlook above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering are currently reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial ONFA consolidation adjustments, minus the interest on debt payable to OEFC. The provision is currently assumed to end once the DRC ends on a legislated fixed end date of April 1, 2018.

5. Reflects April 23, 2014 announcement that DRC will be eliminated for residential users, after December 31, 2015. The end date of DRC for remaining users is legislated to be on April 1, 2018. Estimates are subject to change based on actual consumption.

6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Electricity Sector Outlook

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
On Deck Outlook as of October 2017						
Income from Investment in Government Business Enterprises						
OPG Income[1]	291	299	147	720	608	1,041
OPG - ONFA and other Fair Value Adjustments[2]	172	43	-	-	-	-
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	-
HOI Income[3]	236	500	447	484	566	612
Brampton Income	20	18	-	-	-	-
Total OPG and HOI Income	**719**	**860**	**594**	**1,204**	**1,174**	**1,654**
Other Fees and Licences (Debt Guarantee fee)	**127**	**122**	**102**	**91**	**88**	**81**
Electricity Expenses of the Province						
Provision for Electricity Sector[4]	-	(290)	(140)			
Public Debt Interest - Electricity Sector	(520)	(514)	(454)	(454)	(454)	(454)
Subtotal	(520)	(803)	(594)	(454)	(454)	(454)
Public Debt Interest - Impact of ONFA						
Amortization of Deferred Revenue re profit on sale of H1 notes						
Total Electricity Expenses of the Province	**(520)**	**(803)**	**(594)**	**(454)**	**(454)**	**(454)**
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	3,247	334	381	479	531	668
Other Revenue						
Electricity Debt Retirement Charge[5]	859	621	623	-	-	-
Power Supply Contract Recoveries	875	838	292	325	301	273
Net Reduction of Power Purchase Contracts	172	129	74	41	30	28
Other Fees and Licences	(127)	(122)	(102)	(91)	(88)	(81)
Miscellaneous	9	14	-	-	-	-
Expenses						
Interest on Debt	(596)	(513)	(475)	(438)	(411)	(348)
Power Supply Contract Costs	(875)	(838)	(292)	(325)	(301)	(273)
Electricity Consumer Price Protection Fund	-	-	-	-	-	-
Demand Management Support Costs[6]	(8)	(8)	(10)	-	-	-
Provision for Electricity Sector	-	290	140	-	-	-
Other (Finance)	(7)	(7)	(6)	(6)	(6)	(6)
Total OEFC Income	**3,549**	**737**	**625**	**(15)**	**56**	**261**
Impact on Surplus/(Deficit)	**3,876**	**915**	**727**	**826**	**864**	**1,542**
variance to OEFC check	*(156)*	*(454)*	*(550)*	*-*	*0*	*-*

Notes:

1.OPG's 2016-17 outlook reflected its reported earnings. 2017-18 outlook reflects OPG's latest monthly update. Out-years reflect OPG's preliminary 2017-19 business plan and long-term outlook to 2019-20 (as fiscalized by OPG). 2020-21 estimates are based on OPG's calendar year-based business plan projections and as fiscalized by CEFD staff.

2. Provincial consolidation adjustments for unrealized earnings on the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds, as of the end of December 2016.

3. Hydro One 2016-17 income reflects its reported net income, adjusted for Hydro One IPO impacts. 2017-18 to 2020-21 projections are based on CEFD projections using the latest public information. The Hydro One net income outlook above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering are currently reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial ONFA consolidation adjustments, minus the interest on debt payable to OEFC. The provision is currently assumed to end once the DRC ends on a legislated fixed end date of April 1, 2018.

5. Reflects April 23, 2014 announcement that DRC will be eliminated for residential users, after December 31, 2015. The end date of DRC for remaining users is legislated to be on April 1, 2018. Estimates are subject to change based on actual consumption.

6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Electricity Sector Change Since Budget

$ Millions

($million)	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Changes from Budget 2017 as of October 2017						
Income from Investment in Government Business Enterprises						
OPG Income	(5)	50	(12)	(17)	(24)	2016-17 small decrease due to IFRS adjustment revision and OPG Net Income revision. 2017-18 increase mainly due to deferral of Pickering Unit 6 planned outage to Jan 18, deferral of sale of land at Hearn site from Q1 2017 to later in 2017, partially offsdet by lower gropss margin.
ONFA and other Fair Value Adjustments	35	-	-	-	-	Largely revision to ONFA fair value as of March 31, 2017
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	
HOI Income	(16)	(73)	(78)	(38)	(40)	2016-17 slight decrease from Budget 2017 Interim projection. 2017-18 onwards reflects impacts of OEB decision on Hydro One rates, interest expense on Avitsa debentures (in 2017-18 and 2018-19) and update to Hydro One model update based on Hydro One Q2 results.
Brampton Income	3.3					
Total OPG and HOI Income	**17**	**(22.9)**	**(90)**	**(55)**	**(64)**	
Other Fees and Licences	**-**	**-**	**-**	**-**	**-**	
Electricity Expenses of the Province						
Provision for Electricity Sector	53	(15)	-	-	-	Changes in the Proviision (ESDI) expense reflect net changes in the outlook for Public Debt Interest, and OPG and HOI net income (excludinging ONFA adjustments).
Public Debt Interest - Electricity Sector	(22)	38	38	38	38	2016-17 PDI at ($514m) was slightly larger than ($492m) projected at Interim. 2017-18 change reflects revised projections for Provincial debt interest related to Hydro equity.
Total Electricity Expenses of the Province	**31**	**23**	**38**	**38**	**38**	
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs)	(40)	(24)	3	(7)	(10)	2016-17 decrease largely due to an OPCD Public Accounts PILs adjustment related to reconciling between OPCD and OEFC net opening assets. OPG PILs also slightly lower than projected.
Other Revenue						
Electricity Debt Retirement Charge	(4)	-	-	-	-	
Power Supply Contract Recoveries	99	(0)	(0)	(0)	0	Variance is largely due to retroactive payments that the OEFC made to certain non-utility-generato (NUGs) with former Ontario Hydro power purchase agreement contracts with OEFC. OEFC was required to make these payment following the dismissal by the Supreme Court of Canada of OEFC's application for leave to appeal a judgment of the Court of Appeal of Ontario on a 2015 co decision.
Net Reduction of Power Purchase Contracts	0.1	(0)	(0)	(0)	(0)	
Other Fees and Licences	-	-	-	-	-	
Revenue Pool Residual	-	-	-	-	-	
Miscellaneous	14	-	-	-	-	Higher than projected at Interim.
Expenses						
Interest on Debt	19	(53)	(64)	(69)	(98)	2016-17 higher than projected at Interim. 2017-18 reflects revised debt interest outlook net of revisions to OEFC interest revenue from OPG and Province.
Power Supply Contract Costs	(99)	0	0	0	(0)	Same as Power supply contract recoveries above. Power supply contract costs are fully recovered by power supply contract recoveries.
Electricity Consumer Price Protection Fund	-	-	-	-	-	
Demand Management Support Costs	1.8	-	-	-	-	
Provision for Electricity Sector	(53)	15	-	-	-	Changes in the Proviision (ESDI) expense (negative expense or revenue to OEFC) reflect net changes in the outlook for Public Debt Interest, and OPG and HOI net income (excludinging ONFA adjustments).
Other (Finance)	(1.0)	-	-	-	-	
Total OEFC Income	**(63)**	**(62)**	**(61)**	**(76)**	**(108)**	
Impact on Surplus/(Deficit)	**(14.6)**	**(62)**	**(113)**	**(93)**	**(134)**	

Information: Breakdown of change between revenue and expense

Total Revenue Impact	87	(47)	(87)	(62)	(74)	
Total Expenditure impact	101	15	26	31	60	

Electricity Sector Outlook (PSAB)

Negative Revenue Risks	$ Millions			
($ millions)	Plan			
	2017-18	2018-19	2019-20	2020-21
Generic				
OPG Generation Risk: Nuclear Reliability (-1.6 TWh)[1]	(120)	(120)	(120)	(120)
1% decrease in Hydro One actual load[2]	(57)	(59)	(62)	(63)
Lower OPG's Equity weighting & Return on Equity (ROE)[3]	(12)	(20)	(26)	(45)
Lower Hydro One Return on Equity (ROE)[4]	(9)	(36)	(38)	(40)
Regulatory				
Hydro One Distribution rate application[5]	(50)	(50)	(50)	(50)
OPG Switch from accrual based to cash based accounting for pension and OPEB[6]	(600)			
Regulatory Risk - Timing of Rate Decision[7]	(540)			
OEB Staff Recommendations wrt OPG rate application(May 2017)[8]	(175)	(143)	(151)	(175)
Nuclear Liabilities Cash vs. Accrual[9]	(450)	(450)	(450)	(450)
OEB decision on Hydro One tax recapture (if one-time write-down)[10]	(251)			
Accounting				
Net OPG IFRS Consolidation Risks - Scenario 1b: 15 year historical, update discount rate each year.[11]	-	(475)	(500)	(750)
Other Risks				
Avista Acquisition - Termination fee		(103)		

Note: These risks do not reflect the impacts on electricity sector revenue and expense of reclassification of the Asset Optimi

1. OPG's market and generation risks related to nuclear reliability similar to the scenarios OPG developed for its sales margins to capture major market risk factors (e.g., natural gas prices, coal prices, foreign exchange, nuclear reliability) in its 2012 business plan. Currently, only the nuclear reliability risk is captured at the current regulated rate for OPG's nuclear generation.

2. Estimated revenue impact if Hydro One load for Transmission and Distribution is 1% lower than projected for all years in CEFD Hydro One Forecast. Based on the assumption a 1% increase in load is directly proportional to a 1% change in revenue requirements.

3. Risk range for Hydro One transmission and distribution reflects potential risk of lower ROE by 0.5% vs assumed ROEs in business plan along with reduced deemed debt to equity weighting of 55%/45% from the current 51%/49%.

4. Risk range for Hydro One transmission and distribution reflects potential risk of lower ROE by 0.5% vs assumed ROEs in CEFD Hydro One Forecast based on the most recent rate applications and forecasted ROE rates.

5. OEB is expected to make a decision on Hydro One's Distibution rate application for 2018 during the first half of 2018.

6. The OEB directed a switch to cash-based accounting for years 2014 and 2015. However, the OEB also directed OPG to track the difference between cash based and accrual based accounting in a deferral account, while a generic proceeding is underway for all OEB-regulated electric and gas utilities. OEB September 2017 Report, recommends continuance of variance account which would mitigate this risk. However, the final decision (expected in Fall 2017) will be with the OEB Board.

7. Risk refelects OPG impact if the OEB rate rulings are applied as of the final decision date rather than retroactive to January 1, 2017 . OPG's business plan assumed OEB decision would be effective as of January 1, 2017. OPG estimated an impact of -$60M for each month for which OEB decsion is not retroactive.

8. Reflects OEB staff report (May 2017) reccomendations with respect to OPG's rate application. (Inlcudes OPG rate application updates).

9. Risk refelects impact of OEB decision that OPG switch to cash-basis accounting for regulated recovery of nuclear payment anmounts. OEB staff report (May 2017) appears to mitigate this risk as it makes no decision and recommends revisiting this issue in 5 years at next OEB application.

10. The OEB's Sep. 28, 2017 ruling on Hydro One's Transmission rate application included direction on sharing, with ratepayers, tax savings related to the Hydro One IPO. The estimated annual ongoing impact of this is factored into the current outlook. This risk reflects the impact if a decision is made by Hydro One that the impact of the ruling has to be accounted for as an immediate one-time write-down.
Note: Corresponding Positive Revenue Risks would also need to be incorporated for 2018-19 to 2020-21 if this risk is to be recognized. The risk reflect ther roughly 50% proncial ownership pending recategorization from teh AO Sales and Rentals outlook.

11. OPCD provided IFRS impact estimates at the time of Budget 2017. A portion of these were reflected in in OPG's and Hydro One's net inc0me outlook. The Risk above reflect the impacts iof IFRS not refelcted in the Budget 2017 fiscal plan.
Table below outlines OPG IFRS Risks versus what is built into the Fiscal Plan.

	2017-18	2018-19	2019-20	2020-21
OPG IFRS Risk	(400)	(475)	(700)	(750)
Risks Built into Fiscal Plan	(400)	0	(200)	0
Additional Risks to be picked up	0	(475)	(500)	(750)

Electricity Sector Outlook (PSAB)

Positive Revenue Risks				
($ millions)	**Plan**			
	2017-18	**2018-19**	**2019-20**	**2020-21**
Generic				
OPG Generation Risk: Nuclear Reliability (+1.1 TWh)[1]	85	85	85	85
1% increase in Hydro One actual load[2]	57	59	61	63
Higher OPG Return on Equity (ROE)[3]	6	22	19	33
Higher Hydro One Return on Equity (ROE)[4]	19	69	50	50
Regulatory				
Hydro One Motion to Review OEB Transmission ruling[5]	40	54	41	43
OEB decision on Hydro One tax recapture (if one-time write-down)[6]		6	7	10
Other Risks				
ONFA adjustment increase (as of September 2017 Q3)[7]	171			

zation strategy or updates to AO strategy.

1. OPG's market and generation risks related to nuclear reliability similar to the scenarios OPG developed for its sales margins to capture major market risk factors (e.g., natural gas prices, coal prices, foreign exchange, nuclear reliability) in its 2012 business plan. Currently, only the nuclear reliability risk is captured at the current regulated rate for OPG's nuclear generation.

2. Estimated revenue impact if Hydro One load for Transmission and Distribution is 1% higher than projected for all years in CEFD Hydro One Forecast. Based on the assumption a 1% increase in load is directly proportional to a 1% change in revenue requirements.

3. Risk range for OPG reflects potential risk of higher ROE in 2018-2021 (for nuclear base) vs assumed ROE in OPG's 2016 business plan and corresponding rate application. Assumed ROE is 9.85%, respresenting recent in 2010.

4. Risk range for Hydro One transmission and distribution reflects potential risk of higher ROE vs assumed ROEs in the Hydro One CEFD Forecast for 2018-2021. Assumed ROE is 9.85%, representing recent high in 2010.

5. On October 18, 2017, Hydro One filed a Notice of Motion to Review and vary the Decision and Order dated September 28, 2017. Upside risks based on Hydro One's motions to vary the OEB decision.

6. The OEB's Sep. 28, 2017 ruling on Hydro One's Transmission rate application included direction on sharing, with ratepayers, tax savings related to the Hydro One IPO. The estimated annual ongoing impact of this is factored into the current outlook. This risk reflects the impact if a decision is made by Hydro One that the impact of the ruling has to be accounted for as an immediate one-time write-down.
Note: Corresponding Negative Revenue Risks would also need to be incorporated for 2017-18 if this risk is to be recognized

7. Reflects consolidation adjustment to OPG net income, whereby the realized portion of gains or losses of OPG's nuclear funds are added or subtracted from OPG net income.

ONTARIO ELECTRICITY FINANCIAL CORPORATION

On Deck Outlook as of March 2017

$ Millions

	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Revenue						
Revenue Pool Residual						
Debt Retirement Charge	859	625	623	-	-	-
Payments-in-lieu of tax:						
OPG	268	302	315	366	408	537
Legacy Hydro One (Including Brampton)	2,929	7	2	2	2	2
Hydro One CIT dedicated to OEFC	3	20	20	22	23	25
MEUs	27	44	68	86	105	114
Total PILs & CIT dedicated to OEFC[1]	3,228	373	405	476	538	679
Interest :						
OPG	173	179	168	153	135	135
H1						
IESO	2	3	3	3	3	3
Province	520	492	492	492	492	492
Other	28	10	5	5	5	5
Total Interest	723	684	668	653	635	635
Power Supply Contract Recoveries	875	739	292	325	301	273
Amortization of NUG liability	172	129	74	41	30	28
Electricity sector dedicated income	3	342	525	-	-	-
Gain to OEFC under s. 50.3	172	-	-	-	-	-
Miscellaneous	9	-	-	-	-	-
	6,041	2,893	2,587	1,495	1,504	1,615
Expense						
Debt interest	1,319	1,216	1,090	1,027	977	885
Interest on nuclear risk funding						
Demand Management Support Costs	8	10	10	-	-	-
Amortization of deferred debt costs	-	-	-			
Power Supply Contract Costs	875	739	292	325	301	273
Debt Guarantee fee	127	122	102	91	88	81
Operating	7	6	6	6	6	6
	2,336	2,093	1,500	1,449	1,372	1,245
Excess (Deficiency) of Revenue over Expense	**3,705**	**800**	**1,087**	**46**	**132**	**370**
Prior period adjustment	87					
Stranded Debt - Year End	**4,393**	**3,593**	**2,506**	**2,460**	**2,328**	**1,958**

Note: All the Hydro One ownership broadening impacts, other than the ownership change from the initial IPO in 2015 [and the secondary offering in April 2016], are in the asset optimisation line (Sales and Rentals) and not in the current Outlook file.

ONTARIO ELECTRICITY FINANCIAL CORPORATION

On Deck Outlook as of October 2017 **$ Millions**

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Revenue						
Revenue Pool Residual						
Debt Retirement Charge	859	621	623	0	0	0
Payments-in-lieu of tax:						
OPG	268	224	299	378	411	539
Legacy Hydro One (Including Brampton)	2,929	4	2	2	2	2
Hydro One CIT dedicated to OEFC	3	25	12	13	13	13
MEUs	27	112	68	86	105	114
Total PILs & CIT dedicated to OEFC[1]	3,228	364	381	479	531	668
Interest :						
OPG	173	167	169	179	175	148
H1						
IESO	2	2	3	3	3	3
Province	520	514	454	454	454	454
Other	28	20	20	20	10	10
Total Interest	723	703	646	656	642	615
Power Supply Contract Recoveries	875	838	292	325	301	273
Amortization of NUG liability	172	129	74	41	30	28
Electricity sector dedicated income	3	302	140	0	0	0
Gain to OEFC under s. 50.3[2]	172	411	550	0	0	0
Miscellaneous	9	14	0	0	0	0
	6,041	3,382	2,706	1,501	1,504	1,585
Expense						
Debt interest	1,319	1,216	1,121	1,094	1,053	963
Interest on nuclear risk funding						
Demand Management Support Costs	8	8	10	0	0	0
Amortization of deferred debt costs	0	0	0			
Power Supply Contract Costs	875	838	292	325	301	273
Debt Guarantee fee	127	122	102	91	88	81
Operating	7	7	6	6	6	6
	2,336	2,191	1,531	1,516	1,448	1,323
Excess (Deficiency) of Revenue over Expense	3,705	**1,191**	**1,175**	**(15)**	**56**	**261**
Prior period adjustment	87					
Stranded Debt - Year End	4,393	**3,202**	**2,027**	**2,042**	**1,985**	**1,724**

1

Payments-in-lieu of tax:	2015-16 Public Accounts
OPG	290
Legacy Hydro One (Including Brampton)	2,941
Hydro One CIT dedicated to OEFC	0
MEUs	15
	3,247

2 **2017-18 value preliminary estimate, subject to change.**

ONTARIO ELECTRICITY FINANCIAL CORPORATION

Changes from Budget 2017 as of October 2017 **$ Millions**

	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Revenue						
Debt Retirement Charge	(4)	-	-	-	-	
Payments-in-lieu of tax:						
OPG	(78)	(16)	12	4	2	2016-17 variance is largely due to method of reporting OPG PILs by OEFC and OPG.
Legacy Hydro One (Including Brampton)	(3)	-	-	-	-	
Hydro One CIT dedicated to OEFC	5	(8)	(9)	(10)	(12)	Adjustment based on updated information in Hydro One rate application
MEUs	68	-	-	-	-	Large increase in 2016-17 from $80M payment during transfer of H01 Brampton to new consolidated MEU Alectra.
Total PILs	(9)	(24)	3	(7)	(10)	
Interest :						
OPG	(12)	1	26	40	13	Update to OPG interest outlook (wrt interest on OEFC loan).
H1	-	-	-	-	-	
IESO	(1)	-	-	-	-	
Province	22	(38)	(38)	(38)	(38)	2016-17 PDI at ($514m) was slightly larger than ($492m) projected at Interim. 2017-18 change reflects revised projections for Provincial debt interest related to Hydro equity.
Other	10	15	15	5	5	
Total Interest	19	(22)	3	7	(20)	
Power Supply Contract Recoveries	99	(0)	(0)	(0)	0	Variance is largely due to retroactive payments that the OEFC made to certain non-utility-generators (NUGs) with former Ontario Hydro power purchase agreement contracts with OEFC. OEFC was required to make these payment following the dismissal by the Supreme Court of Canada of OEFC's application for leave to appeal a judgment of the Court of Appeal of Ontario on a 2015 court decision.
Amortization of NUG liability	0	(0)	(0)	(0)	(0)	
Electricity sector dedicated income	(41)	(385)	-	-	-	Changes to ESDI (offset ny MoF Provision expense) largely reflect combined revisions to OPG and Hydro One net income and revisions to public debt intetest.
Gain to OEFC under s. 50.3	411	550	-	-	-	
Miscellaneous	14	-	-	-	-	
	489	119	6	(0)	(30)	
Expense						
Debt interest	-	31	67	76	78	Revised outlook for OEFC debt interest outlook
Interest on nuclear risk funding	-	-	-	-	-	
Demand Management Support Costs	(2)	-	-	-	-	
Amortization of deferred debt costs	-	-	-	-	-	
Power Supply Contract Costs	99	(0)	(0)	(0)	0	Same as Power supply contract recoveries above. Power supply contract costs are fully recovered by power supply contract recoveries.
Debt Guarantee fee	-	-	-	-	-	
Operating	1	-	-	-	-	
	98	31	67	76	78	
Excess (Deficiency) of Revenue over Expense	**391**	**88**	**(61)**			
Stranded Debt - Year End	**3,202**	**2,027**	**2,042**	**1,985**	**1,724**	

Provision for Electricity Sector (Dedicated Electricity Earnings/Electricity Sector Dedicated Earnings)

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Income from Investment in Government Business Enterprises						
OPG Income	291	299	147	720	608	1,041
Hydro One Income[1]	232	501	447	484	566	612
Hydro One Brampton (if applied separately)		15				
Total Income	**523**	**815**	**594**	**1,204**	**1,174**	**1,654**
Public Debt Interest - Electricity Sector						
OPG			(300)	(300)	(300)	(300)
Hydro One[1]			(154)	(154)	(154)	(154)
Public Debt Interest - Electricity Sector (OEFC Interest revenue)	**(520)**	**(514)**	**(454)**	**(454)**	**(454)**	**(454)**
MOF Provision Expense (before adjustments)	**3**	**302**	**140**	**750**	**720**	**1,199**
Other Adjustments						
Prior-year Adjustment[2]		3				
Exclude Brampton[3]		(15)				
MOF Provision Expense (after other adjustments)	**0**	**290**	**140**	**750**	**720**	**1,199**
Cumulative Shortfall Adjustment						
Opening Balance	0	0	0	0	0	0
Deduction / (Addition)	0	0	0	0	0	0
Ending Balance	0	0	0	0	0	0
Dedicated Electricity Earnings (all adjustments) (Public Accounts)	**0**	**290**	**140**	**750**	**720**	**1,199**
Electricity Sector Dedicated Income (OEFC Annual Report)	**3**	**302**	**140**			

Notes:

1. The Hydro One financials above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering are currently reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

2. 2016-17 Adjustment was due to the discrepancy between the numbers in MOF expense in PA 2015-16 and OEFC Financials in 2015-16 due to timing issues. $3M adjustment rectifies this discrepancy

3. Brampton was excluded from the Ministry of Finance's ESDI allocation.

Ontario Power Generation

OPG Income - Budget 2017

$ Millions

	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
OPG Net Income After Tax (Adjusted)	291	304	97	732	625	1,066
OPG Net Income After Tax	*291*	*379*	*480*	*678*	*726*	*913*
Extraordinary Gains	-	-	-	-	-	-
GA - OPG Trust Interest Revenue			*17*	*54*	*99*	*153*
OPG IFRS consolidation risk picked up in Fiscal Plan		(75)	(400)		(200)	
ONFA and other Fair Value Adjustments	(75)	8				
ONFA Adjustments	-	8				
Other Fair Value Adjustments	(75)					

OPG PIL - Budget 2017

$ Millions

	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Net Income Before Tax	383	396	572	867	795	1364
Net Income After Tax (Adjusted)	291	304	97	732	625	1066
Income Taxes	92	92	92	135	170	298
GRC: Payable to OEFC	198	196	205	212	219	220
Proxy Property Tax	16	14	18	19	19	19
Ontario Capital Tax	0	0	0	0	0	0
Total	**306**	**302**	**315**	**366**	**408**	**537**

OPG Income - October 2017

$ Millions

	Actual	Actual	Current Outlook			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
OPG Net Income	291	377	818	678	726	913
Adjustment for OPG HQ gain on sale[1]			(283)			
Extraordinary Gains	0	0	0	0	0	0
GA Financing - OPG Trust Interest Revenue[2]			12	42	82	128
OPG IFRS consolidation risk reflected in Fiscal Plan[3]		(78.00)	(400)		(200)	
OPG Net Income (Adjusted before ONFA)	**291**	**299**	**147**	**720**	**608**	**1,041**
ONFA Adjustments	247	49				
Other Fair Value Adjustments	(75)	(6)				
ONFA and other Fair Value Adjustments	**172**	**43**				
OPG Net Income	**463**	**342**	**147**	**720**	**608**	**1,041**

OPG PIL - August 2017

$ Millions

	Actual	Actual	Current Outlook			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Income Before Tax	383	308	684	855	778	1340
OPG Net Income (Adjusted before ONFA)	291	299	147	720	608	1041
OPG Income Tax (PILs)	92	9	162	135	170	298
Tax adjustment for OPG HQ gain on sale[1]			(95)			
GRC: Payable to OEFC	198	201	214	224	222	222
Proxy Property Tax to OEFC	16	14	18	19	19	19
Ontario Capital Tax	0	0	0	0	0	0
Total OPG PILs	**306**	**224**	**299**	**378**	**411**	**539**

1. As part of Asset Optimization Plan the projected proceeds are currently reported in OEP/MoF Sales and Rentals line. To be re-categorized after the transaction is completed and in coordination with OEP and SIFB.
2. This reflects interest earnings on GA financing costs which are consolidated back to Province
3. See Risks tab for IFRS impacts that were not reflected in Fiscal Plan, and table below.

	2017-18	2018-19	2019-20	2020-21
OPG IFRS Risk	(400)	(475)	(700)	(750)
Risks Built into Fiscal Plan	(400)	0	(200)	0
Additional Risks to be picked up	0	(475)	(500)	(750)

Hydro One Net Income and PILs

Hydro One Income - Budget 2017
($ millions)

	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Hydro One Net Income After Tax	685	737	742	802	862	931
Hydro One - Unrealized Gains Adjustment						

2016-17 to 2020-21 from CEFD Hydro One 2016 model.

Hydro One PIL - Budget 2017
($ millions)

	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Net Income After Tax	685	737	742	802	862	931
Income Taxes PILs	132	160	181	205	212	225
Proxy Property Tax	2	2	2	2	2	2
Ontario Capital Tax	0	0	0	0	0	0
Total	**134**	**162**	**183**	**207**	**214**	**227**

Hydro One (Post IPO Scenario) - Budget 2017
($ millions)

	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Assumed Provincial share		70.0%	70.0%	70.0%	70.0%	70.0%
Hydro One Net Income	236	516	520	562	603	652
Brampton Net Income	20	15				
Hydro One PILs		0	0	0	0	0
Hydro One CIT	3	20	20	22	23	25
Brampton PILs		5				
Proxy Property Tax		2	2	2	2	2
Total	**2886**	**27**	**22**	**24**	**25**	**27**

Hydro One Income - October 2017
($ millions) — $ Millions

	Actual	Actual	Current Outlook			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Hydro One Net Income After Tax			623	666	753	818
Debenture Costs Impacts (After Tax)			(34)	(39)		
Hydro One Net Income After Tax - Including Adjustments	670	680	589	627	753	818
Hydro One - Net Income Attributable to Preferred Shareholders	15	18				
Hydro One - Unrealized Gains Adjustment						

2017-18 to 2020-21 from CEFD Hydro One 2016 model.

Hydro One (100% Ownership)
($ millions) — $ Millions

	Actual	Actual	Current Outlook			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Net Income After Tax - Common Shares	670	680	589	627	753	818
Net Income After Tax - Preferred Shares	15	18				
Income Taxes PILs	132	160	181	205	212	225
Proxy Property Tax	2	2	2	2	2	2
Ontario Capital Tax	0	0	0	0	0	0
Total	**134**	**162**	**183**	**207**	**214**	**227**

Hydro One (Post IPO Scenario) - March 2017
$ Millions

	Actual	Actual	Current Outlook			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Assumed Provincial share		70.1%	70.1%	70.1%	70.1%	70.1%
Net Income After Tax - Common Shares	670	680	589	627	753	818
Net Income After Tax - Preferred Shares	15	18	18	18	18	18
adjustment for lower Provincial share		(204)	(177)	(188)	(225)	(245)
Hydro one IPO-related and other adjustments*	(449)					
Hydro One IFRS Adjustment to Province		7				
OPCD adjustment for Equity advances		(2)				
Adjust OEB decision/rebasing to ~50% provincial ownership**			16	27	21	22
Hydro One - Unrealized Gains Adjustment						
Total Hydro One Income - Province	**236**	**500**	**447**	**484**	**566**	**612**
Brampton Net Income - For Provision/ESDI	20	15				
other adjustments	(24)	2				
Combined Income for ESDI	232	501	447	484	566	612
Brampton Net Income - Public Accounts	**20**	**18**				
Hydro One PILs		2				
Proxy Property Tax		2	2	2	2	2
Brampton PILs						
Hydro One CIT	3	25	12	13	13	13
Total H1 PILs (incl. CIT)		29	14	15	15	15
Total H1 PILs (excl CIT)		4	2	2	2	2
Total	**2,886**	**29**	**14**	**15**	**15**	**15**

* Hydro one IPO-related and other adjustments	2015-16
Deferred Tax Asset (Post IPO Portion)- 100%	(2,619)
Deferred Tax Asset (Pre IPO Portion) - 100%	(191)
Deferred Tax Asset - Province	2,392
Loss of H1 Net Income	(50)
Consolidation adjustment	19

** An adjustment is made for OEB decision and rebasing impacts to show them at about 50% Provincial allocation, pending recategorization of AO amounts from Sales and Rentals.

Hydro One 2015-16 Net Income Estimation (USGAAP) ($M)

Q2 2015[1]	Q3 2015[2]	Q4 2015[1]	Q1 2016[2]	Fiscal Year 2015-16
131	188	143	208	**670**
	9		6	**15**

2016	Q1 2017	cal Year 2016-17
721	167	**680**
19	5	**18**

2015-16 PILs Estimation (Accounting Numbers)	Exc. B	Inc. B
2015 Income Tax	105	105
Q1 2016 Income Tax	33	33
Q1 2015 Income Tax	(45)	(45)
Income Taxes PILs	93	93
Departure Tax	2,600	2,600
Additional PILs	191	191
Brampton PILs	(4)	
Proxy Property Tax	2	2
Total	**2882**	**2886**

Public Debt Interest and Section 50.3 payments

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Hydro One Public Debt Interest and Section 50.3 payments						
Government Annual Interest Costs - Hydro One	220	220	220	220	220	220
Reduction in Interest Costs due to Broadening[1]		(29)	(66)	(66)	(66)	(66)
Province Annual Interest Costs - Hydro One Debt	**220**	**191**	**154**	**154**	**154**	**154**
Province Annual Interest Cost - OPG Debt	300	300	300	300	300	300
Total Public Debt Interest	**520**	**514**	**454**	**454**	**454**	**454**

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Gain to OEFC under s. 50.3	172	411	550	0	0	0

1. The Hydro One reduction in interest costs above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering are currently reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

PROVINCIAL CONSOLIDATION ADJUSTMENTS
Ontario Nuclear Funds Agreement

	2015-16	2016-17	2017-18
Adjustment for Change in OPG Reported Net Income			
Adjustment for DSF Unrealized Earnings			
Unrealized Earnings as at beginning of year	0	0	
Unrealized Earnings as at fiscal year end / latest quarter	(175)	0	
Bruce Variance Account Adjustment	(82)	0	
OPG Net Income Adjustment	(93)	0	
Adjustment for UFSF Unrealized Earnings			
Unrealized Earnings as at beginning of year	0	0	
Unrealized Earnings as at fiscal year end / latest quarter	(82)	56	
Bruce Variance Account Adjustment	(42)	28	
OPG Net Income Adjustment	(40)	28	
Unrealized Earnings -- Fiscal YTD	**(133)**	**28**	
Adjustment for Change in Due to Province			
Adjustment for DSF Due to Province			
Due to Province (cost basis) as at beginning of year	0	39	
Unrealized Earnings as at fiscal year end / latest quarter	39	79	
Change in Due to Province -- Fiscal YTD	**39**	**40**	
Adjustment for UFSF Due to Province			
Due to Province (cost basis) as at beginning of year	295	370	
Unrealized Earnings as at fiscal year end / latest quarter	370	407	
Change in Due to Province -- Fiscal YTD	**75**	**37**	
Provincial Consolidation Adjustment	**247**	**49**	

Other Data

	Actual	Plan			
	2016-17	2017-18	2018-19	2019-20	2020-21
Debt Retirement Charge	621	0	0	0	0

	Plan				
	2016-17	2017-18	2018-19	2019-20	2020-21
Power Supply Contract Recoveries	838	292	325	301	273

	Plan				
	2016-17	2017-18	2018-19	2019-20	2020-21
Interest					
OPG	167	169	179	175	148
IESO	2	3	3	3	3
Other (Net)	20	20	20	10	10
Expense					
Debt interest	1216	1121	1094	1053	963

	Actual	Plan			
	2016-17	2017-18	2018-19	2019-20	2020-21
MEU - PIL Income Tax	109.8				
MEU - PIL Property Tax	0.6				
MEU - GRC	1.2				
TOTAL MEU PILs	111.6				

	Actual	Plan			
	2016-17	2017-18	2018-19	2019-20	2020-21
Miscellaneous/Other (OEFC FS)	14				
Demand Management Support Costs (IEI)	8	10			
Operating [Expense]	7	6	6	6	6
Interest on nuclear risk funding	-	-	-	-	-
Amortization of deferred debt costs	-	-	-	-	-
Amortization of NUG liability	129	74	41	30	28
Debt Guarantee Fee	122				

Expense (Electrictiy Summary Tab)					
Other (Finance)	-7	-6	-6	-6	-6
Demand Management Support Costs (IEI)	-8	-10			
Debt Guarantee Fee	(122)				

OFHP debt and interest projections, by calendar year

$ nominal million	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
FAA w/ Interest, Fees, Readjustment Principle Recovery, Readjustment*	- 1,396	- 2,189	- 2,296	- 2,414	- 2,204	- 1,700	- 1,050	- 492	- 61	79	129	354	714	1,251	1,188	1,348	1,419	1,901	2,087	2,128	2,062	2,099	1,796	1,527	1,392	1,379	1,310	1,341	1,357	1,526	2,034
Interest Paid	32	116	225	343	466	577	667	733	778	814	851	883	896	888	872	854	830	791	736	673	607	540	475	420	372	326	279	231	179	121	45
Closing Debt Balance	1,428	3,734	6,254	9,011	11,681	13,958	15,674	16,899	17,677	18,491	19,342	19,904	19,904	19,541	19,226	18,732	18,143	17,033	15,682	14,227	12,773	11,214	9,893	8,786	7,766	6,713	5,682	4,571	3,394	1,989	0

*Delta between IESO GA cost forecast and Total GA paid by ratepayer, inclusive of interest
Notes: model assumes interest rate of 4.5% and data is exclusive of OPG financing fees

Date: October 19, 2017
Source: Ministry of Energy

From:	John Kim
To:	Ronald Kwan
Subject:	FW: FHP - OPG Performance Fee
Date:	Wednesday, July 05, 2017 2:08:25 PM
Attachments:	GA - Performance Fee Calculation v2.xlsx

Hi Ron,

This is not intended to challenge anyone's figure but to get a sense of where the numbers are.

All said, we would benefit from updated estimates for everything, i.e. interest rate, GA forecast, etc. but roughly $1.2 mn likely is a fair number.

John

From: Ronald Kwan
Sent: Wednesday, July 05, 2017 12:08 PM
To: John Kim <John.Kim@ofina.on.ca>
Subject: FW: FHP - OPG Performance Fee

From: Ken Kandeepan
Sent: July-05-17 11:59
To: Scott Nelms (ENERGY) <Scott.Nelms@ontario.ca>
Cc: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; Carlos Yep <Carlos.Yep@ofina.on.ca>; Graham Monroe <Graham.Monroe@ofina.on.ca>; Mike Manning <Mike.Manning@ofina.on.ca>; James Devine <James.Devine@ofina.on.ca>; Veinot, Cindy (TBS) <Cindy.Veinot@ontario.ca>
Subject: FHP - OPG Performance Fee

Hi Scott

I am writing this to you as an FYI since there may be some push back from OPG. I am cc'ing Cindy as well given the accounting implications raised by OPG. As you may be aware, OPG provided us with the proposed methodology for computing the performance fee. Both the benchmark and the actual include the 44% debt issued by OPG to the Trust which is in turn fully funded by the Province's equity injection.

Given that there are no capital market decision-making associated with this component of the debt, we are reluctant to sign off on OPG's methodology in its current form. OPG is not particularly happy with our response and posits that the accounting treatment requires a performance fee. While I agree that the E&Y opinion does refer to a performance fee I am a little doubtful that E&Y specified that all of the debt should be part of the computation. I have requested that OPG provide me with any specific reference by E&Y on the performance fee methodology. If E&Y does require that the benchmark and actual include the total debt issuance, we can reconsider our stance.

Finally, the performance fee methodology computes the fee for a particular year by applying the difference between the benchmark and the actual on the 5% that is borrowed by OPG. We requested and obtained confirmation that the performance fee will be limited to new borrowings by OPG and not apply to any refinancing. OPG finds this acceptable and it also ensures that the performance fee will be capped at $1.2 million or so per annum.

Thanks

Ken k

Base

Z:\Users\CEF\Hydro 2017\Electricity Prices\Mitigation Proposals\De

Global Impacts	
$ nominal million	
IESO GA Forecast + Extrapolation	
Ratepayer GA Payment	
Accumulated Debt	
Interest on debt in previous period	

Note: Assumes all interest is paid for by ratepayers and not accumulated.

Incremantal Debt	
Total Debt	
Applicable Total Debt	

	Total Debt	
Capital Markets	Tranche A	51%
OPG via OEFC (Province Equity)	Tranche B	39%
OPG via OEFC (Province Equity)	Tranche C1	5%
OPG via Capital Markets	Tranche C2	5%

Total Debt, Tranche A + Tranche C2	
Payout of Performance based on Spread =	1%
Payout - 5% of Total Debt, OPG Investment	**5%**

Total
Annual Max

Note: Assumes all interest is accumulated and refinanced.

Incremantal Debt	
Total Debt	
Applicable Total Debt	

	Total Debt	
Capital Markets	Tranche A	51%
OPG via OEFC (Province Equity)	Tranche B	39%
OPG via OEFC (Province Equity)	Tranche C1	5%
OPG via Capital Markets	Tranche C2	5%

Total Debt, Tranche A + Tranche C2	
Payout of Performance based on Spread =	1%
Payout - 5% of Total Debt, OPG Investment	**5%**

Total
Annual Max

ebt Financing the GA\GA Structure\GA and OPG Modelling (TBS)

2017-May	2017-Nov	2018-May	2018-Nov	2019-May	2019-Nov	2020-May	2020-Nov	2021-May
5832	6172	5706	6029	5570	6199	5867	5835	5228
4596	4926	4469	4787	4339	4738	4303	4403	3875
1267	2544	3846	5185	6547	8174	9944	11627	13274
0	32	64	97	131	165	206	251	294

1267	1246	1237	1242	1231	1461	1564	1432	1353
1267	2512	3749	4992	6223	7684	9248	10680	12033
1267	2512	3749	4992	6223	7684	9248	10680	12033

646	1281	1912	2546	3174	3919	4716	5447	6137
494	980	1462	1947	2427	2997	3607	4165	4693
63	126	187	250	311	384	462	534	602
63	126	187	250	311	384	462	534	602

TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE

709	1407	2100	2795	3485	4303	5179	5981	6738
7.1	14.1	21.0	28.0	34.8	43.0	51.8	59.8	67.4
0.35	**0.70**	**1.05**	**1.40**	**1.74**	**2.15**	**2.59**	**2.99**	**3.37**

132.26
5.65

1267	1278	1301	1340	1362	1627	1770	1683	1647
1267	2544	3846	5185	6547	8174	9944	11627	13274
1267	2544	3846	5185	6547	8174	9944	11627	13274

646	1298	1961	2644	3339	4169	5072	5930	6770
494	992	1500	2022	2553	3188	3878	4535	5177
63	127	192	259	327	409	497	581	664
63	127	192	259	327	409	497	581	664

TRUE	TRUE	TRUE	TRUE	FALSE	TRUE	FALSE	TRUE	TRUE

709	1425	2154	2904	3666	4577	5569	6511	7433
7.1	14.2	21.5	29.0	36.7	45.8	55.7	65.1	74.3
0.35	**0.71**	**1.08**	**1.45**	**1.83**	**2.29**	**2.78**	**3.26**	**3.72**

290.54
7.84

2021-Nov	2022-May	2022-Nov	2023-May	2023-Nov	2024-May	2024-Nov	2025-May	2025-Nov
5541	5127	5369	4939	5616	5365	5551	5076	5277
4162	3883	4195	3893	4712	4635	4795	4420	5004
14988	16611	18204	19710	21112	22376	23697	24951	25855
335	379	420	460	498	533	565	599	630
1379	1244	1174	1046	904	730	756	656	273
13412	14656	15830	16875	17780	18510	19265	19921	20195
13412	14656	15830	16875	17780	18510	19265	19921	20195
6840	7474	8073	8606	9068	9440	9825	10160	10299
5231	5716	6174	6581	6934	7219	7514	7769	7876
671	733	791	844	889	925	963	996	1010
671	733	791	844	889	925	963	996	1010
TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE
7511	8207	8865	9450	9957	10366	10789	11156	11309
75.1	82.1	88.6	94.5	99.6	103.7	107.9	111.6	113.1
3.76	**4.10**	**4.43**	**4.73**	**4.98**	**5.18**	**5.39**	**5.58**	**5.65**
1714	1623	1593	1506	1402	1264	1321	1254	904
14988	16611	18204	19710	21112	22376	23697	24951	25855
14988	16611	18204	19710	21112	22376	23697	24951	25855
7644	8472	9284	10052	10767	11412	12085	12725	13186
5845	6478	7100	7687	8234	8727	9242	9731	10083
749	831	910	986	1056	1119	1185	1248	1293
749	831	910	986	1056	1119	1185	1248	1293
TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE
8393	9302	10194	11038	11823	12530	13270	13973	14479
83.9	93.0	101.9	110.4	118.2	125.3	132.7	139.7	144.8
4.20	**4.65**	**5.10**	**5.52**	**5.91**	**6.27**	**6.64**	**6.99**	**7.24**

2026-May	2026-Nov	2027-May	2027-Nov	2028-May	2028-Nov	2029-May	2029-Nov	2030-May
4838	5551	5324	5640	5216	5317	4826	5082	4687
4878	5566	5464	6036	5892	6304	5861	6121	5742
26467	27121	27666	27969	28000	27721	27386	27038	26667
653	669	685	699	707	707	700	692	683
-41	-15	-140	-396	-675	-987	-1035	-1040	-1055
20154	20139	19999	19603	18928	17941	16906	15866	14812
20154	20139	19999	19603	18928	17941	16906	15866	14812
10278	10271	10199	9997	9653	9150	8622	8092	7554
7860	7854	7800	7645	7382	6997	6593	6188	5777
1008	1007	1000	980	946	897	845	793	741
1008	1007	1000	980	946	897	845	793	741
TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE
11286	11278	11199	10978	10599	10047	9467	8885	8295
112.9	112.8	112.0	109.8	106.0	100.5	94.7	88.9	82.9
5.64	**5.64**	**5.60**	**5.49**	**5.30**	**5.02**	**4.73**	**4.44**	**4.15**
613	654	545	303	31	-279	-335	-348	-371
26467	27121	27666	27969	28000	27721	27386	27038	26667
26467	27121	27666	27969	28000	27721	27386	27038	26667
13498	13832	14110	14264	14280	14138	13967	13789	13600
10322	10577	10790	10908	10920	10811	10680	10545	10400
1323	1356	1383	1398	1400	1386	1369	1352	1333
1323	1356	1383	1398	1400	1386	1369	1352	1333
TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE
14822	15188	15493	15662	15680	15524	15336	15141	14933
148.2	151.9	154.9	156.6	156.8	155.2	153.4	151.4	149.3
7.41	**7.59**	**7.75**	**7.83**	**7.84**	**7.76**	**7.67**	**7.57**	**7.47**

2030-Nov	2031-May	2031-Nov	2032-May	2032-Nov	2033-May	2033-Nov	2034-May	2034-Nov
4658	4173	4540	4253	4362	3972	4096	3740	3279
5714	5241	5614	5342	5456	5081	5207	4865	4397
26285	25880	25460	25015	24553	24065	23562	23032	22496
674	664	654	643	632	620	608	595	582
-1055	-1069	-1074	-1089	-1093	-1109	-1111	-1125	-1118
13756	12688	11614	10525	9432	8323	7213	6087	4970
13756	12688	11614	10525	9432	8323	7213	6087	4970
7016	6471	5923	5368	4810	4245	3678	3105	2535
5365	4948	4530	4105	3678	3246	2813	2374	1938
688	634	581	526	472	416	361	304	248
688	634	581	526	472	416	361	304	248
TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE
7704	7105	6504	5894	5282	4661	4039	3409	2783
77.0	71.1	65.0	58.9	52.8	46.6	40.4	34.1	27.8
3.85	**3.55**	**3.25**	**2.95**	**2.64**	**2.33**	**2.02**	**1.70**	**1.39**
-382	-405	-420	-446	-461	-488	-503	-530	-536
26285	25880	25460	25015	24553	24065	23562	23032	22496
26285	25880	25460	25015	24553	24065	23562	23032	22496
13405	13199	12985	12757	12522	12273	12017	11746	11473
10251	10093	9930	9756	9576	9385	9189	8983	8774
1314	1294	1273	1251	1228	1203	1178	1152	1125
1314	1294	1273	1251	1228	1203	1178	1152	1125
TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE
14720	14493	14258	14008	13750	13476	13195	12898	12598
147.2	144.9	142.6	140.1	137.5	134.8	131.9	129.0	126.0
7.36	**7.25**	**7.13**	**7.00**	**6.87**	**6.74**	**6.60**	**6.45**	**6.30**

2035-May	2035-Nov	2036-May	2036-Nov	2037-May	2037-Nov	2038-May	2038-Nov
2730	2836	2598	2699	2473	2569	2353	2444
3858	3962	3737	3837	3624	3718	3516	3606
21937	21365	20766	20153	19511	18855	18168	17466
568	554	540	525	509	493	476	459
-1128	-1126	-1139	-1138	-1151	-1149	-1163	-1161
3842	2716	1577	439	-711	-1861	-3023	-4185
3842	2716	1577	439	-711	-1861	-3023	-4185
1960	1385	804	224	0	0	0	0
1498	1059	615	171	0	0	0	0
192	136	79	22	0	0	0	0
192	136	79	22	0	0	0	0
TRUE	TRUE	TRUE	TRUE	FALSE	FALSE	FALSE	FALSE
2152	1521	883	246	0	0	0	0
21.5	15.2	8.8	2.5	0.0	0.0	0.0	0.0
1.08	**0.76**	**0.44**	**0.12**	**0.00**	**0.00**	**0.00**	**0.00**
-559	-572	-599	-613	-642	-656	-686	-702
21937	21365	20766	20153	19511	18855	18168	17466
21937	21365	20766	20153	19511	18855	18168	17466
11188	10896	10591	10278	9951	9616	9266	8908
8555	8332	8099	7860	7609	7353	7086	6812
1097	1068	1038	1008	976	943	908	873
1097	1068	1038	1008	976	943	908	873
TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE
12285	11965	11629	11286	10926	10559	10174	9781
122.8	119.6	116.3	112.9	109.3	105.6	101.7	97.8
6.14	**5.98**	**5.81**	**5.64**	**5.46**	**5.28**	**5.09**	**4.89**

2039-May	2039-Nov	2040-May	2040-Nov	2041-May	2041-Nov	2042-May	2042-Nov
2240	2326	2132	2214	2029	2107	1931	2005
3414	3500	3318	3399	3228	3305	3142	3215
16732	15982	15199	14398	13562	12707	11817	10905
441	423	404	384	364	343	321	299
-1175	-1173	-1187	-1185	-1199	-1198	-1212	-1210
-5359	-6533	-7719	-8905	-10104	-11301	-12513	-13723
-5359	-6533	-7719	-8905	-10104	-11301	-12513	-13723
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0
FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
0	0	0	0	0	0	0	0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.00	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
-733	-751	-783	-801	-835	-855	-891	-911
16732	15982	15199	14398	13562	12707	11817	10905
16732	15982	15199	14398	13562	12707	11817	10905
8534	8151	7751	7343	6917	6481	6026	5562
6526	6233	5928	5615	5289	4956	4608	4253
837	799	760	720	678	635	591	545
837	799	760	720	678	635	591	545
TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE
9370	8950	8511	8063	7595	7116	6617	6107
93.7	89.5	85.1	80.6	75.9	71.2	66.2	61.1
4.69	**4.47**	**4.26**	**4.03**	**3.80**	**3.56**	**3.31**	**3.05**

2043-May	2043-Nov	2044-May	2044-Nov	2045-May	2045-Nov	2046-May	2046-Nov
1837	1909	1749	1816	1664	1729	1584	1645
3061	3131	2985	3052	2914	2977	2846	2906
9957	8986	7976	6942	5868	4768	3626	2456
275	252	227	201	175	148	120	92
-1224	-1223	-1237	-1235	-1250	-1248	-1263	-1261
-14947	-16170	-17406	-18642	-19891	-21139	-22402	-23663
-14947	-16170	-17406	-18642	-19891	-21139	-22402	-23663
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0
FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
0	0	0	0	0	0	0	0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.00	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
-949	-971	-1010	-1034	-1074	-1100	-1142	-1169
9957	8986	7976	6942	5868	4768	3626	2456
9957	8986	7976	6942	5868	4768	3626	2456
5078	4583	4068	3540	2993	2432	1849	1253
3883	3504	3111	2707	2288	1860	1414	958
498	449	399	347	293	238	181	123
498	449	399	347	293	238	181	123
FALSE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE
5576	5032	4466	3888	3286	2670	2030	1376
55.8	50.3	44.7	38.9	32.9	26.7	20.3	13.8
2.79	**2.52**	**2.23**	**1.94**	**1.64**	**1.34**	**1.02**	**0.69**

2047-May	2047-Nov	2048-May	2048-Nov	2049-May	2049-Nov
1507	1566	1434	1490	1365	1418
2783	2840	1434	1490	1365	1418
1243	0	0	0	0	0
62	31	0	0	0	0
-1276	-1274	0	0	0	0
-24939	-26213	-26213	-26213	-26213	-26213
-24939	-26213	-26213	-26213	-26213	-26213
0	0	0	0	0	0
0	0	0	0	0	0
0	0	0	0	0	0
0	0	0	0	0	0
FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
0	0	0	0	0	0
0.0	0.0	0.0	0.0	0.0	0.0
0.00	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
-1214	-1243	0	0	0	0
1243	0	0	0	0	0
1243	0	0	0	0	0
634	0	0	0	0	0
485	0	0	0	0	0
62	0	0	0	0	0
62	0	0	0	0	0
TRUE	TRUE	FALSE	FALSE	FALSE	FALSE
696	0	0	0	0	0
7.0	0.0	0.0	0.0	0.0	0.0
0.35	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

Base - 5-Year Refinancing

Z:\Users\CEF\Hydro 2017\Electricity Prices\Mitigation Proposals\De

Global Impacts	
$ nominal million	
IESO GA Forecast + Extrapolation	
Ratepayer GA Payment	
Accumulated Debt	
Interest on debt in previous period	

Note: Assumes all interest is paid for by ratepayers and not accumulated.

Incremantal Debt	
Total Debt	
Applicable Total Debt	

	Total Debt	
Capital Markets	Tranche A	51%
OPG via OEFC (Province Equity)	Tranche B	39%
OPG via OEFC (Province Equity)	Tranche C1	5%
OPG via Capital Markets	Tranche C2	5%

Total Debt, Tranche A + Tranche C2	
Payout of Performance based on Spread =	1%
Payout - 5% of Total Debt, OPG Investment	**5%**

Total
Annual Max

Note: Assumes all interest is accumulated and refinanced.

Incremantal Debt	
Total Debt	
Applicable Total Debt	

	Total Debt	
Capital Markets	Tranche A	51%
OPG via OEFC (Province Equity)	Tranche B	39%
OPG via OEFC (Province Equity)	Tranche C1	5%
OPG via Capital Markets	Tranche C2	5%

Total Debt, Tranche A + Tranche C2	
Payout of Performance based on Spread =	1%
Payout - 5% of Total Debt, OPG Investment	**5%**

Total
Annual Max

ebt Financing the GA\GA Structure\GA and OPG Modelling (TBS)

2017-May	2017-Nov	2018-May	2018-Nov	2019-May	2019-Nov	2020-May	2020-Nov	2021-May
5832	6172	5706	6029	5570	6199	5867	5835	5228
4596	4926	4469	4787	4339	4738	4303	4403	3875
1267	2544	3846	5185	6547	8174	9944	11627	13274
0	32	64	97	131	165	206	251	294

1267	1246	1237	1242	1231	1461	1564	1432	1353
1267	2512	3749	4992	6223	7684	9248	10680	12033
1267	2512	3749	4992	4956	5172	5499	5688	5810

646	1281	1912	2546	2527	2638	2804	2901	2963
494	980	1462	1947	1933	2017	2144	2218	2266
63	126	187	250	248	259	275	284	290
63	126	187	250	248	259	275	284	290

TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE

709	1407	2100	2795	2775	2896	3079	3185	3254
7.1	14.1	21.0	28.0	27.8	29.0	30.8	31.9	32.5
0.35	**0.70**	**1.05**	**1.40**	**1.39**	**1.45**	**1.54**	**1.59**	**1.63**

22.54
1.63

1267	1278	1301	1340	1362	1627	1770	1683	1647
1267	2544	3846	5185	6547	8174	9944	11627	13274
1267	2544	3846	5185	5280	5629	6099	6442	6727

646	1298	1961	2644	2693	2871	3110	3285	3431
494	992	1500	2022	2059	2195	2378	2512	2623
63	127	192	259	264	281	305	322	336
63	127	192	259	264	281	305	322	336

TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE

709	1425	2154	2904	2957	3152	3415	3608	3767
7.1	14.2	21.5	29.0	29.6	31.5	34.2	36.1	37.7
0.35	**0.71**	**1.08**	**1.45**	**1.48**	**1.58**	**1.71**	**1.80**	**1.88**

31.18
1.91

2021-Nov	2022-May	2022-Nov	2023-May	2023-Nov	2024-May	2024-Nov	2025-May	2025-Nov
5541	5127	5369	4939	5616	5365	5551	5076	5277
4162	3883	4195	3893	4712	4635	4795	4420	5004
14988	16611	18204	19710	21112	22376	23697	24951	25855
335	379	420	460	498	533	565	599	630
1379	1244	1174	1046	904	730	756	656	273
13412	14656	15830	16875	17780	18510	19265	19921	20195
5728	5408	5150	4843	4368	3854	3436	3046	2415
2921	2758	2626	2470	2228	1966	1752	1553	1232
2234	2109	2008	1889	1703	1503	1340	1188	942
286	270	257	242	218	193	172	152	121
286	270	257	242	218	193	172	152	121
TRUE	TRUE	TRUE	TRUE	TRUE	FALSE	TRUE	TRUE	TRUE
3207	3028	2884	2712	2446	2158	1924	1706	1352
32.1	30.3	28.8	27.1	24.5	21.6	19.2	17.1	13.5
1.60	**1.51**	**1.44**	**1.36**	**1.22**	**1.08**	**0.96**	**0.85**	**0.68**
1714	1623	1593	1506	1402	1264	1321	1254	904
14988	16611	18204	19710	21112	22376	23697	24951	25855
6814	6667	6577	6436	6124	5765	5492	5241	4743
3475	3400	3354	3282	3123	2940	2801	2673	2419
2658	2600	2565	2510	2388	2248	2142	2044	1850
341	333	329	322	306	288	275	262	237
341	333	329	322	306	288	275	262	237
TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE
3816	3733	3683	3604	3429	3228	3076	2935	2656
38.2	37.3	36.8	36.0	34.3	32.3	30.8	29.3	26.6
1.91	**1.87**	**1.84**	**1.80**	**1.71**	**1.61**	**1.54**	**1.47**	**1.33**

2026-May	2026-Nov	2027-May	2027-Nov	2028-May	2028-Nov	2029-May	2029-Nov	2030-May
4838	5551	5324	5640	5216	5317	4826	5082	4687
4878	5566	5464	6036	5892	6304	5861	6121	5742
26467	27121	27666	27969	28000	27721	27386	27038	26667
653	669	685	699	707	707	700	692	683
-41	-15	-140	-396	-675	-987	-1035	-1040	-1055
20154	20139	19999	19603	18928	17941	16906	15866	14812
1644	874	78	-592	-1226	-2198	-3093	-3737	-4116
838	446	40	0	0	0	0	0	0
641	341	30	0	0	0	0	0	0
82	44	4	0	0	0	0	0	0
82	44	4	0	0	0	0	0	0
TRUE	TRUE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
921	489	44	0	0	0	0	0	0
9.2	4.9	0.4	0.0	0.0	0.0	0.0	0.0	0.0
0.46	**0.24**	**0.02**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
613	654	545	303	31	-279	-335	-348	-371
26467	27121	27666	27969	28000	27721	27386	27038	26667
4091	3424	2715	2114	1533	600	-280	-931	-1333
2087	1746	1385	1078	782	306	0	0	0
1596	1335	1059	824	598	234	0	0	0
205	171	136	106	77	30	0	0	0
205	171	136	106	77	30	0	0	0
TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	FALSE	FALSE	FALSE
2291	1918	1520	1184	858	336	0	0	0
22.9	19.2	15.2	11.8	8.6	3.4	0.0	0.0	0.0
1.15	**0.96**	**0.76**	**0.59**	**0.43**	**0.17**	**0.00**	**0.00**	**0.00**

2030-Nov	2031-May	2031-Nov	2032-May	2032-Nov	2033-May	2033-Nov	2034-May	2034-Nov
4658	4173	4540	4253	4362	3972	4096	3740	3279
5714	5241	5614	5342	5456	5081	5207	4865	4397
26285	25880	25460	25015	24553	24065	23562	23032	22496
674	664	654	643	632	620	608	595	582
-1055	-1069	-1074	-1089	-1093	-1109	-1111	-1125	-1118
13756	12688	11614	10525	9432	8323	7213	6087	4970
-4184	-4218	-4252	-4287	-4325	-4364	-4402	-4438	-4462
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
0	0	0	0	0	0	0	0	0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.00	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
-382	-405	-420	-446	-461	-488	-503	-530	-536
26285	25880	25460	25015	24553	24065	23562	23032	22496
-1436	-1506	-1578	-1652	-1732	-1815	-1898	-1982	-2057
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
0	0	0	0	0	0	0	0	0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.00	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

2035-May	2035-Nov	2036-May	2036-Nov	2037-May	2037-Nov	2038-May	2038-Nov
2730	2836	2598	2699	2473	2569	2353	2444
3858	3962	3737	3837	3624	3718	3516	3606
21937	21365	20766	20153	19511	18855	18168	17466
568	554	540	525	509	493	476	459
-1128	-1126	-1139	-1138	-1151	-1149	-1163	-1161
3842	2716	1577	439	-711	-1861	-3023	-4185
-4481	-4496	-4510	-4530	-4554	-4577	-4601	-4624
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0
FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
0	0	0	0	0	0	0	0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.00	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
-559	-572	-599	-613	-642	-656	-686	-702
21937	21365	20766	20153	19511	18855	18168	17466
-2128	-2197	-2266	-2343	-2426	-2511	-2598	-2687
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0
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FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
0	0	0	0	0	0	0	0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.00	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

2039-May	2039-Nov	2040-May	2040-Nov	2041-May	2041-Nov	2042-May	2042-Nov
2240	2326	2132	2214	2029	2107	1931	2005
3414	3500	3318	3399	3228	3305	3142	3215
16732	15982	15199	14398	13562	12707	11817	10905
441	423	404	384	364	343	321	299
-1175	-1173	-1187	-1185	-1199	-1198	-1212	-1210
-5359	-6533	-7719	-8905	-10104	-11301	-12513	-13723
-4648	-4672	-4696	-4720	-4744	-4769	-4794	-4818
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0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0
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FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
0	0	0	0	0	0	0	0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.00	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
-733	-751	-783	-801	-835	-855	-891	-911
16732	15982	15199	14398	13562	12707	11817	10905
-2779	-2873	-2969	-3068	-3170	-3275	-3382	-3492
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0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0
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FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
0	0	0	0	0	0	0	0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.00	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

2043-May	2043-Nov	2044-May	2044-Nov	2045-May	2045-Nov	2046-May	2046-Nov
1837	1909	1749	1816	1664	1729	1584	1645
3061	3131	2985	3052	2914	2977	2846	2906
9957	8986	7976	6942	5868	4768	3626	2456
275	252	227	201	175	148	120	92
-1224	-1223	-1237	-1235	-1250	-1248	-1263	-1261
-14947	-16170	-17406	-18642	-19891	-21139	-22402	-23663
-4843	-4868	-4893	-4919	-4944	-4970	-4995	-5021
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0
FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
0	0	0	0	0	0	0	0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.00	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
-949	-971	-1010	-1034	-1074	-1100	-1142	-1169
9957	8986	7976	6942	5868	4768	3626	2456
-3606	-3722	-3841	-3963	-4089	-4218	-4350	-4486
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0
FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
0	0	0	0	0	0	0	0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.00	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

2047-May	2047-Nov	2048-May	2048-Nov	2049-May	2049-Nov
1507	1566	1434	1490	1365	1418
2783	2840	1434	1490	1365	1418
1243	0	0	0	0	0
62	31	0	0	0	0
-1276	-1274	0	0	0	0
-24939	-26213	-26213	-26213	-26213	-26213
-5047	-5073	-3811	-2550	-1274	0
0	0	0	0	0	0
0	0	0	0	0	0
0	0	0	0	0	0
0	0	0	0	0	0
FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
0	0	0	0	0	0
0.0	0.0	0.0	0.0	0.0	0.0
0.00	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
-1214	-1243	0	0	0	0
1243	0	0	0	0	0
-4625	-4768	-3626	-2456	-1243	0
0	0	0	0	0	0
0	0	0	0	0	0
0	0	0	0	0	0
0	0	0	0	0	0
FALSE	FALSE	FALSE	FALSE	FALSE	TRUE
0	0	0	0	0	0
0.0	0.0	0.0	0.0	0.0	0.0
0.00	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

From: Ronald Kwan
To: John Kim
Subject: FW: FHP - OPG Performance Fee
Date: Wednesday, July 05, 2017 12:07:34 PM

From: Ken Kandeepan
Sent: July-05-17 11:59
To: Scott Nelms (ENERGY) <Scott.Nelms@ontario.ca>
Cc: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; Carlos Yep <Carlos.Yep@ofina.on.ca>; Graham Monroe <Graham.Monroe@ofina.on.ca>; Mike Manning <Mike.Manning@ofina.on.ca>; James Devine <James.Devine@ofina.on.ca>; Veinot, Cindy (TBS) <Cindy.Veinot@ontario.ca>
Subject: FHP - OPG Performance Fee

Hi Scott

I am writing this to you as an FYI since there may be some push back from OPG. I am cc'ing Cindy as well given the accounting implications raised by OPG. As you may be aware, OPG provided us with the proposed methodology for computing the performance fee. Both the benchmark and the actual include the 44% debt issued by OPG to the Trust which is in turn fully funded by the Province's equity injection.

Given that there are no capital market decision-making associated with this component of the debt, we are reluctant to sign off on OPG's methodology in its current form. OPG is not particularly happy with our response and posits that the accounting treatment requires a performance fee. While I agree that the E&Y opinion does refer to a performance fee I am a little doubtful that E&Y specified that all of the debt should be part of the computation. I have requested that OPG provide me with any specific reference by E&Y on the performance fee methodology. If E&Y does require that the benchmark and actual include the total debt issuance, we can reconsider our stance.

Finally, the performance fee methodology computes the fee for a particular year by applying the difference between the benchmark and the actual on the 5% that is borrowed by OPG. We requested and obtained confirmation that the performance fee will be limited to new borrowings by OPG and not apply to any refinancing. OPG finds this acceptable and it also ensures that the performance fee will be capped at $1.2 million or so per annum.

Thanks

Ken k

From: John Kim
To: Ronald Kwan
Subject: FW: FHP - OPG Performance Fee
Date: Thursday, July 06, 2017 3:37:39 PM
Attachments: RE BN FSM Fees 29 June 2017.docx.msg

There you go. I thought I forwarded to you via iphone but might have not gotten sent.

-----Original Message-----
From: Nelms, Scott (MOF) [mailto:Scott.Nelms@ontario.ca]
Sent: Wednesday, July 05, 2017 4:36 PM
To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>; Veinot, Cindy (TBS) <Cindy.Veinot@ontario.ca>; John Kim <John.Kim@ofina.on.ca>; Carlos Yep <Carlos.Yep@ofina.on.ca>; Nadine Petsche (MOF) <Nadine.Petsche@ontario.ca>
Subject: FW: FHP - OPG Performance Fee

Fee note as discussed. The note focuses on OEB role, but perhaps we should revisit the quantum of the fee. Let me know if you have comments.

Sent with BlackBerry Work
(www.blackberry.com)

From: Calwell, Carolyn (ENERGY/MEDEI/MRI)
<Carolyn.Calwell@ontario.ca<mailto:Carolyn.Calwell@ontario.ca>>
Date: Wednesday, Jul 05, 2017, 1:20 PM
To: Nelms, Scott (MOF) <Scott.Nelms@ontario.ca<mailto:Scott.Nelms@ontario.ca>>, McKinlay, Tom (ENERGY) <Tom.McKinlay@ontario.ca<mailto:Tom.McKinlay@ontario.ca>>
Cc: Montgomery, Kaitlin (MOF) <Kaitlin.Montgomery@ontario.ca<mailto:Kaitlin.Montgomery@ontario.ca>>
Subject: RE: FHP - OPG Performance Fee

I think we are aligned. Does OFA have some suggestions about how to structure the fee? Feel free to float the "option 2" from the note and see if they have suggestions about how to make it better. I haven't yet sent that note up, as I am trying to work in some research that Jackson did (attached for your reference).

From: Nelms, Scott (MOF)
Sent: July-05-17 12:15 PM
To: Calwell, Carolyn (ENERGY/MEDEI/MRI); McKinlay, Tom (ENERGY)
Cc: Montgomery, Kaitlin (MOF)
Subject: FW: FHP - OPG Performance Fee

Fyi – more complications on the fee issue.

From: Ken Kandeepan [mailto:Ken.Kandeepan@ofina.on.ca]
Sent: July 5, 2017 11:59 AM
To: Nelms, Scott (MOF)
Cc: Kwan, Ronald (OFA); Yep, Carlos (OFA); Monroe, Graham (OFA); Manning, Mike (OFA); Devine, James (OFA); Veinot, Cindy (TBS)
Subject: FHP - OPG Performance Fee

Hi Scott

I am writing this to you as an FYI since there may be some push back from OPG. I am cc'ing Cindy as well given the accounting implications raised by OPG. As you may be aware, OPG provided us with the proposed methodology for computing the performance fee. Both the benchmark and the actual include the 44% debt issued

by OPG to the Trust which is in turn fully funded by the Province's equity injection.

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Finally, the performance fee methodology computes the fee for a particular year by applying the difference between the benchmark and the actual on the 5% that is borrowed by OPG. We requested and obtained confirmation that the performance fee will be limited to new borrowings by OPG and not apply to any refinancing. OPG finds this acceptable and it also ensures that the performance fee will be capped at $1.2 million or so per annum.

Thanks

Ken k

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From: Huang, Jackson (MEDG/MRIS) [Jackson.Huang@ontario.ca]
To: Carolyn Calwell (MCSS) [Carolyn.Calwell@ontario.ca]
CC: James Rehob (ENERGY) [James.Rehob@ontario.ca]
Subject: RE: BN FSM Fees 29 June 2017.docx
Date: Tuesday, July 04, 2017 20:59:37

Hi Carolyn,

Further to my earlier email, please see summary of precedents below for your review and consideration, which outlines the consideration and discussions James and I had last week regarding FSM fees:

1. Ontario Nuclear Funds Agreement (ONFA): Not directly applicable.

* ONFA focuses more on the ability of the funds to meet future liabilities. The funds under ONFA are assets set aside for future costs (like a pension fund), and the FSM is managing liabilities to be repaid over time to fund short-term costs. Any performance payments based on the return of funds under the ONFA will not be directly applicable to the management of funding obligations under the OFHPA.

* The fees payable to the fund custodians/fund managers under the ONFA are set out in separate Segregated Fund Custodial Agreements, but we did not find a copy of such agreements. OPG makes contribution to the funds established under the ONFA, but does not seem to manage any of them.

* We found the adjustment mechanism for the fund value of the Used Fuel Segregated Fund (UFSF) established under the ONFA potentially helpful in developing a "cost-plus" strategy for FSM fees:

o Under the ONFA, through the adjustment mechanism, any surplus (where actual fund value > "fixed" fund value) in the UFSF is returned to the Province, and the Province must make further payments to cover any deficits.

o The "fixed" balance of the UFSF (i) covers all costs relating to the management of used nuclear fuel (including any brokerage and management fees for the fund), and (ii) grows by a rate of return equal to the discount rate (which is a fixed rate above inflation, as defined under the ONFA).

* In a proposed "cost-plus" model for FSM fees, the formula could provide for (i) all direct and indirect costs incurred by the FSM; and (ii) a minimum required rate of return set by the OEB (to give OEB meaningful discretion) to provide the FSM with the profit it must receive in order to be given the appropriate accounting treatment.

o The FSM's minimum required rate of return could be expressed:

(i) inversely in relation to the weighted-average interest rate (for example, weighted by dollar amount of each funding obligation) of all new funding obligations incurred during a calendar year; and/or

(ii) as a percentage [fixed under regulation or determined by OEB] of the "surplus" (where present value of all funding obligations discounted at a fixed rate [to be prescribed or determined by OEB] > actual present value of all funding obligations) or "deficit" during a period
[Note: this most closely tracks the adjustment mechanism in ONFA and creates a direct relationship between the FSM fees and the dollar effect of FSM's management; a period can be more than one calendar year which means the FSM fees payable for a calendar year would not change until a triggering event]

2. IESO Rate Order: Not applicable.

* The IESO's business plan for 2016-2018 was first approved by the Minister, and then submitted to the OEB for approval. The same approval process (with business plan first approved by the Minister) does not apply to the FSM.

* The decision, EB-2015-0275, mainly focused on a specific issue in the rate application: whether a single per MWh usage fee should be charged for domestic and export market participants. In its decision, the OEB relied on a cost allocation study to set separate usage fees for export market participants, such that a revenue-to-cost ratio of close to 100% would be achieved for each group of market participants. The OEB accepted IESO's expenses and revenue requirements in the business plan that was approved by the Minister.

* A revenue-to-cost ratio test would not be appropriate for the FSM. A target revenue-to-cost ratio of 100% would not generate any profits/losses for the FSM to meet the accounting requirement.

3. Distribution Rate-Protection Program (DRP). May be useful for setting benchmarks/comparators

* Under this program, OEB has considerable discretion to approve base distribution rates for all distributors serving DRP consumers, and caps the base distribution rate charged to DRP consumers at the lowest among these distributors.

* One way to give OEB meaningful participation in setting FSM fees is to have the regulation prescribe specific comparators (e.g. enumerating specific entities who are seen by Government as appropriate comparators for OPG (e.g. OFA) to benchmark its costs and financial structure against), and allow OEB to determine a "maximum". Beneath that cap, the FSM is able to demonstrate whether or not it has provided the most cost-efficient approach to conduct financing activities (a modified prudence test which provides an outer limit and retains some discretion for the Board to evaluate actual success in meeting economic and other cost-minimization goals).

Please let me know if you have any questions or if you would like to discuss anything.

Thanks,

Jackson

From: Calwell, Carolyn (ENERGY/MEDEI/MRI)
Sent: July-04-17 4:11 PM
To: Huang, Jackson (MEDG/MRIS)
Subject: FW: BN FSM Fees 29 June 2017.docx

Hi Jackson, were you able to find any helpful precedent that might inform how we approach this issue?

Carolyn

From: Rehob, James (ENERGY)
Sent: June-30-17 10:02 AM
To: Nelms, Scott (MOF); Christie, Tim (ENERGY); Cayley, Daniel (ENERGY); O'Riordan, Eamon (ENERGY)
Cc: McKinlay, Tom (ENERGY); Huang, Jackson (MEDG/MRIS); Calwell, Carolyn (ENERGY/MEDEI/MRI); Montgomery, Kaitlin (MOF)
Subject: BN FSM Fees 29 June 2017.docx

Confidential/Solicitor & Client Privileged

June 30, 2017

Good morning, Scott, Tim, Daniel and Eamon. Please find attached LSB's draft note on FSM Fees and options for OEB review and approval. Scott, in particular, we are hoping for your detailed review and comment, if that is possible, by before Tuesday morning, please. We hope to have this note up to ADM/DM on Tuesday.

With best regards,

James and Jackson

James P. H. Rehob

Senior Counsel

Ministry of the Attorney General

Legal Services Branch

MAG Civil Law Division

Ministry of Energy, Ministry of Economic Development and Growth, Ministry of Research, Innovation and Science, Ministry of Infrastructure, Accessibility Directorate of Ontario

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From:	Ken Kandeepan
To:	Ronald Kwan; Mike Manning; John Psinas; John Kim; James Devine; Carlos Yep
Cc:	Anna Strathy
Subject:	FW: Fair Hydro - OPG Fees regulation
Date:	Thursday, September 07, 2017 5:15:08 PM
Attachments:	Blackline - Fees regulation (vs Province Aug 28 Draft).pdf Fees Regulation - Combined Torys and OPG comments - Sep 7 2017.docx

Hi All

Pls note, the draft regulation appears to cover both the performance fee and the asset management fee, let me know if you have any comments on the former and I will consolidate and forward to Dan Shear in Energy who can act as the conduit to OPG. I will also make the point that the asset management fee structure is outside the OFA's scope.

Thanks

Ken k

From: WONG Leslie -LAWDIV [mailto:leslie.wong@opg.com]
Sent: Thursday, September 07, 2017 3:53 PM
To: Dan Shear (ENERGY) <Dan.Shear@ontario.ca>
Cc: Steen Hume (CAB) <Steen.Hume@ontario.ca>; Hilary Cox (ENE) <Hilary.Cox@ontario.ca>; Scott Nelms (ENERGY) <Scott.Nelms@ontario.ca>; James Rehob (ENERGY) <James.Rehob@ontario.ca>; Tom McKinlay (MAG) <Tom.McKinlay@ontario.ca>; Carolyn Calwell (MCSS) <Carolyn.Calwell@ontario.ca>; 'Ramchandani, Rima' <rramchandani@torys.com>; Feldman, Michael <mfeldman@torys.com>; Myers, Jonathan <jmyers@torys.com>; Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>; LIU Sheen -TREASURY <sheen.liu@opg.com>; LEE John -TREASURY <john.s.lee@opg.com>; RYFA Ken -TREASURY <ken.ryfa@opg.com>; LAURETA LAPIRA May -TREASURY <may.lapira@opg.com>; MCAULEY Tyler -LAWDIV <tyler.mcauley@opg.com>
Subject: Fair Hydro - OPG Fees regulation

Dear Dan,

I understand that you will be working on the regulation regarding OPG's management fees under the Fair Hydro program.

Please find attached a draft of the regulation containing combined comments from OPG and our external counsel. Attached are a clean and a blackline against the draft that we received from the Province on August 28

Note that we have aimed to meet the Province's objective to provide the OEB with a meaningful role in reviewing OPG's fees, but within the constraints of the accounting treatment requirements. Based on our discussions with E&Y, the methodology for determining OPG's fees and the scope of OEB's review in the attached meet the accounting treatment requirements. E&Y also confirmed the view that a proposed cost-plus approach with the ability of the OEB to amend the methodology and benchmarks would jeopardize the desired accounting treatment.

Let us know if you have any questions. Once you have had a chance to review, we should set up a call or meeting to discuss.

Note that I have copied Torys as well as Ken Kandeepan at the OFA. Ken had reviewed previous drafts of the fees regulation and we have also contemplated in the regs that the OFA may provide advice to the OEB on the appropriate benchmarks, as has been discussed at recent rate mitigation meetings.

Note that I am out of the country from September 8-14, inclusive, but will be able to check e-mail during my absence.

Regards,

Les

Leslie Wong
Senior Counsel
Ontario Power Generation Inc.
700 University Avenue, H18 G26.1, Toronto, ON M5G 1X6
T: (416) 592-3110 **|** E: leslie.wong@opg.com

From: Calwell, Carolyn (ENERGY/MEDEI/MRI) [mailto:Carolyn.Calwell@ontario.ca]
Sent: Monday, August 28, 2017 5:23 PM
To: LEE John -TREASURY; WONG Leslie -LAWDIV
Cc: Hume, Steen (ENERGY); Cox, Hilary (ENERGY); Nelms, Scott (MOF); Rehob, James (ENERGY); McKinlay, Tom (ENERGY)
Subject: EXTERNAL – Fees regulation

*** Exercise caution. This is an EXTERNAL email. DO NOT open attachments or click links from unknown senders or unexpected email. ***

John, Les – in aid of restarting our discussion about the fees that will be payable to OPG as financial services manager, please find attached a draft regulation. Based on the June drafts we provided, this version reflects the Ministry's view that there must be a meaningful role for the OEB.

John, I am mindful that you flagged concerns that this approach would impair the accounting treatment that OPG is seeking. If that is still the case, then we will need to understand that in more detail. Also, rather than rejecting outright any role for the OEB, it would be helpful if OPG can assist in identifying middle ground.

I understand that there is a desire to talk about this further at the Thursday morning meeting. I would also be happy to talk to you in advance of Thursday's meeting.

Carolyn

Carolyn Calwell
Legal Director
MAG Civil Law Division
Ministries of Energy / Economic Development & Growth /
Research, Innovation & Science / Infrastructure / Accessibility
416-212-8392

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FEES RIDER – subs. 19 (3) of the Act ~~– August 28, 2017~~

(x.1) For the purposes of this section:

1. (1) For the purposes of subsection 19 (3) of the Act, the Financial Services Manager may establish and charge fees to financing entities in relation to the ~~following matters:~~

~~1.~~ ~~The~~ services provided by the Financial Services Manager to financing entities, which may include services related to planning, financing, negotiation and execution of agreements, front office services and administrative services.

~~2. The costs of doing anything that the Financial Services Manager is required or permitted to do under the Act.~~(2) The fees mentioned in subsection (1) shall be calculated annually and shall be comprised of a base fee and a variable fee based on performance.

(~~2) The~~3) In addition to the fees mentioned in subsection (1) ~~may provide for a fixed fee and a variable fee based on performance.~~, the Financial Services Manager shall be entitled to be reimbursed by the applicable financing entity for all out-of-pocket costs and expenses incurred in connection with its duties under the Act or under any management agreement with the applicable financing entity, including, without limitation, the costs and expenses of underwriters or selling agents for funding obligations; banking fees; fees of issuing and paying agents for funding obligations; fees of trustees; fees incurred in the preparation of financial statements, financial reports, compliance certificates and tax returns; fees of legal counsel; government filing or registration fees; and any third-party independent consultants required to be retained under these regulations.

2.~~(1) The fixed fee shall be equal to the reasonable cost of services provided to all financing entities plus a reasonable rate of return.~~ (1)(a) The base fee referred to in subsection 1(2) shall be payable monthly and calculated as follows:

(A x B) / 12

where,

A = a percentage, expressed as a per annum rate, based on market comparable fees charged by service providers for similar services as determined by the Financial Services Manager and subject to review by the Board under section 4, and

B = the average of the opening and closing balances of the aggregate principal amount of outstanding funding obligations issued by all financing entities in the previous calendar month.

Note: Draft language provided for the purpose of instructions to Ontario Legislative Counsel. Final content of regulation is subject to drafting by OLC.

(b) Subject to review by the Board under section 4,

(i) for so long as the outstanding aggregate principal amount of funding obligations of all financing entities is equal to or less than $10 billion and until the end of the calendar year in which such amount exceeds $10 billion, "A" in the formula set out in subsection (1)(a) shall be equal to 10 basis points, or 0.1%, and

(ii) commencing on the first day of the calendar year following the year in which the outstanding aggregate principal amount of funding obligations of all financing entities exceeds $10 billion, "A" in the formula set out in subsection (1)(a) shall be equal to 8 basis points, or 0.08%.

(2) The variable fee referred to in subsection 1(2), shall be calculated as ~~follows~~the sum of the amounts calculated, using the following formula, for all tranches of net incremental funding obligations issued by all financing entities in the relevant year:

$$(A \times (B - C)) \times 5\%$$

Where,

A = the principal amount of ~~all tranches~~the applicable tranche of net incremental annual funding obligations,

B = the ~~forecasted weighted interest rate of~~forecast interest rate for the applicable tranche of net incremental annual funding obligations, as determined by the Financial Services Manager on or before the end of the calendar year prior to the calendar year in which the fee is being determined and based on the term of the applicable tranche of net incremental annual funding obligations, and

C = the actual ~~weighted~~ interest rate ~~of~~for the applicable tranche of net incremental annual funding obligations~~.~~,

(3) For the purposes of subsection 2(2), "net incremental annual funding obligation" means the aggregate of all funding obligations issued by all financing entities in a calendar year, including senior debt and subordinated debt, but, for greater certainty, not including any debt outstanding at the beginning of such calendar year and not including g any refinancing funding obligations incurred in such calendar year.

Note: Draft language provided for the purpose of instructions to Ontario Legislative Counsel. Final content of regulation is subject to drafting by OLC.

(4) The variable fee payable for any calendar year ~~shall not be~~ :

(a) where the aggregate principal amount of funding obligations of all financing entities outstanding at the end of such calendar year is $10 billion or less, shall not be

1. more than 1% of (5% × the net incremental annual funding obligations), or

2. less than -1% of (5% × the net incremental annual funding obligations) ~~.~~; and

(b) where the aggregate principal amount of funding obligations of all financing entities outstanding at the end of such calendar year is greater than $10 billion, shall not be

1. more than 2% of (5% × the net incremental annual funding obligations), or

2. less than -2% of (5% × the net incremental annual funding obligations)

(5) If the variable fee is a negative amount, such amount shall be deducted from the ~~fixed~~base fee payable in the following calendar year in twelve equal monthly instalments.

(6) Where there is more than one financing entity, the fees allocated to and payable by a financing entity shall be allocated in proportion to the outstanding aggregate amount of funding obligations of such financing entity.

3.(1) ~~When the~~The Financial Services ~~Manger submits~~Manager shall submit its proposed fees to the Board for approval no later than ■, ~~the Financial Services Manager~~201■ and shall provide the following in its submission:

1. ~~The methodology that the Financial Services Manager has used to calculate its proposed fixed and variable fees.~~ ~~2.~~ The methodology that the Financial Services Manager has used to benchmark ~~the~~ each component of the proposed fee.

~~3.~~2. The period of time during which the Financial Services Manager is proposing to charge its proposed fee.

~~5. The identity of the financing entities that are required to pay the~~3. The calculation of its proposed base and variable fees.

Note: Draft language provided for the purpose of instructions to Ontario Legislative Counsel. Final content of regulation is subject to drafting by OLC.

~~6.~~4. Such other information as the Board may require.

(2) ~~The Board is not bound by any methodology or benchmark provided to it by the Financial Services Manager under subsection (1).~~ The Financial Services Manager may from time to time, but not more than once in any 12 month period, submit proposed amendments to its fees to the Board.

(3) If the Financial Services Manager submits proposed amendments to its fees to the Board, the proposed amendments shall be submitted no later than 120 days before the Financial Services Manager intends for the amended fees to be charged.

(4) Subsections 3(2) and 3(3) do not apply in the first 12 months after this regulation comes into force.

(5) Subsection 3(1) applies with such modifications as the context may require to any submission by the Financial Services Manager for approval to amend its fees.

4.(~~3~~1) The Board may approve the proposed fees ~~or proposed amendments~~submitted by the Financial Services Manager under subsection 3(1) or subsection 3(2) or may refer the ~~proposal~~submission back to the Financial Services Manager for further consideration with the Board's recommendations. In making such recommendations in respect of fees proposed under subsection 3(1) or subsection 3(2), the Board may give due consideration to the advice of the Ontario Financing Authority as to the appropriate benchmarks and range of values for item "A" in the base fee component in subsection 2(1)(a).

(2) Once every three years after the Board has approved the fees submitted by the Financial Services Manager under subsection 3(1) or subsection 3(2), or more frequently if the Board requires but not more frequently than annually, the Board may request the Financial Services Manager to engage, on behalf of and at the cost of the financing entities, a third-party independent consultant to review and advise as to the appropriate benchmarks and range of values for item "A" in the base fee component in subsection 2(1)(a) and shall give due consideration to such advice.

(3) For any review by the Board and any consultant engaged pursuant to subsection 4(2), the Board and such consultant shall give due consideration to market comparables, being the fees charged by managers that provide similar level and scope of services as the Financial Services Manager to securitization vehicles, pension and other investment funds, hedge funds and other similar funds in North America.

(4) Fees established by the Financial Services Manager and approved by the Board, and any applicable taxes on such fees, shall be included in the definition of "expenses" for the purposes of determining finance amounts under the Act.

~~4.(1) The Financial Services Manager may from time to time, but not more than once in any 12 month period, submit proposed amendments to its fees to the Board.~~

~~(2) If the Financial Services Manager submits proposed amendments, the proposed amendments shall be submitted no later than 120 days before the Financial Services Manager intends for the fees to be charged.~~

~~(3) Subsections (1) and (2) do not apply in the first 12 months after this regulation comes into force.~~

5.~~(1) Section 3 applies with such modifications as the context may require to any application by the Financial Services Manager for approval to amend its fees.~~

~~6.(1) Where there is more than one financing entity, the total amount payable by a financing entity in respect of fees shall be proportional to the services that it receives from the Financial Services Manager.~~7.(1) ~~Upon~~When approving the ~~first fee~~fees submitted by the Financial Services Manager under subsection 3(1), the Board may ~~make it~~approve such fees retroactive to a date prior to the date of the Board's approval ~~and~~, but not earlier than July 1, 2017.

[(2) The Financial Services Manager shall establish a deferral account in connection with subsection 19(3) of the Act that records costs incurred by the Financial Services Manager in providing services referred to in section 1 during the period from July 1, 2017 to the day before the date of the Board's first order under subsection 19(3) of the Act.] [NTD: Necessity of this provision to be discussion with the OEB in light of the fact that fees will be recovered as a financing entity expense through the Fair Hydro program and not as part of the fees to be approved by the Board

Document comparison by Workshare Compare on Thursday, September 07, 2017 3:20:07 PM

Input:	
Document 1 ID	file://\\Catou-ogfspuwss\217803$\G\Les Wong's Documents\Fair Hydro Plan\Fees Regulation\Latest Drafts\Fees Rider 28 August 2017.docx
Description	Fees Rider 28 August 2017
Document 2 ID	file://\\Catou-ogfspuwss\217803$\G\Les Wong's Documents\Fair Hydro Plan\Fees Regulation\Latest Drafts\Fee Regulation - Combined Torys and OPG comments - Sep 7 2017.docx
Description	Fee Regulation - Combined Torys and OPG comments - Sep 7 2017
Rendering set	Standard

Legend:	
Insertion	
~~Deletion~~	
~~Moved from~~	
Moved to	
Style change	
Format change	
~~Moved deletion~~	
Inserted cell	
Deleted cell	
Moved cell	
Split/Merged cell	
Padding cell	

Statistics:	
	Count
Insertions	72
Deletions	42
Moved from	10
Moved to	10
Style change	0
Format changed	0
Total changes	134

FEES RIDER – subs. 19 (3) of the Act

(x.1) For the purposes of this section:

1. (1) For the purposes of subsection 19(3) of the Act, the Financial Services Manager may establish and charge fees to financing entities in relation to the services provided by the Financial Services Manager to financing entities, which may include services related to planning, financing, negotiation and execution of agreements, front office services and administrative services.

(2) The fees mentioned in subsection (1) shall be calculated annually and shall be comprised of a base fee and a variable fee based on performance.

(3) In addition to the fees mentioned in subsection (1), the Financial Services Manager shall be entitled to be reimbursed by the applicable financing entity for all out-of-pocket costs and expenses incurred in connection with its duties under the Act or under any management agreement with the applicable financing entity, including, without limitation, the costs and expenses of underwriters or selling agents for funding obligations; banking fees; fees of issuing and paying agents for funding obligations; fees of trustees; fees incurred in the preparation of financial statements, financial reports, compliance certificates and tax returns; fees of legal counsel; government filing or registration fees; and any third-party independent consultants required to be retained under these regulations.

2. (1)(a) The base fee referred to in subsection 1(2) shall be payable monthly and calculated as follows:

(A x B) / 12

where,

A = a percentage, expressed as a per annum rate, based on market comparable fees charged by service providers for similar services as determined by the Financial Services Manager and subject to review by the Board under section 4, and

B = the average of the opening and closing balances of the aggregate principal amount of outstanding funding obligations issued by all financing entities in the previous calendar month.

(b) Subject to review by the Board under section 4,

(i) for so long as the outstanding aggregate principal amount of funding obligations of all financing entities is equal to or less than $10 billion and until the end of the calendar year in which such amount exceeds $10 billion, "A" in the formula set out in subsection (1)(a) shall be equal to 10 basis points, or 0.1%, and

(ii) commencing on the first day of the calendar year following the year in which the outstanding aggregate principal amount of funding obligations of all financing entities exceeds $10 billion, "A" in the formula set out in subsection (1)(a) shall be equal to 8 basis points, or 0.08%.

(2) The variable fee referred to in subsection 1(2), shall be calculated as the sum of the amounts calculated, using the following formula, for all tranches of net incremental funding obligations issued by all financing entities in the relevant year:

$$(A \times (B - C)) \times 5\%$$

Where,

A = the principal amount of the applicable tranche of net incremental annual funding obligations,

B = the forecast interest rate for the applicable tranche of net incremental annual funding obligations, as determined by the Financial Services Manager on or before the end of the calendar year prior to the calendar year in which the fee is being determined and based on the term of the applicable tranche of net incremental annual funding obligations, and

C = the actual interest rate for the applicable tranche of net incremental annual funding obligations,

(3) For the purposes of subsection 2(2), "net incremental annual funding obligation" means the aggregate of all funding obligations issued by all financing entities in a calendar year, including senior debt and subordinated debt, but, for greater certainty, not including any debt outstanding at the beginning of such calendar year and not including g any refinancing funding obligations incurred in such calendar year.

(4) The variable fee payable for any calendar year:

(a) where the aggregate principal amount of funding obligations of all financing entities outstanding at the end of such calendar year is $10 billion or less, shall not be

1. more than 1% of (5% × the net incremental annual funding obligations), or

2. less than -1% of (5% × the net incremental annual funding obligations); and

(b) where the aggregate principal amount of funding obligations of all financing entities outstanding at the end of such calendar year is greater than $10 billion, shall not be

1. more than 2% of (5% × the net incremental annual funding obligations), or

2. less than -2% of (5% × the net incremental annual funding obligations)

(5) If the variable fee is a negative amount, such amount shall be deducted from the base fee payable in the following calendar year in twelve equal monthly instalments.

(6) Where there is more than one financing entity, the fees allocated to and payable by a financing entity shall be allocated in proportion to the outstanding aggregate amount of funding obligations of such financing entity.

3.(1) The Financial Services Manager shall submit its proposed fees to the Board for approval no later than ■, 201■ and shall provide the following in its submission:

1. The methodology that the Financial Services Manager has used to benchmark each component of the proposed fee.

2. The period of time during which the Financial Services Manager is proposing to charge its proposed fee.

3. The calculation of its proposed base and variable fees.

4. Such other information as the Board may require.

(2) The Financial Services Manager may from time to time, but not more than once in any 12 month period, submit proposed amendments to its fees to the Board.

(3) If the Financial Services Manager submits proposed amendments to its fees to the Board, the proposed amendments shall be submitted no later than 120 days before the Financial Services Manager intends for the amended fees to be charged.

(4) Subsections 3(2) and 3(3) do not apply in the first 12 months after this regulation comes into force.

(5) Subsection 3(1) applies with such modifications as the context may require to any submission by the Financial Services Manager for approval to amend its fees.

4.(1) The Board may approve the proposed fees submitted by the Financial Services Manager under subsection 3(1) or subsection 3(2) or may refer the submission back to the Financial Services Manager for further consideration with the Board's recommendations. In making such recommendations in respect of fees proposed under subsection 3(1) or subsection 3(2), the Board may give due consideration to the advice of the Ontario Financing Authority as to the appropriate benchmarks and range of values for item "A" in the base fee component in subsection 2(1)(a).

(2) Once every three years after the Board has approved the fees submitted by the Financial Services Manager under subsection 3(1) or subsection 3(2), or more frequently if the Board requires but not more frequently than annually, the Board may request the Financial Services Manager to engage, on behalf of and at the cost of the financing entities, a third-party independent consultant to review and advise as to the appropriate benchmarks and range of values for item "A" in the base fee component in subsection 2(1)(a) and shall give due consideration to such advice.

(3) For any review by the Board and any consultant engaged pursuant to subsection 4(2), the Board and such consultant shall give due consideration to market comparables, being the fees charged by managers that provide similar level and scope of services as the Financial Services Manager to securitization vehicles, pension and other investment funds, hedge funds and other similar funds in North America.

(4) Fees established by the Financial Services Manager and approved by the Board, and any applicable taxes on such fees, shall be included in the definition of "expenses" for the purposes of determining finance amounts under the Act.

5.(1) When approving the fees submitted by the Financial Services Manager under subsection 3(1), the Board may approve such fees retroactive to a date prior to the date of the Board's approval, but not earlier than July 1, 2017.

[(2) The Financial Services Manager shall establish a deferral account in connection with subsection 19(3) of the Act that records costs incurred by the Financial Services Manager

in providing services referred to in section 1 during the period from July 1, 2017 to the day before the date of the Board's first order under subsection 19(3) of the Act.] [NTD: Necessity of this provision to be discussion with the OEB in light of the fact that fees will be recovered as a financing entity expense through the Fair Hydro program and not as part of the fees to be approved by the Board

From:	John Kim
To:	Ronald Kwan
Subject:	FW: OFA Feedback re Fair Hydro Plan
Date:	Monday, July 31, 2017 1:42:24 PM
Attachments:	FHPA Regulations - Fees.docx Draft Subordianted Debt Term Sheet.doc

---

From: Carlos Yep
Sent: Monday, July 31, 2017 12:31 PM
To: John Kim <John.Kim@ofina.on.ca>
Subject: FW: OFA Feedback re Fair Hydro Plan

John
I have scheduled a meeting for this afternoon at 230pm

1)We can not comment on the fixed fee.
2)Ken jas been involved on the variable / performance fee – we want to be the new net incremental debt
3)For the equity injection, we still want OFA not as a counterparty

C

From: Ken Kandeepan
Sent: Sunday, July 30, 2017 12:31 PM
To: Carlos Yep <Carlos.Yep@ofina.on.ca>; Mike Manning <Mike.Manning@ofina.on.ca>; James Devine <James.Devine@ofina.on.ca>
Subject: FW: OFA Feedback re Fair Hydro Plan

Hi

I have no idea why OPG did not include you in the addressee list, maybe we can have quick discussion on this on Monday if you are available.

Thanks

Ken k

From: LIU Sheen -TREASURY [mailto:sheen.liu@opg.com]
Sent: Friday, July 28, 2017 5:32 PM
To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
Cc: LEE John -TREASURY <john.s.lee@opg.com>; RYFA Ken -TREASURY <ken.ryfa@opg.com>; WONG Leslie -LAWDIV <leslie.wong@opg.com>

Subject: OFA Feedback re Fair Hydro Plan

Ken,

Thanks for providing your concurrence in the Trust's approach to performance benchmarking. In order to move forward with completing all Fair Hydro Plan related legal documents, could you please also confirm your agreement to the methodology/process as illustrated in the other two documents provided to you in the past (both attached above for your reference)? Specifically, we would appreciate your confirmation re the following items:

1. Fee Structure, including both fixed and variable fees (as described in FHPA Regulations – Fees.docx)
2. The process of (a) taking out subordinated loan from OFA; and (b) establishing relevant pricing (as described in Draft subordinated Debt Term Sheet.doc)

If you have other outstanding comments relating to Fair Hydro Plan, please also let us know so that we could incorporate them before finalizing the structure and legal documents.

Your timely response will be appreciated.

Regards

Sheen

From: Ken Kandeepan [mailto:Ken.Kandeepan@ofina.on.ca]
Sent: Tuesday, July 18, 2017 1:05 PM
To: LAURETA LAPIRA May -FIN & C CTRL
Cc: MAUTI John -FIN & C CTRL; LEE John -TREASURY; Mike Manning; Graham Monroe; Carlos Yep; James Devine; JORDA Jenny -FIN & C CTRL; GORE Michael -FIN & C CTRL; LIU Sheen -TREASURY
Subject: EXTERNAL – RE: EY concurrence re: Draft Trust Performance Fee Recommendations

*** Exercise caution. This is an EXTERNAL email. DO NOT open attachments or click links from unknown senders or unexpected email. ***

Thank you May, the email from E&Y is clear and given a choice between a performance methodology, that in our opinion, is not entirely reflective of capital markets decision making and jeopardizing the consolidation of the Trust, we are opting to accept OPG's methodology for the construction of the benchmark.

Pls proceed accordingly.

Ken k

From: LAURETA LAPIRA May -FIN & C CTRL [mailto:may.lapira@opg.com]
Sent: Monday, July 17, 2017 2:40 PM
To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
Cc: MAUTI John -FIN & C CTRL <john.mauti@opg.com>; LEE John -TREASURY <john.s.lee@opg.com>; Mike Manning <Mike.Manning@ofina.on.ca>; Graham Monroe <Graham.Monroe@ofina.on.ca>; Carlos Yep <Carlos.Yep@ofina.on.ca>; James Devine <James.Devine@ofina.on.ca>; JORDA Jenny -FIN & C CTRL <jenny.jorda@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; LIU Sheen -TREASURY <sheen.liu@opg.com>
Subject: EY concurrence re: Draft Trust Performance Fee Recommendations

Hi Ken,

My name is May Lapira and I'm the newest addition to the Treasury team. Jenny has been working hard to get me updated on the accounting aspects of the Fair Hydro Plan so we can transition future correspondences over to me.

Per our discussion during the call earlier today, we have reached out to EY to obtain concurrence on our interpretation of their accounting position. Please see attached the email trail from EY's senior manager Brittany Keenan confirming that excluding the equity injection component from the definition of a 'benchmark bond' would result in non-commercial terms and could ultimately result in OPG not being able to consolidate the financing entity.

Please let me know if you have any follow up questions on this matter.

I look forward to working with you,
May

May Laureta Lapira, CPA, CA | Senior Manager, Treasury | Ontario Power Generation
700 University Avenue, Toronto ON M5G 1X6 | Tel: (416) 592-3721| Fax: (416) 592-7758 |E-mail: may.lapira@opg.com

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Fees, subs. 19 (3) of the Act

(x.1) For the purposes of this section, "incremental annual funding obligation" means the aggregate of all funding obligations issued by all financing entities in a calendar year.

10xx. (1) For the purposes of subsection 19 (3) of the Act, the Financial Services Manager may establish and charge fees to financing entities in relation to the following matters:

1. The services provided by the Financial Services Manager to financing entities, which may include services related to planning, financing, negotiation and execution of agreements, the payment of costs and expenses on behalf of a financing entity, front office services and administrative services.

2. The costs of doing anything that the Financial Services Manager is required or permitted to do under the Act.

(2) The fees mentioned in subsection (1) shall be established annually and shall be comprised of a fixed fee and a variable fee based on performance.

(x.2) The fixed fee referred to in (2) shall be payable monthly and calculated as follows:

$$(A \times B) / 12$$

Where,

A = a percentage, expressed as a per annum rate, based on market comparable fees determined by the Financial Services Manager charged by service providers for similar services, and

B = the average of the opening and closing balances of the aggregate principal amount of outstanding funding obligations issued by all financing entities in the previous calendar month.

(x.3) The variable fee referred to in (2) shall be calculated as the sum of the amounts calculated, using the following formula, for all tranches of funding obligations issued by all financing entities in the relevant year:

$$(A \times (B - C)) \times D$$

Where,

A = the principal amount of the applicable tranche of incremental annual funding obligations,

B = the forecast interest rate for the applicable tranche of incremental annual funding obligations, as determined by the Financial Services Manager on or before the end of the calendar year prior to the calendar year in which the fee is being determined and based on the term of the applicable tranche of incremental annual funding obligations,

C = the actual interest rate for the applicable tranche of incremental annual funding obligations,

D = 5%

(3) The variable fee payable for any calendar year shall not be:

1. more than 1% of (D × the incremental annual funding obligations), or

2. less than -1% of (D × the incremental annual funding obligations).

(3.x) If the variable fee is a negative amount, such amount shall be deducted from the fixed fee payable in the following calendar year in twelve equal monthly instalments.

Board approval of fees, subs. 19 (4) of the Act

11xx. (1) The Financial Services Manager shall submit its proposed fees, together with the methodology used for determining its proposed fees, to the Board for approval no later than August 31, 2017. ***[NTD: Need to determine how to deal with the 1st fee. Understand that OPG is proposing a fixed fee for this year. OPG: There will not be a variable fee for the 1st year.]***

(2) The Board may approve the fees proposed under (1) and the methodology used to determine those fees or it may refer the proposal back to the Financial Services Manager for further consideration with the Board's recommendations.

(3) The Financial Services Manager may from time to time, but not more than once in any 12 month period, submit proposed amendments to the approved methodology for determining fees, together with its proposed fees based on such proposed amendments, to the Board and the Board may approve the proposed amendments and the proposed fees or may refer the proposal back to the Financial Services Manager for further consideration with the Board's recommendations.

(4) If the Financial Services Manager submits proposed amendments to its approved methodology for determining fees, the proposed amendments together with the proposed fees based on such proposed amendments shall be submitted to the Board for approval no later than 120 days before the Financial Services Manager intends for the fees, determined on the basis of the amended methodology, to commence being charged.

(5) Section 10 applies with such modifications as the context may require to any application by the Financial Services Manager for approval to amend the approved methodology for determining fees and for approval of the resulting fees.

(6) The Financial Services Manager may annually establish and charge fees to financing entities in accordance with the methodology approved by the Board under (2) or (3), as applicable, and such fees shall be deemed to have been approved by the Board for purposes of subsection 19(4) of the Act provided that, in each year where the Financial Services Manager establishes and charges fees that are deemed to have been approved under this subsection, the Financial Services Manager shall submit to the Board, for information purposes, a report setting out the fees that have been established for the year and demonstrating that the approved methodology has been appropriately applied.

(7) When the Financial Services Manager submits its proposed fees and methodology under (1), or its proposed amendments to the approved methodology and resulting proposed fees under (3), the Financial Services Manager shall provide the Board with the following:

1. The methodology that the Financial Services Manager has used to calculate its fixed and variable fees.

2. The methodology that the Financial Services Manager has used to benchmark the market comparable fees charged by service providers for similar services.

3. The identity of the financing entities that are liable to pay the proposed fees.

4. Such other information as the Board may require.

(x.1) Fees established by the Financial Services Manager and approved by the Board shall be included in the definition of “expenses” for the purposes of determining finance amounts under the Act.

Fair Hydro Plan – Subordinated Debt Loan Arrangement
Term Sheet

- Parties: OPG, Fair Hydro Trust, OFA

- In accordance with the Master Subscription Agreement among OPG, OFA and Ministry of Energy, the Province agrees to inject 44% of total funding of GA asset by way of equity subscriptions in OPG, and OPG agrees to use the equity subscription amounts solely for funding the Fair Hydro Trust's subordinated debt (Equity Injection Plan) requirements as part of the Fair Hydro Plan

- OPG will lend the equity injection from the Province to Fair Hydro Trust by way of subordinated debt (one or more mezzanine level)

- Initial credit rating will be assigned to the subordinated debt of Fair Hydro Trust

- Based on monthly funding requirement of GA asset, the Trust will use short term financing, such as bank facilities, and take out bonds once accumulative short term funding reaches certain levels.

- The mechanism to implement Equity Injection Plan will be based on monthly equity injections reflecting funding requirements of GA asset

- Interest rates on the subordinated debt will be established as follows:

    - During the Trust short term financing period when bank facilities are used as funding vehicles, the interest rate on subordinated debt will be the sum of (1) funding rate on senior debt, and (2) additional spread margin of [xx], reflecting the credit rating difference between the senior and subordinated debt

    - At the time when senior bonds are being issued to take out (term out) the short term financing, OPG will seek indicative coupon rates on the subordinated debt from dealers, reflecting the sum of underlying Government of Government of Canada yield of equivalent term and the appropriate credit spread. The average indicative coupon rate from dealers will be calculated and set as the subordinated debt rate. The process will be similar to the one established for pricing of OPG debt drawn from OEFC facilities.

From:	John Kim
To:	Ronald Kwan
Subject:	FW: OFHP fees reg
Date:	Thursday, October 12, 2017 5:27:23 PM
Attachments:	reg2017.0512.e04 with drafting instrns for leg counsel v4.docx

Fyi, something that I'm working on with guys upstairs.

From: John Kim
Sent: Thursday, October 12, 2017 5:27 PM
To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>; Carlos Yep <Carlos.Yep@ofina.on.ca>
Cc: Mike Manning <Mike.Manning@ofina.on.ca>; James Devine <James.Devine@ofina.on.ca>; Anna Strathy <Anna.Strathy@ofina.on.ca>
Subject: FW: OFHP fees reg

Hi Ken, Carlos,

Just catching up on emails and attached see additional request related to the draft reg.

I will aim to provide draft response to the Qs below tomorrow based on our comments and CMD's, as well.

Thanks,

John

From: Katona, Keley (MOF) [mailto:Keley.Katona@ontario.ca]
Sent: Thursday, October 12, 2017 2:06 PM
To: John Kim <John.Kim@ofina.on.ca>
Cc: Tim Christie (ENERGY) <Tim.Christie@ontario.ca>; Daniel Cayley (ENERGY) <Daniel.Cayley@ontario.ca>; Montgomery, Kaitlin (MOF) <Kaitlin.Montgomery@ontario.ca>
Subject: FW: OFHP fees reg

Hi John,

Further to my call, attached is the latest draft reg. Could you review the NTD for the OFA and also address any outstanding questions per below? This was discussed at a meeting that Gadi and Ron attended this morning and it's likely tracking to Cabinet next week with the goal of finalizing before the weekend.

Thanks,
Keley

From: Cayley, Daniel (ENERGY)
Sent: October-11-17 2:04 PM
To: Kim, John (OFA)
Cc: Christie, Tim (ENERGY)
Subject: OFHP fees reg

Hi John – our lawyers have a few questions below related to the OPG fair hydro plan fees reg that they were hoping to get your input on as soon as possible. Please let me know if you think a call with us/our lawyers would be faster than getting us written answers.

#1 – On the process for establishing the base fee and variable fee, which could theoretically spill over into the year to which the new fees would apply (if OEB approval was not obtained until then), the thinking would be to have the old fees apply until the new fees were approved by the OEB, and then have a "retroactive" adjustment of the fees (retroactively adjusting them back to the beginning of the year the new fees take effect). Since the base fee and variable fee are payable monthly, the "retroactive" adjustment would be made in the month following the month in which the new fees were finalized. The question for OFA is whether it would be appropriate to have a retroactive fee adjustment.

#2 – Re: discussion between OPG and OFA about what "market comparable fees", OPG has proposed that there be a requirement for five sets of fees, four of which would be fees charged by full-service managers of securitization vehicles, and the fifth of which would be fees charged by an asset manager (or management and financial services provider) in respect of any one of pension funds, other structured investment funds, hedge funds or other similar structured funds. Does the OFA have any comments on this approach or the viability of finding five such comparators? The Board has suggested that the FSM be required to submit fee comparators but that the Board have the ability to also include comparators that it chooses (e.g. on the advice of consultants/experts it retains).

#3 – Are there "market comparable fees" that allow the person charging the fees to also recover out-of-pocket costs over and above the fees?

#4 – Can the OFA provide comments on the below draft definition of "market comparable fees" reads as follows (the NTDs are for OFA's input)?

ıarket comparable fees" means fees, expressed as a **[yearly?]** percentage rate, charged by asset managers **[or management and financial service providers?]** in Canada or another jurisdiction specified by the Board for services that are similar to the services provided by the Financial Services Manager under the Act in terms of,

[NTD: (1) Confirm *yearly* percentage rate. (2) Confirm whether to include "or management and financial service providers". If this is to be included, what does

this mean? Is it a well-recognized industry term of art?]

the type of services provided, being services in respect of funds including **securitization vehicles**, pension funds, other **structured** investment funds, hedge funds and other similar **structured** funds, **[NTD: Confirm "securitization vehicles" and "structured".]**

the scope of the services provided,

the level of the services provided, and

the dollar amount of assets under management;

Thanks,

Daniel

CONFIDENTIAL **REG2017.0512.e**
Until filed with the **4-TP**
Registrar of Regulations

ONTARIO REGULATION

made under the

ONTARIO FAIR HYDRO PLAN ACT, 2017

FEES

Definitions

1. (1) In this Regulation,

"average monthly funding obligation" means, in respect of a month, the amount determined in accordance with subsection (2);

"average annual funding obligation" means, in respect of a year, the sum of the average monthly funding obligations for the year;

"market comparable fees" means fees, expressed as a yearly percentage rate, charged by asset managers [or management and financial service providers] in Canada or another jurisdiction specified by the Board for services that are similar to the services provided by the Financial Services Manager under the Act in terms of,

[NTD for leg counsel: I am trying to get more clarity around "management and financial service providers". I am not sure whether the intent is to say "management service providers or financial service providers". If the intent is to refer to a "management and financial service provider", I will try to ascertain whether this is a well-understood industry "term of art" (since based on a brief search it did not appear to be).]

(a) the type of services provided, being services in respect of funds including securitization vehicles, pension funds, other structured investment funds, hedge funds and other similar structured funds,

(b) the scope of the services provided,

Commented [DS1]: NTD for OEB: Is "specified by" the right way to say this?

Commented [DS2]: NTD for ESP/MoF: Should there be a "temporal" connection too? E.g. "… services that are similar to, and provided at a time that is similar to the time the services are provided by, the FSM …".

(c) the level of the services provided, and

(d) the dollar amount of assets under management;

"funding tranche" means an ~~specific~~ issuance of ~~debt by a financing entity and constitutes all or part of a~~ funding obligations of a particular series, class or type that have the same terms;

"FSM services" means services provided by the Financial Services Manager to financing entities in relation to the management and administration of the financing entities and the investment asset, including in relation to funding obligations incurred or that are planned to be incurred by the financing entities;

"market comparable forecast interest rates" means, in relation to a potential funding tranche described in the submissions mentioned in subsection 6 (3) or 6 (4), interest rates charged by lenders in Canada **[at the time the submissions are made]** for a debt obligation that,

(a) has a principal amount that is comparable to the principal amount of the funding tranche,

(b) has a term that is comparable to the term of the funding tranche **[in terms of length and commencement],**

(c) is based on a type of instrument that is comparable to the type of instrument of the funding tranche,

(d) has payment rights that are similar to the payment rights of the funding tranche, and

(e) is issued by an issuer with a risk profile comparable to the risk profile of the financing entity issuing the funding tranche;

Commented [DS3]: NTD for OPG/MoF: Should this contemplate "posted" rates rather than rates "charged by"?

"net annual funding obligation" means, in respect of a year, the sum of the principal amounts of funding tranches issued in the year, other than any funding tranches that constitute a refinancing;

(2) For the purposes of determining the average monthly funding obligation for a month, the following formula applies:

$$(A + B) / 2$$

Where,

A = the sum of the balances on the first day of the month of the principal amount of all outstanding funding obligations incurred by financing entities,

B = the sum of the balances on the last day of the month of the principal amount of all outstanding funding obligations incurred by financing entities.

Forecast interest rate

1.1 For the purposes of this Regulation, the Financial Services Manager shall determine the forecast interest rate for a funding tranche that forms part of the net annual funding obligation for a year, by taking into account the following factors:

1. The interest rate for debt of or guaranteed by the Government of Ontario with a term or duration that is comparable to the term or duration of the funding tranche.
[NTD for leg counsel: We are confirming whether we need to refer to both "term" and "duration" here and in 2 ii below (and if yes, how these terms mean different things).]

2. The estimated credit spread, relative to the interest rate described in paragraph 1, for a debt obligation that,

   i. has a principal amount that is comparable to the principal amount of the funding tranche,

   ii. has a term that is comparable to the term of the funding tranche **[in terms of length and commencement]**,

   iii. is based on a type of instrument that is comparable to the type of instrument of the funding tranche, ~~and~~

   iv. has payment rights that are similar to the payment rights of the funding tranche, and

   v. is issued by an issuer with a risk profile comparable to the risk profile of the financing entity issuing the funding tranche.

3. Anticipated fees and commissions expected to be payable in connection with the issuance of the funding tranche.

Commented [DS4]: NTD for OPG/MoF: Even if the term is the same length, would the commencement date of the term not also be relevant?

Commented [DS5]: NTD for OPG: Energy Policy is asking whether the fees and commissions are relevant to the determination of the forecast interest rate for the tranche, given that they are recoverable by the FSM under s. 7(2) below.

Fees that may be established, charged

2. (1) For the purposes of subsection 19 (3) of the Act, the fees established and charged by the Financial Services Manager may be charged to financing entities ~~in relation to the management and administration of financing entities and the investment asset, including in relation to funding obligations incurred or that are planned to be incurred by~~for FSM services provided to the financing entities.

(2) A fee mentioned in subsection (1) shall be comprised of a base fee calculated under section [3] and a variable fee calculated under section [6].

(3) For the purposes of subsection 19 (3) of the Act, fees may be established and charged by the Financial Services Manager to financing entities for the recovery of costs and expenditures, as provided for in section [7].

(4) The Financial Services Manager shall not establish or charge any fees to financing entities other than those fees provided for under this Regulation.

Base fee

3. (1) Subject to sections [5.1] and [5.2], the Financial Services Manager shall establish the proposed base fee for a month as follows:

1. Determine the amount that is 0.075 per cent of the average monthly funding obligation for the preceding month.

2. Divide the amount determined under paragraph 1 by 12.

(2) The first month in respect of which the base fee may be established is ~~July~~ November 2017.

[OLC Note: Just need to confirm -- will there be an average monthly funding obligation for the month of June 2017? If not, it would not be possible to apply this method in respect of July 2017.] **[NTD for leg counsel: The first funding obligation may not be incurred until around November 2017. The base fee for a month would be zero if there was no average monthly funding obligation for the preceding month (i.e. if it was zero).]**

(3) The Financial Services Manager shall submit to the Board the base fee proposed to be charged in respect of the period from November 1, 2017 to December 31, 2018 no later than October 31, 2017.

(4) The Financial Services Manager shall submit to the Board the base fee proposed to be charged in respect of any year after 2018 no later than 120 days before the start of the year in respect of which the base fee would be charged.

[NTD for leg counsel: Let's move the submission provisions (other than the amendment submission provision) from section 9 to the respective sections that deal with the fee in question. As you will see in s. 6 and 7 below, the submission process will be different for each of the types of fees (base, variable, and costs/expenditures).]

[Further NTD for leg counsel: The Board's review of the base fee for the period from July 1, 2017 to December 31, 2018 will be limited to ensuring that the base fee is calculated correctly (i.e. calculated in accordance with ss. 5 (3)).]

Commented [DS6]: NTD for OPG/OEB: The policy instruction is to provide that costs and expenditures are recoverable so long as they relate to the matters described in s. 7.1(1), and that the Board review the costs and expenditures from that perspective.

In order to implement this instruction and give the Board the authority to review, we have to deem the costs and expenditures to be fees.

Commented [DS7]: NTD for OPG/OEB: Ss. 19(4) of the OFHPA requires the Board to approve fees.

Board review of base fee

5.1 (1) The Board shall refuse to approve the proposed base fee mentioned in subsection 5 (3) if the Board is of the view that the proposed base fee was not established in accordance with subsection 3 (1).

(2) If the Board refuses to approve the proposed base fee,

(a) the Board shall provide reasons for the refusal; and

(b) the Financial Services Manager shall submit to the Board a revised proposed base fee that is established in accordance with subsection 3 (1)

[NTD for leg counsel: If the Board does not refuse to approve a proposed base fee under ss. (1) or (3), then we should explicitly say that the Board will approve the proposed base fee. Please tweak ss. 5.1 (1) and (3) accordingly.]

(3) The Board may refuse to approve a proposed base fee mentioned in subsection 5 (4) if the Board is of the view that the proposed base fee is materially inconsistent with market comparable fees.

[OLC Note: Should this section only apply starting January 1, 2019?]

[OLC Note: Are you sure that this is the only reason why the Board can refuse the proposed base fee?]

[NTD for leg counsel: In response to your notes, for the proposed base fee applicable in 2019 and beyond, the only basis upon with the Board can withhold approval is inconsistency with market comparable fees. For the proposed base fee applicable July 1 – Dec31/17 and Jan1 – Dec31/18, the Board can only withhold approval if the base fee is inconsistent with the formula in s. 3(1).]

Commented [DS8]: Explanatory note for OEB: The reg-making powers in s. 19 of the OFHPA don't appear to provide the same ability to impose on the Board (by reg.) the base fee as with the OESP reg-making powers in ss. 79.2(6) of the OEBA.

(~~1.1~~4) If the Board refuses to approve the proposed base fee,

(a) the Board shall provide reasons for the refusal and may make recommendations to the Financial Services Manager regarding the determination of a base fee that is consistent with market comparable fees; and

(b) the Financial Services Manager shall submit to the Board,

(i) a revised proposed base fee that takes into consideration the recommendations of the Board, if any**;** and

(ii) a description of the methodology that the Financial Services Manager has applied to determine the revised proposed base fee, including details concerning the market comparable fees that the Financial Services Manager considered.

(5) [NTD for leg counsel: Please add a provision that says that the process (i.e. the process outlined in ss. (1) and (2) above, or (3) and (4) above) will be repeated until the Board approves a proposed base fee for the year in question, unless you are of the view that that is already clearly implicit in those provisions.]

(6) [NTD for leg counsel: Please add a provision that says that:

- **Until a new proposed base fee is approved, the FSM may continue to charge the most current Board-approved base fee (if any).**

- **Once the new proposed base fee is approved by the Board, the FSM shall make a "retrospective" adjustment to the base fee (in the month following the month in which the approval is given). The adjustment will be the difference (positive or negative) between the base fee actually charged in the relevant period up to that point, and the new base fee approved by the Board for that period. In other words, the Board approved fee would be "retrospectively" applied to the whole period. By "period" I mean either the initial period from Nov1/17 – Dec31/18 or any calendar year starting with 2019. Note that any amendment to fees (under s. 9.1) would only apply prospectively starting in the month following the month in which the amendments were approved by the Board.]**

Variable fee

6. (1) Subject to subsection (2) and section 6.1, the Financial Services Manager shall establish the variable fee for a year after 2017 as follows:

1. Apply the following formula in respect of each funding tranche that forms part of the net annual funding obligation for the year:

$$(A \times (B - C)) \times 0.05$$

Where,

A = the principal amount of the funding tranche,

B = the forecast interest rate for the funding tranche, and

C = the actual interest rate for the funding tranche.

2. Calculate the sum of the amounts determined by applying the formula under paragraph 1.

(2) If the circumstances set out in Column 1 of the following Table apply in a year, the variable fee payable for a year is subject to the rules set out opposite those circumstances in Column 2 of the Table:

Item	Column 1 Circumstances	Column 2 Rules
1.	The average annual funding obligations are $10 billion or less.	The variable fee payable for the year shall not be more than 1 per cent of the amount that is 5 per cent of the net annual funding obligation for the year. The variable fee payable for the year shall not be less than -1per cent of the amount that is 5 per cent of the net annual funding obligation.
2.	The average annual funding obligations are greater than $10 billion.	The variable fee payable for the year shall not be more than 2 per cent of the amount that is 5 per cent of the net annual funding obligation for the year. The variable fee payable for the year shall not be less than -2 per cent of the amount that is 5 per cent of the net annual funding obligation for the year.

(3) The Financial Services Manager shall make submissions to the Board in respect of the **[variable fee proposed to be charged in 2018, including the]** forecast interest rates for the funding tranches anticipated to be issued in 2018, no later than **[October 31, 2017]**.

Commented [DS9]: NTD for OPG/OEB: Is this wording appropriate?

(4) The Financial Services Manager shall make submissions to the Board in respect of the variable fee proposed to be charged in any year after 2018, including the forecast interest rates for the funding tranches anticipated to be issued in the year, no later than 120 days before the beginning of the year.

(5) If the Financial Services Manager has not submitted a forecast interest rate under subsection (3) or (4) for a funding tranche that will be issued in a year after 2017, the Board may require the Financial Services Manager to submit a proposed forecast interest rate for the funding tranche **[and may specify the time by which the submission must be made],** or the Board may determine the funding tranche taking into consideration the forecast interest rates submitted by the Financial Services Manager for the year under subsection (3) or (4).

Commented [DS10]: NTD for OPG: The policy instruction is to not require the Board to apply linear interpolation to come up with a forecast interest rate, because the approach would be too prescriptive for this fairly limited subset of total fees.

Board review of variable fee

6.1 (1) The Board may refuse to approve a proposed variable fee if the Board is of the view that any forecast interest rate used for the purposes of subsection 6 (1) is inconsistent with ~~[~~market comparable forecast interest rates~~]~~.

[OLC Note: We provide an explanation for how to determine "market comparable fees" but we say nothing about how to determine "market comparable forecast interest rates". Please instruct.]

[NTD for leg counsel: We have created a new defined term "market comparable forecast interest rates" to address this.]

[OLC Note: Are you sure this is the only reason why the Board may refuse the proposed variable fee?] **[NTD for leg counsel: Yes.]**

(2) If the Board refuses to approve the proposed variable fee,

(a) the Board shall provide reasons for the refusal and may make recommendations to the Financial Services Manager regarding each forecast interest rate that the Board found was inconsistent with [market comparable forecast interest rates]; and

(b) the Financial Services Manager shall submit to the Board,

(i) a revised proposed fee that takes into consideration the recommendations of the Board, if any, and

(ii) a description of the methodology that the Financial Services Manager has applied to determine revised forecast interest rates for each funding tranche in respect of which the Board found an inconsistency with [market comparable forecast interest rates].

Fees for costs and expenditures

7. (1) The Financial Services Manager may establish and charge fees for the recovery from a financing entity of any costs and expenditures incurred by the Financial Services Manager,

(a) on behalf of the financing entity in connection with the Financial Services Manager's duties under the Act in relation to the financing entity; or

(b) under a management agreement between the Financial Services Manager and the financing entity, where the agreement provides for the reimbursement of the costs and expenditures.

(2) The costs and expenditures referred to in subsection (1) may include costs and expenditures in respect of the following:

1. Underwriters or selling agents for funding obligations.

2. Banking fees, including structuring fees or work fees.

3. Fees of issuing and paying agents for funding obligations.

4. Fees of trustees.

5. Fees incurred in the preparation of financial statements, financial reports, compliance certificates and tax returns.

6. Fees of legal counsel.

7. Rating agency fees.

8. Filing or registration fees.

9. Direct costs of the Financial Services Manager for employees who are dedicated to providing FSM services to financing entities.

~~(3) The costs and expenditures referred to in subsection (1) shall not include any overhead costs of the Financial Services Manager, including [….].~~
~~[OLC Note: The phrase "overhead costs" seems a bit vague. Examples would help.]~~

Board review of fees for costs, expenditures

7.1 (1) The Board may refuse to approve a proposed fee for costs and expenditures or a portion of a proposed fee for costs and expenditures if the Board is of the view that the proposed fee is in respect of costs and expenditures that were not incurred in relation to the management and administration of financing entities and the investment asset, including in relation to funding obligations incurred or that are planned to be incurred by the financing entities.

(2) If the Board refuses to approve the proposed fee or a portion of the proposed fee, the amount not approved shall not be payable to the Financial Services Manager and the associated costs and expenditures shall not be recoverable by the Financial Services Manager from the financing entity.

~~(a) the Board shall provide reasons for the refusal and may make recommendations to the Financial Services Manager regarding the proposed fee; and~~

~~(b) the Financial Services Manager shall submit to the Board,~~

~~(i) a revised proposed fee that takes into consideration the recommendations of the Board, if any, and~~

~~(ii) a description of how the proposed fee is in respect of costs and expenditures that were incurred in relation to the management and administration of financing entities and the investment asset.~~

Charging of fees

8. (1) Subject to sections [5.1], [6.1] and [7.1], in charging fees, the Financial Services Manager shall provide for,

(a) the base fee for a month to be payable within **[x]** days after the end of the month;

Commented [DS11]: NTD: Need to specify when the base fee is payable.

(b) the variable fee for a year to be payable in the following calendar year in twelve equal monthly instalments that coincide with the payment of the base fee for each month; and

(c) the fee for costs and expenditures for a month to be payable within [x] days after the end of the month.

Commented [DS12]: NTD: Need to specify when the fee for costs and expenditures is payable.

(2) If the variable fee for a year is a negative amount, it shall be deducted in twelve equal monthly instalments from the base fee payable in the following year.

(3) Where there is more than one financing entity, the portion of the fees allocated to and payable by a financing entity shall be based on its proportionate share of the average principal amount of funding obligations for the applicable period.

Commented [DS13]: NTD: Should this be based on the average of the opening and closing balances for the applicable period (e.g. year)?

(4) For the purposes of determining the average principal amount of funding obligations under subsection (3), the formula set out in subsection 1 (2) applies with necessary modifications.
[OLC Note: Please confirm that this works.]

Submissions to Board

9.1 ~~(1) The Financial Services Manager shall make submissions to the Board in respect of fees proposed to be charged in 2018 no later than October 31, 2017.~~

Formatted: section-e

~~(2) The Financial Services Manager shall make submissions to the Board in respect of fees proposed to be charged in respect of any year after 2018 no later than 120 days before the start of the year in respect of which the fees would be charged.~~

~~(3)~~ The Financial Services Manager may, no more frequently than once in any consecutive twelve month period, make submissions to the Board to amend any base fee or variable fee~~s~~ approved by the Board, and the provisions of section [5.1]. [6.1] or [7.1], as applicable, apply in respect of the submissions.

Board approval, general

10. (1) For the purpose of determining whether to approve a proposed fee, the Board shall consider the information provided by the Financial Service Manager in its submission relating to the proposed fee.

(2) For the purpose of determining whether to approve a proposed base fee or variable fee, the Board may consider, as it determines to be appropriate, the advice provided by third party consultants and experts. **[NTD for leg counsel: We want to retain this provision, but the Board noted that they already have this ability without needing to specifically include it here. The Board flagged the risk of an adverse interpretation in other contexts where the Board is not given explicit statutory authority to consider advice of third party consultants and experts. Can we word this ss. 10(2) in such a way that it is just "for greater clarity"?]**

Commencement

11. This Regulation comes into force on the day it is filed.

From:	John Kim
To:	Ronald Kwan
Cc:	Usman Zahid; Gavin He
Subject:	FW: OFHP fees reg
Date:	Friday, October 13, 2017 2:38:39 PM
Attachments:	reg2017.0512.e04 with drafting instrns for leg counsel v4_EFB_v3.docx Draft Fees Regulation for OPG Trust and OFHP_OFA Q&As_Markup3.docx

Hi Ron,

We have consolidated comments / edits from FTD and CMD.

Thanks,

John

From: John Kim
Sent: Friday, October 13, 2017 2:01 PM
To: Carlos Yep <Carlos.Yep@ofina.on.ca>
Cc: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>; Mike Manning <Mike.Manning@ofina.on.ca>; James Devine <James.Devine@ofina.on.ca>; Anna Strathy <Anna.Strathy@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>
Subject: RE: OFHP fees reg

Here's the Qs and As. Put this in a Word so people can edit easily.

John

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Cc: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>; Mike Manning <Mike.Manning@ofina.on.ca>; James Devine <James.Devine@ofina.on.ca>; Anna Strathy <Anna.Strathy@ofina.on.ca>
Subject: RE: OFHP fees reg

Hi Carlos,

We added our comments to the draft regulation. Before sending back, I would like full review. The Qs and As will be sent shortly.

Energy staff have followed up on this (copied you and Ken on that response), reminding them of our email to them dated September 27, 2017.

Thanks,

John

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ıarket comparable fees" means fees, expressed as a **[yearly?]** percentage rate, charged by asset managers **[or management and financial service providers?]** in Canada or another jurisdiction specified by the Board for services that are similar to the services provided by the Financial Services Manager under the Act in terms of,

[NTD: (1) Confirm *yearly* percentage rate. (2) Confirm whether to include "or management and financial service providers". If this is to be included, what does this mean? Is it a well-recognized industry term of art?]

the type of services provided, being services in respect of funds including **securitization vehicles**, pension funds, other **structured** investment funds, hedge funds and other similar **structured** funds, **[NTD: Confirm "securitization vehicles" and "structured".]**

the scope of the services provided,

the level of the services provided, and

the dollar amount of assets under management;

Thanks,

Daniel

CONFIDENTIAL
Until filed with the
Registrar of Regulations

REG2017.0512.e
4-TP

ONTARIO REGULATION

made under the

ONTARIO FAIR HYDRO PLAN ACT, 2017

FEES

Definitions

1. (1) In this Regulation,

"average monthly funding obligation" means, in respect of a month, the amount determined in accordance with subsection (2);

"average annual funding obligation" means, in respect of a year, the sum of the average monthly funding obligations for the year;

"market comparable fees" means fees, expressed as a yearly percentage rate, charged by asset managers [or management and financial service providers] in Canada or another jurisdiction specified by the Board for services that are similar to the services provided by the Financial Services Manager under the Act in terms of,

[NTD for leg counsel: I am trying to get more clarity around "management and financial service providers". I am not sure whether the intent is to say "management service providers or financial service providers". If the intent is to refer to a "management and financial service provider", I will try to ascertain whether this is a well-understood industry "term of art" (since based on a brief search it did not appear to be).]

(a) the type of services provided, being services in respect of funds including securitization vehicles, pension funds, other structured investment funds, hedge funds and other similar structured funds,

(b) the scope of the services provided,

Commented [OFA1]: OFA is of the view that there should be no mention of references to securitization vehicles, active managed funds and/or hedge funds or any investments of that sort be included in the regulation. The financing entity has a very different structure and operates differently from securitization vehicles, hedge funds etc., so such market comparable fees/rates referencing such investment types would not be good representation of the benchmark in this situation.

Commented [DS2]: NTD for OEB: Is "specified by" the right way to say this?

Commented [DS3]: NTD for ESP/MoF: Should there be a "temporal" connection too? E.g. "… services that are similar to, and provided at a time that is similar to the time the services are provided by, the FSM …".

(c) the level of the services provided, and

(d) the dollar amount of assets under management;

"funding tranche" means an ~~specific~~ issuance of ~~debt by a financing entity and constitutes all or part of a~~ funding obligations of a particular series, class or type that have the same terms;

"FSM services" means services provided by the Financial Services Manager to financing entities in relation to the management and administration of the financing entities and the investment asset, including in relation to funding obligations incurred or that are planned to be incurred by the financing entities;

"market comparable forecast interest rates" means, in relation to a potential funding tranche described in the submissions mentioned in subsection 6 (3) or 6 (4), interest rates charged by lenders in Canada **[at the time the submissions are made]** for a debt obligation that,

(a) has a principal amount that is comparable to the principal amount of the funding tranche,

(b) has a term that is comparable to the term of the funding tranche **[in terms of length and commencement]**,

(c) is based on a type of instrument that is comparable to the type of instrument of the funding tranche,

(d) has payment rights that are similar to the payment rights of the funding tranche, and

(e) is issued by an issuer with a risk profile comparable to the risk profile of the financing entity issuing the funding tranche;

Commented [DS4]: NTD for OPG/MoF: Should this contemplate "posted" rates rather than rates "charged by"?

"net annual funding obligation" means, in respect of a year, the sum of the principal amounts of funding tranches issued in the year, other than any funding tranches that constitute a refinancing;

(2) For the purposes of determining the average monthly funding obligation for a month, the following formula applies:

$$(A + B) / 2$$

Where,

A = the sum of the balances on the first day of the month of the principal amount of all outstanding funding obligations incurred by financing entities,

B = the sum of the balances on the last day of the month of the principal amount of all outstanding funding obligations incurred by financing entities.

Forecast interest rate

1.1 For the purposes of this Regulation, the Financial Services Manager shall determine the forecast interest rate for a funding tranche that forms part of the net annual funding obligation for a year, by taking into account the following factors:

1. The interest rate for debt of or guaranteed by the Government of Ontario with a term or duration that is comparable to the term or duration of the funding tranche. **[NTD for leg counsel: We are confirming whether we need to refer to both "term" and "duration" here and in 2 ii below (and if yes, how these terms mean different things).]**

2. The estimated credit spread, relative to the interest rate described in paragraph 1, for a debt obligation that,

   i. has a principal amount that is comparable to the principal amount of the funding tranche,

   ii. has a term that is comparable to the term of the funding tranche **[in terms of length and commencement]**,

   iii. is based on a type of instrument that is comparable to the type of instrument of the funding tranche, ~~and~~

   iv. has payment rights that are similar to the payment rights of the funding tranche, and

   v. is issued by an issuer with a risk profile comparable to the risk profile of the financing entity issuing the funding tranche.

3. Anticipated fees and commissions expected to be payable in connection with the issuance of the funding tranche.

Fees that may be established, charged

2. (1) For the purposes of subsection 19 (3) of the Act, the fees established and charged by the Financial Services Manager may be charged to financing entities ~~in relation to the management and administration of financing entities and the investment asset, including in relation to funding obligations incurred or that are planned to be incurred by~~for FSM services provided to the financing entities.

(2) A fee mentioned in subsection (1) shall be comprised of a base fee calculated under section [3] and a variable fee calculated under section [6].

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Commented [DS5]: NTD for OPG/MoF: Even if the term is the same length, would the commencement date of the term not also be relevant?

Commented [DS6]: NTD for OPG: Energy Policy is asking whether the fees and commissions are relevant to the determination of the forecast interest rate for the tranche, given that they are recoverable by the FSM under s. 7(2) below.

(3) For the purposes of subsection 19 (3) of the Act, fees may be established and charged by the Financial Services Manager to financing entities for the recovery of costs and expenditures, as provided for in section [7].

(4) The Financial Services Manager shall not establish or charge any fees to financing entities other than those fees provided for under this Regulation.

Base fee

3. (1) Subject to sections [5.1] and [5.2], the Financial Services Manager shall establish the proposed base fee for a month as follows:

1. Determine the amount that is 0.075 per cent of the average monthly funding obligation for the preceding month.

2. Divide the amount determined under paragraph 1 by 12.

(2) The first month in respect of which the base fee may be established is ~~July~~ November 2017.

[OLC Note: Just need to confirm -- will there be an average monthly funding obligation for the month of June 2017? If not, it would not be possible to apply this method in respect of July 2017.] **[NTD for leg counsel: The first funding obligation may not be incurred until around November 2017. The base fee for a month would be zero if there was no average monthly funding obligation for the preceding month (i.e. if it was zero).]**

(3) The Financial Services Manager shall submit to the Board the base fee proposed to be charged in respect of the period from November 1, 2017 to December 31, 2018 no later than October 31, 2017.

(4) The Financial Services Manager shall submit to the Board the base fee proposed to be charged in respect of any year after 2018 no later than 120 days before the start of the year in respect of which the base fee would be charged.

[NTD for leg counsel: Let's move the submission provisions (other than the amendment submission provision) from section 9 to the respective sections that deal with the fee in question. As you will see in s. 6 and 7 below, the submission process will be different for each of the types of fees (base, variable, and costs/expenditures).]

[Further NTD for leg counsel: The Board's review of the base fee for the period from July 1, 2017 to December 31, 2018 will be limited to ensuring that the base fee is calculated correctly (i.e. calculated in accordance with ss. 5 (3)).]

Commented [DS7]: NTD for OPG/OEB: The policy instruction is to provide that costs and expenditures are recoverable so long as they relate to the matters described in s. 7.1(1), and that the Board review the costs and expenditures from that perspective.

In order to implement this instruction and give the Board the authority to review, we have to deem the costs and expenditures to be fees.

Commented [OFA8]: To start – may need to be clarified

Commented [OFA9]: 7.5bps for 2017 and 2018 to be reviewed by the OEB for future years? This subsection says the OEB to review for the initial proposed base fee also.

Commented [DS10]: NTD for OPG/OEB: Ss. 19(4) of the OFHPA requires the Board to approve fees.

Board review of base fee

5.1 (1) The Board shall refuse to approve the proposed base fee mentioned in subsection 5 (3) if the Board is of the view that the proposed base fee was not established in accordance with subsection 3 (1).

(2) If the Board refuses to approve the proposed base fee,

(a) the Board shall provide reasons for the refusal; and

(b) the Financial Services Manager shall submit to the Board a revised proposed base fee that is established in accordance with subsection 3 (1)

[NTD for leg counsel: If the Board does not refuse to approve a proposed base fee under ss. (1) or (3), then we should explicitly say that the Board will approve the proposed base fee. Please tweak ss. 5.1 (1) and (3) accordingly.]

(3) The Board may refuse to approve a proposed base fee mentioned in subsection 5 (4) if the Board is of the view that the proposed base fee is materially inconsistent with market comparable fees.

[OLC Note: Should this section only apply starting January 1, 2019?]

[OLC Note: Are you sure that this is the only reason why the Board can refuse the proposed base fee?]

[NTD for leg counsel: In response to your notes, for the proposed base fee applicable in 2019 and beyond, the only basis upon with the Board can withhold approval is inconsistency with market comparable fees. For the proposed base fee applicable July 1 – Dec31/17 and Jan1 – Dec31/18, the Board can only withhold approval if the base fee is inconsistent with the formula in s. 3(1).]

Commented [DS11]: Explanatory note for OEB: The reg-making powers in s. 19 of the OFHPA don't appear to provide the same ability to impose on the Board (by reg.) the base fee as with the OESP reg-making powers in ss. 79.2(6) of the OEBA.

(~~1.1~~4) If the Board refuses to approve the proposed base fee,

(a) the Board shall provide reasons for the refusal and may make recommendations to the Financial Services Manager regarding the determination of a base fee that is consistent with market comparable fees; and

(b) the Financial Services Manager shall submit to the Board,

(i) a revised proposed base fee that takes into consideration the recommendations of the Board, if any**;** and

(ii) a description of the methodology that the Financial Services Manager has applied to determine the revised proposed base fee, including details concerning the market comparable fees that the Financial Services Manager considered.

(5) **[NTD for leg counsel: Please add a provision that says that the process (i.e. the process outlined in ss. (1) and (2) above, or (3) and (4) above) will be repeated until the Board approves a proposed base fee for the year in question, unless you are of the view that that is already clearly implicit in those provisions.]**

(6) **[NTD for leg counsel: Please add a provision that says that:**

- **Until a new proposed base fee is approved, the FSM may continue to charge the most current Board-approved base fee (if any).**

- **Once the new proposed base fee is approved by the Board, the FSM shall make a "retrospective" adjustment to the base fee (in the month following the month in which the approval is given). The adjustment will be the difference (positive or negative) between the base fee actually charged in the relevant period up to that point, and the new base fee approved by the Board for that period. In other words, the Board approved fee would be "retrospectively" applied to the whole period. By "period" I mean either the initial period from Nov1/17 – Dec31/18 or any calendar year starting with 2019. Note that any amendment to fees (under s. 9.1) would only apply prospectively starting in the month following the month in which the amendments were approved by the Board.]**

Variable fee

6. (1) Subject to subsection (2) and section 6.1, the Financial Services Manager shall establish the variable fee for a year after 2017 as follows:

1. Apply the following formula in respect of each funding tranche that forms part of the net annual funding obligation for the year:

$$(A \times (B - C)) \times 0.05$$

Where,

A = the principal amount of the funding tranche,

B = the forecast interest rate for the funding tranche, and

C = the actual interest rate for the funding tranche.

2. Calculate the sum of the amounts determined by applying the formula under paragraph 1.

(2) If the circumstances set out in Column 1 of the following Table apply in a year, the variable fee payable for a year is subject to the rules set out opposite those circumstances in Column 2 of the Table:

~~Item~~	~~Column 1~~ ~~Circumstances~~	~~Column 2~~ ~~Rules~~
~~1.~~	~~The average annual funding obligations are $10 billion or less.~~	The variable fee payable for the year shall not be more than 1 per cent of the amount that is 5 per cent of the net annual funding obligation for the year. The variable fee payable for the year shall not be less than -1per cent of the amount that is 5 per cent of the net annual funding obligation.
~~2.~~	~~The average annual funding obligations are greater than $10 billion.~~	~~The variable fee payable for the year shall not be more than 2 per cent of the amount that is 5 per cent of the net annual funding obligation for the year.~~ ~~The variable fee payable for the year shall not be less than -2 per cent of the amount that is 5 per cent of the net annual funding obligation for the year.~~

(3) The Financial Services Manager shall make submissions to the Board in respect of the **[variable fee proposed to be charged in 2018, including the]** forecast interest rates for the funding tranches anticipated to be issued in 2018, no later than **[October 31, 2017]**.

(4) The Financial Services Manager shall make submissions to the Board in respect of the variable fee proposed to be charged in any year after 2018, including the forecast interest rates for the funding tranches anticipated to be issued in the year, no later than 120 days before the beginning of the year.

(5) If the Financial Services Manager has not submitted a forecast interest rate under subsection (3) or (4) for a funding tranche that will be issued in a year after 2017, the Board may require the Financial Services Manager to submit a proposed forecast interest rate for the funding tranche **[and may specify the time by which the submission must be made],** or the Board may determine the funding tranche taking into consideration the forecast interest rates submitted by the Financial Services Manager for the year under subsection (3) or (4).

Board review of variable fee

6.1 (1) The Board may refuse to approve a proposed variable fee if the Board is of the view that any forecast interest rate used for the purposes of subsection 6 (1) is inconsistent with ~~[~~market comparable forecast interest rates~~]~~.

[OLC Note: We provide an explanation for how to determine "market comparable fees" but we say nothing about how to determine "market comparable forecast interest rates". Please instruct.]

[NTD for leg counsel: We have created a new defined term "market comparable forecast interest rates" to address this.]

[OLC Note: Are you sure this is the only reason why the Board may refuse the proposed variable fee?] **[NTD for leg counsel: Yes.]**

(2) If the Board refuses to approve the proposed variable fee,

Commented [OFA12]: Delete references to the table and column 1 and column 2, consistent with the comment below.

Commented [OFA13]: In our previous correspondence, dated September 27, 2017 from Ken Kandeepan to Scott Nelms, we suggested deletion of column 1 and item 2.

Commented [DS14]: NTD for OPG/OEB: Is this wording appropriate?

Commented [DS15]: NTD for OPG: The policy instruction is to not require the Board to apply linear interpolation to come up with a forecast interest rate, because the approach would be too prescriptive for this fairly limited subset of total fees.

Commented [OFA16]: Same comment as above. OFA is of the view that there should be no mention of references to securitization vehicles, active managed funds and/or hedge funds or any investments of that sort be included in the regulation. The financing entity has a very different structure and operates differently from securitization vehicles, hedge funds etc., so such market comparable fees/rates referencing such investment types would not be good representation of the benchmark in this situation.

(a) the Board shall provide reasons for the refusal and may make recommendations to the Financial Services Manager regarding each forecast interest rate that the Board found was inconsistent with ~~[~~market comparable forecast interest rates~~]~~; and

(b) the Financial Services Manager shall submit to the Board,

(i) a revised proposed fee that takes into consideration the recommendations of the Board, if any, and

(ii) a description of the methodology that the Financial Services Manager has applied to determine revised forecast interest rates for each funding tranche in respect of which the Board found an inconsistency with ~~[~~market comparable forecast interest rates~~]~~.

~~Fees~~ Reimbursements for costs and expenditures

7. (1) The Financial Services Manager may establish and charge fees for the recovery from a financing entity of any costs and expenditures incurred by the Financial Services Manager,

(a) on behalf of the financing entity in connection with the Financial Services Manager's duties under the Act in relation to the financing entity; or

(b) under a management agreement between the Financial Services Manager and the financing entity, where the agreement provides for the reimbursement of the costs and expenditures.

(2) The costs and expenditures referred to in subsection (1) may include costs and expenditures in respect of the following:

1. Underwriters or selling agents for funding obligations.

2. Banking fees, including structuring fees or work fees.

3. Fees of issuing and paying agents for funding obligations.

4. Fees of trustees.

5. Fees incurred in the preparation of financial statements, financial reports, compliance certificates and tax returns.

6. Fees of legal counsel.

7. Rating agency fees.

8. Filing or registration fees.

9. Direct costs of the Financial Services Manager for employees who are dedicated to providing FSM services to financing entities.

~~(3) The costs and expenditures referred to in subsection (1) shall not include any overhead costs of the Financial Services Manager, including [….].~~
~~[OLC Note: The phrase "overhead costs" seems a bit vague. Examples would help.]~~

Board review of fees for costs, expenditures

7.1 (1) The Board may refuse to approve a proposed fee for costs and expenditures or a portion of a proposed fee for costs and expenditures if the Board is of the view that the proposed fee is in respect of costs and expenditures that were not incurred in relation to the management and administration of financing entities and the investment asset, including in relation to funding obligations incurred or that are planned to be incurred by the financing entities.

(2) If the Board refuses to approve the proposed fee or a portion of the proposed fee, the amount not approved shall not be payable to the Financial Services Manager and the associated costs and expenditures shall not be recoverable by the Financial Services Manager from the financing entity.

~~(a) the Board shall provide reasons for the refusal and may make recommendations to the Financial Services Manager regarding the proposed fee; and~~

~~(b) the Financial Services Manager shall submit to the Board,~~

~~(i) a revised proposed fee that takes into consideration the recommendations of the Board, if any, and~~

~~(ii) a description of how the proposed fee is in respect of costs and expenditures that were incurred in relation to the management and administration of financing entities and the investment asset.~~

Charging of fees

8. (1) Subject to sections [5.1], [6.1] and [7.1], in charging fees, the Financial Services Manager shall provide for,

(a) the base fee for a month to be payable within **[x]** days after the end of the month;

Commented [DS17]: NTD: Need to specify when the base fee is payable.

(b) the variable fee for a year to be payable in the following calendar year in twelve equal monthly instalments that coincide with the payment of the base fee for each month; and

(c) the fee for costs and expenditures for a month to be payable within [x] days after the end of the month.

Commented [DS18]: NTD: Need to specify when the fee for costs and expenditures is payable.

(2) If the variable fee for a year is a negative amount, it shall be deducted in twelve equal monthly instalments from the base fee payable in the following year.

(3) Where there is more than one financing entity, the portion of the fees allocated to and payable by a financing entity shall be based on its proportionate share of the average principal amount of funding obligations for the applicable period.

Commented [DS19]: NTD: Should this be based on the average of the opening and closing balances for the applicable period (e.g. year)?

(4) For the purposes of determining the average principal amount of funding obligations under subsection (3), the formula set out in subsection 1 (2) applies with necessary modifications.
[OLC Note: Please confirm that this works.]

Submissions to Board

9.1 ~~(1) The Financial Services Manager shall make submissions to the Board in respect of fees proposed to be charged in 2018 no later than October 31, 2017.~~

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~~(2) The Financial Services Manager shall make submissions to the Board in respect of fees proposed to be charged in respect of any year after 2018 no later than 120 days before the start of the year in respect of which the fees would be charged.~~

~~(3)~~ The Financial Services Manager may, no more frequently than once in any consecutive twelve month period, make submissions to the Board to amend any base fee or variable fee~~s~~ approved by the Board, and the provisions of section [5.1]. [6.1] or [7.1], as applicable, apply in respect of the submissions.

Board approval, general

10. (1) For the purpose of determining whether to approve a proposed fee, the Board shall consider the information provided by the Financial Service Manager in its submission relating to the proposed fee.

(2) For the purpose of determining whether to approve a proposed base fee or variable fee, the Board may consider, as it determines to be appropriate, the advice provided by third party consultants and experts. **[NTD for leg counsel: We want to retain this provision, but the Board noted that they already have this ability without needing to specifically include it here. The Board flagged the risk of an adverse interpretation in other contexts where the Board is not given explicit statutory authority to consider advice of third party consultants and experts. Can we word this ss. 10(2) in such a way that it is just "for greater clarity"?]**

Commencement

11. This Regulation comes into force on the day it is filed.

Draft Fees Regulation for OPG Trust and OFHP

Question 1: On the process for establishing the base fee and variable fee, which could theoretically spill over into the year to which the new fees would apply (if OEB approval was not obtained until then), the thinking would be to have the old fees apply until the new fees were approved by the OEB, and then have a "retroactive" adjustment of the fees (retroactively adjusting them back to the beginning of the year the new fees take effect). Since the base fee and variable fee are payable monthly, the "retroactive" adjustment would be made in the month following the month in which the new fees were finalized. The question for OFA is whether it would be appropriate to have a retroactive fee adjustment.

OFA Comment: OFA would defer this item to Energy and OFA staff are of the view that retroactive adjustments of the fees applying once the rates are finalized would be acceptable. This would mean that the old rates would continue to apply until the decisions are made by the OEB.

Question 2: Re: discussion between OPG and OFA about what "market comparable fees", OPG has proposed that there be a requirement for five sets of fees, four of which would be fees charged by full-service managers of securitization vehicles, and the fifth of which would be fees charged by an asset manager (or management and financial services provider) in respect of any one of pension funds, other structured investment funds, hedge funds or other similar structured funds. Does the OFA have any comments on this approach or the viability of finding five such comparators? The Board has suggested that the FSM be required to submit fee comparators but that the Board have the ability to also include comparators that it chooses (e.g. on the advice of consultants/experts it retains).

OFA Comment: OFA had indicated that the earlier proposal of 10 bps for the initial proposed base fee was too high and since then a decision to set the initial proposed base fee at 7.5 bps was made. While the 7.5 bps would be applicable in the first year of operations it was also agreed that the OEB will retain an outside expert to provide recommendations on an appropriate rate based on a market survey. In the draft regulation provided by Energy on October 12, 2017, the draft regulation would require the OEB to set the base fee rates based on the market comparable fees. OFA staff are of the view that there should be no references made in the draft regulation about investment vehicles listed in the Question 2 and in Question 4, including securitization vehicles, actively managed investment funds, structured investment funds, hedge funds and/or other types of structured funds. Securitization vehicles, for example, involve significant amount of work 'packaging' a large number of underlying assets into an investment structure. The financing entity has a very different structure and operates differently from securitization vehicles, hedge funds etc., so such market comparable fees/rates referencing such investment types would not be good representation of the benchmark in this situation.

Question 3: Are there "market comparable fees" that allow the person charging the fees to also recover out-of-pocket costs over and above the fees?

OFA Comment: OFA staff are of the view that this is acceptable if done in accordance with the Act and if appropriately audited.

Question 4: Can the OFA provide comments on the below draft definition of "market comparable fees" reads as follows (the NTDs are for OFA's input)?

"market comparable fees" means fees, expressed as a **[yearly?]** percentage rate, charged by asset managers **[or management and financial service providers?]** in Canada or another jurisdiction specified by the Board for services that are similar to the services provided by the Financial Services Manager under the Act in terms of,

[NTD: (1) Confirm *yearly* percentage rate. (2) Confirm whether to include "or management and financial service providers". If this is to be included, what does this mean? Is it a well-recognized industry term of art?]

(a) the type of services provided, being services in respect of funds including **securitization vehicles**, pension funds, other **structured** investment funds, hedge funds and other similar **structured** funds, **[NTD: Confirm "securitization vehicles" and "structured".]**

(b) the scope of the services provided,

(c) the level of the services provided, and

(d) the dollar amount of assets under management;"

OFA Comment: OFA staff are of the view that there should be no references made in the draft regulation about investment vehicles listed in the Question 2 and Question 4, including securitization vehicles, actively managed investment funds, structured investment funds, hedge funds and/or other types of structured funds. Securitization vehicles, for example, involve significant amount of work 'packaging' a large number of underlying assets into an investment structure. The financing entity has a very different structure and operates differently from securitization vehicles, hedge funds etc., so such market comparable fees/rates referencing such investment types would not be good representation of the benchmark in this situation.

From: John Kim
To: Ronald Kwan
Subject: FW: OPG - Sub Debt + Variable Fee
Date: Monday, July 31, 2017 1:43:11 PM

FYI.

From: Carlos Yep
Sent: Monday, July 31, 2017 12:58 PM
To: John Kim <John.Kim@ofina.on.ca>
Subject: RE: OPG - Sub Debt + Variable Fee

I just forwarded some communication between Ken, OPG and E&Y

The calculations on one of the documents is missing the word "NET"
Ie we do not want to pay performance on any re-financing only on new net financing

---

From: John Kim
Sent: Monday, July 31, 2017 12:54 PM
To: Carlos Yep <Carlos.Yep@ofina.on.ca>
Subject: RE: OPG - Sub Debt + Variable Fee

Could you send me the latest on the performance fee (fixed and variable)?

From: Carlos Yep
Sent: Monday, July 31, 2017 12:27 PM
To: John Kim <John.Kim@ofina.on.ca>
Subject: FW: OPG - Sub Debt + Variable Fee

From:	Ronald Kwan
To:	John Kim; Bruno Amara
Cc:	Usman Zahid; Francisco Chinchon
Subject:	FW: OPG 2018-2021 Business Plan
Date:	Tuesday, February 13, 2018 12:12:46 PM
Attachments:	OPG 2018-2021 BPlan w Transmittal.blord to mstr.18feb12.pdf

Hi,

Please review.

Ron

From: Calwell, Carolyn (ENERGY) [mailto:Carolyn.Calwell@ontario.ca]
Sent: February-13-18 12:08
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Talwar, Shruti (ENERGY) <Shruti.Talwar@ontario.ca>
Subject: FW: OPG 2018-2021 Business Plan

Hi Ron – wanted to get this over to you. Shruti will also share with staff. We are just beginning our review.

Carolyn

From: KING Catriona -OFFCORPSEC [mailto:catriona.king@opg.com]
Sent: February 12, 2018 7:14 PM
To: Thibeault, Glenn (ENERGY)
Cc: Imbrogno, Serge (ENERGY); Calwell, Carolyn (ENERGY); LYASH Jeffrey -PRESIDENT; Bernard Lord; LORD Bernard -BOARDCHAIR; HARTWICK Ken -FINANCE; ROWE Jennifer -CORPAFFAIRS
Subject: OPG 2018-2021 Business Plan

Dear Minister Thibeault,

Please see attached correspondence, sent on behalf of OPG Board Chair Bernard Lord, submitting OPG's 2018-2021 Business Plan for your concurrence, per the Memorandum of Agreement with the shareholder.
thx

Catriona King | Vice President, Corporate Secretary | Ontario Power Generation Inc.
700 University Avenue, Suite H19 D26, Toronto, Ontario M5G 1X6 | W: 416.592.4474 | C: 416.524.4421| F: 416.592.4555 |
| E: **catriona.king@opg.com**
Good Governance is Good Business

ONTARIO POWER GENERATION

Bernard Lord
Board Chair

700 University Ave, Toronto, ON M5G 1X6

Tel: 416-592-2115
bernard.lord@opg.com

February 12, 2018

The Honourable Glenn Thibeault
Minister of Energy
4th Floor, Hearst Block
900 Bay Street
Toronto, Ontario
M7A 2E1

Sent by email

Dear Minister,

On behalf of the OPG Board of Directors (the Board), I am writing to provide you with OPG's 2018-2021 Business Plan (the Plan) which was approved by the Board at its meeting on February 12, 2018, in fulfillment of our 2015 Memorandum of Agreement.

Highlights of the 2018-2021 Business Plan:

Overall, the 2018-2021 Business Plan shows improvement compared to last year's business plan in large part due to efficiency efforts on Operations Maintenance & Administration (OM&A) costs and improvements and optimization in our generation forecast. This plan fully reflects the outcome of the OEB Decision on OPG's base regulated rates. This is the first such business plan with OPG operating under incentive regulation for regulated hydroelectric assets and a custom incentive regulation approach for regulated nuclear assets. The key highlights of the business plan, excluding the impact of the Fair Hydro Plan, on a calendar year basis, are as shown in the table below:

	Actual	Business Plan			
	2017	2018	2019	2020	2021
Net Income Attributable to Shareholder, excl. Fair Hydro Trust *($ millions)*	859	995	968	764	1,160
Total Return to Shareholder, excl. Fair Hydro Trust *($ millions)*	1,393	1,391	1,422	1,259	1,667
Return on Equity, excl. Fair Hydro Trust	7.7%	8.5%	7.7%	5.7%	8.1%
Debt Ratio, excl. Fair Hydro Trust*	34%	36%	33%	30%	26%
Enterprise Total Generating Cost *($/MWh)*	50.7	54.7	50.6	53.9	48.9
Production (net of Surplus Baseload Generation) *(TWh)*	73.8	72.4	74.5	70.6	71.0
OM&A Expenses from Ongoing Operations *($ millions)*	2,819	2,850	2,732	2,807	2,570
Capital Expenditures *($ millions)*	1,926	2,082	1,859	1,781	1,830
Total Headcount (Regular and Term Employees)	9,354	9,434	9,358	9,287	9,180

*Excludes Class A Shares and Fair Hydro Trust Senior Debt

The final revenue rates for OPG are still to be finalized by the OEB. The OEB Decision on revenue requirements was released December 28, 2017. A draft Payment Amounts Order (PAO) was submitted by OPG on January 17, 2018. Subsequent Intervenor and Board staff submissions were made and OPG filed its Final Reply to the PAO process on February 5, 2018. A final decision on the payments process, that will determine OPG's cash flow through rates, will be issued by the OEB sometime in the first half of this year. The payments process is more complicated than in previous applications as it must reflect a rate smoothing proposal that meets the intent of the updated O. Reg 53/05 that aims to make smoother customer bills. Smoothing does not impact OPG's financial commitments to the Province.

Total Return to Shareholder (the combination of Net Income, Income Tax and non income tax PILS) is forecast to be $5.9 billion for the fiscal years ended March 31, 2018 to 2021 as noted in the table below:

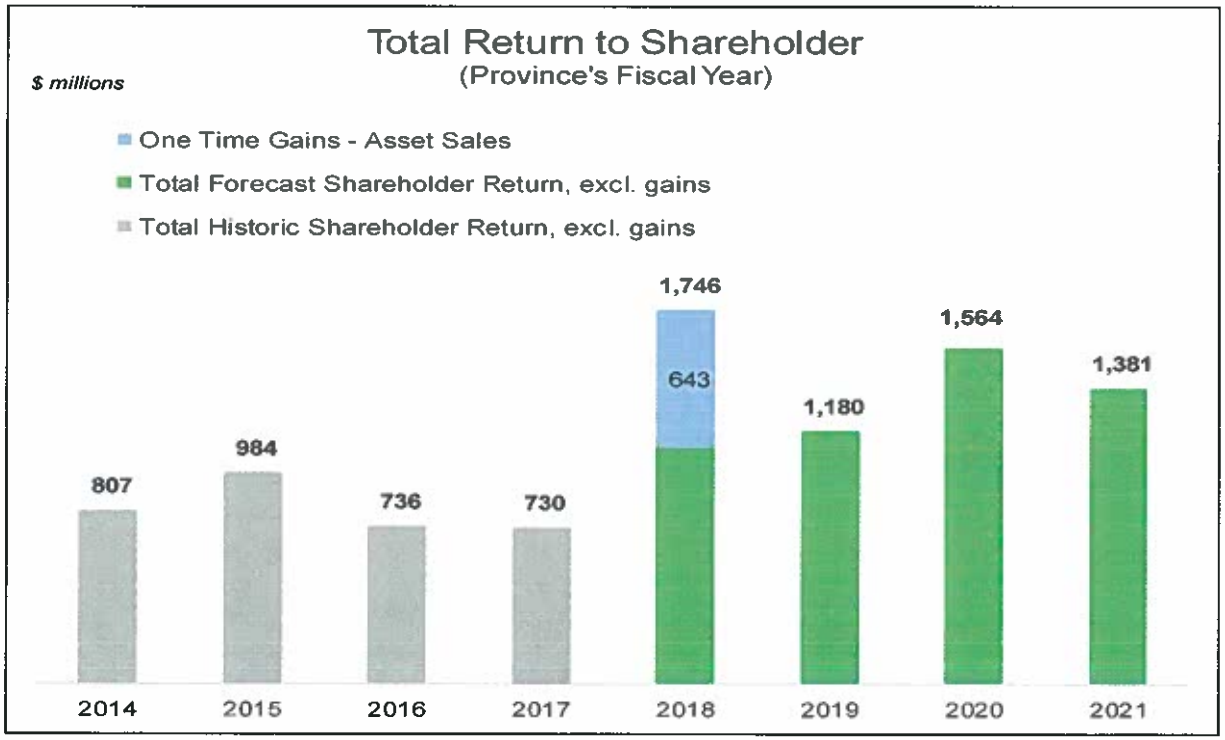
Total Shareholder Return

$ millions	2018*	2019	2020	2021	Total
Net Income Attributable to Shareholder	**1,195**	**795**	**1,053**	**877**	
Non Income Tax PILs					
GRC: Payable to OEFC	206	209	212	212	
GRC: Payable to MOF	103	101	103	103	
GRC: Payable to Niagara Parks Commission	7	7	7	8	
Property Tax Payable to OEFC	13	14	14	13	
Total Non Income Tax PILs	**330**	**331**	**336**	**335**	
Income Tax PILs	**221**	**54**	**175**	**169**	
Total Shareholder Return**	**1,746**	**1,180**	**1,564**	**1,381**	**5,871**
Improvement from 2017-2019 Business Plan	**528**	**4**	**307**	**-**	**838**

* Includes Gain from Sale of 700 University (EBT $376M; Net Income $283M), and an estimate of the Sale of Lakeview (EBT ~$270M; Net Income ~$200M)

** Excludes EBT from Fair Hydro Plan of $10M, $80M, $150M and $225M for fiscal years ended March 31, 2018-2021

The fiscal results achieved in the 2018-2021 Business Plan reflect an improvement of over $800M compared to last year's plan for the fiscal years 2018 – 2020. In fact, since 2014 when our financial commitments were first communicated using the Total Return to Shareholder metric, OPG's results have been stable as seen in the chart below and are forecast to show a positive trend over the plan period.



While the OEB Decision disallowed a variety of revenue requirement items, OPG has taken proactive steps that will help mitigate a large portion of those disallowances including:

- Reducing over $600M in OM&A costs between 2018 and 2021 through cost cutting and efficiency measures. These steps will also help position OPG to be a more efficient operator, particularly in planning for the ultimate shutdown of the Pickering generating station in 2024.
- Leveraging off the excellent performance of Pickering and outage execution in general in the nuclear fleet, generation improvements are planned from nuclear and reflected in the forecast

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- Continuing to invest in our hydroelectric operations to optimize performance and availability to increase generation output from the hydroelectric assets

OPG remains focused on delivering projects safely, with high quality, on time and on budget. Major development projects over the Plan period are consistent with the recent 2017 LTEP, and include:

- Continuing and completing the refurbishment of the first *Darlington* unit (Unit 2), on time and on budget;
- Commencing the execution phase of the second Darlington unit (Unit 3) for refurbishment;
- Expansion of the *Ranney Falls* hydroelectric station in 2017/18 and other smaller hydroelectric redevelopments;
- Execution of dam safety upgrade initiatives at Lower Mattagami;
- Completion of the 44 MW Nanticoke solar project by 2019; and
- Investments of $200 million in organic growth opportunities leveraging OPG's core competencies beyond the current core generation portfolio.

With respect to the Darlington Refurbishment project, OPG is satisfied that the OEB agrees with the company's position that the program is a well planned, well controlled large project and that the OEB has agreed to put into service the $4.8 billion costs of Unit 2 as tabled by OPG in addition to the $0.4 billion in remaining pre requisite projects excluding the Heavy Water Storage and Drum Handling Facility. Combined with projects that have been placed into the rate base previously, total life to date in-service capital from Darlington Refurbishment will be approximately $5.5 billion by the time Unit 2 is completed.

In terms of impact to customers, OPG's payments application would result in a typical residential customer bill increase of $0.65 per month per year over the 5-year rate period. In return, the first of the four Darlington units will have been refurbished, providing decades of clean, reliable supply of electricity at a cost lower than other alternatives; a fact that was validated by the Financial Accountability Office's report on refurbishments in Ontario that was issued in November 2017. In addition, the life of Pickering will have been extended through 2024, reducing customer cost by over $600 million. The cost to customers of electricity generated by OPG during this period is expected to remain approximately 40% below the average non-OPG cost of electricity in Ontario.

Critical Factors in the 2018-2021 Business Plan

There are a number of factors that impact achieving this Business Plan that I would like to bring to your attention.

- **Pickering Relicensing:** The Plan reflects the continued investment and work required to support the continued operations of the Pickering plant until 2024 with CNSC approval. The OEB has confirmed and accepted the incremental investment required to achieve the extended operating life for the station and the economic regulatory risk has been greatly reduced. The needed work to ensure the ability to operate the units longer is being executed through upcoming outages at the station. While this critical work is ongoing, the nuclear business has been able to execute outages as planned and has optimized outage schedules to increase reliability and generation output from the plant. A key piece to complete the path forward for Pickering will be success at the upcoming hearing with the CNSC to renew the station's operating license. The existing license is set to expire at the end of August 2018. A 10 year operating license is being sought that would see the plant through to its end of commercial operations as well as allow for the defueling and other key work required to safely lay up the units. Support from across the company and from stakeholders will be crucial as part of the relicensing exercise. The benefits of an extended Pickering station life include reduced CO_2 emissions, support for lower smoothed nuclear rates during refurbishment of Darlington, and continued employment for the approximate 4,000 staff impacted by a Pickering closure. An earlier closure of the station would not deliver the benefits noted and would trigger severance and other closure related costs that would put upward pressure on customer prices.

- **Continued support for Darlington refurbishment efforts:** OPG is approaching the mid point in the schedule for refurbishment of Unit 2 and the project is tracking on time and on budget. While the subsequent unit planned for refurbishment (Unit 3) will not commence execution until Unit 2 is successfully returned to service by February 2020 at the latest, planning efforts and acquisition of long lead time materials must continue. To end of 2017, $93 million has been spent on planning activities for Unit 3 with a further $540 million planned over the 2018 – 2020 period prior to breaker open. OPG

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is pleased that the Province has agreed with OPG's assessment of progress to date and is not exercising an "off ramp" for Unit 3. This is another clear milestone for the project and OPG is looking forward to continued support from the Province that will culminate in the refurbishment of all 4 units within the overall budget of $12.8 billion.

- **Collective Bargaining impacts:** 2018 is a watershed year in terms of setting a path forward with our unionized workforce. The OEB, in its Decision, sent clear signals that the cost basis of OPG's regulated operations does not benchmark favourably on several fronts including compensation and in portions of corporate support costs. The fact that our total compensation for our unionized workforce, inclusive of pension and benefits, benchmarks above median sends a clear mandate to address these issues as part of collective bargaining. While such changes are difficult to achieve, 2018 offers a key opportunity in that both agreements with the Power Workers Union and the Society of Energy Professionals come due during the year.

- **Fair Hydro Plan:** The end of 2017 marked the commencement of OPG's involvement as the financial services manager for the Fair Hydro Plan. Over time, additional equity infusion from the Province will be made in part to finance portions of the global adjustment deferred asset that is being acquired from the IESO. Through this process, OPG will earn financial returns, mainly from the Province's incremental equity investment, that will be returned to the Province via increased net income. As disclosed in the footnote to the Total Shareholder Return forecast above, those amounts become larger as more of the deferred Global Adjustment asset is acquired by the Fair Hydro Trust, reaching $225 in net income by 2021.

- **OPG's Capital Allocation:** The business plan is focused on increasing net income and ROE from core operations through improved operational performance of the generating fleet and a number of steps to realign the corporate cost structure and operating model. In turn, OPG's increasingly improving financial performance, cost effective public debt platform and industry experience position the company well for developing a portfolio of organic and external investment options in low-carbon generating assets and potential extensions to the business complementary to existing operations.

OPG's 2018-2021 Business Plan sets ambitious but achievable goals and targets, and will deliver increased value to the Shareholder and Ontario electricity customers. OPG has demonstrated stable returns to the shareholder over the past 5 years and the 2018-2021 Business Plan forecasts a positive, increasing trend.

With the regulatory certainty provided by the OEB in its recent decision, the path forward for OPG is clear: to continue to provide reliable, safe and economic generation of electricity while challenging existing cost structures to drive enhanced efficiencies. OPG will achieve this while staying focussed on the successful execution of Darlington refurbishment and looking for growth opportunities to leverage existing operational strength. OPG's current business portfolio is heavily weighted on Ontario-centric regulated nuclear and hydroelectric generation. Although perceived as relatively low risk, this lack of diversification increases OPG's overall business viability risk. Diversifying OPG's business by developing a portfolio of options of future storage, gas, solar, hydroelectric and nuclear opportunities inside and outside of Ontario, focusing on innovation including investments in disruptive innovation, and investigating potential extensions to OPG's business is necessary to reduce OPG's overall business viability risk over the long term. With its strong financial position, OPG will continuously monitor for business growth opportunities and, where appropriate and with the support of the Shareholder, act as needed in order to maintain OPG's scale as a valuable public asset.

Sincerely,

Bernard Lord

cc. OPG Board of Directors
Serge Imbrogno, Deputy Minister of Energy

Enclosure

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OPG's 2018-2021 Business Plan

February 12, 2018

ONTARIO POWER GENERATION

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Overview

OPG's 2018-2021 Business Plan is focused on continuing to drive sustained value for the Shareholder and customers in line with the Company's strategic direction and builds on the progress made to date in advancing the underlying strategic imperatives of operational excellence, project excellence, financial strength and social licence. The plan is aligned with Ontario's 2017 Long-Term Energy Plan (LTEP), through continuing to execute the Darlington refurbishment, implement plans for Pickering continued operation to 2024, invest in hydroelectric fleet upgrades and development, and pursue commercial innovation strategies in the electricity sector. The plan reflects the Ontario Energy Board's (OEB) December 28, 2017 decision on OPG's 2017-2021 regulated rates and includes preliminary, unaudited results for OPG's 2017 fiscal year. Financial information presented includes the impact of consolidating the Fair Hydro Trust established in December 2017 to finance Ontario's Fair Hydro Plan.

The plan is underpinned by the Company's strategic direction that seeks to deliver an appropriate return on the Shareholder's investment in OPG, while maintaining the Company's position as the low cost provider of safe, clean and reliable electricity in Ontario. The plan makes progress toward achieving these strategic priorities by implementing key enterprise and business unit level initiatives and by establishing goals to drive plan-over-plan improvement in operational and financial performance. The plan builds on OPG's strong performance in 2017, seeking to maximize the value of existing assets by continuing to further improve fleet performance and optimize nuclear outages during a period of relative regulatory certainty provided by the OEB's recent decision. At the same time, the plan recognizes that the OEB's decision to disallow certain operations, maintenance and administration (OM&A) expenses, in large part based on benchmarking results for OPG's historical cost and operating performance, and reduce capital funding for the nuclear business will challenge OPG's ability to earn the target rate of return on the Shareholder's investment, absent changes to the Company's current cost structure.

OPG's ability to successfully deliver on the strategic direction requires a realignment of the Company's cost structure and operating model in order to further improve the cost performance of the core generating fleet, including corporate support functions. Continuous improvement in operational and cost performance should support more favourable outcomes of future OEB decisions. Longer-term success also requires a platform for material strategic investments to maintain and enhance OPG's scale, risk profile and energy industry leadership across carbon-friendly technologies, particularly as the Company prepares for post-Pickering operations. This includes continuing to take steps to enhance the Company's sustainable footprint in line with the Company's social licence strategic imperative. In pursuing these strategies, an absolute priority for OPG remains maintaining a strong nuclear and public safety record, while delivering the Darlington refurbishment on time and on budget.

The financing of the Fair Hydro Trust impacts OPG's net income and return profiles. In order to evaluate performance plans and results on a comparable basis, additional financial metrics are required within OPG's operations. In the discussion that follows, the following terms are used to describe OPG's financial performance:

- ***Net income*** and ***Total Return on Equity (ROE)*** are based on OPG's consolidated financial performance and corporate capital structure, including the impact of the Fair Hydro Trust;
- ***Operating net income*** and ***Operating ROE*** exclude the impact of the Fair Hydro Trust and exclude the gains on sale of 700 University Ave. property and the Lakeview site and corresponding dividend payments to the Shareholder from net income and corporate capital structure;
- ***Regulated ROE*** is return on OPG's regulated operations calculated using an equity thickness of 45%, as reflected in the deemed capital structure used by the OEB to set OPG's regulated rates.

Highlights of the 2018-2021 Business Plan are as follows:

- Operating net income and Operating ROE are trending upward over the period on higher nuclear production, lower OM&A costs, and rate base growth upon return to service of Darlington Unit 2;
- Operating net income and Operating ROE temporarily decline in 2020 due to the six-unit Pickering VBO and other major planned outages scheduled in the year;
- The Fair Hydro Trust contributes to increasing amounts of incremental net income as the total investment interest grows, driving down Total ROE due to Province's equity injections;

- Operating cash flow inclusive of Fair Hydro Trust returns is sufficient to fund capital expenditures over the period, with OPG's debt ratio excluding Fair Hydro Trust dropping to 26% by 2021, assuming no acquisition investments;
- Net income and ROE in 2017 are adversely affected by a partial-year effective date of June 1, 2017 for new regulated rates.

2018-2021 Business Plan Summary	Actual	Business Plan			
	2017	2018	2019	2020	2021
Net Income Attributable to Shareholder *($ millions)*	860	1,043	1,066	919	1,373
Operating Net Income Attributable to Shareholder *($ millions)*	576	795	968	764	1,160
Total Return on Equity	7.6%	8.1%	7.2%	5.4%	7.1%
Operating Return on Equity	5.3%	6.8%	7.7%	5.7%	8.1%
Regulated Return on Equity	Average of 8.2% over the 2017 to 2021 period				
Debt Ratio, excl. Fair Hydro Trust*	34%	36%	33%	30%	26%
Enterprise Total Generating Cost *($/MWh)*	50.7	54.7	50.6	53.9	48.9
Production (net of Surplus Baseload Generation) *(TWh)*	73.8	72.4	74.5	70.6	71.0
OM&A Expenses from Ongoing Operations *($ millions)*	2,819	2,850	2,732	2,807	2,570
Capital Expenditures *($ millions)*	1,926	2,082	1,859	1,781	1,830
Total Headcount (Regular and Term Employees)	9,354	9,434	9,358	9,287	9,180

*Excludes Class A Shares and Fair Hydro Trust Senior Debt

Key Assumptions and Risks

- Province's concurrence is received to proceed with the refurbishment of subsequent Darlington units, and the project continues to be executed consistent with the approved overall project budget and schedule. Failure to receive the concurrence or to meet project cost and schedule commitments could potentially result in significant write-offs against net income as well as reputational damage. Costs incurred for Darlington Unit 2 refurbishment and pre-requisite projects beyond total in-service amounts including contingency approved by the OEB for 2017-2021 will be subject to a future prudence review. The OEB has found that OPG's performance on the Darlington refurbishment should be evaluated at the overall program level rather than by individual component.
- Activities continue to be successfully carried out to enable Pickering continued operation beyond 2020, with a corresponding operating licence granted by the Canadian Nuclear Safety Commission (CNSC) by August 2018. Inability to extend Pickering operation beyond 2020 would result in advancement of significant employee downsizing and organizational restructuring impacts and station decommissioning expenditures, and require OPG to notify the OEB. Continuing Pickering operation has a moderating effect on OPG's nuclear rates.
- OPG's strategy to pursue non-organic expansion options including gas, solar and hydroelectric assets primarily outside of Ontario and potential extensions to the business must meet Shareholder's expectations. Lack of material growth investments and their commensurate contributions to scale, income and cash flow, together with a less diversified asset portfolio, will result in a loss of scale following retirement of Pickering, increase the risk of being unable to withstand significant variances or shocks to the business plan, diminish ability to support de-carbonisation policy and ultimately erode the value of Shareholder's investment.
- Future employee termination costs associated with the Pickering end of commercial operations are not included in the business plan. Accounting criteria requiring recognition of a liability for these costs are currently assumed to be met during the next nuclear rate-setting period, commencing in 2022. Recognition of the costs prior to 2022 would require assurance over their future recovery in order to avoid a significant charge against net income.

- Inability to retain and attract leadership talent and qualified management employees could adversely impact the execution of Darlington refurbishment, continued Pickering operation and other strategic priorities. Management and staff must continue to adapt to OPG's evolving corporate culture and higher level of commercial discipline, including commercial implications of the recently established public debt platform.
- OPG continues to report its financial results under United States generally accepted accounting principles (US GAAP) rather than International Financial Reporting Standards (IFRS), with the Ontario Securities Commission expected to grant an extension to the exemption allowing OPG to prepare its consolidated financial statements under US GAAP. Adoption of IFRS would be expected to cause significant volatility in OPG's net income compared to US GAAP.
- OPG's pension, OPEB and nuclear waste obligations, and related funds are exposed to financial market conditions. The plan assumes that the funds perform according to long-term expectations.

Further details of the key planning assumptions for the 2018-2021 period are found in Appendix 1 and additional key risks to the plan are identified in Appendix 2.

Net Income, Total Shareholder Return and Customer Price

Total net income attributable to the Shareholder is forecast to grow from $860 million in 2017 to $1,373 million in 2021, reflecting regulated rates based on the OEB's 2017-2021 rate decision inclusive of a significant increase in rate base upon return to service of Darlington Unit 2, continuous operational improvement, and the impact of the Fair Hydro Trust. This includes a plan-over-plan increase of ~$390 million in 2018-2021 Operating net income. The planned net income levels are critically dependent on OPG's ability to achieve targeted OM&A cost reduction and production goals set out in the plan, and ability to deliver the Darlington refurbishment on time and on budget.

Successful execution of the business plan will allow OPG to contribute $5.7 billion in earnings and taxes to the Shareholder over the 2018-2021 period, excluding the impact of the Fair Hydro Trust, while continuing to substantially mitigate the cost of electricity in the province. The overall customer cost of OPG's generation, taking into account the impact of the OEB's 2017-2021 rate decision, will continue to track approximately 40% below other generators in Ontario. Per OPG's proposed payment amounts order filed with the OEB in January 2018, regulated rates resulting from the OEB's decision would produce consistent annual increases of 0.4% or $0.65 on a typical residential customer's monthly bill during the 2017 to 2021 period, deferring recovery of about $750 million in OPG nuclear revenues (including interest) to future periods. The OEB is expected to issue the final payment amounts order during the first half of 2018.

The Fair Hydro Trust is forecast to contribute over $500 million in net income over the period, reflecting the spread earned on the equity contributions from the Province to fund 44% of OPG's financing of the Trust. Although the gain on the Lakeview sale is expected to contribute $200 million to net income in 2018, OPG is required to transfer the majority of the proceeds from the sale to the Province. The transfer is included in planned dividend payments to the Shareholder of over $475 million in 2018, which also includes the transfer of the majority of the proceeds from the sale of the 700 University Ave. property in 2017.

Operations, Maintenance & Administration Costs

Total plan-over-plan reductions in OM&A expenses from ongoing operations are ~$800 million over the 2018-2021 period, including ~$600 million that contributes to net income and is primarily associated with cost structure, nuclear outage and other business optimization initiatives and other changes that are not subject to true-up with customers through OEB-authorized regulatory deferral and variance accounts. A number of these initiatives are aimed at achieving sustainable productivity enhancements and cost efficiencies through optimization of resources, processes and technology, and will prepare the Company for post-Pickering operations. The initiatives are supported by a continuing corporate culture shift, significant investments in technology, and a clear focus on commercial discipline. While these planned OM&A savings are substantial, they fall short by ~$200 million of fully offsetting the shortfall in OM&A cost recoveries based on the OEB's decision, which negatively affects OPG's ability to achieve the regulated ROE target. Future business plans are expected to target additional cost improvement opportunities to close this gap by 2021.

The major sources of plan-over-plan OM&A cost reductions not subject to true up with customers are nuclear outage costs, corporate support function costs, operating business unit base OM&A programs, and Renewable Generation project costs. These reductions are underpinned by a lower headcount of ~410 employees, on average in each year plan over plan, reflecting productivity improvements and resourcing strategies aimed at mitigating Pickering closure downsizing costs. The remaining $200 million in plan-over-plan reductions in OM&A expenses from ongoing operations is from lower pension and other post-employment benefit (OPEB) costs, the majority of which will be returned to customers through OEB-authorized regulatory accounts.

Production

Higher forecast nuclear generation of 4.4 TWh compared to the previous plan, primarily reflecting outage cycle frequency and other optimization initiatives and equipment reliability improvements at Pickering, and an increase in regulated hydroelectric generation (adjusted for surplus baseload generation (SBG)) contribute ~$475 million in incremental revenue over the term of the plan. The Pickering forced loss rate target is reduced from 5.0% to 3.5% in this plan. The increase in regulated hydroelectric revenue is mainly due to higher operating efficiency, lower assumed market constraints on production and an assumed one-year deferral in the execution of a Sir Adam Beck I GS power canal outage to 2021. OPG will continue to optimize major project work sequencing in Renewable Generation, with the final timing of the power canal outages being determined as part of the planning phase of the project. The plan also reflects advancement of the planned Pickering vacuum building outage (VBO) from 2021 into 2020, shifting about 1.5 TWh of generation across the two years and contributing to a plan-over-plan reduction in net income in 2020. OPG continues to assess mitigating actions in light of an extensive nuclear outage program currently planned for 2020 that includes four major planned outages, return to service of Darlington Unit 2 and commencement of Unit 3 refurbishment, in addition to the Pickering VBO.

Main offsetting factors to the plan-over-plan increase in net income include lower regulated revenue and other impacts reflecting the results of the OEB's 2017-2021 rate decision relative to OPG's request, an increase in depreciation expense resulting from capital investments in the accelerated digital transformation strategy and Darlington plant requirements and timing of in-service asset additions, and an updated forecast of Global Adjustment costs for OPG's electricity grid withdrawals based on updated non-OPG renewable generation cost information published by the Independent Electricity System Operator (IESO).

Return on Equity and Capital Structure

Operating ROE increases from 5.3% in 2017 to 8.1% by 2021. These ROE levels are an improvement over the previous plan. Total ROE is forecast to peak at 8.1% in 2018, mainly on account of the gain on the Lakeview sale, and to decline thereafter to 7.1% in 2021. Total ROE will be generally lower than Operating ROE due to returns on the Fair Hydro Trust related equity contributions from the Province being lower than the return on the majority of OPG's operating assets. Owing mainly to the OEB's disallowances of certain requested OM&A costs, the 2018 planned results achieve a Regulated ROE of approximately 7%, below the OEB prescribed return of 8.78% used in setting OPG's regulated rates. Regulated ROE is expected to achieve the OEB-prescribed level by the end of the planning period and averages 8.2% over the 2017-2021 period.

Operating ROE is lower than the Regulated ROE of 8.78% prescribed by the OEB in all years of the plan, reflecting OEB's disallowance of costs as well as OPG's debt ratio remaining below the 55% level reflected in the OEB-approved deemed capital structure. By 2021, OPG's planned debt ratio excluding the Fair Hydro Trust drops to 26%, assuming no capital is deployed on non-organic expansion, such as acquisitions. Management continues to examine the optimization of the Company's capital structure. The business plan is based on an existing capital allocation approach supporting Darlington refurbishment, sustaining capital investment in generating assets and maintaining flexibility to invest in the energy sector. In 2018, OPG will review and formalize a capital allocation policy to guide capital deployment decisions, including a framework for a future dividend policy.

Taking into account planned operating performance and capital investments as well as the implications of the Fair Hydro Trust, forecast credit metrics and operating cash flow levels for the business plan period are expected to continue to support OPG's current investment grade credit rating and cost effective sourcing of funds under the public debt platform. By 2021, OPG's debt is forecast at $5.9 billion, which is largely

consistent with current levels, as operating cash flow inclusive of Fair Hydro Trust returns is sufficient to fund capital expenditures over the period. The Fair Hydro Trust external senior debt is projected to increase to $5.9 billion by 2021.

Capital Investments and Business Development

In addition to realigning the cost structure and operating model, OPG's strategy to improve ROE is to expand the business through strategic investments earning commensurate risk-adjusted market rates of return. This strategy will help to optimize the capital structure by gradually reducing equity and increasing debt, while increasing net income. With limited organic development opportunities expected in Ontario, non-organic investments in a portfolio of low-carbon generating assets primarily outside of Ontario as well as potential extensions to OPG's business will be essential to ensuring the Company is able to deliver long-term Shareholder value.

In support of this strategy, the plan allocates incremental capital funding of ~$200 million for potential organic business development investments over the 2018-2021 period, including expansion of nuclear isotopes sales and nuclear services, future regulation procurement projects and investments in other innovative technologies that would leverage OPG's core competencies. Although non-organic investments are not specifically assumed in the plan, OPG forecasts that up to $3 billion would be available for such investments over the plan term through increased leverage. OPG recognizes that the amount and timing of non-organic investments will depend on market opportunities and Shareholder's expectations, and will take into account the need for continued excellence in core operations and Darlington refurbishment execution and the need to maintain OPG's credit metrics. Based on these factors, OPG would take a measured, paced approach to the non-organic element of its strategy.

Total capital expenditures over the planning period are ~$570 million higher compared to the previous plan. In addition to the incremental $200 million to fund organic business expansion opportunities, this includes ~$120 million in additional investment to support industry-leading performance at Darlington post refurbishment and ~$40 million of incremental investment in OPG's accelerated digital transformation strategy to enable productivity improvement and modernize information technology infrastructure. Darlington refurbishment expenditures inclusive of a revised cost estimate for the Heavy Water Storage and Drum Handling Facility (D2O Project) increase by ~$105 million compared to last year's plan due to timing of expenditures, with total cost flows through Unit 2 return to service remaining consistent with Board-approved levels. The D2O Project is expected to be completed within the funds previously released to the Darlington refurbishment program.

Planned non-refurbishment capital investments in nuclear regulated assets and information technology are higher than amounts allowed by the OEB in setting regulated rates for 2017 to 2021. In setting the nuclear rates, the OEB disallowed certain capital project costs, reduced OPG's forecast of non-refurbishment capital in-service additions included in rate base for the duration of the 2017-2021 rate-setting period, and applied an efficiency stretch factor to further reduce OPG's revenues from in-service additions. Management believes that proceeding with planned capital investments in excess of 2017-2021 rate base amounts is prudent because they will provide long-term value by improving asset performance and enabling operating cost reductions. The remaining undepreciated value of these investments is expected to be included in rate base in the next rate application. In addition, the plan reflects implementation of an enterprise-wide scalable project delivery model and project management system aimed at ensuring consistent delivery of all projects on time and on budget. Together with demonstrated strong performance in delivering on the planned capital program, these enhancements should support improved OEB decision outcomes in the future.

The plan continues to reflect resource levels necessary to support the execution of several current major projects in line with approved project budgets and schedules, including return to service of refurbished Darlington Unit 2 by February 2020 and commencement of Darlington Unit 3 execution immediately thereafter, completion of the Ranney Falls GS redevelopment by 2019, and completion of the Nanticoke solar facility by 2019. These projects are continuing to track on budget and on schedule. Pre-execution expenditures incurred for the refurbishment of Darlington Unit 3, including acquisition of long lead-time materials and components, are $93 million as of December 31, 2017, with a further ~$540 million reflected in the plan over 2018 to February 2020. Planned development, re-development and station upgrade

projects over the business plan period are expected to increase OPG's total renewable generation capacity by 170 MW by 2021, including the Ranney Falls GS and Nanticoke solar facility projects.

The plan supports OPG's ongoing commitment to continued engagement with the Saugeen Ojibway Nation toward securing support for the proposed low and intermediate level waste deep geologic repository (L&ILW DGR), recognizing the impact of inherent uncertainty in the ultimate outcome of the Environmental Assessment decision on the timing of project construction. During the planning period, OPG will also continue to maintain the Darlington new site preparation licence, and plans to complete the decommissioning of the former Nanticoke GS by 2020 and the former Lambton GS by 2021.

The plan reflects an increased and accelerated focus on innovation and technology, both to drive efficiencies in current operations and to build momentum for new business opportunities leveraging disruption in the energy sector. A combination of capital and OM&A funding is included in the plan in areas such as transportation electrification, nuclear innovation, distributed generation technologies, smart grids and other disruptive innovation technologies. These investments will help leverage OPG's clean electricity in support of action on climate change, including positioning OPG as a leader in transportation electrification in Ontario and driving a pan-Canadian nuclear strategy. These investments will also enhance OPG's brand and social licence.

Social Licence

During the planning period, OPG will focus on building its brand and reinforcing its social licence, with an emphasis on high standards of public trust and transparency, leadership in clean, cost-effective energy generation and innovation, community engagement and Indigenous Relations. OPG will continue to leverage Power with Purpose as the key platform for stakeholder outreach and branding initiatives, and will build on the Company's existing customer engagement activities to more formally incorporate customer engagement into subsequent business plans, as expected by the OEB. OPG will also focus on fostering a diverse, progressive and engaged workforce to enable the Company's future success.

During 2018, OPG will expand the communication of its social licence focus as part of its financial reporting framework, including through external disclosures related to Environment, Sustainability and Governance. Emerging guidance in North America will increase the requirements in this area, bringing public companies in line with more advanced disclosures common in Europe. OPG is well positioned with its virtually emission free generation fleet to move towards a leadership position in this area.

Labour Considerations

OM&A cost savings, operating cash flow and net income levels ultimately achieved during the planning period as well as the ability to implement longer-term cost structure changes will be impacted by outcomes of collective agreement negotiations with the Power Workers' Union (PWU) and The Society of Energy Professionals during 2018. Collective agreement outcomes, as well as staffing strategies, will impact the ability to mitigate future employee termination and related costs as a result of the end of Pickering commercial operations, estimated between $1 billion and $2 billion. Consistent with previous business plans, a liability for such employee termination costs is not included in the 2018-2021 Business Plan. US GAAP requires employee termination costs to be recognized when the scope, timing and amount of the downsizing program can be reasonably estimated with sufficient detail and would be unlikely to change significantly. The termination costs associated with the Pickering retirement are assumed to meet net income recognition criteria in 2022 at the earliest, and were not included in the setting of 2017-2021 regulated rates.

A discussion of the 2018-2021 Business Plan, organized by each of OPG's four strategic imperatives, is provided below. The detailed financial and headcount information is included in Appendix 3.

Financial Strength

In line with the Company's commercial mandate, OPG's objective is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future growth. In pursuing commercial objectives, OPG takes into account the

impact on Ontario electricity customers by continuously seeking further efficiencies in the Company's cost structure.

The business plan is focused on increasing net income and ROE from core operations through improved operational performance of the generating fleet and a number of steps to realign the corporate cost structure and operating model. In turn, OPG's increasingly improving financial performance, cost effective public debt platform and industry experience position the Company well for developing a portfolio of organic and non-organic investment options in low-carbon generating assets and potential extensions to the business complementary to existing operations. Pursuing such investments will position OPG for long-term success, enabling it to deliver long-term Shareholder value and maintain scale in view of the upcoming Pickering retirement.

To facilitate this strategy, OPG will develop a capital allocation policy in 2018 aimed at maintaining OPG's current investment grade credit rating and providing long-term value to the Shareholder. This policy will outline expectations on how the Company's capital will be deployed between its existing asset base and potential expansion opportunities, and develop a framework for a future dividend policy. A balance needs to be struck among these available uses of capital to ensure deployment is targeted in the areas that provide the best path forward for sustained growth and returns in the longer term.

Regulated Rates

The plan reflects the impact of the OEB's decision on OPG's 2017-2021 rate application issued on December 28, 2017. On January 17, 2018, OPG filed a proposed payment amounts order with the OEB implementing the decision's findings in a manner that would result in consistent annual increases of 0.4% or $0.65 on a typical residential customer's monthly bill during the 2017 to 2021 period. The plan reflects this proposal.

For the nuclear operations, the OEB determined the level of costs and return on rate base allowed for recovery as part of each year's revenue requirement, net of an accumulating annual efficiency stretch factor of 0.6%. In the payment amounts order submission, OPG included a rate smoothing proposal based on the allowed revenue requirements and production levels, consistent with O. Reg. 53/05 as amended in March 2017. The objective of rate smoothing is to make the total OPG weighted average payment amounts more stable during the Darlington refurbishment and Pickering closure period by adjusting the nuclear regulated rate within the weighted average payment amount calculation. These adjustments to the nuclear rates determine the annual amounts of nuclear revenue to be recorded in a deferral account for recovery in the post-refurbishment period. Amounts deferred under rate smoothing in a given period are recognized by OPG as income of that period, with the deferral account recorded as a regulatory asset on the balance sheet. Under OPG's proposal, the deferral account balance would reach ~$750 million by the end of 2021, inclusive of interest at approximately 4.5% per annum authorized by the OEB pursuant to the regulation. The regulation requires the total accumulated deferred balance to be recovered over a period of up to 10 years beginning at the end of the Darlington refurbishment project.

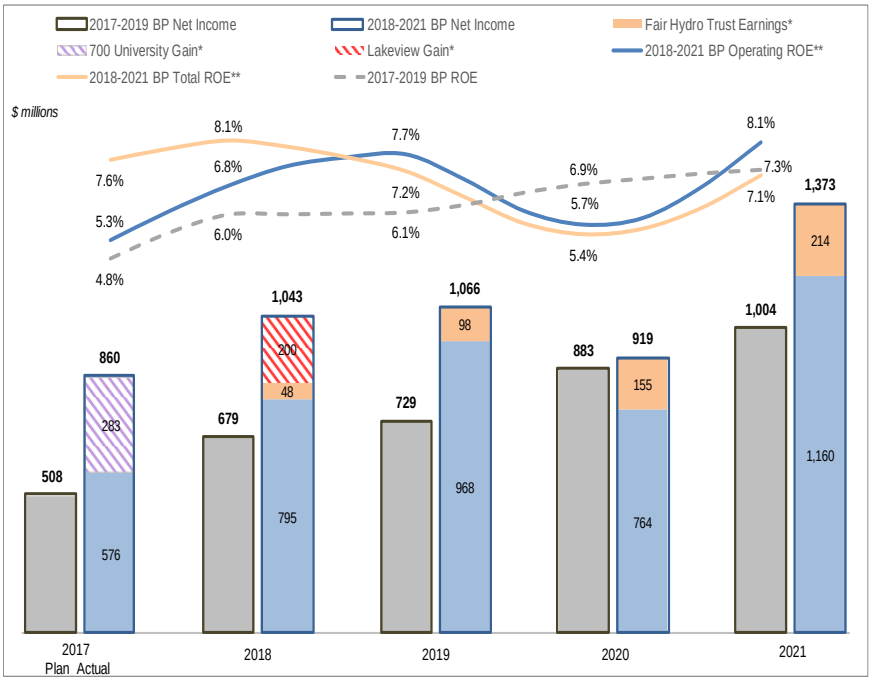
For the hydroelectric operations, the OEB's decision approved an inflation-based formula net of a 0.3% efficiency stretch factor to establish rates for each year. The results of the formula for 2017 and 2018 are known based on inflationary inputs published by the OEB for use in incentive regulation formulas, yielding hydroelectric rate increases of 1.4% in 2017 and 0.9% in 2018. The 2019-2021 hydroelectric rates will be set annually before the beginning of each year based on inputs published by the OEB, and are assumed in the plan to increase by 1.0% in 2019 and 1.5% in each of 2020 and 2021.

Approved regulated rates and rate smoothing deferral amounts for the 2017-2021 period will be determined by the OEB's issuance of the final payment amounts order. OPG expects to start receiving revenue under approved new rates in the first half of 2018. In the payment amounts order submission, OPG has proposed to delay the collection of the retrospective revenue shortfall for the period between the June 1, 2017 effective date of the new rates and their implementation date to the three-year period beginning January 1, 2019, in order to mitigate the impact on customer bills in 2018. The retrospective revenue shortfall will be recorded as income in the period to which the revenue shortfall relates. The revenue shortfall recorded in net income in 2017 is ~$480 million.

Consistent with OEB's expectations, the plan assumes an OEB application in 2018 for clearance of deferral and variance account balances recorded over 2016 and 2017 as well as the balance recorded in the pension and OPEB cash-to-accrual deferral account since November 2014. The regulatory treatment of pension and OPEB costs is discussed under the Operational Excellence section.

Net Income and Return on Equity

Net income attributable to the Shareholder is forecast to increase from $860 million in 2017 to $1,373 million in 2021, with Total ROE decreasing from 7.6% to 7.1% as the effect of higher earnings is more than offset by a forecast increase in the equity base reflecting the Province's equity contributions funding 44% of the Fair Hydro Trust financing.



* Net of Tax
** Total ROE = Operating ROE + Fair Hydro Trust Earnings + Gains on sale of the 700 University Ave. property and Lakeview site

Operating net income attributable to the Shareholder increases from $576 million in 2017 to $1,160 million in 2021, as Operating ROE increases from 5.3% in 2017 to 8.1% in 2021. Cumulatively for the 2018-2021 period, forecast operating net income levels are a plan-over-plan improvement of ~$390 million. The improvement in net income and ROE is highly dependent on achieving substantial reductions in OM&A costs and increases in production targeted in the plan, and ability to deliver the Darlington refurbishment on time and on budget.

The major drivers of plan-over-plan changes in 2018-2021 Operating net income are as follows:

- Revenue from higher production at Pickering reflecting lowering of forced loss rate target, outage cycle and other optimization initiatives, and current performance expectations (+$345 million);
- Higher revenue from regulated hydroelectric production primarily due to higher operating efficiency, lower assumed market constraints and an assumed one-year deferral in the start of planned execution of the Sir Adam Beck I GS power canal outage from 2020 to 2021 (+$130 million);
- Company-wide reductions in OM&A costs not subject to true up with customers through OEB-authorized regulatory accounts, as further detailed in the Operational Excellence section (+$600 million);
- Lower interest expense, primarily due to lower OPG borrowing requirements (+$75 million);
- Lower regulated revenue and other impacts reflecting disallowances and other adjustments from the OEB's 2017-2021 rate decision, and updated inputs into the approved hydroelectric incentive regulation rate-setting formula (-$665 million);
- Increases in depreciation expense as a result of investments in the accelerated digital transformation strategy and sustaining nuclear capital projects and timing of in-service asset additions over the period (-$165 million), partly offset by higher capitalized interest (+$40 million);
- Updated forecast of Global Adjustment costs for OPG's electricity grid withdrawals based on non-OPG renewable generation cost information published by the IESO (-$125 million); and
- Net change in income tax expense related to above items (+$130 million).

The planned 2018 Operating net income attributable to the Shareholder of $795 million is an improvement over the results for 2017 of $576 million, with a further improvement to $968 million forecast in 2019. The earnings in 2017 are negatively impacted by a partial-year effective date of June 1, 2017 for new regulated rates, which resulted in forgone net income of ~$325 million. Other factors underpinning the year-over-year increases in 2018 and 2019 include:

- Higher nuclear production in 2017 and 2019 reflecting outage optimization initiatives;
- Lower OM&A expenses in 2019 due to fewer major planned outages at Pickering and cost efficiency improvements;
- Write-off of previously incurred developmental capital expenditures and higher expenses associated with inventory obsolescence costs in 2017;
- Annual regulated hydroelectric rate increases under the incentive regulation formula;
- Year-over-year increases in capitalized interest for the Darlington refurbishment capital expenditures; and
- Earnings from the Nanticoke solar facility upon completion in 2019.
- The year-over-year favourable factors in 2018 are partially offset by higher depreciation expense in 2018 as a result of increased investments in the accelerated digital transformation strategy and timing of in-service asset additions, and higher detritiation services revenue in 2017 reflecting increased demand and stronger performance of the Tritium Removal Facility.

Operating net income attributable to the Shareholder is forecast to temporarily decrease to $764 million in 2020, with Operating ROE declining to 5.7%, mainly due to a larger planned outage program at Pickering, including advancement of the six-unit VBO from 2021, that significantly decreases production and increases OM&A expenses. Other factors impacting the year-over-year Operating net income change in 2020 include:

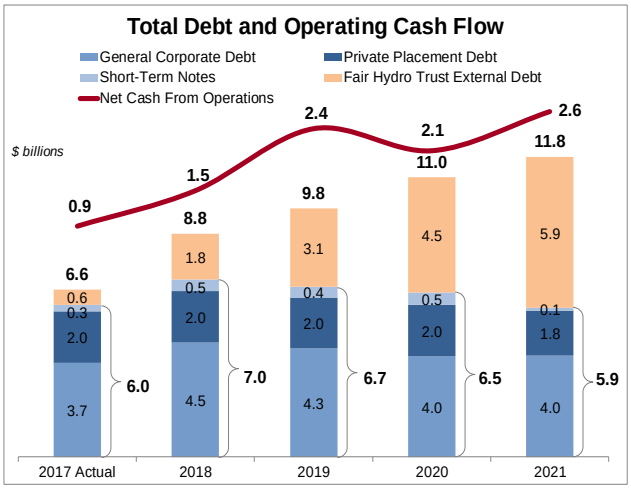
- Lower hydroelectric production due to the planned forebay and crossover canal outage at the Sir Adam Beck I GS in 2020;
- Lower capitalized interest for the Darlington refurbishment capital expenditures as the first refurbished unit returns to service in February 2020; and
- Expiry of the Thunder Bay biomass energy supply agreement in January 2020.
- These factors are partially offset by the impact of the first refurbished Darlington unit entering rate base and regulated hydroelectric rate increases under the incentive regulation formula.

Planned Operating net income attributable to the Shareholder increases to $1,160 million in 2021, compared to 2020, reflecting an increase in nuclear production and lower outage OM&A expenses due to multiple planned outages at Pickering in 2020, no major planned outages at Darlington in 2021 and continued efficiency improvements, and higher capitalized interest for the Darlington refurbishment capital expenditures. These factors are partially offset by the impact of lower regulated hydroelectric generation in 2021.

Net income contribution from the Fair Hydro Trust increases from $48 million in 2018 to $214 million in 2021, predominantly on account of the spread earned on the Province's equity injections into OPG to fund 44% of the Trust financing requirement. The net income contribution from the Trust is net of interest costs on OPG's debt to fund 5% of the Trust financing requirement. OPG's management fees represent a small fraction of the Trust's net income contribution and range from $1 million to $9 million annually between 2017 and 2021, before taxes.

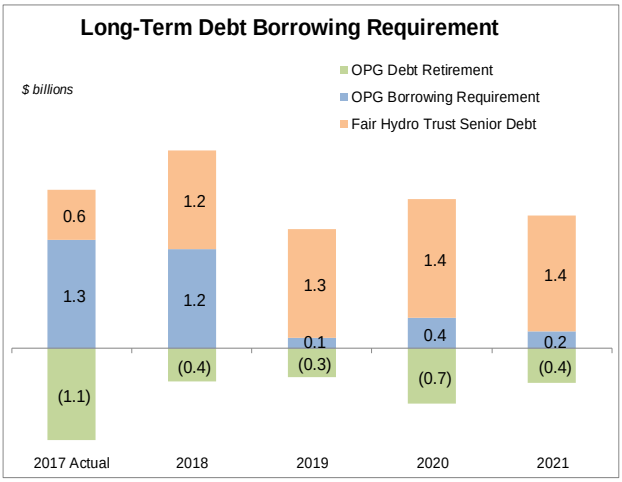
The plan includes a forecast after-tax gain of $200 million on the Lakeview sale in 2018, which temporarily increases Total ROE to 8.1% in 2018. The sale was not included in the previous plan.

Financing and Liquidity



Forecast operating cash flow, inclusive of Fair Hydro Trust impacts, increases from $0.9 billion in 2017 to $2.6 billion in 2021. The increase in 2018 over 2017 is due to the implementation of regulated rate increases in 2018, partially offset by lower nuclear production in 2018. The increase in 2019 is due to higher nuclear production, lower OM&A costs, assumed commencement of collection of retrospective revenue for the period between June 1, 2017 and the implementation date of new regulated rates in 2018, and rate riders assumed to result from the 2018 deferral and variance account application to the OEB. A ~5 TWh decline in nuclear production in 2020, compared to 2019, and higher nuclear outage OM&A costs result in a year-over-year decrease in operating cash flow. Higher operating cash flow in 2021 is mainly due to a year-over-year increase in nuclear production and decrease in OM&A costs. The Fair Hydro Trust contribution to operating cash flow grows over the period commensurate with increased earnings from the Trust.

In aggregate, operating cash flow inclusive of Fair Hydro Trust impact is sufficient to fund capital expenditures over the planning period, with OPG's total debt (i.e. excluding the Fair Hydro Trust external senior debt) forecast to decrease from $6.0 billion in 2017 to $5.9 billion in 2021. This assumes no capital is deployed on non-organic expansion such as acquisitions. The assumed effective interest rate for new general corporate debt during the planning period is an average of 5.0%. OPG's sources of general corporate debt include credit facilities with the Ontario Electricity Financial Corporation and the public debt platform. The Fair Hydro Trust external senior debt is forecast to increase to $5.9 billion by 2021, based on forecast cumulative investment interest acquired of $11.8 billion. The assumed effective interest rate for new Fair Hydro Trust external senior debt over the planning period is 4.25%, on average.

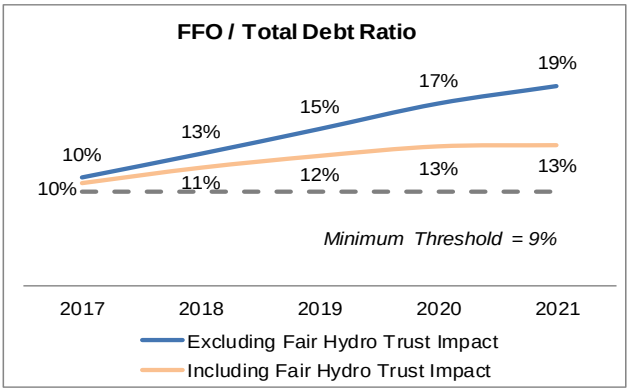


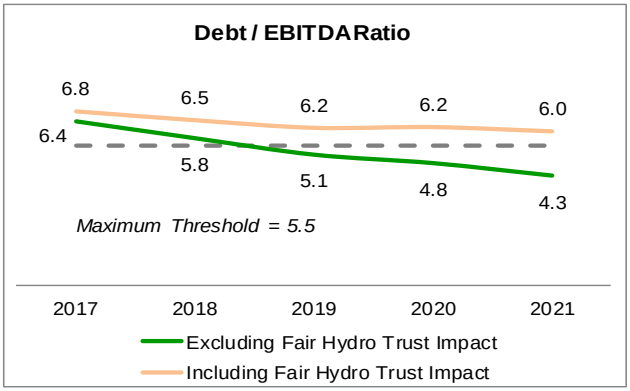
OPG's debt ratio excluding the Fair Hydro Trust external senior debt is forecast to decline from 36% in 2018 to 26% in 2021, absent any major non-organic growth investments. This is below the 55% level reflected in the OEB deemed capital structure used to set regulated rates, which results in a lower value of the Shareholder's investment in the Company. In setting OPG's 2017-2021 regulated rates, the OEB rejected OPG's request to decrease the debt portion of the deemed capital structure from 55% to 51% and increase the equity portion from 45% to 49%. A higher debt portion of the deemed capital structure contributes to lower regulated revenues. Management continues to examine the optimization of the Company's corporate capital structure and approach to capital allocation.

OPG's strategy to expand its business portfolio through organic development and non-organic investments will help to optimize the corporate capital structure by increasing net income while gradually reducing equity and increasing debt. Although non-organic investments are not specifically assumed in the plan, OPG forecasts that up to $3 billion would be available for such investments over the business plan term through increased leverage. OPG recognizes that the amount and timing of external investments will depend on market opportunities and Shareholder's expectations, and will take into account the need for continued excellence in core operations and Darlington refurbishment execution and the need to maintain OPG's credit metrics. Based on these factors, OPG would take a measured, paced approach to external investments.

Credit Metrics

Maintaining an investment grade credit rating is critical to OPG's continued ability to access cost effective financing. To support this objective, OPG monitors the Funds From Operations (FFO) to Total Debt ratio and the Debt to Earnings Before Interest, Taxes and Depreciation and Amortization (EBITDA) ratio, which are the core measures used in Standard & Poor's credit rating methodology. Total Debt, as defined by Standard & Poor's, includes pension and OPEB liabilities. The forecast credit metrics and forecast operating cash flow levels for the planning period are expected to continue to support OPG's current investment grade credit rating.





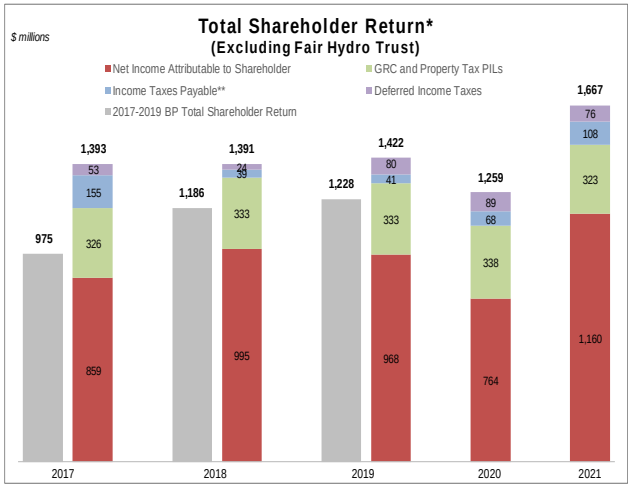
The FFO/Total Debt ratio, both with and without the impact of the Fair Hydro Trust, will remain within threshold over the planning period. The ratio without the Fair Hydro Trust improves steadily over the 2017 to 2021 period as FFO increases. FFO increases in 2018 due to the full-year impact of new regulated rates compared to seven months in 2017, in 2019 due to higher nuclear production and commencement of rate riders for recovery of deferral variance accounts, in 2020 due to an increase in revenue from the return to service of Darlington Unit 2, and in 2021 due to higher nuclear production and lower OM&A costs. With the Fair Hydro Trust, the ratio is somewhat lower and more stable than without the Fair Hydro Trust, as a result of the Trust's external senior debt, partially offset by incremental income from the spread earned on the Province's equity injections.

Excluding the impact of the Fair Hydro Trust, the Debt/EBITDA ratio is at or below the threshold during the business plan term. As EBITDA increases over the business plan term, the ratio improves. The upward trend in EBITDA is consistent with the drivers of increasing FFO. As anticipated, when the impact of the Fair Hydro Trust is included, the Debt/EBITDA ratio exceeds the threshold in all years of the plan, largely due to the Trust's external senior debt.

Delivering Shareholder Value

OPG's Total Shareholder Return consists of net income, income taxes, hydroelectric gross revenue charge payments, and payments in lieu (PILs) of property taxes to the OEFC. OPG plans to contribute $5.7 billion in Total Shareholder Return over the 2018-2021 period, not including the impact of the Fair Hydro Trust. Total Shareholder Return on OPG's fiscal basis is projected to increase over the period as net income increases.

Over the 2017-2019 period, OPG expects to contribute $4.2 billion in Total Shareholder Return not including the impact of the Fair Hydro Trust, which represents an increase of ~$800 million over the 2017-2019 commitments made to the Province based on the previous plan, primarily due to higher net income across all three years.



* On OPG's fiscal basis
** Includes income tax PILs and amounts recoverable from, or payable to ratepayers

The Fair Hydro Trust is forecast to contribute an additional $685 million to the Province, predominantly through the spread earned on the Province's equity injection to fund 44% of the Trust's financing.

In 2017, OPG received proceeds from the sale of OPG's 700 University Ave. property. The forecast for 2018 includes proceeds from the sale of the Lakeview site. In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder in respect of these transactions. Both of these properties are non-core assets of OPG's unregulated business.

Operational Excellence

The plan recognizes that strong core operational and cost performance is foundational to OPG's continued success and longer term strategy. Continuous improvement in performance is expected by the Shareholder, customers and the OEB. In addition to directly affecting output and cost levels, operational and cost performance is a critical driver of rate application outcomes. Benchmarking is a key tool used by the OEB to assess regulated assets' performance as part of rate applications, including as the basis for determining efficiency stretch factors for nuclear and regulated hydroelectric businesses. Continuous improvement in performance and associated benchmarking should support more favourable outcomes of future OEB decisions.

OPG remains focused on improving asset reliability, increasing output and safely generating electricity at a low cost, with performance targets over the planning period set to drive excellence in these areas. The plan builds on OPG's improved performance in a number of areas in 2017, seeking to maximize the value of existing assets and further improve fleet performance during a period of relative regulatory certainty provided by the OEB's 2017-2021 rate decision. This includes implementing initiatives aimed at maximizing generation revenue and improving reliability performance at Pickering based on continued operations to 2024, positioning Darlington for industry-leading operational and cost performance post refurbishment, and maintaining and improving strong reliability and cost effectiveness of the hydroelectric fleet. These initiatives complement an enterprise-wide set of initiatives to improve productivity and realign the Company's cost structure and operating model, discussed under the Operations, Maintenance & Administration Expenses section. In driving these improvements, OPG remains committed to achieving the highest standards of workplace and public safety across its operations and will continue to invest in maintaining and enhancing the safety and security of its generating facilities.

Nuclear Operations

OPG is focused on improving reliability performance and increasing output from the nuclear fleet. This includes initiatives aimed at executing optimized planned outages along with improving equipment reliability, implementing integrated asset management planning, and enhancing maintenance programs. A key driver of improved equipment reliability and station performance is the development and implementation of the Monitoring and Diagnostic Centre. The Centre will facilitate collection and analysis of data to improve early detection of equipment degradation, reduce unplanned maintenance and optimize performance of major components. Improved station performance also will be supported by a greater focus on asset management planning aimed at early identification of project requirements and development of an optimized investment strategy. Maintenance and outage programs over the planning period will continue to focus on improved work planning, preparation and execution.

These and other initiatives will support a reduction to Pickering's forced loss rate target to 3.5% from 5.0% starting in 2018 as well as achievement of Darlington's top-quartile forced loss rate target of 1.0%. A temporarily higher forced loss rate is assumed for Darlington Unit 2 upon return to service following refurbishment, based on industry experience. OPG will continue to target top-quartile forced loss rate performance for the station as refurbished units achieve steady-state operations post refurbishment.

OPG benchmarks the costs of the Pickering and Darlington stations against other nuclear stations using indicators that measure performance on a per MWh basis. With a combination of the smaller size Pickering units relative to the majority of industry peers and impacts of moving through refurbishment of the Darlington units, the benchmarking of units on a per MWh basis will continue to pose some challenges in light of the OEB's 2017-2021 regulated rate decision that emphasized benchmarking results. As discussed further in the Operations, Maintenance & Administration Expenses section, the OEB used benchmarking to support a more aggressive efficiency stretch factor in setting OPG's 2017-2021 nuclear regulated rates. In

order to achieve an appropriate rate of return and position itself for more favourable future rate application outcomes, OPG will seek to implement commensurate productivity improvements and maximize production output over the business plan period.

Although Pickering is expected to continue to benchmark in the fourth quartile for unit energy cost due to its smaller unit size, the station's 2017 actual results and forward targets demonstrate an improvement of ~$10/MWh in the Total Generating Cost (TGC) measure, on average, compared to the previous plan. As anticipated, Darlington's cost performance continues to be temporarily impacted by higher project costs associated with asset life cycle and plant life extension work and increased outage costs to address the aging management program, with resulting third quartile target performance over the 2018-2020 period expected to improve to the second quartile by 2021. On a per unit basis, OPG's all-in operating and capital expenditures for the nuclear stations continue to be amongst the lowest in the industry. In addition to Pickering's forced loss rate performance, plan-over-plan improvement is observed at both stations in several operational targets including All Injury Rate, Collective Radiation Exposure, and On-line Corrective Maintenance Backlogs. The operational targets for the Nuclear business unit are further detailed in Appendix 4.

Hydroelectric Operations

OPG continues to focus on increasing the utilization of existing hydroelectric assets through increases in energy output and, where economic, increases in capacity, as well as identifying opportunities for cost efficiencies in line with the incentive regulation model. Operational performance initiatives over the business planning period will aim to increase water to wire efficiency, improve operational flexibility and optimize outage planning to maximize availability and returns during high demand periods, subject to water conditions. The forecast fleet-wide availability for hydroelectric assets averages 87% during the business plan period, with a target equivalent forced outage rate of 1.8% on average. The availability of the contracted hydroelectric assets is projected to reach 92% by 2021 as major work including overhauls, upgrades and sluicegate replacements at the Lower Mattagami stations is completed. The availability of the regulated hydroelectric assets temporarily declines from an average of 88% over the 2018-2021 period to 85% in 2021 reflecting a Sir Adam Beck I GS power canal outage assumed in the summer of 2021. OPG will add approximately 170 MW of incremental capacity to its renewable generation fleet over the plan term, including through completion of the Ranney Falls GS and Nanticoke solar facility projects, frequency conversion of Sir Adam Beck I GS Units 1 and 2, runner upgrade program and other value enhancing projects.

OPG is pursuing innovation and technology-based improvements in asset management and equipment maintenance strategies in order to reduce costs and increase reliability of the hydroelectric stations. This includes expanding the Monitoring and Diagnostic Centre concept beyond nuclear operations and transitioning to digital work management. Objectives of the Monitoring and Diagnostic Centre for Renewable Generation operations include developing a common data historian and a data architecture strategy that will optimize asset management, facilitate a move from preventative maintenance to condition-based maintenance and reduce forced outage costs through predictive failure modelling capability. In addition to improving work flow efficiency, digital work management is expected to improve staff engagement in line with OPG's cultural shift.

OPG's hydroelectric operations are regularly benchmarked against peer utilities in North America. Based on 2016 data, 19 out of OPG's 25 large regulated hydroelectric facilities benchmarked in the top two quartiles for unit energy costs. This group of 19 facilities represents 94% of the energy delivered from the regulated hydroelectric fleet. Eighteen out of the 25 large regulated hydroelectric facilities benchmarked in the top two quartiles for availability. The operational and cost improvement initiatives identified in the plan will help support OPG's hydroelectric benchmarking standing. An integrated strategy is being developed in 2018 to assess hydroelectric benchmarking performance, taking into account incentive regulation implications. The operational targets for the Renewable Generation business unit are further detailed in Appendix 5.

Key enterprise level and business unit initiatives that will support achievement of strategic objectives and business plan goals are detailed in Appendix 6.

Safety

OPG is committed to high standards of public and workplace safety and will continue to operate all of its facilities in a safe, secure and reliable manner, while making investments to maintain and enhance the safety of its generating assets. This includes continuing to operate with nuclear safety and waterways safety as overriding priorities by maintaining a strong focus on nuclear safety programs, continuing to invest in nuclear safety systems and dam and other waterway safety upgrades, and further strengthening public awareness regarding water safety.

In the past five years, as a result of lessons learned from the Fukushima accident, OPG has strengthened the nuclear safety program at its stations by installing multiple portable emergency mitigating equipment units, enhancing emergency preparedness and response capability, and improving protocols and procedures in response to potential adverse events. Probabilistic safety assessment results have confirmed that these initiatives have further strengthened the safety of OPG's nuclear plants. Through its annual evaluation of the safety performance of Canada's nuclear plants, the CNSC has concluded that both Pickering and Darlington operate at the highest level of nuclear safety.

OPG continues to demonstrate strong industry leadership with its hydroelectric Dam and Public Safety Program, which encompasses public safety and emergency management over the Company's 241 dams and 66 hydroelectric facilities. The program is considered to be international best practice in a number of areas. During the planning period, OPG will continue to make investments in dam safety, with planned project work at hydroelectric sites totalling ~$120 million over period, in addition to the $300 million Little Long Dam Safety project discussed under the Project Excellence section. OPG will also continue to maintain a strong water safety education and outreach program.

OPG has consistently achieved top quartile workplace safety performance compared to the Canadian Electricity Association benchmark and although it did not meet the internal target, 2017 safety performance was the third-best year in the Company's history. OPG will continue to set aggressive but achievable internal targets to drive continuous improvement in safety performance. Achievement of safety goals will be supported through continued branding and integration of the "iCare Enough to Act" initiative aimed at renewing employees' personal commitment to safety, strengthening of an enterprise wide "values-based" safety culture through peer coaching, information sharing and work planning, and a focus on the use of human performance tools such as increased field supervisory oversight, situational awareness, communication, and procedural use and adherence.

Additionally, business unit specific initiatives are being implemented to target improved safety performance over the planning period. Renewable Generation will execute on a broad-based safety improvement plan targeting significant cultural and work program improvements in the safety management system. Objectives include strengthening proactive reporting, enhancing linkage of the embedded health and safety advisors with local senior management, modifying human performance practices based on internal and external benchmarking and reinforcing a culture of personal leadership in safety. In the Nuclear organization, safety programs are being implemented to re-energize the safety culture through communication, recognition, human performance coaching and risk management. Leveraging consistent best quartile performance at both Pickering and Darlington, business plan targets for safety at the nuclear stations have been set to drive further improvement over the previous plan, toward the ultimate goal of zero injuries.

Environment

OPG remains committed to meeting its environmental compliance obligations, including any commitments it makes, with the objective of surpassing these compliance obligations where it makes business sense. In keeping with the business plan, OPG will continue to manage its operations to minimize environmental risks and seek opportunities for environmental leadership. OPG's priorities over the planning period include keeping radiological emissions as low as reasonably achievable, preventing significant environmental events, and implementing a transportation electrification strategy discussed in the Social Licence section as well as initiatives to enhance biodiversity.

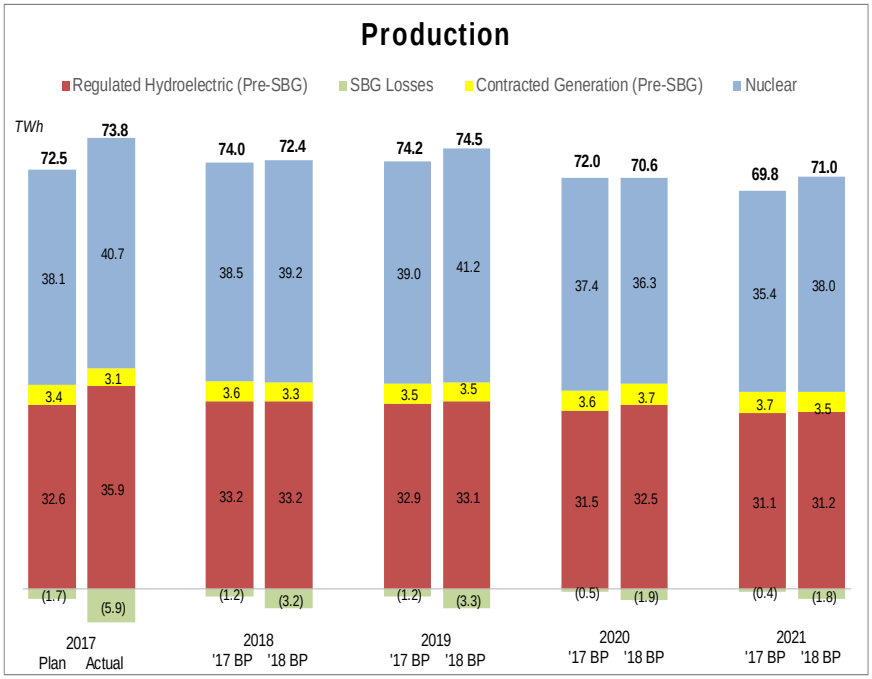
In 2017, OPG met or outperformed its targets for spills, environmental infractions, carbon-14 emissions to air and radioactive waste, with no significant environmental events. Performance for tritium emissions to

air and water during 2017 remained less than one percent of the regulatory limit. The Company will pursue further improvement in environmental performance through setting of more stringent targets in this plan, including in the area of spills and infractions for Renewable Generation and radioactive waste, infractions and tritium emissions for the nuclear operations.

To maximize the benefits of its biodiversity initiatives, OPG has developed biodiversity management plans that identify priority natural areas, conservation goals, risks and proposed actions. In 2017, OPG's continued efforts to protect and restore habitat, promote biodiversity education and awareness, and help the recovery of species were recognized by the Canadian Electricity Association with the 2017 Sustainable Electricity award for Commitment to Continuous Performance Improvement. OPG will continue to advance its biodiversity efforts during the business plan period.

Production

Total planned OPG production net of SBG impacts is 288.5 TWh over the period. Adjusted for SBG impacts, total planned production is 298.7 TWh, which is 5.4 TWh higher than in the previous plan.



The plan-over-plan increase is primarily driven by higher nuclear production of 4.4 TWh, mainly at Pickering. The increase in Pickering production includes lowering of the forced loss rate from 5.0% to 3.5% (1.4 TWh increase) reflecting reliability improvements and current performance expectations, outage frequency optimization through transition from a 24-month to 30-month outage cycle (1.6 TWh increase) and outage scope and duration optimization initiatives (1.4 TWh increase). The changes in outage frequency include the deferral of a Pickering Unit 6 planned outage from the fall of 2017 to 2018, a major driver of the year-over-year decrease in nuclear production in 2018, and result in fewer major planned outages at Pickering in 2019.

The Pickering production plan includes advancement of the Pickering VBO to 2020 from 2021, consistent with current CNSC license requirements, which reduces generation by 1.5 TWh in 2020, with a corresponding increase in 2021. The Pickering VBO is assumed to require a 30-day outage for all six operating units at the station.

The Darlington production plan is virtually unchanged from the previous business plan, including an assumed temporary increase in the forced loss rate and number of planned outage days as the first refurbished unit returns to service in early 2020 and a partial overlap of the second and third unit refurbishments in 2021. No major outages are scheduled at Darlington in 2021 as two units undergo refurbishment.

With the return to service of Darlington Unit 2, the start of Darlington Unit 3 refurbishment, the Pickering VBO and four major planned outages across both plants, the 2020 nuclear outage program is extensive and complex. OPG continues to assess mitigating actions taking into account the impact on resources and execution capability, while ensuring that regulatory and other work program requirements continue to be met and support improved station performance.

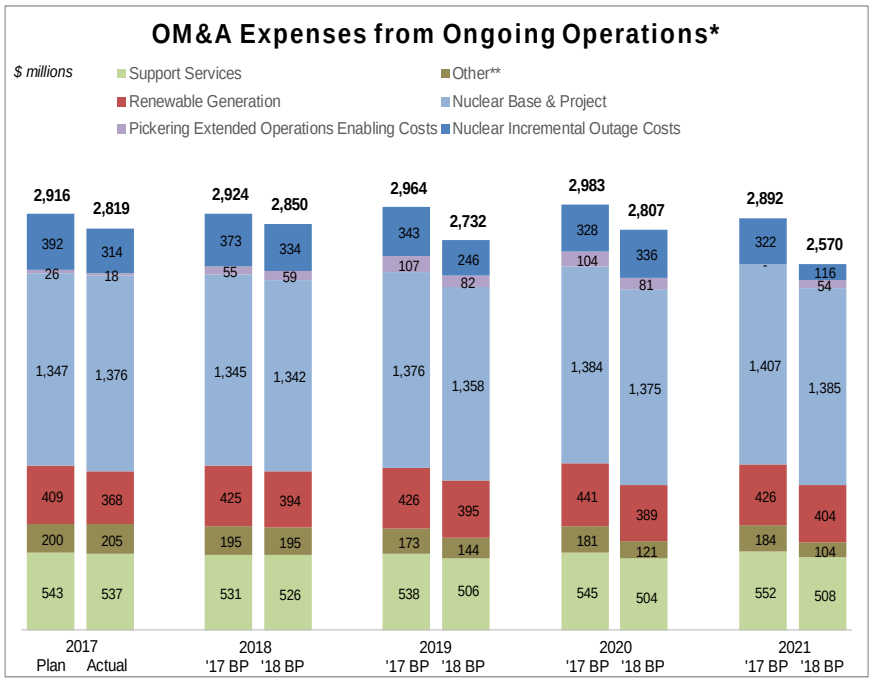
The hydroelectric production plan reflects a return to median water flows following extremely high water flows and resulting SBG conditions in 2017. SBG-adjusted regulated hydroelectric and contracted fleet production over the business plan term is 1.0 TWh higher compared to the previous plan, primarily due to an assumed one-year deferral of a Sir Adam Beck I GS power canal rehabilitation outage from the summer of 2020 to the summer of 2021. The outage reduces hydroelectric production by ~1.2 TWh in 2021. OPG will continue to optimize major project work sequencing in Renewable Generation, with the final timing of the power canal outages being determined as part of the planning phase of the project. The plan also continues to reflect a series of outages at the Sir Adam Beck units to accommodate Hydro One's planned work in the Beck switchyard over the planning period, and an outage at the Sir Adam Beck I GS in 2020 for work to rehabilitate the forebay and crossover canal. Planned contracted fleet production peaks in 2020 due to increased production at the Lennox GS reflecting anticipated increased operation to support IESO system reliability requirements.

SBG conditions are projected to result in forgone hydroelectric production of 10.2 TWh during the 2018-2021 period, an increase of 6.9 TWh compared to the previous plan, primarily as a result of an updated, lower OPG forecast of Ontario grid demand. SBG conditions are expected to be lower in 2020 and 2021 than in earlier years owing mainly to lower OPG nuclear production and commencement of Bruce unit refurbishments.

OPG's three wholly-owned thermal stations with a total capacity of close to 2,500 MW will continue to provide the electricity system with the flexibility to meet system demand and capacity requirements during the business plan term under their respective energy supply agreements. The current Thunder Bay biomass energy supply agreement expires in January 2020, with agreements for Lennox and Atikokan stations expiring within several years of the business plan period. These assets are unique in their operational flexibility and in the world-leading biomass innovation. The economics of these assets post existing contracts may be impacted by structural changes to Ontario's electricity market being contemplated through the IESO Market Renewal Program. OPG continues to be an active participant in the IESO's Market Renewal engagement process to ensure that the impacts of a redesigned electricity market are understood, the unique flexibility of OPG's assets is appropriately valued and the Company's operations are optimized under the new market rules.

Operations, Maintenance & Administration Expenses

The plan is targeting reductions of ~$600 million in OM&A expenses from ongoing operations over the 2018-2021 period compared to the previous plan, excluding ~$200 million in lower pension and OPEB costs the majority of which are subject to true up with customers through OEB-authorized deferral and variance accounts. These reductions reflect steps being taken to improve efficiency and align OPG's organizational structure and operating model with post-Pickering operations. The reductions of ~$600 million will be primarily enabled through optimization of resources, processes and technology and other business optimization initiatives across the organization, including nuclear outage optimization. Business optimization and organizational design work is currently underway as part of the OPG25 strategic initiative



* Excludes Darlington refurbishment OM&A expenses and all OEB variance and deferrral account offsets

** Includes centrally held pension / OPEB costs, insurance and other corporate level costs

to identify opportunities for reductions in operating costs, mainly in corporate Support Services and nuclear base OM&A programs. In addition to delivering improved financial results through increased net income during the business plan term and supporting more favourable outcomes of future OEB decisions, these changes will benefit customers by helping to position Darlington for industry-leading performance post refurbishment, further improve the cost effectiveness of the hydroelectric fleet and mitigate the Pickering closure downsizing costs. The major sources of cost reductions reflected in the plan are nuclear outage costs (~$255 million), Support Services costs (~$125 million), Nuclear base OM&A programs (~$85 million), Renewable Generation base OM&A programs (~$60 million) and Renewable Generation project costs (~$75 million).

The plan's cost reduction targets recognize that OPG's regulated rates for the business plan term have been set under an incentive based regulation methodology that is informed by the OEB's Renewed Regulatory Framework (RRF). Achieving operational effectiveness through meaningful efficiency incentives is a main focus of the RRF. In setting incentive regulation rates for OPG, the OEB applied efficiency stretch factors that reduced OPG's recoverable OM&A costs by an increasing amount each year over the business plan term, in addition to disallowing recovery of certain OM&A costs. Taking into account these adjustments, OM&A cost levels allowed by the OEB are ~$800 million lower than the OM&A cost levels reflected in the previous business plan. Therefore, while the plan-over-plan cost reductions of ~$600 million committed in this business plan are substantial, they do not fully offset, by ~$200 million, the shortfall in OM&A cost recoveries based on the OEB's decision. This negatively impacts OPG's ability to achieve the Regulated ROE target. Future business plans are expected to target additional cost improvement opportunities to close this gap by 2021. The OEB used OPG's external benchmarking of OPG's regulated operations' historical operational and cost performance to support the majority of cost reductions applied in setting the regulated rates. Benchmarking results are expected to continue to form a material part of OEB's assessment of OPG's cost levels in future rate applications.

Compared to the previous plan, the major changes to OM&A expenses from ongoing operations for the 2018-2021 period are as follows:

- Reductions in nuclear outage costs reflecting outage frequency optimization at Pickering, in addition to ~$45 million in savings realized in 2017 (-$140 million);
- Reductions in nuclear outage costs reflecting outage scope, duration and vendor scheduling optimization savings at Pickering and Darlington (-$115 million);
- Savings in Nuclear base OM&A costs from lower nuclear staffing levels reflecting strategies to leverage attrition and increase resource flexibility, optimization of operator training, and maintenance and other work program efficiencies (-$120 million), partially offset by higher materials requirements for the stations based on current experience compared to plan (+$35 million);
- Savings in Renewable Generation base OM&A costs, including from regionalization initiatives such as the integration of Central Operations, control room consolidation, and work management and organizational realignment efficiencies (-$60 million);
- Savings in corporate Support Services costs reflecting business optimization initiatives and organizational changes in support of the OPG25 initiative (-$125 million), including the following:
    - Reductions in Real Estate and Supply Chain costs from advancement of OPG's planned lease exit strategy, facilities staffing and maintenance efficiencies and automation, and organizational redesign initiatives;
    - Lower People & Culture function costs reflecting a decrease in staffing levels and other costs, including simplifying human resource support processes, leveraging digital solutions and streamlining training qualifications;
    - Lower Finance costs reflecting amalgamation of functions and other organizational design initiatives, rationalization of processes, and implementation of a corporate-wide shared services model. The corporate-wide shared services model is expected to be expanded to other shared services functions currently performed throughout the Company; and
    - Savings in Chief Information Office costs reflecting redesign of functions and processes including greater emphasis on automation, robotic processing and enhanced self-serve capability, software cost optimization, and digitization and other cost elimination initiatives.

    - These reductions are partially offset by an increase in project costs in 2018 in support of the digital transformation strategy and incremental costs over the planning period in support of the transportation electrification strategy.
- Changes in timing and accounting classification of certain planned Renewable Generation projects reflecting portfolio re-prioritization and more advanced scope definition (-$75 million); and
- Lower insurance costs reflecting savings achieved in the nuclear liability insurance program (-$25 million) and elimination of the annual fee for the Province's financial guarantee to the CNSC due to the fully funded status of the nuclear segregated funds (-$15 million).

In addition to varied levels of Pickering extended operations enabling costs that have been reflowed from the previous plan in line with the revised outage schedule, year-over-year changes in OM&A expenses from ongoing operations over the 2018-2021 period include:

- Variability in nuclear outage costs reflecting timing of planned outages, including fewer planned outages at Pickering in 2019 and 2021 under the optimized outage cycle, the Pickering VBO in 2020 and no major planned outages at Darlington in 2021. The movement of the Pickering VBO from 2021 in the previous plan shifted ~$40 million in OM&A costs to 2020 in this plan;
- Reductions in staffing levels and other cost drivers reflecting continued focus on productivity improvement and business optimization initiatives, net of assumed labour escalation and other inflationary impacts;
- Write-off of previously incurred development capital expenditures and higher expenses associated with nuclear inventory obsolescence costs in 2017; and
- Higher nuclear base OM&A costs of ~$15 million in 2019 related to the CNSC's Fitness for Duty program, compared to 2018. Consistent with the previous plan, total program costs over the planning period are estimated at ~$40 million.

The Darlington Refurbishment project expenses vary over the planning period with the expected timing of pressure tube and feeder removal activities and other work programs not eligible for capitalization.

The regulatory variance and deferral account impacts to OM&A expenses increase to 2020 due to lower pension and OPEB costs and then decline in 2021 reflecting timing changes in Pickering extended operations enabling costs compared to the OEB-approved levels.

Pension and OPEB Costs

Lower pension and OPEB costs compared to the previous plan are due to higher discount rates, better than expected pension asset performance, lower headcount and updated actuarial inputs. As in the previous plan, projected pension and OPEB costs are decreasing year over year during the planning period, mainly reflecting projected pension asset returns and lower amortization of net historical actuarial losses. The regulated business portion of the plan-over-plan and year-over-year changes in pension and OPEB costs is offset by corresponding changes in the cash-to-accrual deferral account, discussed below.

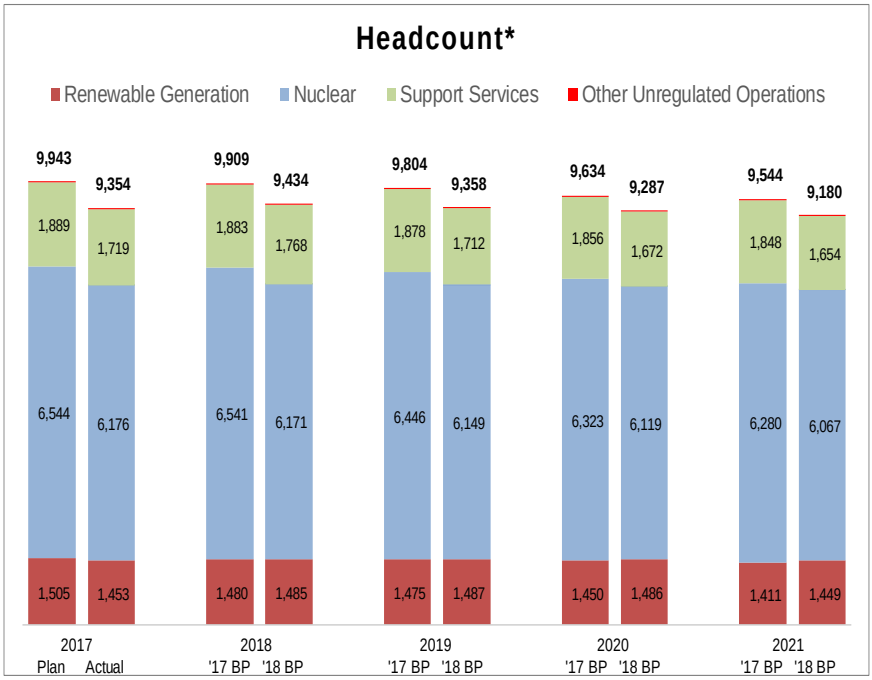
The 2017-2021 regulated rates limit the recovery of OPG's pension and OPEB costs to cash amounts, with the difference between accrual and cash amounts continuing to be recorded in an OEB authorized deferral account in place since 2014. In 2017, the OEB issued its final report on the regulatory treatment of pension and OPEB costs, establishing the accrual basis of accounting as the default rate-setting method for regulated utilities in Ontario. As required by the report, OPG will seek the OEB's approval to resume the accrual basis of recovery and begin to collect the balance accumulated in the deferral account, through a deferral and variance account application planned later in 2018. OPG must begin to collect the account balance by November 2019 in order to avoid writing off a portion of the balance against net income as would be required by US GAAP. The deferral account balance stood at ~$600 million at the end of 2017.

Headcount

Significant staffing reductions are being realized across the organization, compared to the previous plan, as part of efforts to realign the corporate cost structure and drive productivity improvement and operational efficiencies. These ongoing efforts will support the OPG25 initiative in implementing operating model and

organizational design strategies to ensure cost effectiveness of post-Pickering operations, and will help to mitigate downsizing costs related to the Pickering closure.

Actual year-end 2017 headcount was ~590 lower than expected in the previous plan, with ~370 fewer employees in the Nuclear organization, ~170 fewer employees in Support Services organizations and ~50 fewer employees in Renewable Generation. This overall trend continues over the 2018-2021 period as forecast headcount is lower by ~410 employees, on average, in each year. Nuclear organization headcount includes employees working on the Darlington refurbishment.



* 2017-2019 BP and 2017 Actuals have been restated for 2018 organizational changes. Includes PWU Term employees.

Nuclear headcount is lower by ~270 employees on average over the period, compared to the previous plan. The reduction leverages attrition opportunities and a move towards a more flexible staffing strategy to fulfil short-term operating needs while considering long-term staffing goals in support of the OPG25 initiative. Headcount for Support Services organizations decreases by ~165 on average over the period, compared to the previous plan. The decrease includes ~95 employees in Finance, ~35 employees in People & Culture and ~35 employees in Chief Administrative Office and is expected to be achieved through work elimination, technology advances and organizational redesign. Renewable Generation headcount increases by ~20 employees on average, compared to the previous plan, primarily adding staff in support of project planning, management and execution.

Notwithstanding plan-over-plan reductions, high levels of attrition reflecting employee demographics and a commitment to increase work execution will necessitate some replacement hiring to fill key vacancies in certain areas over the planning period. Through filling of existing vacancies, headcount is expected to increase by 80 employees year over year in 2018, before beginning to decline thereafter.

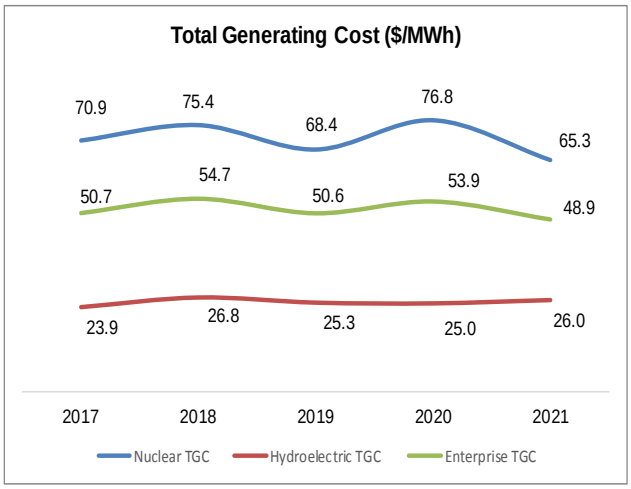
By the end of 2021, headcount is expected to be ~255 lower than at the end of 2018, reflecting efficiency improvement and organizational redesign initiatives and the impact on work programs from the approaching Pickering end of life. These reductions are expected to be realized by leveraging attrition and through selective use of temporary resources in line with collective agreement provisions. The decline in future staffing levels also reflects the expiry of the current Thunder Bay biomass energy supply agreement in 2020.

Staffing levels discussed above include PWU Term Employees. The plan assumes continued utilization of this category of non-regular employees negotiated in the 2015 round of collective bargaining with a view to adding fewer regular staff in circumstances where they are likely to be laid off as a result of the end of Pickering commercial operations. Term Employees attract a lower termination cost than regular PWU employees, do not receive pension or benefits from OPG and represent a key strategy to mitigate downsizing costs upon retirement of Pickering. The plan reflects an addition of ~300 PWU Term Employees over the period, primarily in the Nuclear organization, bringing the total number of PWU Term Employees to ~440 by 2021. Continued use of Term Employees requires renegotiation as part of the 2018 round of collective bargaining.

Collective bargaining results will also continue to impact future OEB rate application outcomes, as OEB cost disallowances have been historically based, in part, on OPG's compensation benchmarking including wages, pension and benefits. While OPG has made progress in containing unionized employee wage costs and implementing pension reform in the last round of bargaining, it must seek to continue to make further gains in this area in order to improve its cost structure.

Total Generating Cost

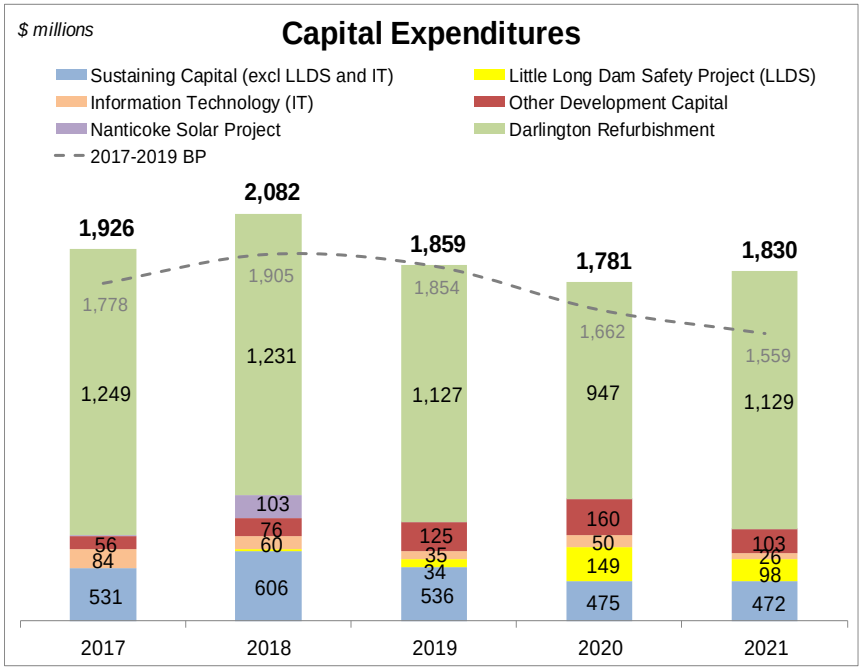
Total Generating Cost (TGC) per MWh is OPG's enterprise-wide measure of operational cost effectiveness. The measure includes OM&A expenses from ongoing operations, fuel expense (including gross revenue charge and other water rental costs) and sustaining capital expenditures, and is calculated on SBG-adjusted production volumes. In addition to continuing to exclude development capital expenditures, the measure also excludes expenditures on two planned large hydroelectric projects, the $200 million Sir Adam Beck I GS Water Conveyance System project and the $300 million Little Long Dam Safety project, starting with this planning cycle.



Targets for Enterprise TGC per MWh over the period range from a low of $48.9 (in 2021) to a high of $54.7 (in 2018), compared to $50.7 in 2017. The fluctuations in the measure over the period reflect the nuclear outage profile, including the Pickering VBO and Darlington refurbishment-related outage impacts, initiatives to reduce OM&A costs, variability in sustaining capital expenditure levels and, in 2017, high SBG-adjusted hydroelectric production due to extremely high water levels. If Darlington units were not undergoing refurbishment and would continue to operate consistent with targeted performance for the station's un-refurbished units and if the Pickering units would continue to operate in lieu of the VBO, the plan would yield Enterprise TGC per MWh targets of ~$5 lower, on average. The 2017 metric on this basis would have been similarly lower.

Project Excellence

Asset base growth through investment in existing assets, organic development and acquisition is a key element of OPG's strategy to achieve sustainable increases in profitability and ROE levels and to maintain appropriate scale in the longer term.



In addition to refurbishing the Darlington station, OPG's planned capital program will continue to make investments in sustaining and improving the performance of existing assets and will continue to execute the organic growth element of the corporate strategy, including through relatively modest expansion of hydroelectric generating capacity, completion of the Nanticoke solar facility and investments in nuclear and other low-carbon technology innovation complementary to OPG's core competencies. The planned capital program is aligned with the 2017 LTEP.

Total capital expenditures planned for the Darlington refurbishment, sustaining investments in existing assets and organic development projects are $7.5 billion over the 2018-2021 period, ranging from $1.8 billion to $2.1 billion per year. Over the period, this represents an increase of ~$570 million compared to the previous plan. The major drivers of the increase are timing of Darlington refurbishment expenditures (~$105 million), incremental investment in Darlington sustaining capital (~$120 million), accelerated digital transformation strategy (~$40 million), and incremental funding for potential organic growth opportunities (~$200 million). As discussed under the Financial Strength section, non-organic growth investments are not assumed in the plan and will need to be aligned with market opportunities and Shareholder's expectations.

Darlington Refurbishment

Darlington refurbishment expenditures total $4.4 billion over the period, an increase of ~$105 million from the previous plan due to timing of expenditures. Consistent with previous business plans and OEB approvals, the plan continues to reflect the high confidence budget and schedule for the Darlington refurbishment, with total cost flow through Unit 2 return to service consistent with Board-approved levels. This includes the D2O Project, which is expected to be completed in the first half of 2019 within the funds already released to the Darlington refurbishment program.

Planned Darlington refurbishment in-service amounts are consistent with amounts approved by the OEB in setting the 2017-2021 regulated rates. In particular, the OEB has allowed inclusion of a total of $5.5 billion in Darlington refurbishment in-service additions through 2021, including pre-requisite projects other than the D2O Project. The plan reflects Unit 2 returning to service in February 2020, with Unit 3 refurbishment commencing immediately thereafter and the third unit refurbishment beginning in 2021. Pre-execution expenditures incurred for the Unit 3 refurbishment, including acquisition of long lead-time materials and components, are $93 million as of 2017 year-end, with a further ~$540 million reflected in the plan over 2018 to February 2020.

Sustaining Capital

Total sustaining capital expenditures for nuclear operations are $1.3 billion over the period, declining from ~$385 million in 2018 to ~$245 million in 2021. This represents a total increase of ~$120 million from the previous plan, primarily on account of the Darlington capital program in 2018 and 2019. The program is focused on ensuring Darlington is well positioned to transition to steady-state operations and achieve and maintain industry-leading performance as soon as possible following refurbishment. The increase in expenditures reflects continued optimization of the capital program recognizing historical under-investment relative to peers, with significant plant investments targeted to be completed before multiple Darlington units are under refurbishment later in the plan. These investments include life cycle management projects, upgrades and additions of facilities, and work in support regulatory commitments. The Darlington capital program is expected to decline toward the end of the planning period and during the remainder of the refurbishment period. Consistent with the previous plan, the Pickering capital program declines over the period in line with the planned end of life in 2024.

OPG remains focused on delivering all projects safely, on time, on budget and with high quality and is committed to executing its capital plan. In 2017, OPG delivered on its capital program commitments with aggregate spending on sustaining capital projects meeting internal targets. To improve consistency of project outcomes across the organization, OPG has implemented common enterprise-wide project governance and a scalable project delivery model, as well as project management system and tools, leveraging industry standards. OPG is also focused on strengthening internal project management capability, with project management proficiency development programs launched in 2017 for existing and new project managers. In 2018, OPG will transition to an enterprise wide Project Management Centre of Excellence that will provide portfolio and project management standards and services for all projects across OPG.

In setting OPG's nuclear regulated rates for 2017-2021, the OEB disallowed certain capital project costs based on an assessment of OPG's performance on the projects, reduced OPG's forecast of 2017-2021 non-Darlington refurbishment capital in-service additions based on an assessment of OPG's ability to deliver on the capital plan, and applied an accumulating annual efficiency stretch factor of 0.6% to reduce

revenues earned by OPG from an allowed level of forecast in-service additions. Continuing to execute the capital program as planned and delivering on efforts to improve project performance will support improved outcomes of OEB's future assessments of OPG's capital costs.

Excluding the Sir Adam Beck I GS Water Conveyance System project, regulated hydroelectric sustaining capital expenditures total ~$510 million over the 2018-2021 period, an average ~$125 million per year, consistent with the previous plan. This includes a number of projects to maintain and enhance availability when needed and reliability as well as increase capacity of OPG's renewable fleet, including:

- Unit overhauls and upgrades across the fleet, including Sir Adam Beck 1, Sir Adam Beck Pump, R.H. Saunders, Otto Holden, Barrett Chute and Silver Falls generating stations.
- Flow control equipment replacements in Northwest Operations including automatic sluicegate system replacements at Whitedog Falls GS and Caribou Falls GS scheduled for completion in 2019 and 2020 respectively; and
- Electrical equipment, headgate and sluicegate replacements in Eastern Operations including generator breaker replacements at Des Joachims GS, to be completed in 2020 and 2021;

Planning work on the $200 million Water Conveyance System project to rehabilitate the Sir Adam Beck I GS power canal and associated structures has commenced. The project will repair concrete deterioration and restore the original flow capacity of the power canal, ensuring reliable operations for the next 50 years. The project is expected to come into service over two years following the start of execution.

Contracted hydroelectric sustaining expenditures include the $300 million Little Long Dam Safety project (formerly the Lower Mattagami Dam Safety project), planned to be completed by 2022. The project will address dam safety requirements on the Lower Mattagami River in line with OPG's commitment to dam safety excellence, earning a return under the Lower Mattagami hydroelectric energy supply agreement once in service. Total project expenditures are consistent with the previous plan, but have been deferred to start later in the planning period.

Sustaining expenditures include ~$170 million for information technology projects, including an increase of ~$40 million over the previous plan for investments in OPG's accelerated digital transformation strategy, largely over 2018 and 2019. The digital transformation strategy will serve as an enabler to productivity improvements and business optimization opportunities, by modernizing OPG's information technology infrastructure and by providing the technology foundation and tools aimed at maximizing workforce and field productivity and efficiency across the organization. Projects are focused on four key strategic areas: Digital Modernization; Generation Support; OPG25 Support; and Infrastructure Improvement. More than half of the projects are to be invested directly in the generation business units. OPG will also continue to make investments in maintaining a reliable, cyber-safe information technology environment and reducing cyber-related operational risks.

Business Development Capital

Organic development expenditures over the planning period total ~$570 million. This includes previously planned projects as well as incremental funding of ~$200 million for organic business development opportunities. Previously planned projects include completion of the Ranney Falls GS redevelopment, construction of the Nanticoke solar facility, frequency conversion of Sir Adam Beck GS Units 1 and 2 to 60 Hz to increase capacity, and potential redevelopment of the Calabogie GS. The Ranney Falls GS project is tracking on schedule and on budget, construction of the Nanticoke facility is scheduled to begin in the first quarter of 2018, the Sir Adam Beck frequency conversion is planned to begin execution in 2019, and the Calabogie GS redevelopment is being assessed as part of the definition phase. The Ranney Falls GS and the Nanticoke solar facility are scheduled to come into service during 2019.

Incremental funding for potential organic business development investments included in the plan contemplates such additional opportunities as expansion of nuclear isotopes sales and nuclear services, future regulation procurement projects and an investment in a disruptive innovation venture fund. OPG will continue to strategically assess investment opportunities for decarbonising, disruptive energy sector technologies beyond the Company's core generation portfolio, with the goal of building a competitive advantage in this area.

OPG has been successful with the organic growth element of its strategy, including through recent completion of the 28 MW Peter Sutherland Sr. GS, and will continue to explore broader business expansion opportunities as described above. Nevertheless, organic growth opportunities in Ontario's electricity sector remain limited including due to uncertain future electricity demand levels, and OPG's current asset portfolio continues to be heavily weighted on Ontario-centric regulated nuclear and hydroelectric generation. The non-organic element of OPG's corporate strategy, executed in a paced manner with due consideration of core operational and financial impacts, is therefore essential to ensuring that OPG is ultimately able to deliver appropriate Shareholder value and improve its risk profile.

Provision Expenditures

Planned expenditures against a previously established provision for nuclear station decommissioning and waste management average ~$350 million per year over the 2018-2021 period. The expenditures include costs for ongoing used fuel and low & intermediate level waste interim storage operations and projects, the planning phase of the Pickering Safstor project, Nuclear Waste Management Organization's siting process activities for the Adaptive Phased Management used fuel disposal program, and continuing activities in support of obtaining a preparation and construction licence for the L&ILW DGR. The plan supports OPG's ongoing commitment to continued engagement with the Saugeen Ojibway Nation toward securing support for the L&ILW DGR, including developing a response to the federal Minister of Environment and Climate Change request for OPG to update its analysis of potential cumulative effects of the project on the Saugeen Ojibway Nation's physical and cultural heritage, taking into account the results of the Saugeen Ojibway Nation Community Process. In recognition of inherent uncertainty in the ultimate impact of the Environmental Assessment decision on the timing of project construction, planned expenditures on the L&ILW DGR project over the 2018-2021 period are ~$400 million lower than in the previous plan. Nuclear provision expenditures are funded from the nuclear segregated funds for decommissioning and long-term management of fuel and waste and from operating cash flow for interim storage operations.

The plan also includes provision expenditures of ~$75 million and ~$85 million over the period to 2021 for decommissioning of the former Nanticoke GS by 2020 and the former Lambton GS by 2021, respectively. Projected decommissioning expenditures for these sites reflect more advanced planning and contract scope details.

Social Licence

As the largest electricity generator in Ontario with diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust and building the Company's brand. OPG works to maintain public trust through community engagement, transparency, corporate citizenship initiatives and Indigenous relations. OPG focuses on building and maintaining its social licence through safe, reliable, environmentally-responsible operations that continue to mitigate Ontario's electricity prices, support climate change initiatives and foster diversity and inclusion in the workplace.

Supporting Decarbonisation and Climate Change Goals

OPG is proud of its transition to a low-carbon electricity generation portfolio and is helping the Province meet its climate change and greenhouse gas reduction commitments. With a generating fleet that is 99% emission-free, OPG avoids over 30 million tonnes of greenhouse gas emissions annually in comparison to a fleet of gas generators. To ensure a supply of clean power for generations to come, OPG's operational and organic growth strategies are focused on innovation, technology, and energy and storage development. This includes maintaining the nuclear portion of OPG's generation portfolio, participating in the development of new nuclear technologies, evaluating and implementing plans to increase hydroelectric generation, and investing in other low-carbon technologies. Through investment in these areas, OPG seeks to support Ontario's climate change goals while building momentum for new business opportunities. OPG's business plan supports Ontario's climate change goals through a transportation electrification strategy, participation in Ontario's cap and trade program, organic expansion of the renewable generating fleet and the supply of safe, reliable and clean power to homes, businesses and industry throughout the province.

The goal of OPG's transportation electrification strategy is to position the Company as a leader in the electrification of Ontario's transportation sector. As part of the strategy, OPG is implementing fleet-wide electric vehicle adoption goals and charging station infrastructure across the Company's work locations, and is assessing vehicle-grid integration and hydrogen applications for the transportation sector. This strategy is intended to leverage OPG's clean, reliable and cost-effective electricity to support action on climate change, create growth opportunities for OPG, and enhance OPG's brand and social licence.

OPG has been a participant in Ontario's cap and trade program since it came into effect on January 1, 2017. This market-based program sets an annual cap for greenhouse gas emissions, with targets becoming more stringent over time. Compliance with these requirements does not have a significant financial cost impact on OPG's business plan given OPG's virtually emission-free generating fleet and the contractual arrangements in place for the greenhouse gas emitting assets in OPG's fleet.

Looking ahead, climate change and the extreme weather associated with it could pose strategic risks for OPG. Longer term changes in precipitation patterns and amounts, water temperatures, and ambient air temperatures can impact the availability and quality of water resources for OPG's operations. These changes could potentially affect electricity production at hydroelectric stations, and cooling water efficiency at nuclear and thermal stations. To date, OPG has not experienced significant impacts attributable to climate change or extreme weather, but the Company is assessing the short and long-term risks and identifying climate change adaptation requirements. OPG continues to participate in climate change adaptation initiatives with municipal and regional governments, the Ontario Ministry of the Environment and Climate Change, the Ontario Ministry of Energy, and Natural Resources Canada. OPG is also monitoring developments in climate science, adaptation activities, and potential changes to policy and regulatory requirements.

New guidance is expected shortly for North American listed public companies that will see a stronger emphasis on climate-related disclosures and reporting requirements as part of the financial reporting framework. Given OPG's commitment to climate change mitigation, the Company will position itself to move toward a leadership position in this area and will increase disclosures in regulatory filings during 2018.

Pursuing Clean Energy Business Development Opportunities

Expanding clean generation from the Company's renewable generation fleet is a key focus of OPG's organic business development plans. As detailed in the Operational Excellence and Project Excellence sections, OPG expects to add approximately 170 MW of renewable generation capacity to its fleet over the business plan period, including through construction of a 44 MW solar facility at the former Nanticoke GS site in partnership with the Six Nations of the Grand River and investments in developing, re-developing and upgrading of hydroelectric facilities. OPG will continue to optimize electricity production and seek opportunities to further expand capacity from its province-wide hydroelectric fleet by balancing the economic, environmental, social, and legal requirements associated with the affected watersheds.

OPG sees significant socio-economic and commercial potential in the role that nuclear energy can continue to play in a decarbonizing economy. In addition to making significant investments in OPG's existing nuclear fleet to continue to provide Ontario with cost-effective, carbon-free baseload generation, through refurbishment of Darlington and extension of Pickering operations to 2024, OPG plans to strategically participate in the development of potential innovative and advanced nuclear reactor technologies. As Canada's largest nuclear operator with extensive experience, a strong safety record and a commitment to climate change mitigation, OPG is well positioned to be a pan-Canadian driving force in this area. With respect to OPG's existing nuclear operations, it is expected that the refurbished Darlington station will reduce greenhouse gas emissions by an estimated 297 million tonnes over its life, which is the equivalent of removing two million fossil-fuelled cars per year from Ontario's roads.

In addition to being a mainstay of Ontario's baseload electricity supply, OPG's nuclear operations continue to be a source of important isotopes that serve significant needs in society. From the life-saving Cobalt-60 isotope, which sterilizes medical devices and food, to tritium, which can act as a self-powered light source, these innovative nuclear products help millions of people around the world. Isotope production is an example of a good business opportunity for OPG that validates the Company's social licence and Power with Purpose vision.

Partnering with Indigenous Communities

OPG is committed to continuing to build mutually beneficial working relations with Indigenous communities proximate to the Company's current and future operations. The Company believes and takes pride in establishing and maintaining these relationships through dialogue founded in respect and aimed at preserving openness, transparency and trust. These strong partnerships are vital to maintaining OPG's social licence in the communities and are a source of critical competitive advantage while developing clean, renewable power in the province.

Throughout the planning period, OPG will continue to engage proactively with Indigenous communities, people, businesses and organizations through a number of diverse initiatives. This includes pursuing additional generation-related development partnerships, collaborating on capacity building initiatives and projects, and continuing to conduct community outreach efforts. As part of capacity building, OPG will continue to advance its Indigenous Business Engagement initiative that will increase Indigenous access to procurement opportunities, as well as to expand Indigenous recruitment initiatives aimed at increasing employment opportunities, including in the nuclear generation industry. As a member of the Canadian Council of Aboriginal Businesses, OPG is also working towards a new assessment submission in 2018 under the Council's Progressive Aboriginal Relations certification program, with the goal of achieving a Gold certification.

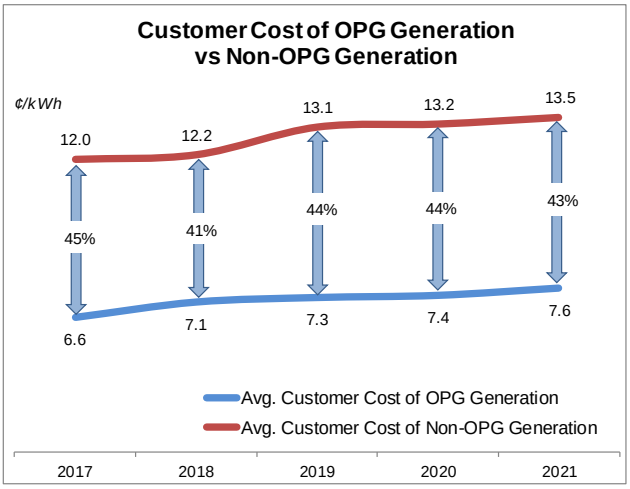
OPG continues its engagement with Indigenous communities regarding the Company's nuclear operations, including collaboration with the Saugeen Ojibway Nation in respect of the proposed L&ILW DGR. OPG has previously committed that the project would not proceed without Saugeen Ojibway Nation's support. OPG is also proactively engaging with Indigenous communities proximate to the Pickering station regarding the station's relicensing and collaborated with the CNSC to ensure access to participant funding in the hearing process.

Expanding the OPG Brand and Creating a Diverse, Progressive Workforce

In support of its strategic direction, OPG continues to expand its branding efforts to reinforce the Company's social licence, increase stakeholder awareness and build a stronger presence amongst the public. Power with Purpose remains the platform for the Company's key outreach and branding initiatives. OPG will continue to use Power with Purpose to emphasize the Company's role as a leader in clean energy generation and innovation, as a cost-effective moderator of electricity prices, and as a driver of economic and community well-being. Additionally, a new "Be the Generation" recruitment campaign to appeal to both prospective and current employees is being developed. Be the Generation aims to present the opportunities to make a difference when working for OPG as a forward-looking company that takes pride in caring about people, the environment, the economy and the future. Likewise, OPG's "Made in Ontario" campaign will continue to capture OPG's efforts to secure a clean energy future for the province.

OPG is focused on building a workforce that is representative of the communities and customers it serves and is committed to provide a diverse and equitable workplace where all employees can realize their full potential with equal access to opportunities. In support of this, OPG has developed a long-term Diversity and Inclusion strategy into 2020, reflected its commitment in the performance contracts of all Company's executives, and strives to hire diverse candidates by reaching out to designated groups and including diversity in succession plans. Leveraging the unique perspectives, talents and experiences of a diverse workforce will enable OPG to grow and compete well into the future.

Moderating Electricity Prices and Contributing to the Economy



The plan reflects the OEB's decision on OPG's 2017-2021 rate application, which, based on OPG's proposed payment amounts order, will result in a consistent annual increase of 0.4% or $0.65 on the typical residential customer's monthly bill during the 2017 to 2021 period. Taking into the account this impact, the average cost to customers of electricity generated by OPG will continue to track approximately 40% below the average of non-OPG cost of electricity in Ontario over the period to 2021.

The forecast trajectory of OPG's average cost reflects nuclear regulated rates under rate smoothing proposed in OPG's payment amounts order submission, as well as a forecast of regulated hydroelectric rates under the OEB-approved incentive regulation formula. The increase in the non-OPG cost of electricity in 2019 reflects the terms of the refurbishment agreement between Bruce Power and IESO, whereby Bruce Power begins to receive a higher price commencing one year before the first unit is scheduled to commence refurbishment in 2020.

The average non-OPG cost of electricity trajectory over the business plan term is higher than OPG's forecast in the previous plan. This is primarily due to an updated OPG forecast of wind and solar electricity system costs based on updated non-OPG renewable generation cost information published by the IESO, and a reduction in the annual Ontario grid demand forecast averaging 2.5 TWh. Lower grid demand decreases the need for gas generation that is used to spread the fixed portion of non-OPG generator costs, thereby increasing the average non-OPG cost.

OPG will continue to make a significant contribution to the Ontario economy and job creation, including through the refurbishment and continued operation of the Darlington station and extending the operating life of the Pickering station to 2024. In addition to continuing to powering one in every five homes in Ontario, the Darlington station's refurbishment and subsequent operation are estimated to boost Ontario's Gross Domestic Product by $90 billion and create and sustain over 14,000 jobs annually over the station's life.

Engaging Electricity Consumers

Customer engagement is a priority for OPG, both because of its social license strategic imperative and because of its largely regulated operations. OPG routinely engages customers and opinion leaders through provincial and host community surveys, community liaison groups, focus groups, and ongoing contact with key industry associations. Engagement topics cover areas of critical importance to OPG's business, including safety, reliability and environmental protection. The OEB increasingly expects regulated utilities' business plans to be shaped by customer engagement. The OEB has confirmed that, although OPG does not have a direct transactional relationship with electricity consumers, it expects OPG's business plans to be informed by customer engagement. OPG has committed to more formally incorporate customer engagement into its business planning process over time and will build on its existing customer engagement activities as it prepares subsequent business plans.

APPENDIX 1: KEY PLANNING ASSUMPTIONS

Operational and Project Assumptions

- Refurbishment of Darlington Unit 2 is completed by February 2020, with Unit 3 refurbishment starting immediately after Unit 2 is returned to service and Unit 1 refurbishment starting in 2021. D2O Project is in service in the first half of 2019
- Pickering station operates until 2024. The plan includes additional costs and outage days to enable Pickering operations beyond 2020, in line with the business case approved by the Board
- A station-wide Vacuum Building Outage takes place at Pickering in 2020
- The plan reflects currently approved accounting station service lives for Pickering Units 1 & 4 to 2022, Pickering Units 5-8 to 2024, Darlington to 2052, Bruce Units 1-4 to 2052 and Bruce Units 5-8 to 2061
- Employee termination costs related to the Pickering closure are not included in the plan. Accounting criteria requiring recognition of a liability for these costs are assumed to be met in 2022 at the earliest
- Site preparation and construction licence is received for the proposed L&ILW DGR
- Incremental funding is allocated in the plan for potential initial planning and preparation activities related to the study of new nuclear facilities. The new nuclear Darlington site preparation licence is maintained
- Sir Adam Beck I GS Units 1 & 2 are converted to 60 Hz frequency, with the first unit in service in 2021
- Sir Adam Beck I GS power canal rehabilitation takes place over 2021 and 2022, subject to optimization of major project work sequencing in Renewable Generation
- Ranney Falls GS project is in service in 2019 and Little Long Dam Safety project is completed by 2022
- Nanticoke solar facility is in service in the first quarter of 2019. Former Nanticoke GS and Lambton GS are decommissioned, with demolition and site brownfield completed by 2020 and 2021, respectively
- Thunder Bay GS operates until the end of current biomass energy supply agreement in January 2020
- First Bruce unit refurbishment starts in 2020, as per the Bruce Power refurbishment agreement
- Assumed Ontario grid demand growth rate is approximately 0% on average over the planning period

Financial and Rate Regulation Assumptions

- OEB approves nuclear base rates and rate smoothing deferrals to 2021 as proposed in OPG's January 2018 draft payment amounts order. Hydroelectric base rates increase by 1% in 2019 and by 1.5% in each of 2020 and 2021 under the OEB-approved incentive regulation formula
- OPG's next deferral and variance account application is filed in 2018, with OEB approving clearance of the pension and OPEB cash-to-accrual deferral account as part of the application
- Lakeview site sale takes place in the first quarter of 2018, with a corresponding dividend paid in 2018, in addition to the dividend related to the sale of the 700 University Ave. property. No other dividends are assumed pending review and formalization of a capital allocation policy
- Acquisitions are not included in the plan as opportunities are evaluated as they arise
- Nuclear Fund investments earn 5.15%/yr
- Pension fund investments earn 6%/yr. Accounting discount rates for valuing the benefit obligation for pension and other post-retirement benefits are 3.8% and 3.9%, respectively
- The plan reflects the January 1, 2017 actuarial funding valuation of OPG's registered pension plan as filed with the regulator and assumes a subsequent valuation as of January 1, 2020
- Pending the outcome of 2018 round of bargaining, inflationary impacts on salary costs are assumed post current collective agreements. Ability to utilize PWU Term Employees is assumed to continue
- Both OEFC credit facilities and public debt platform are used for long-term corporate debt purposes. Effective interest rate for new OPG debt over the planning period is 5.0%, on average
- The plan reflects OPG's role as the Financial Services Manager of the Fair Hydro Plan, including consolidation of the Fair Hydro Trust. Effective interest rate for Fair Hydro Trust senior debt over the planning period is 4.25%, on average
- OPG continues to prepare its consolidated financial statements and report its financial results in accordance with US GAAP

APPENDIX 2: KEY RISKS

The key risks associated with the 2018-2021 Business Plan are outlined below.

Operational and Project Risks

- Failure to maintain the Darlington refurbishment cost and schedule commitments per the approved project budget and schedule
- Inability to meet the objectives of the first unit refurbishment, resulting in sub-optimal post-refurbishment performance
- Risk of the Province not concurring with the refurbishment of subsequent Darlington units
- Inability to achieve production targets, including risks associated with unit capability factors, planned nuclear outage performance, nuclear station lifecycle management, and human performance
- Risk of increased operating costs as a result of greater-than-planned deterioration of station components and systems, discovery of unexpected conditions, and/or equipment failures
- Risk of technical challenges in confirming ability to operate Pickering beyond 2020, and/or failure to obtain regulatory assurance from the CNSC in support of the station's continued operations, including inability to renew the operating licence without conditions
- Inability to progress realignment of the Company's cost structure and operating model in line with the OPG25 plan
- Inability to retain and attract leadership talent and qualified management employees during the Darlington refurbishment and continued Pickering operations, and/or inability of management and staff to adapt to OPG's evolving corporate culture and higher level of commercial discipline
- Failure to appropriately staff operational and support groups in critical skill areas given ongoing demographic challenges and strategies aimed at mitigating Pickering closure downsizing impacts

Financial and Rate Regulation Risks

- Risk of unfavourable outcomes of the 2018 round of collective bargaining, which could impact operating costs, Pickering closure employee termination costs and future OEB rate application outcomes
- Risk of requirement to recognize employee termination costs associated with the Pickering end of commercial operations prior to 2022, which would require assurance over the costs' future recovery in order to avoid a significant charge against net income
- Lack of material growth investments and eventual loss of scale leading to increased risk of inability to withstand unplanned events, diminished ability to support de-carbonisation goals and erosion of Shareholder value
- Risk of federal approval process for L&ILW DGR resulting in significant changes to OPG's nuclear waste management strategies and associated financial obligations, impacting net income and future required contributions to the nuclear segregated funds
- Risk of lower than planned returns on nuclear segregated and pension fund assets as a result of market factors, including equity prices, interest rates, inflation and commodity prices, which would lower net income and potentially increase future funding requirements
- Risk of lower discount rates and other changes in assumptions for future pension and OPEB valuations
- Risk of adoption of IFRS for financial reporting purposes due to inability to extend the Ontario Securities Commission exemption that allows OPG to prepare consolidated financial statements under US GAAP. Adoption of IFRS would be expected to cause significant net income volatility compared to US GAAP

APPENDIX 3: Financial and Headcount Plan Information

Key Financial Metrics *(in millions of dollars unless otherwise noted)*	Actual 2017	Business Plan 2018	 2019	 2020	 2021
Financial Performance Metrics					
Net Income Attributable to Shareholder	860	1,043	1,066	919	1,373
Operating Net Income Attributable to Shareholder	576	795	968	764	1,160
Earnings Before Tax	1,090	1,140	1,239	1,147	1,649
Total Return on Equity*	7.6%	8.1%	7.2%	5.4%	7.1%
Operating Return on Equity*	5.3%	6.8%	7.7%	5.7%	8.1%
Debt Ratio, excl. Fair Hydro Trust****	34%	36%	33%	30%	26%
FFO / Total Debt Ratio, including Fair Hydro Trust Impact *(Minimum threshold of 9%)*	10%	11%	12%	13%	13%
FFO / Total Debt Ratio, excluding Fair Hydro Trust Impact	10%	13%	15%	17%	19%
Debt / EBITDA Ratio, including Fair Hydro Trust Impact (times) *(Maximum threshold of 5.5)*	6.8	6.5	6.2	6.2	6.0
Debt / EBITDA Ratio, excluding Fair Hydro Trust Impact (times)	6.4	5.8	5.1	4.8	4.3
Total Debt at Year-End	6,579	8,757	9,768	10,978	11,777
Net Cash from Operations	944	1,460	2,384	2,067	2,642
Total Return to Shareholder, excluding Fair Hydro Trust Earnings***	1,393	1,391	1,422	1,259	1,667
Cost Performance Metrics					
Nuclear Total Generating Cost** *($/MWh)*	70.9	75.4	68.4	76.8	65.3
Hydroelectric Total Generating Cost** *($/MWh)*	23.9	26.8	25.3	25.0	26.0
Enterprise Total Generating Cost** *($/MWh)*	50.7	54.7	50.6	53.9	48.9
OM&A Expenses from Ongoing Operations	2,819	2,850	2,732	2,807	2,570
Darlington Refurbishment Capital Expenditures	1,249	1,231	1,127	947	1,129
Darlington Refurbishment In-Service Additions	305	24	335	4,698	-
Capital Expenditures excluding Darlington Refurbishment	677	851	731	834	700
In-Service Additions excluding Darlington Refurbishment	968	719	876	527	804
Nuclear Waste and Thermal Decom. Provision Expenditures	313	373	411	435	377

* Calculated using the methodology per OPG's external financial filings

** Total Generating Cost is calculated as: (OM&A expenses from ongoing operations + fuel and Gross Revenue Charge expenses for OPG-operated stations + sustaining capital expenditures)/OPG generation adjusted for surplus baseload generation losses. Sustaining capital expenditures exclude the Little Long Dam Safety project and the Sir Adam Beck 1 GS Water Conveyance System Project. Absent Darlington refurbishment and Pickering VBO, Enterprise TGC would be ~$5/MWh lower on average each year

*** Calculated as: Net Income Attributable to Shareholder + Income Taxes + Gross Revenue Charge + Property Tax PILs

****Excludes Class A Shares and Fair Hydro Trust Senior Debt

Operating Statement - Years Ended December 31 *(in millions of dollars)*	Actual 2017	Business Plan 2018	 2019	 2020	 2021
Electricity Generation Revenues	4,823	4,975	5,583	5,788	5,404
Fuel and Gross Revenue Charge	689	674	686	654	626
Generation Sales Gross Margin	**4,134**	**4,301**	**4,898**	**5,134**	**4,778**
Net Trading Margin	15	18	18	18	18
Non-Electricity Generation Gross Margin	302	258	249	253	235
Total Gross Margin	4,450	4,577	5,165	5,406	5,032
OM&A Expenses (excl. Cost of Goods Sold)	2,806	2,827	2,773	2,914	2,596
Depreciation and Amortization	679	743	1,139	1,318	950
Accretion on Nuclear Waste and Other Liabilities	960	991	1,023	1,055	1,091
Earnings on Nuclear Funds	(801)	(855)	(892)	(928)	(965)
Earnings from Fair Hydro Trust	(1)	(64)	(131)	(206)	(285)
Property Taxes	40	37	38	38	40
Restructuring	-	-	10	-	-
Total Expenses	3,683	3,679	3,961	4,191	3,426
Income before Interest and Other Income	**768**	**897**	**1,204**	**1,215**	**1,605**
Net Interest Expense	95	78	5	102	(9)
Other (Income)/Expense*	(417)	(320)	(40)	(35)	(35)
Income before Tax	**1,090**	**1,140**	**1,239**	**1,147**	**1,649**
Income Tax	209	79	154	209	255
Net Income	**881**	**1,061**	**1,085**	**938**	**1,394**
Net Income Attributable to Shareholder	**860**	**1,043**	**1,066**	**919**	**1,373**
Net Income Attributable to Non-Controlling Interests	21	18	19	20	21

* Includes $28M and $10M in 2017, $26M and $12M in 2018, $28M and $13M in 2019, $27M and $11M in 2020, $27M and $10M in 2021, representing OPG's share of equity income from its 50 percent ownership interests in the Portlands Energy Centre and the Brighton Beach GS, respectively. In 2017, a pre-tax gain of $378M on the sale of 700 University Ave. property is included. In 2018, a pre-tax gain of $267M on the sale of the Lakeview site is included.

Balance Sheet - As at December 31 *(in millions of dollars)*	Actual 2017	Business Plan 2018	 2019	 2020	 2021
Assets					
Current assets					
Cash and cash equivalents	234	273	354	249	301
Short-term investments	188	167	148	130	112
Accounts receivable	515	579	607	546	567
Fuel inventory	309	297	231	218	183
Materials and supplies	103	103	103	103	103
Other current assets	192	192	192	192	192
	1,541	1,612	1,635	1,438	1,458
Property, plant and equipment and intangible assets					
Fixed and intangible assets (net)	21,455	22,774	23,891	24,781	25,741
Other assets					
Financing Receivables	1,179	3,505	6,062	8,874	11,615
Nuclear fixed asset removal and nuclear waste management funds	16,724	17,473	18,233	19,009	19,811
Long-term materials and supplies	355	301	289	276	262
Regulatory assets (net)*	6,637	6,715	6,299	6,200	6,309
Investments subject to significant influence	309	301	291	278	263
Other long-term assets	28	28	28	28	28
	25,231	28,323	31,202	34,666	38,287
Total Assets	**48,228**	**52,709**	**56,727**	**60,884**	**65,486**
Liabilities					
Current liabilities					
Short-term notes payable	260	460	410	485	100
Accounts payable and accrued charges	1,228	1,140	1,092	1,072	1,238
Deferred revenue due within one year	12	-	-	-	-
Current income taxes payable	80	37	83	39	197
Long-term debt due within one year	398	368	663	413	153
	1,978	2,006	2,248	2,008	1,688
Long-term debt	5,921	7,929	8,695	10,080	11,524
Other liabilities					
Fixed asset removal and nuclear waste management liabilities	20,421	21,167	21,921	22,677	23,521
Pension liabilities (non-current)	3,423	3,353	3,275	3,195	3,098
Other post-employment benefit liabilities (non-current)	3,092	3,183	3,275	3,371	3,461
Long-term accounts payable and accrued charges	252	256	238	248	245
Deferred revenue	351	419	410	401	392
Deferred income taxes	879	904	984	1,073	1,149
	28,417	29,282	30,103	30,964	31,867
Equity					
Class A shares	519	1,540	2,664	3,899	5,105
Common shares	5,126	5,126	5,126	5,126	5,126
Retained earnings	6,396	6,957	8,024	8,942	10,316
Accumulated other comprehensive loss	(295)	(292)	(291)	(290)	(290)
Equity attributable to non-controlling interests	165	161	158	154	151
	11,911	13,493	15,681	17,832	20,407
Total Liabilities and Equity	**48,228**	**52,709**	**56,727**	**60,884**	**65,486**

* Includes accrued revenues for new regulated rates for the period from June 1, 2017 to the implementation date of the OEB's decision. The accrued balance is assumed to be collected beginning January 1, 2019 over 3 years.

OM&A Expenses by Business Unit *(in millions of dollars)*	Actual 2017*	Business Plan 2018	2019	2020	2021
Nuclear Operations	1,709	1,736	1,686	1,792	1,554
Renewable Generation	368	394	395	389	404
Other Unregulated Operations	2	2	2	2	2
Total Operations	**2,079**	**2,132**	**2,083**	**2,184**	**1,960**
Chief Administrative Office	171	177	170	169	172
Finance (incl. Chief Information Officer)	255	246	232	231	231
People & Culture	84	79	79	78	78
Corporate Office (inc. Corporate Affairs)	27	25	25	26	26
Total Support Services	**537**	**526**	**506**	**504**	**508**
Total Business Unit Expenditures	**2,616**	**2,658**	**2,590**	**2,688**	**2,468**
Insurance	36	40	42	45	46
Centrally Held Pension and OPEB	95	73	38	5	(15)
Other (incl. Cost of Goods Sold)	73	80	63	69	71
Total Ongoing Operations	**2,819**	**2,850**	**2,732**	**2,807**	**2,570**
OEB Variance and Deferral Account Offsets	(32)	(34)	49	80	14
Darlington Refurbishment Project	36	23	3	38	23
Nuclear New Build**	0	8	10	12	12
Total OM&A Expenses	**2,824**	**2,847**	**2,794**	**2,936**	**2,618**

* Actual 2017 amounts have been restated for 2018 organizational changes

** Includes expenditures budgeted by Support Services

Production *(TWh)*	Actual 2017	Business Plan 2018	2019	2020	2021
Darlington	*19.3*	*19.3*	*19.7*	*17.8*	*16.6*
Pickering	*21.4*	*19.9*	*21.5*	*18.5*	*21.4*
Total Nuclear	40.7	39.2	41.2	36.3	38.0
Regulated Hydroelectric	30.7	30.5	30.4	31.0	29.9
Contracted Generation Portfolio	2.5	2.7	2.9	3.3	3.1
Total Production (Net of SBG Losses)	**73.8**	**72.4**	**74.5**	**70.6**	**71.0**
Regulated Hydroelectric SBG Losses	5.2	2.7	2.7	1.5	1.3
Contracted Plant SBG Losses	0.7	0.6	0.6	0.4	0.5
Total SBG Losses	**5.9**	**3.2**	**3.3**	**1.9**	**1.8**

Headcount by Business Unit**	Actual	Business Plan			
	2017*	2018	2019	2020	2021
Nuclear	6,176	6,171	6,149	6,119	6,067
Renewable Generation	1,453	1,485	1,487	1,486	1,449
Other Unregulated Operations	6	10	10	10	10
Total Operations	**7,635**	**7,666**	**7,646**	**7,615**	**7,526**
Chief Administrative Office	572	599	575	558	556
Finance (incl. Chief Information Officer)	690	707	685	670	658
People & Culture	399	394	384	376	372
Corporate Office (incl. Corporate Affairs)	58	68	68	68	68
Total Support Services	**1,719**	**1,768**	**1,712**	**1,672**	**1,654**
Total Headcount	**9,354**	**9,434**	**9,358**	**9,287**	**9,180**

* Actual 2017 amounts have been restated for 2018 organizational changes

** Includes Term employees

Provision Expenditures *(in millions of dollars)*	Actual	Business Plan			
	2017	2018	2019	2020	2021
Nuclear Decommissioning and Nuclear Waste Management Expenditures					
Nuclear Operations*	276	330	342	347	342
Support Services	14	14	14	14	14
Total Nuclear Provision Expenditures	**290**	**344**	**355**	**361**	**356**
Nanticoke GS Decommissioning	12	13	21	40	-
Lambton GS Decommissioning	11	15	35	22	14
Other	-	0	-	12	7
Total Thermal Decommissioning Expenditures	**23**	**28**	**56**	**74**	**21**
Total Provision Expenditures	**313**	**373**	**411**	**435**	**377**

* Includes expenditures for the Darlington Refurbishment Project nuclear waste containers

Capital Expenditures *(in millions of dollars)*	Actual 2017	Business Plan 2018	 2019	 2020	 2021
Sustaining					
Nuclear	357	384	353	289	244
Regulated Hydroelectric					
Sir Adam Beck Water Conveyance System Project	3	8	7	20	90
Other Projects	118	144	125	122	117
Total Regulated Hydroelectric	121	152	133	142	207
Contracted Generation Portfolio					
Little Long Dam Safety Project	-	6	34	149	98
Other Projects	37	45	30	14	8
Total Contracted Generation Portfolio	37	51	65	163	106
Support Services					
Information Technology Projects	84	60	35	50	26
Other Projects	16	24	20	29	13
Total Support Services	100	84	56	80	40
Total Sustaining Capital	**615**	**672**	**606**	**674**	**597**
Development Projects*					
Darlington Refurbishment Project***	1,249	1,231	1,127	947	1,129
Ranney Falls GS Redevelopment**	25	35	13	0	-
Sir Adam Beck Units 1 & 2 Conversion	1	9	41	37	36
Nanticoke Solar Project**	6	103	0	0	0
Calabogie GS Redevelopment**	2	3	3	61	18
Other Business Development	28	28	69	62	49
Total Development Projects	**1,311**	**1,410**	**1,253**	**1,107**	**1,233**
Total Capital Expenditures	**1,926**	**2,082**	**1,859**	**1,781**	**1,830**

* While in definition phase, projects are budgeted by Corporate Business Development (within Finance) and, while in execution phase, projects are budgeted by Renewable Generaiton and other Support Services organizations

** Includes expenditures budgeted by Renewable Generation and Support Services

*** Includes expenditures budgeted by the Nuclear organization and Support Services

Financing and Liquidity Outlook - Years Ended Dec 31	Actual	Business Plan			
(in millions of dollars)	2017	2018	2019	2020	2021
Opening Cash Balance	**186**	**234**	**273**	**354**	**249**
Net Operating Cash Inflows before the following:	**1,723**	**2,227**	**3,070**	**2,646**	**3,113**
Earnings from Fair Hydro Trust (pre-tax)	1	64	131	206	285
Interest Paid (excl. Fair Hydro Trust)	(251)	(261)	(264)	(250)	(230)
Nuclear Funds Contribution	-	-	-	-	-
Pension Fund Contribution	(212)	(215)	(219)	(213)	(217)
OPEB Payments	(110)	(112)	(116)	(121)	(125)
Internally Funded Nuclear Provision Expenditures	(208)	(235)	(219)	(202)	(184)
Net Cash from Operations	**944**	**1,468**	**2,384**	**2,067**	**2,642**
Investing Activities					
Sustaining Capital Expenditures	(615)	(672)	(606)	(674)	(597)
Darlington Refurbishment	(1,249)	(1,231)	(1,127)	(947)	(1,129)
Ranney Falls GS Redevelopment	(25)	(35)	(13)	(0)	-
Sir Adam Beck Units 1 & 2 Conversion	(1)	(9)	(41)	(37)	(36)
Nanticoke Solar	(6)	(103)	(0)	(0)	(0)
Other Development	(30)	(32)	(72)	(123)	(68)
Capital Expenditures	**(1,926)**	**(2,082)**	**(1,859)**	**(1,781)**	**(1,830)**
Pre-tax Proceeds from Sale of 700 University Ave. Property	484	-	-	-	-
Pre-tax Proceeds from Sale of Lakeview Site	-	267	-	-	-
Acquisition of Fair Hydro Trust Assets	(1,179)	(2,326)	(2,557)	(2,812)	(2,741)
Proceeds from Deposit Note (Peter Sutherland Sr. GS)	70	-	-	-	-
Other	73	16	-	-	-
Net Cash Outflow for Investing Activities	**(2,478)**	**(4,125)**	**(4,416)**	**(4,593)**	**(4,571)**
Financing Activities					
General Corporate Debt - *Debt Issuance/Refinancing*	1,301	1,191	128	365	200
- *Debt Retirement*	(900)	(395)	(365)	(660)	(185)
Private Placement Debt - *Debt Issuance/Refinancing*	-	-	-	-	-
- *Debt Retirement*	(203)	(3)	(3)	(3)	(228)
Fair Hydro Trust Senior Debt - *Debt Issuance*	601	1,184	1,302	1,432	1,397
Short-Term Notes - *Net Issuance (Repayment)*	260	200	(50)	75	(385)
Issuance of Class A Shares	519	1,022	1,123	1,235	1,206
Dividends Paid	-	(482)	-	-	-
Distribution Paid to Non-Controlling Interests	(15)	(22)	(22)	(23)	(25)
Capital Contribution from Non-Controlling Interest	19	-	-	-	-
Net Cash from Financing Activities	**1,582**	**2,695**	**2,113**	**2,422**	**1,980**
Net Cash Inflow (Outflow) for Period	**48**	**39**	**81**	**(105)**	**52**
Ending Cash Balance	***234***	***273***	***354***	***249***	***301***
Total OPG Debt	***5,978***	***6,971***	***6,681***	***6,458***	***5,860***
Fair Hydro Trust Senior Debt	***601***	***1,786***	***3,088***	***4,519***	***5,917***
Total Consolidated Debt	***6,579***	***8,757***	***9,768***	***10,978***	***11,777***

APPENDIX 4: NUCLEAR FINANCIAL PLAN AND OPERATIONAL TARGETS

Financial Plan

Nuclear	Actual	Business Plan			
(in millions of dollars)	2017	2018	2019	2020	2021
OM&A					
Base*	1,254	1,251	1,276	1,294	1,298
Outage Incremental	314	334	246	336	116
Project Portfolio	123	91	82	82	87
Pickering Extension Enabling Costs	18	59	82	81	54
Darlington Refurbishment Project	36	23	3	38	23
New Nuclear **	0	1	1	1	1
Total Nuclear OM&A	**1,746**	**1,759**	**1,690**	**1,831**	**1,578**
Capital					
Project Portfolio***	357	384	353	289	244
Darlington Refurbishment Project **	1,223	1,203	1,100	921	1,104
Total Nuclear Capital	**1,580**	**1,588**	**1,453**	**1,211**	**1,348**
Nuclear Waste Provision Expenditures	**276**	**331**	**342**	**348**	**343**
Fuel Expense (Pickering and Darlington)	**225**	**226**	**236**	**202**	**201**

* Includes an estimated $4M to $5M per year for work in support of the Renewable Generation business unit

** Excludes expenditures budgeted by Support Services

*** In 2019, includes $16M related to the load of new fuel bundles into the refurbished Darlington Unit 2

Operational Targets

The key 2018-2020 targets for the Nuclear business unit are set out below. These targets reflect the operating environment of the nuclear fleet, including refurbishment activities at the Darlington station.

			Pickering				Darlington			
Metric	NPI Max	Industry Best Quartile	Actual 2017	2018 Annual Target	2019 Annual Target	2020 Annual Target	Actual 2017	2018 Annual Target	2019 Annual Target	2020 Annual Target
All Injury Rate (#/200k hrs worked)[1]	N/A	0.64	0.06	0.22	0.19	0.19	0.40	0.22	0.19	0.19
Collective Radiation Exposure (person-rem/unit)	80.00	45.33	74.36	110.30	83.40	126.10	93.56	79.80	80.00	79.00
Unit Capability Factor (%)	92.0	89.41	80.00	74.6	80.5	69.2	85.17	86.0	87.8	79.3
Forced Loss Rate (%)	1.00	1.49	5.18	3.50	3.50	3.50	1.72	1.00	1.00	4.28
On-line Corrective Maintenance Backlog (work orders/unit)	N/A	4	25	20	12	4	13	7	4	4
WANO NPI (Index)	N/A	96.9	76.7	75.5	76.7	75.5	82.0	91.3	91.7	88.1
Human Performance Error Rate (# per 200k ISAR and contractor hrs)	N/A	0.02	0.12	0.06	0.06	0.06	0.05	0.06	0.06	0.06
Total Generating Cost per MWh[2]	N/A	$38.77	66.01	73.17	64.93	76.08	49.93	51.66	53.91	50.13

[1] All Injury Rate (AIR) has been replaced in 2018 with the Total Reportable Injury Frequency (TRIF). TRIF includes restricted work injuries which is expected to be minimal and as a result there is no change in targets set for AIR.

[2] Consistent with industry definition, metrics exclude centrally-held Pension and OPEB costs, asset service fees, and used fuel expenses. Targets may change subject to allocations and assumptions being finalized. Darlington metrics have been normalized for generation forgone during refurbishment. The non-normalized Darlington actual TGC for 2017 is $71.78/MWh, and the target for 2018 is $70.26/MWh, 2019 is $67.04/MWh, and 2020 is $74.26/MWh.

APPENDIX 5: RENEWABLE GENERATION FINANCIAL PLAN AND OPERATIONAL TARGETS

Financial Plan

Renewable Generation *(in millions of dollars)*	Actual 2017	Business Plan 2018	 2019	 2020	 2021
OM&A					
Regulated Hydroelectric	193	184	183	188	190
Contracted Generation	109	114	115	104	106
Other*	11	6	8	8	8
Total Base OM&A	**313**	**305**	**306**	**300**	**304**
Regulated Hydroelectric	42	71	77	73	90
Contracted Generation	14	18	12	15	10
Total Project OM&A	**56**	**89**	**89**	**89**	**99**
Regulated Hydroelectric	235	255	260	261	279
Contracted Generation	122	133	127	120	116
Other	11	6	8	8	8
Total Renewable Generation OM&A	**368**	**394**	**395**	**389**	**404**
Capital					
Little Long Dam Safety Project	-	6	34	149	98
Sir Adam Beck Water Conveyance System Project	3	8	7	20	90
Other Sustaining	155	185	156	136	125
Total Sustaining Capital	**158**	**199**	**197**	**305**	**313**
Nanticoke Solar	0	103	0	-	-
Ranney Falls GS Redevelopment	24	35	13	0	-
Sir Adam Beck Units 1 & 2 Conversion	0	9	41	37	36
Other Development	36	5	-	-	-
Total Development Capital	**61**	**152**	**54**	**38**	**36**
Total Renewable Generation Capital	**219**	**351**	**251**	**343**	**349**
Total Thermal Decommissioning Expenditures	**23**	**28**	**56**	**74**	**21**
Hydroelectric Gross Revenue Charge and Thermal Fuel Expense					
Regulated Hydroelectric (net of SBG losses)**	320	326	325	330	315
Contracted Generation Portfolio	54	54	52	55	56
Total Hydroelectric Gross Revenue Charge and Thermal Fuel Expense	**374**	**380**	**378**	**385**	**370**

*Includes an estimated $4M per year, in 2018-2021, for work in support of the Nuclear Organization

** Regulated hydroelectric GRC expenses assuming no SBG losses are: $320M in 2017, $360M in 2018, $359M in 2019, $349M in 2020, $331M in 2021.

Operational Targets

The key 2018-2021 Renewable Generation targets designed to drive continuous performance are set out below.

Renewable Generation	Actual 2017	Business Plan 2018	2019	2020	2021
All Injury Rate* *(#/200k hrs worked)*	2.05	1.23	1.06	1.03	1.03
Environment *(#)*					
Category C Spills	3	8	8	8	8
Environmental Infractions	1	7	6	6	6
Capacity *(MW)*	9,928	9,925	9,999	9,851	9,911
Regulated Hydroelectric	6,426	6,412	6,437	6,443	6,502
Contracted Generation (Hydro, Thermal and Solar)	3,500	3,512	3,560	3,407	3,407
Wind	1.8	1.8	1.8	1.8	1.8
Hydroelectric Availability *(%)*	**86.5%**	**87.3%**	**87.4%**	**88.0%**	**85.6%**
Regulated Hydroelectric	88.3%	89.2%	89.7%	89.4%	84.7%
Contracted Generation	74.9%	75.1%	72.5%	78.7%	91.6%
Hydroelectric Equivalent Forced Outage Rate *(%)*	**3.1%**	**2.0%**	**1.8%**	**1.7%**	**1.7%**
Regulated Hydroelectric	3.0%	1.7%	1.7%	1.7%	1.7%
Contracted Generation	3.9%	3.8%	2.1%	1.5%	1.4%
Thermal Equivalent Forced Outage Rate (Operating) *(%)*	2.4%	5.1%	5.1%	5.1%	5.1%
Total Hydroelectric Generating Cost per MWh** *($/MWh)*	23.9	26.8	25.3	25.0	26.0

* All Injury Rate (AIR) has been replaced in 2018 with the Total Reportable Injury Frequency (TRIF). TRIF includes restricted work injuries which is expected to be minimal and as a result there is no change in targets set for AIR.

Key Enterprise Level Initiatives

Core Initiatives

- **OPG25**: The initiative is intended to address the cost structure implications of Pickering closure through the design and implementation of an optimal, cost effective organization for OPG. The initiative also seeks enterprise wide efficiency improvements and cost saving opportunities that will improve corporate profitability, support a culture of continuous improvement, and assist OPG in achieving industry-leading generation cost targets.
- **Darlington for the Future:** The initiative is closely integrated with the OPG25 initiative and seeks operational excellence to ensure industry-leading performance at Darlington post refurbishment. The initiative focusses on consistent achievement of nuclear generation production targets.
- **Equity Optimization**: The initiative is aimed at making balanced decisions going forward between the use of capital for growth investments and the payment of dividends to gradually transition the overall corporate equity thickness from existing ~65% level toward the OEB deemed level of 45%.
- **Building our Business**: OPG's strives to be a leader in the North American transition toward a low carbon future. This initiative focusses on maintaining and enhancing OPG's scale and energy industry leadership across carbon-friendly generation technologies, including potential extensions to OPG's business, investments in commercial innovation and asset acquisitions.

Enabling Initiatives

- **One OPG Culture:** The initiative aims to foster cultural shifts where employees work together at all levels to achieve a greater sense of ownership, in an environment where information flows more freely. The cultural shift will facilitate building a diverse, well-trained, healthy, and engaged workforce committed to the long-term success of the Company and will drive greater alignment of leaders across the organization to achieve desired performance outcomes and behaviours.
- **Resourcing Strategy:** The initiative includes building a "One Company" approach to hiring by delivering a seamless end-to-end experience for new hires, redesigning existing business processes for talent resourcing, and continuing to enhance the updated leadership model to promote empowerment and personal leadership amongst employees.
- **Project Management Centre of Excellence:** The initiative promotes OPG's goal of being the best in the power industry at delivering all projects safely, with high quality, on time and on budget. With OPG continuing to invest significantly in projects over the next decade, the initiative aims to improve consistency of project outcomes through a common, scalable project delivery model, corporate-wide project management standards and services, and development of project management capability.
- **Digital Strategy:** The initiative seeks to enable OPG to achieve productivity improvements and capitalize on business optimization opportunities through technology investments. The initiative's goals include: increasing worker mobility, enhancing collaboration through people-share and networks, increasing automation to improve efficiency, and leveraging digital innovation to increase equipment reliability and reduce operating costs.
- **Regulatory Effectiveness:** The initiative seeks to continue to build more constructive, transparent, flexible and responsive relationships with the OEB and stakeholders, to improve OPG's culture as a regulated entity and deepen the understanding of the regulatory process across the Company, and to improve regulatory process efficiency by exploring opportunities to simplify the rate application process.
- **Relationships and Outreach:** The initiative focuses on developing and implementing an integrated stakeholder program and stakeholder engagement plans with a view to reinforcing OPG's social licence and strengthening the overall OPG brand, both externally and internally. The initiative recognizes the critical importance of respectful, trust-based relationships with communities, employees, stakeholders, regulators and Indigenous Peoples to OPG's social licence and overall success.

Key Business Unit Initiatives

Nuclear

- **Equipment Reliability:** The initiative aims to improve equipment reliability, improve efficiency of the maintenance program and reduce equipment failures to meet forced loss rate targets. A key driver in driving improved equipment reliability and station performance will be the implementation of the Monitoring and Diagnostic Centre. The collection and analysis of data will facilitate early detection of major/critical equipment degradation with the objective of reducing unplanned maintenance.
- **Outage Planning and Execution:** The initiative focuses on delivering predictable outage performance through improved planning and execution of outage work to meet planned outage duration targets.
- **Project Planning and Execution:** The initiative will drive effort in three key areas in order to improve project planning and execution and optimize investment decisions: Nuclear Project Management Office commitment to front end planning and Engineering Project Controls; stakeholder engagement in setting out the proper scope and clear expectations; and support for integrated asset management.
- **Innovation and Technology:** The initiative focuses on improvements in inspection tooling capability that will help to further operational efficiencies in order to meet outage schedules and generation requirements and reduce radiation exposure.
- **Strategic Asset Management:** The initiative focuses on early identification of project requirements and developing an optimized, integrated investment strategy through improved asset options, standard processes and increased oversight.

Renewable Generation

- **Asset Value Enhancement:** The initiative targets adding 170 MW of incremental renewable generation capacity by 2021, including through the Ranney Falls GS and Nanticoke solar facility projects, frequency conversion of Sir Adam Beck I GS Units 1 & 2, and the runner upgrade program.
- **Innovation and Technology:** The initiative pursues innovation and technology-based improvements in asset management and equipment maintenance strategies. This includes leveraging the Monitoring and Diagnostic Centre concept to facilitate a move from preventative to condition-based maintenance and inform asset management decisions, and implementing digital work management to improve work flow efficiency and provide real-time updates on completed tasks.
- **Efficiency Improvement:** The initiative includes continuing to implement regionalization initiatives, control room consolidation, and work management and organizational realignment efficiencies across the fleet. It also includes developing contract management plans to ensure achievement of contract return on equity levels, as well as an assessment of Thunder Bay GS extension options.
- **Safety Performance Improvement:** The initiative involves a broad-based safety improvement plan that targets significant improvements in the Renewable Generation safety management system, including strengthening proactive reporting, enhancing linkage of embedded health and safety advisors with local senior management, internally and externally benchmarking safety best practices, and fostering a culture of personal leadership in safety.

Corporate Support Services

- **Real Estate Security and Flexibility**: Chief Administrative Office (CAO) will negotiate a lease extension of 5 years at the General Motors building to support Darlington Refurbishment. CAO will also seek the flexibility to release OPG from existing lease obligations prior to the end of term.
- **Supply Chain Efficiencies:** CAO will continue to drive efficiencies through value improvement and inventory optimization, and will leverage the new Nuclear asset management tool across Supply Chain.
- **Generation Support Strategies**: Chief Information Office will support key business initiatives to improve the Company's generation facilities in such areas as the Monitoring and Diagnostic Centre, capital asset lifecycle portfolio management, equipment reliability improvement, field productivity and data integration and visualization.
- **Innovative Financial Strategies**: Finance will leverage the public debt program to provide financial

flexibility and optimize capital structure, facilitate growth through technology innovation and organic development, and pursue achievement of long-term target returns on the pension and nuclear segregated funds. Finance will also implement the Fair Hydro Trust to achieve targeted returns.

- **Talent, Succession, Training and Development**: People & Culture will lead processes and programs to ensure talent attraction, enable succession planning, foster a diverse and inclusive workforce, deliver high quality and cost effective training, build project management capabilities, and promote career development.
- **Brand Awareness:** Corporate Affairs will leverage strategic communications, earned and social media, advertising sponsorships and new Made in Ontario corporate reputation campaign to increase awareness of OPG's role in clean air/climate change, support of electrical vehicles and biodiversity initiatives. Engagement and awareness of OPG's site community support and the benefits of the Company's citizenship activities and Indigenous partnerships will also be strengthened.

From: John Kim
To: Ronald Kwan
Cc: Deena Padamadan; Bruno Amara
Subject: FW: OPG Business Plan BN - Review and Input Needed
Date: Monday, May 01, 2017 6:35:46 PM
Attachments: OPG Business Plan - Signed Submission.msg
5 2017-05-09 RAN OPG Business Plan v2.doc

Hi Ron,

Pls. see attached. They are requesting the updated info by tomorrow.

Thanks,

John

From: Strang, James (TBS) [mailto:James.Strang@ontario.ca]
Sent: Monday, May 01, 2017 4:24 PM
To: John Kim <John.Kim@ofina.on.ca>; Judy George-Harris (MGS) <Judy.George-Harris@ontario.ca>
Cc: Chris Skubel (MGS) <Chris.Skubel@ontario.ca>; Laurie Morin (MGS) <Laurie.Morin@ontario.ca>
Subject: OPG Business Plan BN - Review and Input Needed

John,

Attached is the note for the OPG Business Plan item going to TB/MBC same time as OFHP May 9, 2017. Please review and provide comments, and clarification regarding what's in the OPG #s in the 2017 Budget numbers (There are references in the note and the tables on the last two pages need updating to be complete).

Sec Briefing is tomorrow afternoon, would it be possible to get the updated tables in the morning tomorrow? Fair Hydro Plan is also scheduled, but not sure if it or both will be bumped to a separate briefing cycle in advance of May 9, 2017.

Laurie (for Judy) – I've included a description of the international travel aspect (around slide 11, deck in the attached email) and a placeholder for a minute (Judy was aware of the item).

James

From: Pratima Gounden (ENERGY) []
To: James Strang (MOF) [James.Strang@ontario.ca]
CC: Felix Fung (MOF) [Felix.Fung@ontario.ca]; Judy George-Harris (MGS) [Judy.George-Harris@ontario.ca]; Chris Skubel (MGS) [Chris.Skubel@ontario.ca]
Subject: OPG Business Plan - Signed Submission
Date: Monday, May 01, 2017 11:47:56
Attachment 1: image001.jpg
Attachment 2: OPG Business Plan_signed submission.pdf

Hi James,

Attached is a copy of the signed submission for the OPG Business Plan.

We'll walk the original over to the Agenda Office this afternoon.

Thanks,

Pratima Gounden, Team Lead (A)

56 Wellesley Street West, 4th Floor, Toronto ON M7A 2E7

Blackberry: 647-289-4932

Ministry of Economic Development & Growth

Ministry of Energy

Ministry of Infrastructure
Ministry of Research, Innovation & Science

CSD
Corporate
Services
Division
Expertise | Collaboration | Respect | Service Excellence | Integrity

Ontario

Application and Report to Treasury Board/Management Board of Cabinet

(Refer to instructions on next page)

1. MINISTRY: Energy	2. MINISTRY LOG #	3. TB/MBC LOG #
4. TYPE OF REQUEST: Treasury Board General		

5. PURPOSE OF REQUEST: The Ministry of Energy is requesting TB/MBC 1. NOTE the receipt of OPG's 2017-2019 Business Plan. 2. NOTE that the Minister of Energy will provide concurrence with OPG's Business Plan 3. APPROVE OPG's application for Special Status to Approve International Travel under Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive dated January 1, 2017.

6. FINANCIAL DETAILS		($ Millions)							
		Current Year		Year 2		Year 3		Matures In	
		2016/17		2017/18		2018/19		2019/20	
		Operating	Capital	Operating	Capital	Operating	Capital	Operating	Capital
A. Program Current Base	Expense								
	Asset								
B. Program Request (change from existing base)	Expense								
	Asset								
C. Available for Offset	Expense								
	Asset								
D. Net Impact On Program Allocation (B-C)	Expense								
	Asset								
E. Revenue Implications									

7. IMPACT ON FTE LIMIT	Current Year 2016/2017	Year 2 2017/2018	Year 3 2018/2019	Mature in 2019/2020
A. Program Current Base FTE Limit				
B. Program FTEs Request				
C. Available FTE Offset				
D. Net Impact on FTE Limit (B-C)				
E. Change to Ministry Salaries & Wages Allocation (included in the Program Request ($ Millions)				

8. OTHER DECISION FACTORS	Y/N	EXPLANATION
A. Consistent with Government Priorities and Results (If Yes identify key Results) - include details in submission)	Y	MOA between Minister of Energy and OPG
B. Policy approval (if yes identify policy committee and date approved)	N	
C. Key Performance Risks (If yes provide details in submission)	N	
D. Impact on other Ministries (if yes - include sign-off date. Include resources impact in submission)	N	Ministries: N/A
E. Impact on the Fiscal Plan (if yes provide details in submission)	Y	Impact of OPG results

9. AUTHORIZATION /DATE

Signature of Minister — Date:

Glenn Thibeault

Signature of Deputy Minister — Date:

Serge Imbrogno

MINISTRY OF ENERGY

TREASURY BOARD / MANAGEMENT BOARD of CABINET SUBMISSION

ONTARIO POWER GENERATION (OPG) 2017-19 BUSINESS PLAN AND SPECIAL STATUS APPLICATION

May 2017

CONFIDENTIAL

MINISTRY OF ENERGY

ONTARIO POWER GENERATION (OPG)
2017-19 BUSINESS PLAN AND SPECIAL STATUS APPLICATION

MINISTRY REQUEST

The Ministry of ENERGY is requesting that Treasury Board/Management Board of Cabinet (TB/MBC):

1. NOTE the receipt of OPG's 2017-2019 Business Plan.
2. NOTE that the Minister of Energy will provide concurrence with OPG's Business Plan.
3. APPROVE OPG's application for Special Status to Approve International Travel under Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive dated January 1, 2017.

CONTEXT

- As required by the Memorandum of Agreement (MOA) between Ontario Power Generation and the Minister of Energy, OPG provided its Business Plan for 2017-2019 to the Ministry of Energy on November 29, 2016 for concurrence
    - Note that while OPG is seeking concurrence for its three year 2017-19 business plan, the plan also includes financial projections for 2020 and 2021
- With this Business Plan OPG is also making an application for Special Status under the Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive, which allows agencies/organizations, for which international travel may be integral to their business, to seek TB/MBC approval for special status to ensure that the approval process does not have an undue negative effect on its ability to conduct business
- The Minister's concurrence requires presentation of OPG's business plan before TB/MBC
- The Ministry of Energy review and analysis of OPG's business plan is supported by the Electricity Investment and Governance Secretariat, a unit within the Ministry of Finance and the Corporate and Electricity Finance Division of the Ontario Financing Authority (OFA)
- The following provides an overview of OPG's business plan, including:
    1. Business Plan Overview
    2. Other Considerations
- Proceeding with Provincial concurrence now will demonstrate that OPG has support from its shareholder as it implements the plan and provides clarity to

the Ontario Energy Board (OEB) as it reviews OPG's current rate application covering the 2017-2021 period

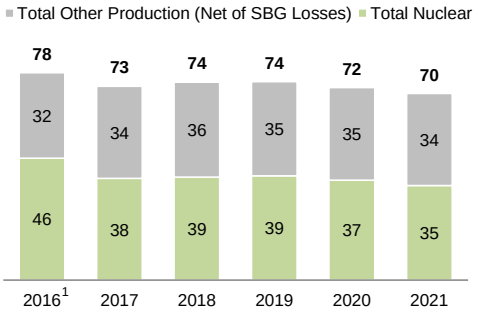
- Business plan forecasts may be affected by Ontario's Fair Hydro Plan (OFHP). Given the stage of implementation of OFHP and the timing of the receipt of the business plan in November 2016, these changes are not reflected in OPG's plan
    - The Ministry anticipates that as part of supporting the financing and administration of the global adjustment smoothing mechanism, OPG would purchase the right to future cash flows from IESO, financed partly by capital infusions from the Province, and majority by third-party lending
    - These changes are generally expected to be fiscally neutral as they would result in an increase in Provincial interest on debt, offset by increases in OPG net income
    - In addition, the Province's net debt position would remain unchanged

1. BUSINESS PLAN OVERVIEW

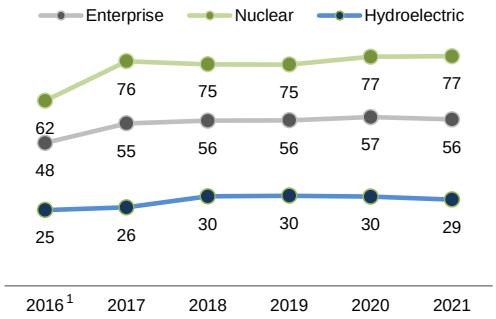
a) Production & Total Cost of Generation

- OPG's production is expected to fall to 69.8 TWh by 2021 from 77.6 TWh in 2016
    - Reflects a declining trend in the Darlington production due to refurbishment outages starting in October 2016
    - Includes a partial overlap starting in 2021 between second and third unit refurbishments, and
    - Includes the Pickering Vacuum Building Outage (VBO) in 2021 requiring the shutdown of all units for the duration of the outage
- While OM&A remains relatively stable over the planning period (see next slide), total generating cost (TGC)* shows an increasing trend over the planning period relative to 2016, reflecting:
    - Lower nuclear production due to Darlington refurbishment outages, and
    - Increased sustaining capital spending (included in TGC) on two large hydroelectric projects, the Lower Mattagami dam safety upgrade and the Sir Adam Beck I GS power canal liner rehabilitation

Production (TWh)



Total Generating Cost ($/MWh)



1. Actuals

*TGC = operations, maintenance and administration (OM&A) expenses from ongoing operations + fuel and Gross Revenue Charge expenses for OPG-operated stations + sustaining capital expenditures) divided by OPG generation adjusted for surplus baseload generation losses

b) Operations, Maintenance and Administration (OM&A) Expenses

- Annual OM&A expenses from ongoing operations are expected to stay consistent over the plan period, averaging $2.9B per year
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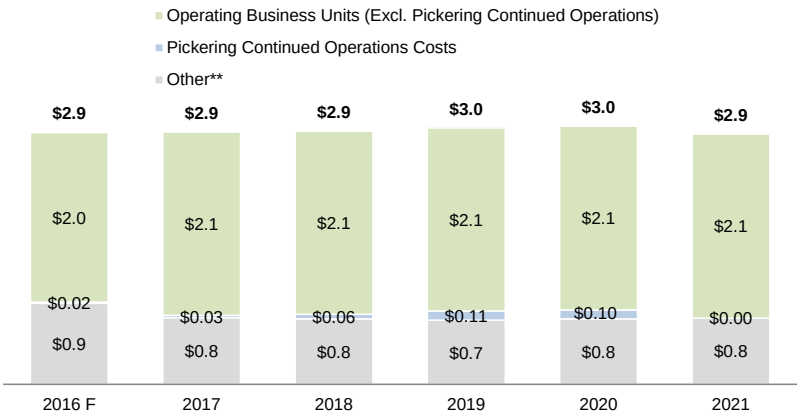
- These increases are partially offset by declining pension and Other Post-Employment Benefits (OPEB) costs over the period due to projected pension asset returns, increased employee contributions, and adoption of a new method for applying discount rates to determine interest components of pension costs

OM&A from Ongoing Operations* ($B)



*Excludes Darlington refurbishment OM&A expenses and all OEB variance and deferral account offsets

** Includes centrally held pension /OPEB costs and support services

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- OPG is forecasting net income attributable to the Shareholder to reach $1B in 2021, from $436M in 2016
    - 2017 net income is forecast to increase as a result of new regulated rates, higher capitalized interest for the Darlington Refurbishment expenditures partially offset by reduced production as a result of planned outages at Sir Adam Beck I and DeCew II hydro stations
    - Net income in 2018 and 2019 is planned to increase, primarily due to higher forecast production, and earnings from Peter Sutherland Sr. GS starting in 2017 and Nanticoke solar facility starting in 2019
- As a result, return-on-equity (ROE) is estimated to increase from 4.2% in 2016 to 7.3% by 2021
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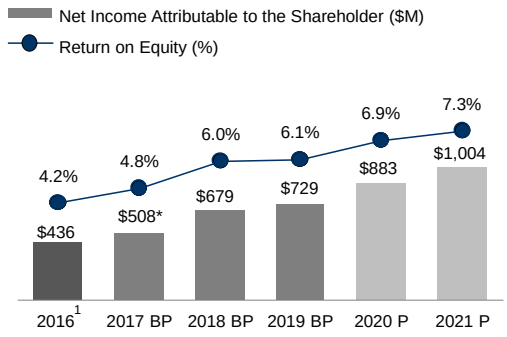
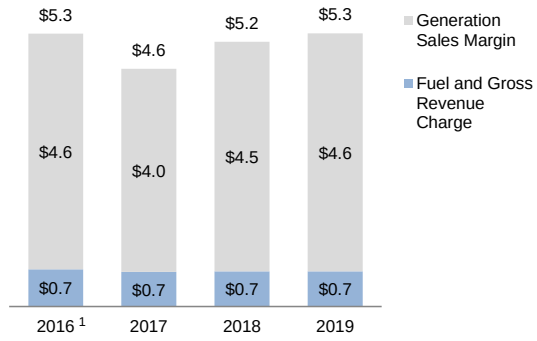
Net Income ($M) and ROE (%)



Revenue Margin ($B)



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d) Provincial Fiscal Impacts: Shareholder Return and Payments-in-Lieu of Taxes

- Total fiscal revenue impacts to the Province, including net income return to the shareholder and payments-in-lieu of taxes, averages ~$1B over the period
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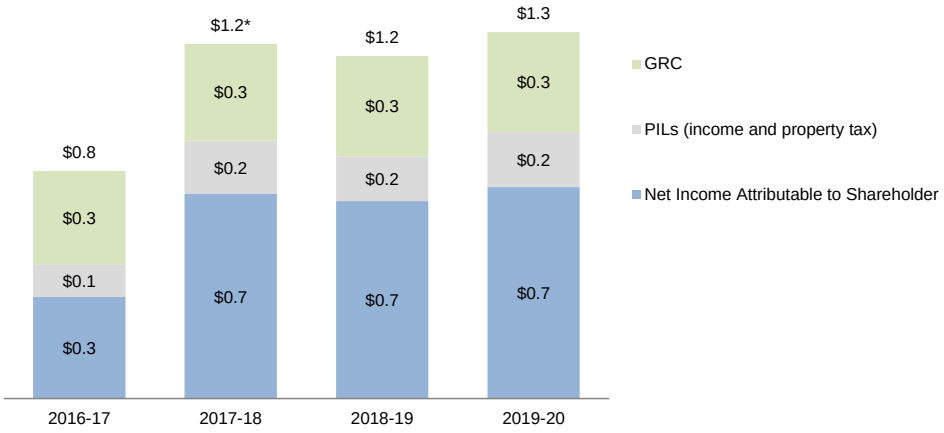
Total Fiscal Revenues ($B)



1. Aside from the water power rental portion of the GRC, paid to the CRF.

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- As part of a company-wide business transformation, OPG saved over $1B in costs from January 2011 to December 2016
    - Headcount has fallen from 11,686 in 2010 to a forecasted 9,009 in 2016 while GWh per headcount has increased from 7.6 to 9.3
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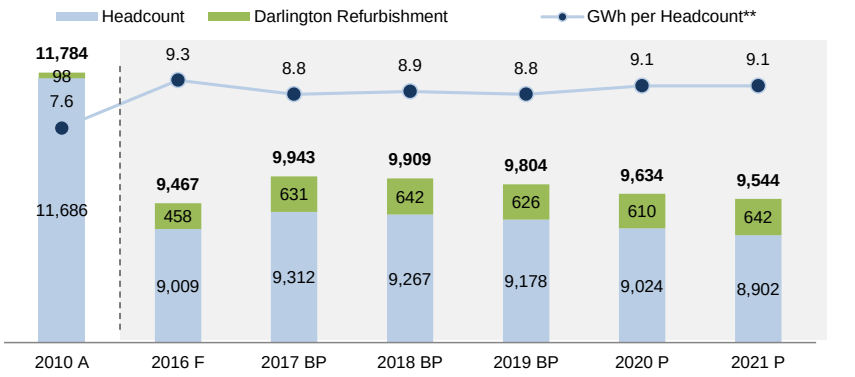
Ongoing Operations Regular Headcount and Productivity



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f) Operating Highlights - Projects and Capital Expenditures

- OPG continues to focus on delivery of its major projects over the plan period, including:
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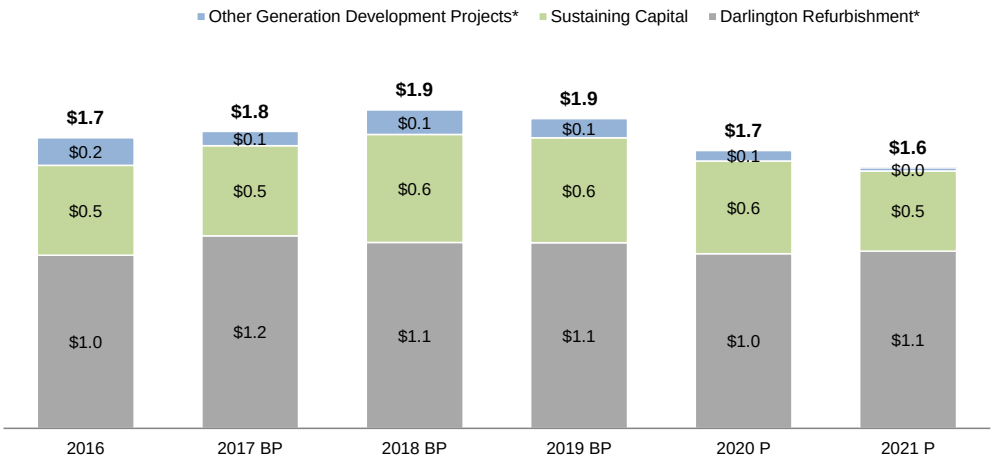
  - **Other Generation Development Projects:** Investments in current (e.g., hydroelectric) and emerging generation technologies including solar and energy storage including construction and operation of the Nanticoke solar facility by 2019

Capital Expenditure Estimates ($B)



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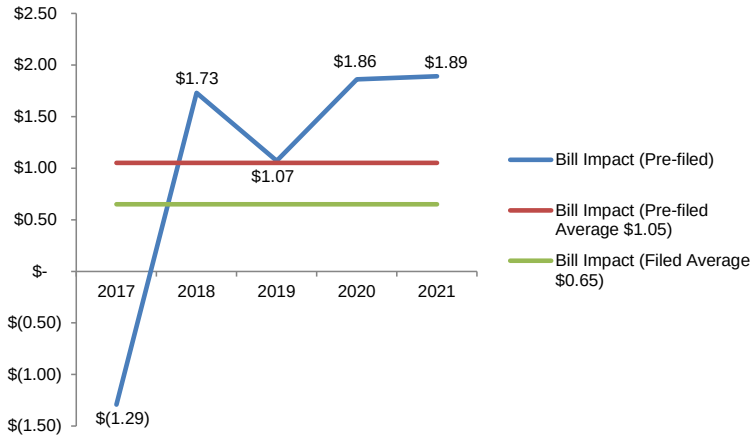
Comparison of Annual Bill Impact ($/Month per year)



*Forecasted in May 2016

Sales

	OPG Head Office	R.L. Hearn Site	Lakeview Site
Current Status	Completed	Agreement Reached	OPG and Infrastructure Ontario are preparing for marketing
Site Description	700 University Ave. and parking garage at 40 Murray St. in Toronto	~33 acres at the R.L. Hearn site in Toronto	~67 acres to be transferred by the purchaser to the City of Mississauga (Municipal Park Lands) and ~110 acres to be developed for mixed uses (Uplands)
Buyer	KingSett Canadian Real Estate Income Fund LP	Studios of America Limited Partner	TBD
Value	Estimated up-front 2017-18 fiscal impact of ~$375M (includes after-tax gain as well as PILs to OEFC)	TBD	TBD
Other Considerations	N/A	N/A	Negotiations with the City have been lengthy and costs to remediate/prepare site may be significant due to concerns regarding site condition
Timing	The sale closed in April 2017	Anticipated to close in Q3 2017	Marketing is planned to start in April 2017, pending negotiations with the City, with an anticipated closing in 2017

Special Status for OPG to Approve International Travel

- On January 24, 2017, OPG's President and CEO wrote to the Deputy Minister to provide a business case and request authority for OPG to approve international travel for its employees. In summary:
    - Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive allows agencies/organizations, for which international travel may be integral to their business, to seek TB/MBC approval for special status to ensure that the approval process does not have an undue negative effect on its ability to conduct business

- OPG believes that international travel is integral to the safe and prudent operation of its business and having OPG's CEO approve international travel will enable more efficient decision-making while significantly lowering travel costs
- OPG cites the importance of enabling its engagement with the international community (in particular in regards to nuclear safety), procurement activities, and investment and due diligence processes for over $30 billion in pension fund and nuclear funds
- OPG requires a high level of international business travel at approximately 90-100 trips annually, while the Darlington Refurbishment Project accounts for 45% of OPG's international travel and is expected see increases over the 10 year life of the project
- OPG indicated that the approval process, which took 23 days on average in 2016, delays flight bookings which results in higher costs as airlines raise fares closer to the travel date
- OPG believes the inability to make timely commitments on events and meetings impacts employee engagement as well as its international relationships and reputation

- OPG is seeking Special Status as part of concurrence with its business plan. OPG has committed to providing semi-annual reports to the Ministry on international travel taken, and continue to be accountable for compliance with all applicable OPS directives, policies and procedures

RECOMMENDATION

The Ministry of ENERGY is requesting that Treasury Board/Management Board of Cabinet (TB/MBC):

1. NOTE the receipt of OPG's 2017-2019 Business Plan.
2. NOTE that the Minister of Energy will provide concurrence with OPG's Business Plan.
3. APPROVE OPG's application for Special Status to Approve International Travel under Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive dated January 1, 2017.

APPENDIX

OPG 2016 Year-End Financials

OPG Balance Sheet as at Dec 31 $B	2016
Assets	
Cash and cash equivalents	0.2
Available-for-sale securities	0.2
Receivables from related parties	0.4
Nuclear fixed asset removal and nuclear waste management funds	0.02
Other current assets	0.9
Total current assets	**$1.7**
Net property, plant and equipment	**$20.0**
Net intangible assets	**$0.1**
Nuclear fixed asset removal and nuclear waste management funds	16.0
Regulatory assets	5.9
Other long-term assets	0.7
Other assets	**$22.5**
Total assets	**$44.4**
Liabilities	
Accounts payable and accrued charges	1.2
Short-term debt and long-term debt due within one year	1.1
Income taxes payable and other current liabilities	0.1
Total current liabilities	**$2.4**
Long-term debt	4.4
Fixed asset removal and nuclear waste management liabilities	19.5
Pension liabilities	3.0
Other post-employment benefit liabilities	2.9
Other liabilities	1.7
	$31.5
Total liabilities	**$33.9**
Equity	
Equity attributable to the Shareholder	10.4
Equity attributable to non-controlling interest	0.1
Total equity	**$10.5**
Total liabilities and equity	**$44.4**

OPG Income Statement Year Ended Dec 31 $B	2016
Revenue	$5.7
Fuel expense	0.7
Gross margin	**$4.9**
Operations, maintenance and administration	2.7
Depreciation and amortization	1.3
Accretion on fixed asset removal and nuclear waste management liabilities	0.9
Earnings on nuclear fixed asset removal and nuclear waste management funds	-0.7
Other expenses	0.02
Total expenses	**$4.2**
Income before other (gains) losses, interest and income taxes	**$0.7**
Other (gains) losses	-0.02
Income before interest and income taxes	**$0.7**
Net interest expense	0.1
Income before income taxes	**$0.6**
Income tax expense	0.2
Net income	**$0.5**
Net income attributable to the Shareholder	**$0.4**
Net income attributable to non-controlling interest	**$0.02**

Ontario

MINISTRY OF
ENERGY

Ontario Power Generation (OPG) 2017-19 Business Plan and Special Status Application

May 2017

Context

- As required by the Memorandum of Agreement (MOA) between Ontario Power Generation and the Minister of Energy, OPG provided its Business Plan for 2017-2019 to the Ministry of Energy on November 29, 2016 for concurrence
  - Note that while OPG is seeking concurrence for its three year 2017-19 business plan, the plan also includes financial projections for 2020 and 2021
- With this Business Plan OPG is also making an application for Special Status under the Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive, which allows agencies/organizations, for which international travel may be integral to their business, to seek TB/MBC approval for special status to ensure that the approval process does not have an undue negative effect on its ability to conduct business
- The Minister's concurrence requires presentation of OPG's business plan before TB/MBC
- The Ministry of Energy review and analysis of OPG's business plan is supported by the Electricity Investment and Governance Secretariat, a unit within the Ministry of Finance and the Corporate and Electricity Finance Division of the Ontario Financing Authority (OFA)
- The following presentation provides an overview of OPG's business plan, including:
  1. Business Plan Overview
  2. Other Considerations

Context *(cont'd)*

- Proceeding with Provincial concurrence now will demonstrate that OPG has support from its shareholder as it implements the plan and provides clarity to the Ontario Energy Board (OEB) as it reviews OPG's current rate application covering the 2017-2021 period

- Business plan forecasts may be affected by Ontario's Fair Hydro Plan (OFHP). Given the stage of implementation of OFHP and the timing of the receipt of the business plan in November 2016, these changes are not reflected in OPG's plan

  - The Ministry anticipates that as part of supporting the financing and administration of the global adjustment smoothing mechanism, OPG would purchase the right to future cash flows from IESO, financed partly by capital infusions from the Province, and majority by third-party lending

  - These changes are generally expected to be fiscally neutral as they would result in an increase in Provincial interest on debt, offset by increases in OPG net income

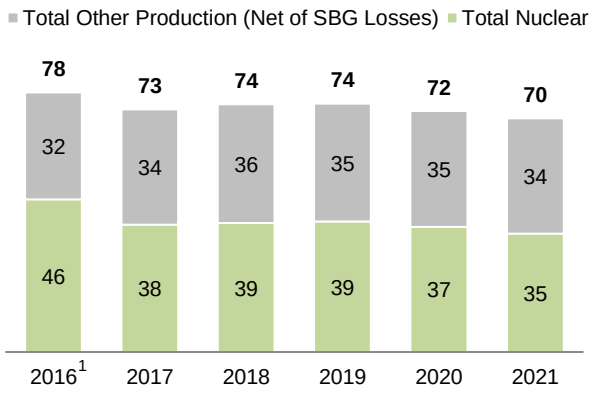
  - In addition, the Province's net debt position would remain unchanged

1. Business Plan Overview

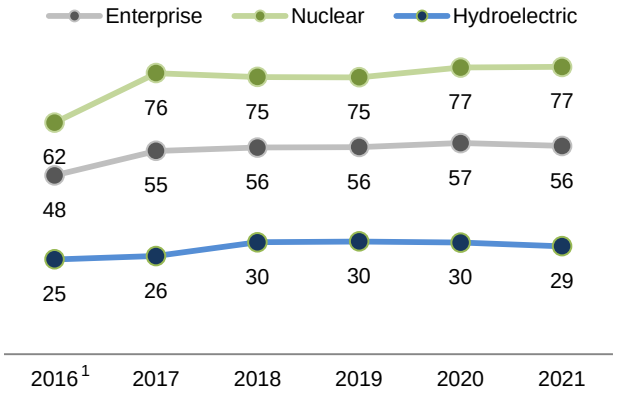
a) Production & Total Cost of Generation

- OPG's production is expected to fall to 69.8 TWh by 2021 from 77.6 TWh in 2016
  - Reflects a declining trend in the Darlington production due to refurbishment outages starting in October 2016
  - Includes a partial overlap starting in 2021 between second and third unit refurbishments, and
  - Includes the Pickering Vacuum Building Outage (VBO) in 2021 requiring the shutdown of all units for the duration of the outage
- While Operations, Maintenance and Administration (OM&A) remains relatively stable over the planning period (see next slide), total generating cost (TGC)* shows an increasing trend over the planning period relative to 2016, reflecting:
  - Lower nuclear production due to Darlington refurbishment outages, and
  - Increased sustaining capital spending (included in TGC) on two large hydroelectric projects, the Lower Mattagami dam safety upgrade and the Sir Adam Beck I GS power canal liner rehabilitation

Production (TWh)



Total Generating Cost ($/MWh)



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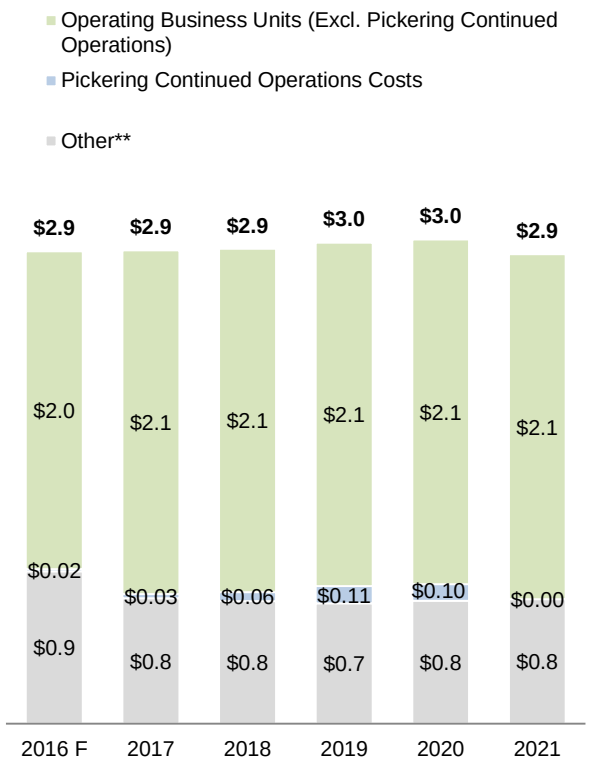

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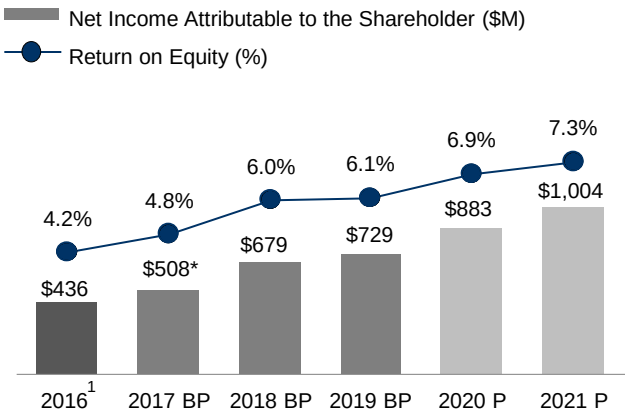

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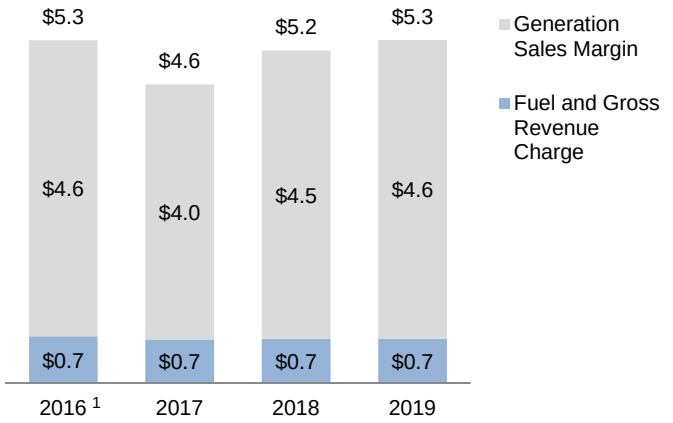

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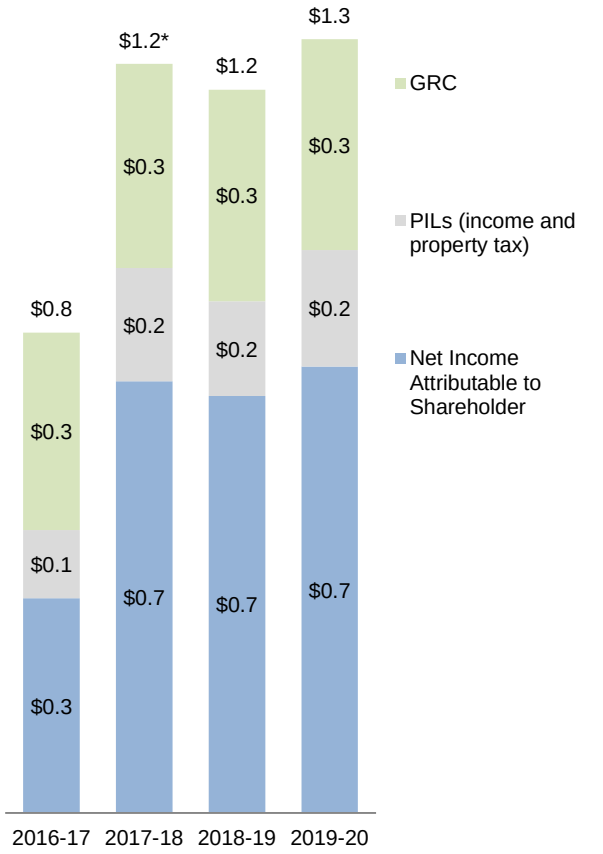

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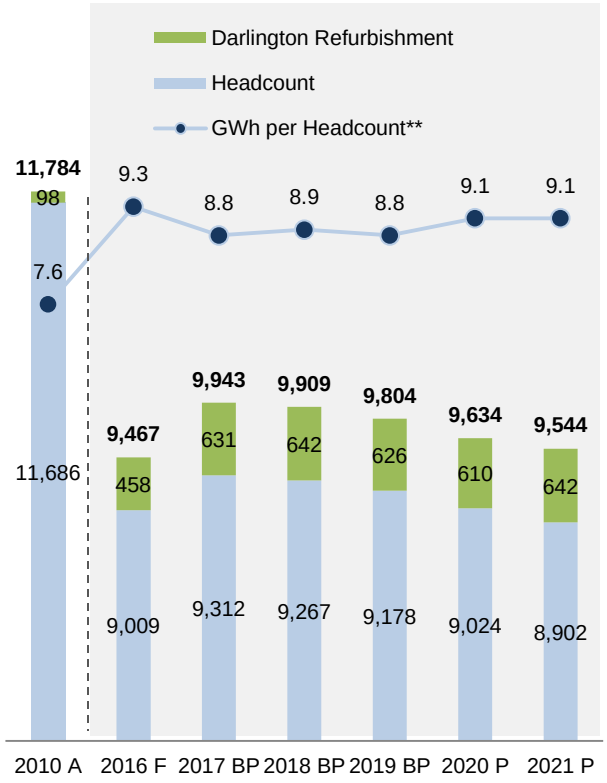

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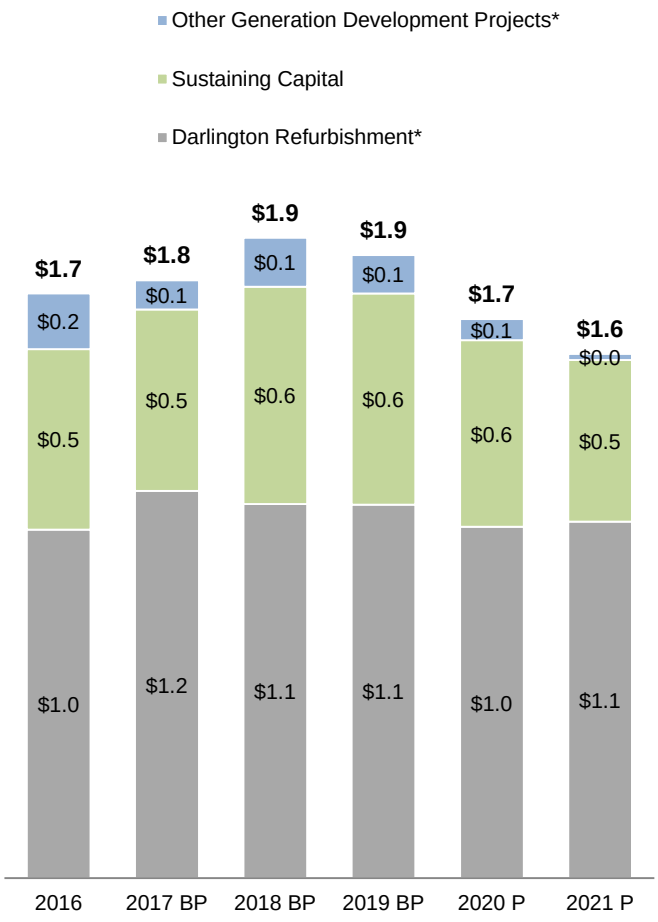

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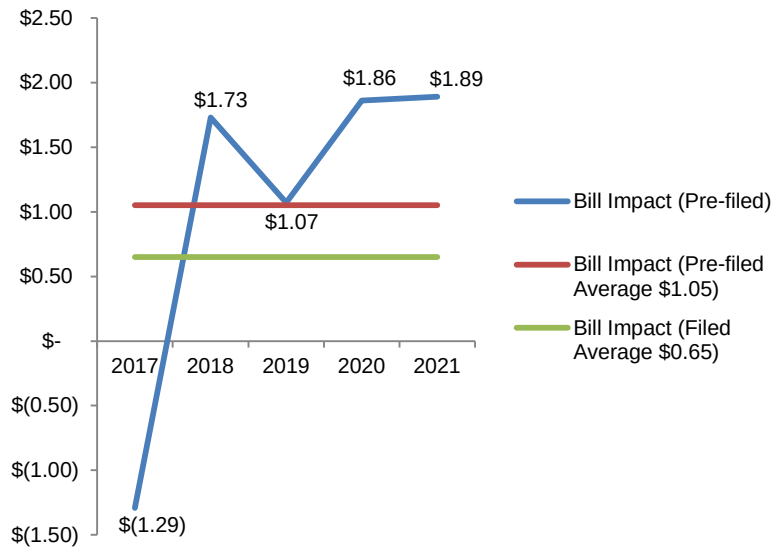
- On March 8, 2017 OPG filed a revised rate smoothing proposal with the OEB, which is expected to decrease the average year-over-year annual impact on the monthly customer bill for an average consumption of 750 KWh/month from about $1.05 to 65 cents per month per year

Comparison of Annual Bill Impact ($/Month per year)



*Forecasted in May 2016

2. Other Considerations

Sales

	OPG Head Office	R.L. Hearn Site	Lakeview Site
Current Status	Completed	Agreement Reached	OPG and Infrastructure Ontario are preparing for marketing
Site Description	700 University Ave. and parking garage at 40 Murray St. in Toronto	~33 acres at the R.L. Hearn site in Toronto	~67 acres to be transferred by the purchaser to the City of Mississauga (Municipal Park Lands) and ~110 acres to be developed for mixed uses (Uplands)
Buyer	KingSett Canadian Real Estate Income Fund LP	Studios of America Limited Partner	TBD
Value	Estimated up-front 2017-18 fiscal impact of ~$375M (includes after-tax gain as well as PILs to OEFC)	TBD	TBD
Other Considerations	N/A	N/A	Negotiations with the City have been lengthy and costs to remediate/prepare site may be significant due to concerns regarding site condition
Timing	The sale closed in April 2017	Anticipated to close in Q3 2017	Marketing is planned to start in April 2017, pending negotiations with the City, with an anticipated closing in 2017

2. Other Considerations

Special Status for OPG to Approve International Travel

- On January 24, 2017, OPG's President and CEO wrote to the Deputy Minister to provide a business case and request authority for OPG to approve international travel for its employees. In summary:
  - Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive allows agencies/organizations, for which international travel may be integral to their business, to seek TB/MBC approval for special status to ensure that the approval process does not have an undue negative effect on its ability to conduct business
  - OPG believes that international travel is integral to the safe and prudent operation of its business and having OPG's CEO approve international travel will enable more efficient decision-making while significantly lowering travel costs
  - OPG cites the importance of enabling its engagement with the international community (in particular in regards to nuclear safety), procurement activities, and investment and due diligence processes for over $30 billion in pension fund and nuclear funds
  - OPG requires a high level of international business travel at approximately 90-100 trips annually, while the Darlington Refurbishment Project accounts for 45% of OPG's international travel and is expected see increases over the 10 year life of the project
  - OPG indicated that the approval process, which took 23 days on average in 2016, delays flight bookings which results in higher costs as airlines raise fares closer to the travel date
  - OPG believes the inability to make timely commitments on events and meetings impacts employee engagement as well as its international relationships and reputation
- OPG is seeking Special Status as part of concurrence with its business plan. OPG has committed to providing semi-annual reports to the Ministry on international travel taken, and continue to be accountable for compliance with all applicable OPS directives, policies and procedures

Appendix

2016 Year-End Financials

OPG Balance Sheet as at Dec 31 $B	2016
Assets	
Cash and cash equivalents	0.2
Available-for-sale securities	0.2
Receivables from related parties	0.4
Nuclear fixed asset removal and nuclear waste management funds	0.02
Other current assets	0.9
Total current assets	**$1.7**
Net property, plant and equipment	**$20.0**
Net intangible assets	**$0.1**
Nuclear fixed asset removal and nuclear waste management funds	16.0
Regulatory assets	5.9
Other long-term assets	0.7
Other assets	**$22.5**
Total assets	**$44.4**
Liabilities	
Accounts payable and accrued charges	1.2
Short-term debt and long-term debt due within one year	1.1
Income taxes payable and other current liabilities	0.1
Total current liabilities	**$2.4**
Long-term debt	4.4
Fixed asset removal and nuclear waste management liabilities	19.5
Pension liabilities	3.0
Other post-employment benefit liabilities	2.9
Other liabilities	1.7
	$31.5
Total liabilities	**$33.9**
Equity	
Equity attributable to the Shareholder	10.4
Equity attributable to non-controlling interest	0.1
Total equity	**$10.5**
Total liabilities and equity	**$44.4**

OPG Income Statement Year Ended Dec 31 $B	2016
Revenue	$5.7
Fuel expense	0.7
Gross margin	**$4.9**
Operations, maintenance and administration	2.7
Depreciation and amortization	1.3
Accretion on fixed asset removal and nuclear waste management liabilities	0.9
Earnings on nuclear fixed asset removal and nuclear waste management funds	-0.7
Other expenses	0.02
Total expenses	**$4.2**
Income before other (gains) losses, interest and income taxes	**$0.7**
Other (gains) losses	-0.02
Income before interest and income taxes	**$0.7**
Net interest expense	0.1
Income before income taxes	**$0.6**
Income tax expense	0.2
Net income	**$0.5**
Net income attributable to the Shareholder	**$0.4**
Net income attributable to non-controlling interest	**$0.02**

TREASURY BOARD / MANAGEMENT BOARD OF CABINET
REQUEST ASSESSMENT NOTE

Ministry:	Energy
Meeting Date:	May 9, 2017
Agenda Class:	Discussion (In Camera)
Last reviewed by: TB/MBC March 24, 2015	**Tracking to: Fast Track** Cabinet (May 10, 2017)

SUBMISSION TITLE:	2017-2019 Business Plan for Ontario Power Generation

Prepared based on draft submission

I. DECISION BEFORE THE BOARD

- Receive Ontario Power Generation's (OPG) 2017-2019 Business Plan

II. RECOMMENDATIONS:

• Receive the 2016-2018 business plan for Ontario Power Generation	*Receive*
• Note Minister of Energy will provide concurrence with OPG's Business Plan	*Note*
• Approval giving special status to OPG under Section 5.3 of the MBC Travel, Meal and Hospitality Expenses Directive, giving it the authority to approve international travel for its employees.	*tbd*

III. FINANCIAL SUMMARY

$ Millions	**2014-15**	**2015-16**	**2016-17**
Initiative cost requested	0.0	0.0	0.0
Initiative cost recommended	0.0	0.0	0.0
Recommended program base	0.0	0.0	0.0
Offset Recommended (Specify Ministry/Program)	0.0	0.0	0.0
Total Fiscal Impact	0.0	0.0	0.0

IV. KEY COMMENTS AND CONSIDERATIONS

As stipulated as part of the 2013-14 Results-based Planning process, the Ministry of Energy is submitting OPG's annual business plans for review by Treasury Board to facilitate incorporating implications into the Province's fiscal plan.

It is under the responsibility of the Minister of Energy on whether or not to provide the Minister's concurrence of OPG's annual multi-year business plan. The Treasury Board submission provides the Minister of Energy with an opportunity to highlight why concurrence is being given and any conditions placed on it. Appendix C provides more information on the concurrence process and the 2013-14 minute.

Under the memorandum of agreement (MOA, July 2015) between the Province (as sole shareholder and the Ministry of Energy as representative of the shareholder) and OPG, the company is required to annually submit its board-approved multi-year business plan to the Minister of Energy for concurrence. The concurrence letter from the Minister to the company will note key elements of the business plan,

how these elements relate to the policy direction and priorities of the Province, and the government's expectation for the performance of the company including indicating any elements of the business plan the government does not concur.

In November 2016, OPG submitted its 2017-2019 Business Plan (Board-approved?) to the Ministry.

Ontario's Fair Hydro Plan (OFHP) is not reflected in OPG's latest Business Plan. The Ministry notes the following OFHP implications for OPG:

- As part of supporting the financing and administration of the global adjustment smoothing mechanism, OPG would develop a Special Purpose Vehicle (OPG Trust) which would use 100 per cent debt financing to purchase the right to future cash flows from IESO.~~,~~ It is proposed that the OPG Trust would raise 51% of required funding directly from capital markets while OPG would provide 49% of the financing requirements. The latter would include 44% debt or equity financing from the Province with OPG raising the remaining 5% from capital markets. ~~financed by capital infusions from the Province (Equity injection via an operating asset, raised from higher debt, with additional shares to the Province as sole shareholder), and by third-party lending~~ (check with OFA – currently 256.3M common shares increasing to….needed? Perhaps explain why there are shares given province is sole shareholder, linked to value of OPG assets/equity)
  - These changes are expected to be fiscally neutral as they would result in an increase in Provincial interest on debt, offset by increases in OPG net income
  - In addition, the Province's net debt position should remain unchanged (Check is OFA)

Financial figures from the OPG Business Plan are included and supplemented with forecast changes for the Ontario Financing Authority, MOF for OFHP implications as part of Province's finalized fiscal plan for the 2017 Budget. The Ministry of Energy indicates it is generally supportive of the fiscal, financial and operational strategies laid out in the business plan.

The earnings before tax (net income and income tax payments in lieu – PILs) of OPG are consolidated on the Province's financial statements and have one-for-one impact on the Province's surplus/deficit position, excluding adjustments that the Province may make upon consolidation of OPG's financials (e.g., unrealized gains or losses). OPG is expected to submit its next multi-year business plan later this year for the period starting January 1, 2017.

Overview of Current Business Plan

OPG's 2017-19 Business Plan details key company undertakings such as business transformation and nuclear refurbishment that will have a substantial electricity system benefit, ratepayer and shareholder impacts. These items were flagged in the previous year's multi-year business plan as well.

- Key Income Statement Forecasts:
  - The figures in the OPG Board approved 2017-2019 Business Plan~~, along with OFA forecast updates for OFHP (TBC),~~ show a decrease in earnings before tax of $~~84M~~ 299M in 201~~6-17~~ ~~-18~~ and $~~89M~~ 556M in 2017-18, primarily due to estimated impact of Ontario Nuclear Funds Agreement-related IFRS risks, followed by increases of $~~59M~~ 12M in 2018-19 and $~~120M~~ 182M in 2019-20 over the estimates in the 2016 Budget.~~.~~

    OPG is forecasting net income attributable to the Shareholder to reach $1B in 2021, from $436M in 2016. Net income in 2017 is forecast to increase as a result of new regulated rates, a gain on sale of OPG's head office, higher capitalized interest for the Darlington Refurbishment expenditures partially offset by reduced production as a result of planned outages at Sir Adam Beck I and DeCew II hydro stations

    Net income in 2018 and 2019 is planned to increase, primarily due to higher production, and earnings from oncoming stations including Nanticoke solar in 2019. Return-on-equity

(ROE) is estimated to increase from 4.2% in 2016 to 7.3% by 2021.

In early January 2017, subsequent to the OPG Board's approval of the 2017-2019 Business Plan, OPG reached an agreement with KingSett Canadian Real Estate Income Fund LP for the purchase of OPG's head office property. The net gain is estimated to be $285M and will be distributed to the Trillium Trust.

These estimates are highly dependent on electricity and financial market conditions, regulatory decisions by the Ontario Energy Board (OEB), potential changes to accounting standards or the basis of consolidation in Public Accounts, operational performance, and/or government policy, which can change materially. The first table in Appendix G shows the changes to Province's fiscal plan.

- Annual Operations, Maintenance & Administration (OM&A) expenses from ongoing operations are expected to stay consistent over the plan period, averaging $2.9B per year.
- The cost of OPG generated electricity to customers is projected to remain ~40% below the average non-OPG cost of electricity to 2018, and over ~30% by 2021. Note: OPG provides predominantly, lower-cost baseload generating capability, rather than more expensive peaking generating capability.
- Headcount Efficiencies – Headcount has fallen from 11,686 in 2010 to a forecasted 9,009 in 2016 while GWh per headcount has increased from 7.6 to 9.3.

  OPG continues ramping up recruitment in 2017 to fill key vacancies in certain areas (particularly in the nuclear business unit) due to high levels of attrition, as well as continued Pickering operations beyond 2020. OPG is forecasting regular headcount to show a net increase of ~300 by the end of 2017 before gradually decreasing to 4% lower than 2017 levels in 2021.

  OPG has hired ~95 Term employees, a new category of non-regular staff negotiated with the Power Workers' Union (PWU) through collective bargaining in 2015. OPG intends to add fewer regular staff in circumstances where they are likely to be laid off as a result of the end of Pickering commercial operations.

- Key Projects:
  - The plan assumes ongoing operations at Pickering for about four years beyond 2020, and as approved by Cabinet, the execution of the Darlington refurbishment consistent with approved budget of $12.8 billion (including escalation and interest), is now under way. First unit refurbishment began in October 2016, Unit 2 is assumed to be returned to service in February 2020 with the second unit refurbishment commencing immediately thereafter and the third unit refurbishment starting in July 2021, assuming necessary concurrence from the Province is obtained.
  - Sustaining capital expenditures average $570M per year include nuclear expenditures unrelated to Darlington refurbishment and costs for continued operation of Pickering (e.g., Upgrades at Sir Adam Beck and upgrades to DeCewII, and investments in current and emerging generation technologies including solar and energy storage including construction and operation of the Nanticoke solar facility).
- Rate Application to the OEB:
  - OPG's 2017-19 Business Plan is dependent on the outcome of its rate filing with the OEB for the five-year period from 2017-2021. Oral hearings began February 2017, decision expected in Q3 2017.
    - OPG 2017-2019 BP assumes new rates effective January 1, 2017. The OEB setting a later effective date would negatively impact OPG's 2017-18 fiscal year

net income by ~$50-60M per month of delay.

- On March 2, 2017 the Province filed an amendment to O.Reg.53/05, which enables OPG to smooth its rates based on OPG's total bill impact, rather than on the basis of nuclear rates only.
- On March 8, 2017 OPG filed a revised rate smoothing proposal with the OEB, which is expected to decrease the average annual impact on the monthly customer bill for an average consumption of 750 KWh/month from about $1.05 to 65 cents per month per year

- OPG Request – Special Stats for OPG to Approve International Travel (Appendix F provides more information):
  - OPG has placed a request with the Ministry for authority to approve international travel for its employees. OPG has asked that this application be included with its BP submission to TB/MBC.
    - Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive allows agencies/organizations, for which international travel may be integral to their business, to seek TB/MBC approval for special status to ensure that the approval process does not have an undue negative effect on its ability to conduct business.
    - OPG cites the importance of enabling its engagement with the international community (in particular in regards to nuclear safety), procurement activities, and investment and due diligence processes for its pension fund and nuclear funds.
    - OPG requires a high level of international business travel at approximately 90-100 trips annually, while Darlington accounts for 45% and is expected see increases.
    - OPG indicated that the approval process, which took 23 days on average in 2016, delays flight bookings which results in higher costs as airlines raise fares closer to the travel date.

Other Key Fiscal Risks:

Regulatory risks: Potential disallowance of recovery of OPG's current or future deferral and variance account balances (including for the proposed nuclear rate smoothing), future treatment of pension costs.

Accounting risks: Any change in the basis of accounting used for consolidation of OPG on the Province's financial statements could result in potentially significant fiscal impacts.

Financing Costs: Higher cost public capital market borrowing (vs the Province's borrowing cost for OEFC to lend to OPG) would have a negative fiscal impact.

Name of analyst:	James Strang	**Phone number:**	7-2071
Date:	May 1, 2017	**Log number:**	
Branch / Division:	General Government, Planning and Resources Branch, PEM, TBS		

APPENDIX A: PROPOSED MINUTE (UNDER DEVELOPMENT)

Note receipt of a Business Plan for Ontario Power Generation.

In this regard,

i.) Note the Minister of Energy will provide Ontario Power Generation (OPG) with a concurrence letter for its Business Plan.

ii.) …..request for special status…international travel

iii.) Direct the Ministry, in consultation with the Ministry of Finance / Ontario Financing Authority, to report back to the Board in early January each year with the approved or latest draft business plans for Ontario Power Generation for fiscal planning purposes.

FINANCIAL IMPACTS: CHANGES TO EXPENSE AND REVENUE					**TABLE B1**
		Fiscal Plan Basis			***Appropriations Basis***
$ Millions		**2014-15**	**2015-16**	**2016-17**	**2014-15**
Initiative cost recommended		0.0000	0.0000	0.0000	
Expense changes:					
Operating item	Oper	0.0000	0.0000	0.0000	0.0000
Capital item	Cap	0.0000	0.0000	0.0000	00000
Revenue changes:					
Revenue increase/offset		0.0000	0.0000	0.0000	
Revenue decrease		0.0000	0.0000	0.0000	
Total Fiscal Impact (draw from c-funds)		**0.0000**	**0.0000**	**0.0000**	**0.0000**

APPENDIX C: CONCURRENCE OVERVIEW

Under agreements between the Province (as sole shareholder) and OPG, the company is required to annually submit its multi-year business plan to the Minister of Energy for concurrence. Review of the business plan by Treasury Board prior to concurrence was stipulated as part of the 2013-14 Results-based Planning process (see below).

Concurrence is typically provided to OPG via a letter from the Minister of Energy. The letter will note key elements of the business plan, how these elements relate to the policy direction and priorities of the Province, and the government's expectation for the performance of the company. The letter may also indicate any elements of the business plan of which the government does not concur and/or provide additional guidance on expectations going forward.

The current submission looks at the multi-year business plan for OPG covering 2016-2018. Concurrence with the plan is still pending.

Below is the 2013-14 Results-based Plan Minute:

Directed the Ministry of Energy and its agencies, Ontario Power Generation Inc. and Hydro One Inc., in consultation with the Ontario Financing Authority, to report back:

- Annually each autumn with the respective multi-year business plans of the agencies as approved by the Boards of the companies, for review by Treasury Board/Management Board of Cabinet.
  - In this regard, the report should include the following, on a calendar and government fiscal year basis:
  - Multi-year financial and operational targets, including net income and earnings-before-tax.
  - Projected revenues and cash flows to the Province, including the Ontario Electricity Financial Corporation.
  - Planned financings from the Ontario Electricity Financial Corporation.
- Quarterly with financial projection updates and progress reports on the agencies' respective business plan targets and any other new developments, initiatives or risks that may have a material fiscal impact on the Province including variance analysis of last quarter and year-to-date against the annual business plan reviewed by Treasury Board/Management Board of Cabinet.

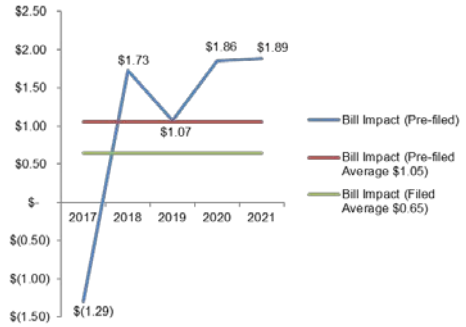
APPENDIX D: SUMMARY OF KEY HIGHLIGHTS FROM OPG BUSINESS PLAN

The Ministry indicates OPG financial and ratepayer forecasts show some changes from last year's business plan projections, as reviewed by Treasury Board in September 2016.

This is in part because 2017 net income is forecast to increase as a result of new regulated rates, higher capitalized interest for the Darlington Refurbishment expenditures partially offset by reduced production as a result of planned outages at Sir Adam Beck I and DeCew II hydro stations.

Also, actions taken by the Province and OPG in early 2017 to enable OPG to smooth its rates based on OPG's weighted average hydroelectric and nuclear all-in rates (which approximates total bill impact), rather than on the basis of nuclear base rates only. OPG filed a revised rate smoothing proposal with the OEB, which is expected to decrease the average year-over-year annual impact on the monthly customer bill for an average consumption of 750 KWh/month from about $1.05 to 65 cents per month per year.

Comparison of Annual Bill Impact ($/Month per year)



Production and Total Cost of Generation

OPG's production is expected to fall to 69.8 TWh by 2021 from 77.6 TWh in 2016. This reflects a declining trend in the Darlington production due to refurbishment outages starting in October 2016 and overlaps between unit refurbishments, as well as, the Pickering Vacuum Building Outage (VBO) in 2021 requiring the shutdown of all units for the duration of the outage.

Total generating cost shows an increasing trend over the planning period relative to 2016, reflecting Lower nuclear production due to Darlington refurbishment outages, increased sustaining capital spending on two large hydroelectric projects (The Lower Mattagami dam safety upgrade and the Sir Adam Beck I GS power canal liner rehabilitation).

Operations, Maintenance and Administration (OM&A) Expenses

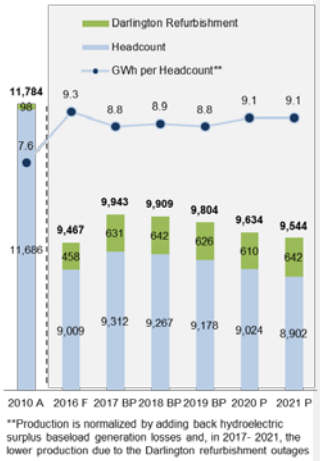
Annual OM&A expenses (excluding Darlington refurbishment OM&A) from ongoing operations are expected to stay consistent over the plan period, averaging $2.9B per year. Increases related to changes in nuclear outage scope at Darlington and planned hiring to fill staffing gaps, and enabling Pickering continued operations, offset by declining pension related costs, due to projected pension asset returns, increases employee contributions, and new method for dermining interest components of pension costs.

Business Transformation and Labour Costs

As part of a company-wide business transformation, OPG saved over $1B in costs from January 2011 to December 2016:

- Headcount has fallen from 11,686 in 2010 to a forecasted 9,009 in 2016 while GWh per headcount has increased from 7.6 to 9.3.
- OPG continues recruitment in 2017 to fill key vacancies in certain areas (particularly in the Nuclear business unit) due to high levels of attrition, as well as continued Pickering operations beyond 2020
  - OPG is forecasting regular headcount to show a net increase of ~300 by the end of 2017 before gradually decreasing to 4% lower than 2017 levels in 2021
  - To date in 2017, OPG has hired ~95 Term employees, a new category of non-regular staff negotiated with the Power Workers' Union (PWU) through collective bargaining in 2015
    - Intention is to add fewer regular staff in circumstances where they are likely to be laid off as a result of the end of Pickering commercial operations, per the terms of the collective agreement

Ongoing Operations Regular Headcount and Productivity



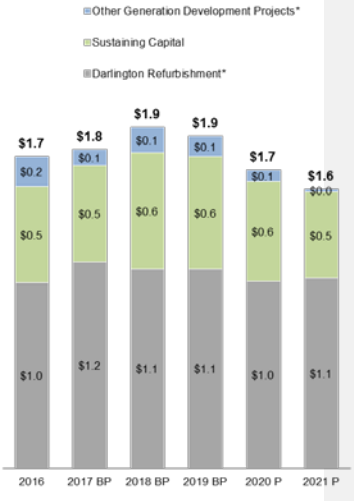
**Production is normalized by adding back hydroelectric surplus baseload generation losses and, in 2017- 2021, the lower production due to the Darlington refurbishment outages

Projects and Capital Expenditures

OPG continues delivery of major projects over the plan period, including:

- Darlington Refurbishment – Unit 2 is assumed to be returned to service in February 2020 with the second unit refurbishment commencing immediately thereafter and the third unit refurbishment starting in July 2021, requiring concurrence from the Province prior to commencement
- Sustaining Capital – Expenditures average $570M, including:
  - Nuclear expenditures unrelated to refurbishment at Darlington and costs for continued operation of Pickering
  - Regulated hydro expenditures including upgrades at Sir Adam Beck and upgrades to DeCew ll
  - Lower Mattagami upgrades in 2018 and 2019
- Other Generation Development Projects – Investments in current (e.g., hydroelectric) and emerging generation technologies including solar and energy storage including construction and operation of the Nanticoke solar facility by 2019

Capital Expenditure Estimates ($B)



*Includes expenditures budgeted by Support Services

Sales

The following table summarizes sales recently completed and currently underway (as of April 2017). The fiscal plan implications of the completed OPG Head Office sale is reflected in the 2017 Budget. (TBC).

	OPG Head Office	R.L. Hearn Site	Lakeview Site
Current Status	Completed	Agreement Reached	OPG and Infrastructure Ontario are preparing for marketing
Site Description	700 University Ave. and parking garage at 40 Murray St. in Toronto	~33 acres at the R.L. Hearn site in Toronto	~67 acres to be transferred by the purchaser to the City of Mississauga (Municipal Park Lands) and ~110 acres to be developed for mixed uses (Uplands)
Buyer	KingSett Canadian Real Estate Income Fund LP	Studios of America Limited Partner	TBD
Value	Estimated up-front 2017-18 fiscal impact of ~$375M (includes after-tax gain as well as PILs to OEFC)	TBD	TBD
Other Considerations	N/A	N/A	Negotiations with the City have been lengthy and costs to remediate/prepare site may be significant due to concerns regarding site condition
Timing	The sale closed in April 2017	Anticipated to close in Q3 2017	Marketing is planned to start in April 2017, pending negotiations with the City, with an anticipated closing in 2017

APPENDIX E: PROVINCIAL FISCAL PLAN IMPLICATIONS OF BUSINESS PLANS PROCEEDING – (UNDER DEVELOPMENT)

Ontario Power Generation is a Government Business Enterprises (GBE), and consolidated to the Province's financials on a modified equity basis. The Province's Fiscal Plan reflects the entity as Income from Business Enterprises and Electricity Payments-in-Lieu of Taxes (PILs) (As Revenue only).

Revenue ($millions)	**2016-17**	**2017-18**	**2018-19**	**2019-20**
2016 Ontario Budget				
Ontario Power Generation				
Net Income	471	586	673	705
Income Tax	224	159	182	108
2017-2019 OPG Business Plan				
Ontario Power Generation				
Net Income	349	702	678	726
Income Tax	~~111~~96	~~184~~166	~~154~~135	~~189~~170
2017 Ontario Budget				
Ontario Power Generation				
Net Income (before IFRS Risk)	379	480	678	726
ONFA-related IFRS Risk	(75)	(400)		
GA – OPG Trust Interest Revenue	17	54	99	153
OPG Head Office*		222		
Net Income	~~387~~304	~~497~~97	732	825
Income Tax	?92	?92	?135	?170
OPG Head Office*		74		
Change in GBE Net Income (Between Budgets)				
Ontario Power Generation	~~(84)~~(167)	~~(89)~~(489)	59	120
Change in GBE Income Tax PILs +/(-)				
Ontario Power Generation	?(132)	?(67)	?(47)	?6
TOTAL OF OPG CHANGES	?(299)	?(556)	?12	?182

- Net Income and PILs contributions from OPG Head Office are included in Sales and Rental under Other Non-Tax Revenue in the 2017 Budget.

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OPG's fiscal results are also impacted by Other PILs to the Ontario Electricity Financial Corporation (OEFC) and the Province. The following table reflects these others impacts in addition to the latest net income and income tax PILs from OPG's August update.

Table below to be updated – OFA

Revenue ($millions)	**2016-17**	**2017-18**	**2018-19**	**2019-20**
2016 Ontario Budget				
Combined Other PILs & Other GRC	342	351	359	
Other PILs (GRC to OEFC, Proxy Property Tax)	213	223	232	
Other GRC (to MOF & Niagara Parks Commission)[1]	129	128	137	
2017~~6~~-1~~9~~8 OPG Business Plan				
Combined Other PILs & Other GRC[2]	~~353~~329	350~~8~~	363~~6~~	362
Other PILs (GRC to OEFC, Proxy Property Tax)[3]	218~~5~~	232~~20~~	243~~20~~	241
Other PILs (GRC to MOF & Niagara Parks Commission)[3]	~~135~~110	118~~40~~	124~~0~~	121
~~OPG Monthly Update (August 2016)~~				
Net Income (including OPG Head Office sale)	~~361~~379	702~~-~~	678~~-~~	726
2017 Budget Adjustments				
ONFA adjustment	8			
OPG Trust Interest Revenue		17	54	99
OPG IFRS consolidation risk reflected in fiscal plan	-75	-400	-	-
Income Tax PILs to OEFC	~~98~~92	166~~-~~	135~~-~~	170

Source: OPG 2017-2019 Business Plan and further details provided by OPG March 14, 2017~~1. The GRC to MOF & Niagara Parks Commission (NPC) is provided to enable comparison to the 2016-18 Business Plan.~~

~~2. Include GRC to OEFC, GRC to MOF and NPC and Proxy Property Tax, provided to TBS by Energy on September 14, 2016.~~

~~3. Preliminary 2016-19 Business Plan forecast provided by Energy, January 29, 2016. (Do not add to the Combined Other PILs & Other GRC row, likely due to rounding.)~~

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From:	Ronald Kwan
To:	John Kim
Subject:	FW: OPG Performance fees
Date:	Monday, May 15, 2017 9:40:43 AM

Hi John,

Comments?

Ron

From: Nelms, Scott (MOF) [mailto:Scott.Nelms@ontario.ca]
Sent: May-15-17 09:17
To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
Cc: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; Mike Manning <Mike.Manning@ofina.on.ca>; Carlos Yep <Carlos.Yep@ofina.on.ca>; Veinot, Cindy (TBS) <Cindy.Veinot@ontario.ca>
Subject: RE: OPG Performance fees

I talked to OPG on this. Here are some other considerations:

- Risk / reward goes both ways. Unlike most management fee structures where the performance fee provides an at risk upside to the manager, but no downside, the distribution of potential benefits and losses is symmetric between ratepayers and OPG.
- OPG's current thinking is that it would work with OFA to set a benchmark for borrowing costs at the start of the year based on GOC yields + a premium. If OPG over-performs (under-performs) the benefit (downside) would be shared between the company and ratepayers 50/50 up to +/- $1M. Above or below $1M, all of the benefit (downside) would flow to ratepayers.
- OPG does not particularly like this symmetry but this is apparently required to meet accounting requirements.
- From my perspective, $1M is a small number, so I am not too concerned about overall impacts on ratepayers.

Thanks,
Scott

From: Ken Kandeepan [mailto:Ken.Kandeepan@ofina.on.ca]
Sent: May 13, 2017 7:32 PM
To: Nelms, Scott (MOF)
Cc: Kwan, Ronald (OFA); Manning, Mike (OFA); Yep, Carlos (OFA); Veinot, Cindy (TBS)
Subject: RE: OPG Performance fees

Hi Scott

Yes the MOF does like OPG to make money since on a PSAB basis it benefits the Province's fiscal

position. In this instance however, the marginal increase to the fiscal bottom line comes at the expense of the ratepayers in terms of additional debt, hence our push back.

Pls see below my responses on the two issues that you have raised. I am cc'ing Cindy as well since she may have her own thoughts and a discussion maybe value added in terms of arriving at a common understanding.

Thanks

Ken K

From: Nelms, Scott (MOF) [mailto:Scott.Nelms@ontario.ca]
Sent: Friday, May 12, 2017 2:54 PM
To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
Cc: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; Mike Manning <Mike.Manning@ofina.on.ca>; Carlos Yep <Carlos.Yep@ofina.on.ca>
Subject: RE: OPG Performance fees

MoF asking OPG to make less money! This feels so backward!

I will chat with OPG to dig in to the rationale. I take your point that OPG will benefit from the loans to the trust. However, I see two weaknesses with the argument:

1) Lenders don't typically consolidate borrowers, so it takes more than interest revenues to meet this test. Not sure if you are referring to the "Power" or "profit" principle. If the former the Province lends to IO for all its needs and yet exercises power since IO is consolidated with the Province in much the same way the Trust and OPG will be consolidated. Note that OPG benefits from the interest income on the 44% relating to the equity injection even if the Trust is not consolidated.
2) Earning interest income on equity is going to take down the company's ROE (one of the key metrics that we are tracking on overall company performance). Therefore I wouldn't see this as a particularly compelling allocation of funds from a commercial perspective. This is a good point however, OPG considers the 44% it lends to the Trust as sub-debt most likely priced higher than the debt borrowed by the Trust from the markets. In the event the interest on the 44% is less than OPG's current ROE of the company, your point holds however, if the interest is higher it actually adds to OPG's ROE.

Scott

From: Ken Kandeepan [mailto:Ken.Kandeepan@ofina.on.ca]
Sent: May 12, 2017 11:24 AM
To: Nelms, Scott (MOF)
Cc: Kwan, Ronald (OFA); Manning, Mike (OFA); Yep, Carlos (OFA)
Subject: OPG Performance fees

Hi Scott

This issue has come up a couple of times and after discussing with Gadi we felt that you may be able to raise it either directly with OPG or via Energy. As the Financial Services Manager, OPG is proposing a performance fee for itself based beating a benchmark for borrowing costs the Trust incurs in presumably the 51% it seeks to borrow from the capital markets.

OPG argues that the latter of the two fundamental principles, "Power" and "Profit" allowing the Trust to be consolidated with OPG requires the implementation of a performance fee structure. The counter argument is that OPG already has access to profit, by virtue of its position as the funding entity for 44% of the debt incurred by the Trust. OPG uses the funds it receives from the Province's equity injection, for which it pays no interest, for this purpose.

Upon consolidation with the Trust, OPG's interest income will therefore increase by the amount of the interest the Trust receives on 44% of its overall debt, a relatively risk free profit source, at least over the duration of the Fair Hydro Plan. While the use of a benchmark is appropriate and contributes to an efficient borrowing program, any performance fees arising from beating the benchmark will effectively be funded by the ratepayers, by increasing the investment asset and the associated debt to be repaid by ratepayers.

Mike and I will be happy to provide any further technical assistance that you may require as you raise this issue.

Thanks

Ken k

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From:	Bruno Amara
To:	Ronald Kwan
Cc:	John Kim
Subject:	FW: OPG Q3
Date:	Monday, October 30, 2017 2:22:37 PM
Attachments:	FW OPG Q3 2017 Submission to Province.msg Q3 2017 OPG MDA - DRAFT - PROVINCE MAILING_EFB_CommentsV3.docx OPG September EFB Questions.docx

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Hi Ron

OPG had sent us Q3 material last week for review. Comments are due today.

Attached is OPG's Q3 Management, Discussion and Analysis with a few EFB comments added to the document (proposed edits or questions).

Also attached are some OPG follow-up questions. These include some follow-up questions to the September monthly and one related to the draft Q3 report.

OPG had also sent a draft press release and financial statements. We had no additional comments on these that are not be covered in the OPG MDA.

Pending your comments and/or approval we can forward to OPG, or we could send through GBED. Please advise.

Thanks
Bruno

Bruno Amara
Sr. Manager, Financial and Regulatory Analysis
Electricity Finance Branch
Corporate and Electricity Finance Division
Ontario Financing Authority

Tel: 416-325-1489
Email: bruno.amara@ofina.on.ca

From: John Kim []
To: Bruno Amara [Bruno.Amara@ofina.on.ca]; Shajee Kathirgamanathan [Shajee.Kathirgamanathan@ofina.on.ca]; Gavin He [Gavin.He@ofina.on.ca]; Esther Jeon [Esther.Jeon@ofina.on.ca]; Atif Ali [Atif.Ali@ofina.on.ca]
Subject: FW: OPG Q3 2017 Submission to Province
Date: Wednesday, October 25, 2017 12:22:36
Attachment 1: Q3 2017 OPG Press Release_PROVINCE MAILING.docx
Attachment 2: Q3 2017 OPG MD&A - DRAFT - PROVINCE MAILING.docx
Attachment 3: Q3 2017 OPG FS Province MAILING.docx

Pls. review and consolidate edits/comments.

From: HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
Sent: Wednesday, October 25, 2017 12:22 PM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>; 'Montgomery, Kaitlin (MOF)' <Kaitlin.Montgomery@ontario.ca>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>
Subject: OPG Q3 2017 Submission to Province

Hi All,

Please find attached OPG's draft Q3 2017 Financial Results Press Release, Management's Discussion and Analysis (MD&A), and Financial Statements for the Province's review.

We would greatly appreciate comments on the above **no later than Monday, Oct 30th**.

These documents will be filed with the Ontario Securities Commission on **Thursday, November 9th** following OPG's Board of Directors meeting.

Kindly forward all comments directly to Philip Ho – philip.ho@opg.com.

To assist the review process, the following are the key items in the Q3 2017 MD&A:

Highlights	
Recent Developments	MD&A p.10-11
Darlington Refurbishment	MD&A p.13-15
Ontario's Fair Hydro Plan	MD&A p.10-11

Philip Ho, CPA, CA | Senior Manager, External Reporting & Accounting Policy | Ontario Power Generation
700 University Avenue, Toronto ON M5G 1X6 | Phone: (416) 592-3320| E-mail: philip.ho@opg.com

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ONTARIO POWER GENERATION

News
from Ontario Power Generation

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www.opg.com

[DRAFT]

Nov. 9, 2017

OPG REPORTS 2017 THIRD QUARTER FINANCIAL RESULTS

Darlington Refurbishment Project Remains on Time and on Budget at One-Year Mark

Toronto: – Ontario Power Generation Inc. (OPG or Company) today reported net income attributable to the Shareholder of $131 million for the third quarter of 2017, compared to $194 million for the same period in 2016.

“The Company’s focus continues to be on ensuring the success of the Darlington Refurbishment Project. Just after the one year mark of work on Darlington’s Unit 2, Canada’s largest clean energy project remains on time and on budget,” said Jeff Lyash, OPG President and CEO. “This is a ten year mega-project that will extend the life of the Darlington nuclear plant by 30 years, boosting Ontario’s GDP by $90 billion and creating more than 14,000 new jobs per year over the station’s life.”

Lyash went on to say, “I am also pleased with the performance of our Pickering Nuclear plant, which has so far generated 2.1 terawatt hours of electricity more than last year. We are applying for a licence to extend the operation of the station until 2024. This will ensure a reliable, clean source of low cost power during the Darlington Refurbishment project and avoid 17 million tonnes of carbon emissions.”

“The successful performance of our assets is built around a strong safety culture. This quarter, the Canadian Nuclear Safety Commission has once again given Pickering and Darlington the highest possible safety ratings,” Lyash added. “Darlington has now achieved this rating for eight consecutive years and Pickering has achieved the highest possible safety rating for the second year in a row.”

“Additionally, OPG successfully completed its first public debt issuance in October, raising $500 million for our general corporate needs and to fund OPG's investment in Ontario’s Fair Hydro Plan,” said Lyash. “This will provide OPG with financial flexibility and further our ability to invest in our projects to the benefit of customers and stakeholders.”

The results for the third quarter continued to be impacted by the expected year-over-year decline in generation revenue, reflecting lower nuclear electricity generation due to the refurbishment outage for Unit 2 at the Darlington Generating Station (GS) without the resetting of base regulated prices, largely offset by higher generation from the Pickering GS and the regulated hydroelectric generating stations. The lower generation revenue was partially offset by lower operations, maintenance and administration (OM&A) expenses across all business segments.

OPG provides electricity at a price that is 40 per cent less than other generators and is the only electricity generator in Ontario that has its prices set through a public hearing process by the Ontario Energy Board (OEB). Earlier in 2017, OPG completed the public hearing process for its current application with the OEB that will set prices for the Company's nuclear and most of its hydroelectric generation for the next five years, with a proposed effective date of January 1, 2017. The OEB is expected to make a decision on the rate application prior to the end of the year. In the meantime, OPG is operating under base regulated prices that were set in 2014 and do not reflect this year's reduced nuclear electricity generation, which is primarily due to the Darlington Refurbishment. As in earlier quarters this year, the continuation of these prices has negatively affected revenue and net income in the third quarter of 2017. The outcome of the current rate application and the effective date of the new regulated prices are expected to affect OPG's revenue and net income for the fourth quarter of 2017.

Net income attributable to the Shareholder was $498 million for the nine months ended September 30, 2017, compared to $449 million for the same period in 2016. The sale of OPG's head office building and parking facility, and the associated one-time gain recorded in the second quarter of 2017, offset the year-to-date reduction in generation revenue and was the main driver of the increase in net income for the nine months ended September 30, 2017, compared to the same period in 2016.

Lower earnings on the nuclear fixed asset removal and nuclear waste management segregated funds of $52 million during the third quarter of 2017 and $41 million during the nine months ended September 30, 2017, compared to the corresponding periods in 2016, also contributed to the year-over-year change in net income.

Generation and Operating Performance

Electricity generated during the three months ended September 30, 2017 was 19.4 terawatt hours (TWh), compared to 19.5 TWh for the same quarter in 2016. Total electricity generated during the nine months ended September 30, 2017 decreased to 56.0 TWh from 59.9 TWh for the same period in 2016. The decrease in electricity generation reflected the expected lower generation from the Darlington GS and lower generation from the contracted plants. The quarter-over-quarter decrease was largely offset by higher generation from the Pickering GS, primarily due to fewer outage days, and higher hydroelectric generation from the regulated stations.

Regulated – Nuclear Generation Segment

Lower nuclear generation of 0.4 TWh and 4.0 TWh during the three and nine month periods ended September 30, 2017, was primarily due to the removal from service of Unit 2 at the Darlington GS for the duration of the unit's refurbishment that began in October 2016 and is expected to continue until early 2020. Offsetting the reduction in generation from the Darlington GS was an increase in generation of 0.9 TWh and 2.1 TWh from the strong performance of the Pickering GS during the three and nine month periods ended September 30, 2017, respectively.

For the three months ended September 30, 2017, the unit capability factor at the Darlington GS for operating units was 96.2 per cent, compared to 89.6 per cent for the same quarter in 2016. The increase is primarily due to a lower number of planned outage days during the third quarter of 2017. For the nine months ended September 30, 2017, the unit capability factor at the Darlington GS was 82.1 per cent,

compared to 87.6 per cent for the same period in 2016. The decrease was primarily a result of a higher number of planned outage days at the station in the first half of 2017, largely driven by constraints related to the transition of the station toward refurbishment.

At the Pickering GS, the unit capability factor increased to 88.7 per cent and 83.8 per cent for the three and nine month periods ended September 30, 2017, respectively, compared to 77.3 and 73.8 per cent for the same periods in 2016, primarily due to outage optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station in 2017.

Regulated – Hydroelectric Segment

Higher generation from the regulated hydroelectric stations of 0.4 TWh and 0.7 TWh during the three and nine month periods ended September 30, 2017, was due to higher water flows, primarily on the eastern Ontario river systems.

The availability of 87.6 per cent at these stations in the third quarter of 2017 was higher than 84.1 per cent for the same quarter in 2016, primarily due to a higher number of planned outages in 2016 as a result of the reservoir refurbishment of the Sir Adam Beck Pump generating station undertaken between April 2016 and February 2017. For the nine months ended September 30, 2017, the availability of the stations marginally decreased to 89.0 per cent, from 89.8 per cent for the same period in 2016. The marginal decrease in the availability was primarily due to a higher number of unplanned outage days at the Northwestern Ontario and Niagara region hydroelectric stations, partially offset by higher availability from the Sir Adam Beck Pump GS.

Contracted Generation Portfolio Segment

Lower generation from the Contracted Generation Portfolio 0.1 TWh and 0.6 TWh during the three and nine month periods ended September 30, 2017, was mainly due to lower generation from the segment's hydroelectric plants.

The availability of these hydroelectric stations for the three months ended September 30, 2017 was 66.1 per cent, compared to 68.2 per cent for the same quarter in 2017. The stations' availability for the nine months ended September 30, 2017 was 76.9 per cent, compared to 79.6 per cent for the same period in 2016. The decrease in the availability was primarily due to an increase in the number of planned outage days at the Lower Mattagami River hydroelectric generating stations.

Total Generating Cost

The Enterprise Total Generating Cost per megawatt hour (MWh) for the three months ended September 30, 2017 was $46.65, compared to $50.72 for the same quarter in 2016. The decrease was mainly due to lower OM&A expenses before the impact of regulatory variance and deferral accounts and higher hydroelectric generation adjusted for surplus baseload generation reflecting higher water flows. The Enterprise Total Generating Cost per MWh for the nine months ended September 30, 2017 was $47.77, compared to $46.74 for the same period in 2016. The increase was expected and mainly a result of lower electricity generation due to the Unit 2 refurbishment outage at the Darlington GS. The increase in Enterprise Total Generating Cost was largely offset

by lower OM&A expenses before the impact of regulatory variance and deferral accounts and higher hydroelectric generation adjusted for surplus baseload generation reflecting higher water flows.

If Unit 2 at the Darlington GS was not currently undergoing refurbishment and had continued to operate in a manner consistent with the performance of the remaining units at the Darlington GS, adjusted for generation constraints on these units related to the transition of the station toward refurbishment, the Enterprise Total Generating Cost would have been approximately $4 per MWh lower for the three and nine months ended September 30, 2017. This sensitivity was calculated using the estimated incremental electricity generation and associated fuel cost that are expected to have resulted in the absence of the refurbishment.

Generation Development

OPG is undertaking a number of generation development and life extension projects in support of Ontario's electricity planning initiatives. Significant developments during the third quarter of 2017 were as follows:

Darlington Refurbishment

The Darlington Refurbishment project is expected to extend the operating life of the four-unit Darlington GS by approximately 30 years. In October 2016, OPG commenced the refurbishment of the first unit, Unit 2, as part of the project. The de-fuelling and islanding of the reactor was completed in the first half of 2017. The Re-tube Tooling Platform for hosting the tooling for the removal, inspection, and installation activities and the setup of specialized tooling and equipment needed for the removal and replacement of the reactor components were completed in the third quarter of 2017. The disassembly of reactor components began in August 2017, with the removal of all 960 feeder tubes completed safely in September 2017. This was followed by the severing of pressure tubes, with the severing of bellows and the removal of end fittings expected to commence thereafter and through the end of 2017.

With the Re-tube Waste Processing Building becoming available for use in November 2017, 17 out of 18 pre-requisite projects in support of the refurbishment execution have been completed. The completion of the Heavy Water Storage and Drum Handling Facility, which has been delayed due to challenges with construction, will resume in the fourth quarter of 2017. The cost of the pre-requisite projects is included in the overall budget for the refurbishment of $12.8 billion.

The overall project continues to track on schedule and on budget. Unit 2 is scheduled to be returned to service, after a 40-month refurbishment outage, in the first quarter of 2020, at which time capital expenditures of approximately $4.8 billion are planned to be placed in service. This includes expenditures incurred during the definition and planning phase of the overall project. Life-to-date capital expenditures were approximately $4.1 billion as at September 30, 2017.

In addition to the execution of refurbishment activities for Unit 2, OPG is continuing planning activities for the refurbishment of the second unit, Unit 3, and is entering into associated commitments to procure major components that require long lead times. As of September 30, 2017, $70 million has been invested in planning activities related to the refurbishment of the second unit.

Ranney Falls Hydroelectric GS

During the third quarter of 2017, OPG continued construction work for a 10 MW single-unit powerhouse on the existing Ranney Falls GS site, as part of the Regulated – Hydroelectric segment. The new unit will replace an existing unit that reached its end of life in 2014. The existing forebay structure demolition has been completed and the upstream cofferdam has been constructed ahead of schedule. Construction continues on the expanded forebay, powerhouse and spillway. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget.

Nanticoke Solar Facility

The construction of a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands under a Large Renewable Procurement contract with the IESO, through Nanticoke Solar LP, a partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation, is planned to commence in the first quarter of 2018. During the third quarter of 2017, the partnership continued work to obtain approvals and permits required to enable the commencement of construction, and progressed procurement activities for equipment and for engineering and construction services. The facility is expected to be completed in the first quarter of 2019.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

(millions of dollars – except where noted)	Three Months Ended September 30 2017	2016	Nine Months Ended September 30 2017	2016
Revenue	**1,217**	1,400	**3,539**	4,265
Fuel expense	**185**	187	**518**	541
Gross margin	**1,032**	1,213	**3,021**	3,724
Operations, maintenance and administration	**635**	666	**2,054**	2,061
Depreciation and amortization	**178**	313	**517**	941
Accretion on fixed asset removal and nuclear waste management liabilities	**235**	232	**709**	696
Earnings on Nuclear Segregated Funds - (a reduction to expenses)	**(196)**	(248)	**(579)**	(620)
Income from investments subject to significant influence	**(11)**	(11)	**(29)**	(28)
Other net expenses (gains)	**11**	13	**(350)**	12
Income before interest and income taxes	**180**	248	**699**	662
Net interest expense	**21**	28	**56**	92
Income tax expense	**19**	22	**128**	109
Net income	**140**	198	**515**	461
Net income attributable to the Shareholder	**131**	194	**498**	449
Net income attributable to non-controlling interest [1]	**9**	4	**17**	12
Income before interest and income taxes				
Electricity generation business segments	**217**	238	**436**	736
Regulated – Nuclear Waste Management	**(36)**	18	**(123)**	(70)
Services, Trading, and Other Non-Generation	**(1)**	(8)	**386**	(4)
Total income before interest and income taxes	**180**	248	**699**	662
Cash flow				
Cash flow provided by operating activities	**485**	530	**698**	1,211
Electricity generation (TWh)				
Regulated – Nuclear Generation	**11.3**	11.7	**30.6**	34.6
Regulated – Hydroelectric	**7.3**	6.9	**23.5**	22.8
Contracted Generation Portfolio [2]	**0.8**	0.9	**1.9**	2.5
Total electricity generation	**19.4**	19.5	**56.0**	59.9
Nuclear unit capability factor (per cent) [3]				
Darlington Nuclear GS	**96.2**	89.6	**82.1**	87.6
Pickering Nuclear GS	**88.7**	77.3	**83.8**	73.8
Availability (per cent)				
Regulated – Hydroelectric	**87.6**	84.1	**89.0**	89.8
Contracted Generation Portfolio – hydroelectric stations	**66.1**	68.2	**76.9**	79.6
Equivalent forced outage rate				
Contracted Generation Portfolio – thermal stations	**2.6**	2.1	**6.0**	1.3
Enterprise Total Generating Cost per MWh ($/MWh) [4]	**46.65**	50.72	**47.77**	46.74
Return on Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI) for the twelve months ended September 30, 2017 and December 31, 2016 (%) [4]			**4.4**	4.2
Funds from Operations (FFO) Adjusted Interest Coverage for the twelve months ended September 30, 2017 and December 31, 2016 (times) [4]			**4.2**	5.1

[1] Relates to the 25 per cent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in the Lower Mattagami Limited Partnership, the 33 per cent interest of Coral Rapids Power Corporation, a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership, and the 10 per cent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP.

[2] Includes OPG's share of generation volume from its 50 per cent ownership interests in the Portlands Energy Centre and Brighton Beach GS.

[3] Nuclear unit capability factor excludes unit(s) during the period in which they are undergoing refurbishment. Unit 2 of the Darlington GS is excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

[4] Enterprise Total Generating Cost per MWh, ROE Excluding AOCI, and FFO Adjusted Interest Coverage are non-GAAP financial measures and do not have any standardized meaning prescribed by US GAAP. Additional information about the non-GAAP measures is provided in OPG's Management's Discussion and Analysis for the three and nine months ended September 30, 2017, in the sections *Highlights – FFO Adjusted Interest Coverage*, *Highlights – Return on Common Equity Excluding Accumulated Other Comprehensive Income*, and *Highlights – Enterprise Total Generating Cost per MWh*, as well as *Supplementary Non-GAAP Financial Measures.*

Ontario Power Generation Inc. is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. Our mission is providing low cost power in a safe, clean, reliable and sustainable manner for the benefit of our customers and shareholder.

Ontario Power Generation Inc.'s unaudited interim consolidated financial statements and Management's Discussion and Analysis as at and for the three and nine month periods ended September 30, 2017 can be accessed on OPG's web site (www.opg.com), the Canadian Securities Administrators' web site (www.sedar.com), or can be requested from the Company.

For further information, please contact: Investor Relations 416-592-6700
webmaster@opg.com

Media Relations 416-592-4008
1-877-592-4008

- 30 -

ONTARIO POWER GENERATION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

2017 THIRD QUARTER REPORT

[DRAFT]

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ONTARIO POWER GENERATION

ONTARIO POWER GENERATION INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) should be read in conjunction with the unaudited interim consolidated financial statements and accompanying notes of Ontario Power Generation Inc. (OPG or Company) as at and for the three and nine months ended September 30, 2017. OPG's unaudited interim consolidated financial statements are prepared in accordance with United States generally accepted accounting principles (US GAAP) and are presented in Canadian dollars.

For a complete description of OPG's corporate strategies, risk management, corporate governance, and the effect of critical accounting policies and estimates on OPG's results of operations and financial condition, this MD&A should also be read in conjunction with OPG's audited consolidated financial statements, accompanying notes, the Annual Information Form, and the MD&A as at and for the year ended December 31, 2016.

As required by *Ontario Regulation 395/11*, as amended, a regulation under the *Financial Administration Act* (Ontario), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. In 2014, the Ontario Securities Commission approved an exemption which allows OPG to apply US GAAP up to January 1, 2019. The term of the exemption is subject to certain conditions, which may result in the expiry of the exemption prior to January 1, 2019. For details, refer to the section, *Critical Accounting Policies and Estimates* under the heading, *Exemptive Relief for Reporting under US GAAP,* in OPG's 2016 annual MD&A. This MD&A is dated November 9, 2017.

FORWARD-LOOKING STATEMENTS

The MD&A contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could", and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

All forward-looking statements involve inherent assumptions, risks, and uncertainties, including those set out in the section, *Risk Management,* and forecasts discussed in the section, *Core Business, Strategy, and Outlook.* All forward-looking statements could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's generating station performance and availability, fuel costs, surplus baseload generation (SBG), cost of fixed asset removal and nuclear waste management, performance and earnings of investment funds, refurbishment of existing facilities, development and construction of new facilities, pension and other post-employment benefit (OPEB) obligations and funds, income taxes, proposed new legislation, the ongoing evolution of Ontario's electricity industry, environmental and other regulatory requirements, health, safety and environmental developments, business continuity events, the weather, financing and liquidity, applications to the Ontario Energy Board (OEB) for regulatory prices, the impact of regulatory decisions by the OEB, and forecasts of earnings, cash flows, Funds from Operations (FFO) Adjusted Interest Coverage, Return on Common Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI), Total Generating Cost (TGC) and capital expenditures. Accordingly, undue reliance should not be placed on any forward-looking statement. The forward-looking statements included in this MD&A are made only as of the date of this MD&A. Except as required by applicable securities laws, OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events, or otherwise.

THE COMPANY

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG was established under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (Province or Shareholder).

As at September 30, 2017, OPG's electricity generation portfolio had an in-service capacity of 16,210 megawatts (MW). OPG operates two nuclear generating stations, 66 hydroelectric generating stations, three thermal generating stations, and one wind power turbine. In addition, OPG and TransCanada Energy Ltd. co-own the 550 MW Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS). OPG and ATCO Power Canada Ltd. co-own the 560 MW Brighton Beach gas-fired combined cycle GS (Brighton Beach). OPG's 50 percent share of the in-service capacity and generation volume of these co-owned facilities is included in the generation portfolio statistics set out in this report. The income from the co-owned facilities is accounted for using the equity method of accounting, and OPG's share of income is presented as income from investments subject to significant influence in the Contracted Generation Portfolio segment.

OPG also owns two other nuclear generating stations, the Bruce A GS and the Bruce B GS, which are leased on a long-term basis to Bruce Power LP (Bruce Power). Income from these leased stations is included in revenue under the Regulated – Nuclear Generation segment. The leased stations are not included in the generation portfolio statistics set out in this report.

All of OPG's owned and co-owned generating facilities are located in Ontario. OPG does not operate PEC, Brighton Beach, the Bruce A GS and the Bruce B GS.

A description of OPG's segments is provided in OPG's 2016 annual MD&A in the section, *Business Segments*.

In-Service Generating Capacity

OPG's in-service generating capacity by business segment as at September 30, 2017 and December 31, 2016 was as follows:

(MW)	As at September 30 2017	December 31 2016
Regulated – Nuclear Generation [1]	**5,728**	5,728
Regulated – Hydroelectric	**6,426**	6,421
Contracted Generation Portfolio [2]	**4,056**	4,028
Total	**16,210**	16,177

[1] The in-service generating capacity as of September 30, 2017 and December 31, 2016 excludes Unit 2 of the Darlington GS. The unit, which has a generating capacity of 878 MW, was taken offline in mid-October 2016 and is currently undergoing refurbishment.

[2] Includes OPG's share of in-service generating capacity of 275 MW for PEC and 280 MW for Brighton Beach.

During the nine months ended September 30, 2017, the total in-service capacity increased by 33 MW. The increase was primarily due to the completion of the Peter Sutherland Sr. hydroelectric GS, which was placed in-service at the end of the first quarter of 2017, and the upgrade of Unit 10 of the Sir Adam Beck 1 hydroelectric GS, which was completed in June 2017.

HIGHLIGHTS

Overview of Results

This section provides an overview of OPG's unaudited interim consolidated operating results. Significant factors which contributed to OPG's results during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, are discussed below.

(millions of dollars – except where noted) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Revenue	**1,217**	1,400	**3,539**	4,265
Fuel expense	**185**	187	**518**	541
Gross margin	**1,032**	1,213	**3,021**	3,724
Operations, maintenance and administration	**635**	666	**2,054**	2,061
Depreciation and amortization	**178**	313	**517**	941
Accretion on fixed asset removal and nuclear waste management liabilities	**235**	232	**709**	696
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(196)**	(248)	**(579)**	(620)
Income from investments subject to significant influence	**(11)**	(11)	**(29)**	(28)
Property taxes	**8**	12	**30**	35
	849	964	**2,702**	3,085
Income before other losses (gains), interest and income taxes	**183**	249	**319**	639
Other losses (gains)	**3**	1	**(380)**	(23)
Income before interest and income taxes	**180**	248	**699**	662
Net interest expense	**21**	28	**56**	92
Income before income taxes	**159**	220	**643**	570
Income tax expense	**19**	22	**128**	109
Net income	**140**	198	**515**	461
Net income attributable to the Shareholder	**131**	194	**498**	449
Net income attributable to non-controlling interest [1]	**9**	4	**17**	12
Electricity production (TWh) [2]	**19.4**	19.5	**56.0**	59.9
Cash flow provided by operating activities	**485**	530	**698**	1,211

[1] Relates to the 25 percent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in the Lower Mattagami Limited Partnership, the 33 percent interest of Coral Rapids Power Corporation, a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership, and the 10 percent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP.

[2] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

Third Quarter

Net income attributable to the Shareholder was $131 million for the third quarter of 2017, a decrease of $63 million compared to the same quarter in 2016. Income before interest and income taxes for the third quarter of 2017 was $180 million, a decrease of $68 million compared to the same quarter in 2016.

Significant factors that reduced income before interest and income taxes:

- Lower earnings from the nuclear base regulated price of approximately $24 million reflecting lower electricity generation of 0.4 terawatt hours (TWh) from the Regulated – Nuclear Generation segment and the continuation of existing base regulated prices set by the OEB in 2014. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS since October 2016, largely offset by an increase in generation from Pickering GS. The increase in generation from the Pickering GS was primarily due to outage optimization, favourable unit conditions and execution of planned outage work. The base regulated prices set in 2014 continue to be in effect pending the OEB's decision on OPG's current application for new regulated prices, expected later in 2017. **[MONITOR]** The existing nuclear base regulated price was set to allow the Company to recover its approved nuclear costs over a higher nuclear production volume, based on the 2014 and 2015 outage profile that did not include a refurbishment outage. OPG has requested January 1, 2017 as the effective date of the new regulated prices.
- Lower earnings on the nuclear fixed asset removal and nuclear waste management funds (Nuclear Segregated Funds) of $52 million.
- Higher depreciation and amortization expense of $16 million in the Regulated – Nuclear Generation segment, excluding amortization expense related to balances in OEB-authorized regulatory variance and deferral accounts (regulatory accounts), primarily due to new assets in service.

The expiry of rate riders for the recovery of approved balances in OEB-authorized regulatory accounts on December 31, 2016 contributed to the decrease in revenue for the three months ended September 30, 2017, compared to the same period in 2016, but was largely offset by a decrease in the amortization expense related to these balances. OPG has requested new rate riders in its current application to the OEB for new regulated prices, with a proposed effective date of January 1, 2017.

Significant factor that increased income before interest and income taxes:

- Lower operations, maintenance and administration (OM&A) expenses of $31 million, mainly in the Regulated – Nuclear Generation segment, as a result of a higher materials and supplies obsolescence charge recognized in the third quarter of 2016, Services, Trading and Other Non-Generation segment due to project expenditures incurred in the third quarter of 2016, and Regulated – Hydroelectric segment due to the timing of repairs and maintenance work in 2017 and a deferral of outages during the high water period.

Net interest expense decreased by $7 million during the third quarter of 2017, compared to the same quarter in 2016, primarily due to a higher amount of interest costs capitalized for the Darlington Refurbishment project expenditures and a higher amount of interest costs deferred in OEB-authorized regulatory accounts.

Income tax expense for the three months ended September 30, 2017 was $19 million, compared to $22 million for the same period in 2016. The decrease in income tax expense was primarily due to lower income before taxes and a higher change in reserves from the resolution of uncertainties, partially offset by a lower amount of tax expense deferred in regulatory assets.

Year-To-Date

Net income attributable to the Shareholder was $498 million for the first nine months of 2017, an increase of $49 million compared to the same period in 2016. Income before interest and income taxes for the first nine months of 2017 was $699 million, an increase of $37 million compared to the same period in 2016.

Significant factor that increased income before interest and income taxes:

- Higher earnings of $390 million from the Services, Trading, and Other Non-Generation segment, primarily reflecting the gain on sale of OPG's head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street that was recognized in the second quarter of 2017. The sale of the

assets was required by a Shareholder Declaration and a Shareholder Resolution. The gain on sale was $283 million, which is net of tax effects of $95 million.

Significant factors that reduced income before interest and income taxes:

- Lower earnings from the nuclear base regulated price of approximately $230 million, partially offset by a decrease in nuclear fuel expense of $22 million, reflecting lower electricity generation of 4.0 TWh from the Regulated – Nuclear Generation segment and the continuation of existing base regulated prices set by the OEB in 2014. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS, partially offset by an increase in generation from Pickering GS.
- Lower earnings on the Nuclear Segregated Funds of $41 million.
- Higher depreciation and amortization expense of $30 million in the Regulated – Nuclear Generation segment, excluding amortization expense related to regulatory account balances, primarily due to new assets in service.
- A gain of $22 million recorded in the first quarter of 2016 to reflect the OEB's decision on OPG's motion asking the OEB to review and vary parts of its November 2014 decision on OPG's regulated prices.

The expiry of rate riders for the recovery of approved balances in OEB-authorized regulatory accounts on December 31, 2016 contributed to the decrease in revenue for the nine months ended September 30, 2017, compared to the same period in 2016, but was primarily offset by a decrease in the amortization expense related to these balances.

Net interest expense decreased by $36 million for the nine months ended September 30, 2017, compared to the same period in 2016, primarily due to a higher amount of interest costs capitalized for the Darlington Refurbishment project expenditures and a higher amount of interest costs deferred in OEB-authorized regulatory accounts.

Income tax expense for the nine months ended September 30, 2017 was $128 million, compared to $109 million for the same period in 2016. The increase in income tax expense was primarily due to higher income before income taxes.

Segment Results

The following table summarizes OPG's income before interest and income taxes by business segment. A detailed discussion of OPG's performance by reportable segment is included in the section, *Discussion of Operating Results by Business Segment*.

(millions of dollars)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Income (loss) before interest and income taxes				
Regulated – Nuclear Generation	**20**	47	**(267)**	17
Regulated – Hydroelectric	**122**	117	**474**	500
Contracted Generation Portfolio	**75**	74	**229**	219
Total electricity generation business segments	**217**	238	**436**	736
Regulated – Nuclear Waste Management	**(36)**	18	**(123)**	(70)
Services, Trading, and Other Non-Generation	**(1)**	(8)	**386**	(4)
	180	248	**699**	662

Electricity Generation

Electricity generation for the three and nine month periods ended September 30, 2017 and 2016 was as follows:

(TWh)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Regulated – Nuclear Generation	**11.3**	11.7	**30.6**	34.6
Regulated – Hydroelectric	**7.3**	6.9	**23.5**	22.8
Contracted Generation Portfolio [1]	**0.8**	0.9	**1.9**	2.5
Total OPG electricity generation	**19.4**	19.5	**56.0**	59.9
Total electricity generation by all other generators in Ontario [2]	**16.6**	19.5	**51.7**	53.8

[1] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.
[2] Non-OPG generation is calculated as the Ontario electricity demand plus net exports, as published by the Independent Electricity System Operator (IESO), minus OPG electricity generation.

Total OPG electricity generation decreased by 0.1 TWh during the third quarter of 2017, compared to the same quarter in 2016, and by 3.9 TWh during the nine months ended September 30, 2017, compared to the same period in 2016. As expected, the lower electricity generation from the Regulated – Nuclear Generation segment was primarily the result of the removal from service of Unit 2 at the Darlington GS for the duration of the unit's refurbishment, which began in October 2016. This decrease in electricity generation was largely offset by an increase in generation from the Pickering GS, primarily due to outage optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station, and higher hydroelectric generation from the Regulated – Hydroelectric segment.

The higher electricity generation of 0.4 TWh and 0.7 TWh from the Regulated – Hydroelectric segment for the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016, was due to higher water flows primarily on the eastern Ontario river systems, net of water spilled as a result of SBG conditions, discussed below.

The lower electricity generation of 0.6 TWh from the Contracted Generation Portfolio segment for the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to higher SBG conditions. The electricity generation from the Contracted Generation Portfolio segment for the three months ended September 30, 2017 was comparable to the same period in 2016.

OPG's operating results are impacted by changes in grid-supplied electricity demand resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. For the three and nine month periods ended September 30, 2017, Ontario's electricity demand as reported by the IESO was 33.6 TWh and 98.5 TWh, respectively, compared to 36.7 TWh and 103.8 TWh for the same periods in 2016, respectively, excluding electricity exports out of the province.

Power that is surplus to the Ontario market is managed by the IESO, mainly through generation reductions at hydroelectric, other grid-connected renewable resources and nuclear stations. Reducing hydroelectric production is the first measure used by the IESO to manage SBG conditions. Low demand conditions in Ontario continued to be prevalent in 2017, resulting in forgone hydroelectric generation for OPG of 1.1 TWh and 4.5 TWh due to SBG conditions in the three and nine month periods ended September 30, 2017, respectively, compared to 0.5 TWh and 3.9 TWh during the same periods in 2016, respectively. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions during these periods was offset by the impact of a regulatory variance account authorized by the OEB. OPG did not forgo any electricity production at its nuclear stations due to SBG conditions.

Average Sales Prices

The majority of OPG's generation is from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments. The same base regulated prices for electricity generated by these segments, authorized by the OEB effective November 1, 2014, were in effect during the first nine months of 2017 as in 2016. These prices will remain in effect until such time as the OEB approves new regulated prices based on OPG's current application. **[MONITOR]** The base regulated prices established in 2014 are discussed in OPG's 2016 annual MD&A in the section, *Revenue Mechanisms for Regulated and Non-Regulated Generation*.

The average sales price for the Regulated – Nuclear Generation segment was 5.8 cents per kilowatt hour (¢/kWh) during the three and nine month periods ended September 30, 2017, respectively, compared to 6.9 ¢/kWh during the same periods in 2016. The decrease in the average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized nuclear rate rider of $10.84 per megawatt hour (MWh) for the recovery of variance and deferral account balances. The average sales price for the Regulated – Hydroelectric segment was 4.1 ¢/kWh during the three and nine month periods ended September 30, 2017, respectively, compared to 4.4 ¢/kWh during the same periods in 2016. The decrease in the average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized regulated hydroelectric rate rider of $3.19/MWh for the recovery of variance and deferral account balances. The rate riders were established to recover approved balances recorded in the variance and deferral accounts in prior years. As such, the year-over-year changes in revenue from the rate riders were largely offset by changes in amortization expense related to these balances. There were no rate riders in effect during the nine months ended September 30, 2017 for either nuclear or regulated hydroelectric generation, pending the outcome of OPG's current application with the OEB for new regulated prices.

Cash Flow from Operations

Cash flow provided by operating activities was $485 million for the three months ended September 30, 2017 and $698 million for the nine months ended September 30, 2017, compared to $530 million and $1,211 million for the same periods in 2016, respectively. The decrease in cash flow provided by operating activities was expected and primarily due to lower generation revenue receipts reflecting lower generation from the Regulated – Nuclear Generation segment as a result of the ongoing refurbishment of Unit 2 at the Darlington GS and the expiry, on December 31, 2016, of the OEB-authorized rate riders for nuclear and regulated hydroelectric generation. The decrease in cash flow during the nine months ended September 30, 2017 was also due to higher income tax instalments.

The decrease in cash flow provided by operating activities for the three and nine month periods ended September 30, 2017 was partly offset by lower OM&A expenditures and lower contributions to the Used Fuel Segregated Fund in 2017. Both the Used Fuel Segregated Fund and the Decommissioning Segregated Fund were determined to be fully funded based on an updated estimate of OPG's nuclear waste management and nuclear facilities decommissioning obligations pursuant to a reference plan approved by the Province, for years 2017 to 2021, under the Ontario Nuclear Funds Agreement (ONFA), effective January 1, 2017. Pursuant to the ONFA, the reference plan is required to be updated at least once every five years. Contributions to either or both of the Nuclear Segregated Funds may be required in the future should the funds be in an underfunded position at the time of the next ONFA reference plan update. The year-over-year decrease in cash flow also was partially offset by the payment of a supplemental rent rebate to Bruce Power in the first quarter of 2016 in relation to a period in 2015. The lease agreement for the Bruce nuclear generating stations was amended in late 2015 to eliminate this rebate provision going forward.

Return on Common Equity Excluding Accumulated Other Comprehensive Income

ROE Excluding AOCI is an indicator of OPG's performance consistent with the Company's strategy to provide value to the Shareholder. ROE Excluding AOCI is measured over a 12-month period.

ROE Excluding AOCI was 4.4 percent for the 12 months ended September 30, 2017, compared to 4.2 percent for the 12 months ended December 31, 2016. The increase was primarily due to higher net income attributable to the Shareholder for the 12 months ended September 30, 2017, which reflected the gain on sale of OPG's head office premises and associated parking facility recorded in the second quarter of 2017, partially offset by the lower earnings from the decrease in nuclear electricity generation reflecting the Unit 2 refurbishment outage at the Darlington GS without a corresponding increase in the nuclear base regulated price, as expected. The lower nuclear generation as a result of the refurbishment outage will continue to negatively affect OPG's ROE Excluding AOCI until such time as new regulated prices are approved by the OEB, anticipated in the fourth quarter of 2017. **[MONITOR]**

Funds from Operations Adjusted Interest Coverage

FFO Adjusted Interest Coverage is an indicator of OPG's ability to meet interest obligations from operating cash flows. The indicator is measured over a 12-month period. FFO Adjusted Interest Coverage for the 12 months ended September 30, 2017 was 4.2 times, compared to 5.1 times for the 12 months ended December 31, 2016. FFO Adjusted Interest Coverage in 2017 reflected a year-over-year decrease in FFO before interest due to lower cash flow provided by operating activities, partially offset by the impact of a lower adjusted interest expense due to a decrease in the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets.

The decrease in the excess of interest on pension and OPEB benefit obligations over expected return on pension plan assets in the nine months of 2017 was primarily due to the change in the method used to estimate the interest cost and service cost components of pension and OPEB costs. Effective January 1, 2017, OPG adopted a full yield curve approach to the estimation of these cost components, by applying the specific spot rates along the yield curve used in the determination of the projected benefit obligations to the relevant projected cash flows. Under the previous method, these components of pension and OPEB costs were calculated using the same single weighted-average discount rates as reflected in the calculation of the benefit obligations. This change in the method was accounted for prospectively, as a change in estimate. The resulting reduction in pension and OPEB costs for the three and nine month periods ended September 30, 2017 did not have a material impact on net income as it was largely offset by the impact of OEB-authorized variance and deferral accounts in the regulated business segments. Further details on the full yield curve approach can be found in the 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Pension and Other Post-Employment Benefits*.

Enterprise Total Generating Cost per MWh

The Enterprise TGC per MWh decreased to $46.65 for the three months ended September 30, 2017, compared to $50.72 for the same quarter in 2016. The decrease was mainly due to lower OM&A expenses before the impact of regulatory accounts and higher SBG-adjusted hydroelectric generation reflecting higher water flows.

The Enterprise TGC per MWh was $47.77 for the nine months ended September 30, 2017, an increase compared to $46.74 for the same period in 2016. The increase was expected and mainly a result of lower electricity generation due to the Unit 2 refurbishment outage at the Darlington GS, largely offset by lower OM&A expenses before the impact of regulatory accounts and higher SBG-adjusted hydroelectric generation reflecting higher water flows.

If Unit 2 at the Darlington GS was not currently undergoing refurbishment and had continued to operate in a manner consistent with the performance of the remaining units at the Darlington GS, adjusting for generation constraints on these units related to the transition of the station toward refurbishment, the Enterprise TGC would have been approximately $4 per MWh lower for both the three and nine month periods ended September 30, 2017. This sensitivity was calculated using the estimated incremental electricity and associated fuel cost that are expected to have resulted in the absence of the refurbishment.

Nuclear Total Generating Cost per MWh

The Nuclear TGC per MWh was $58.75 for the three months ended September 30, 2017, which was comparable to $58.55 for the same quarter in 2016. For the three months ended September 30, 2017, the higher generation at the Pickering GS and the impact of lower OM&A expenses before the impact of regulatory accounts was mostly offset by the expected decrease in nuclear electricity generation reflecting the Unit 2 refurbishment outage at the Darlington GS and higher sustaining capital expenditures. The Nuclear TGC per MWh was $67.87 for the nine months ended September 30, 2017, compared to $61.07 for the same period in 2016. The increase in the Nuclear TGC per MWh for the nine months ended September 30, 2017 was expected and primarily due to the decrease in nuclear electricity generation, partially offset by lower OM&A expenses before the impact of regulatory accounts.

Hydroelectric Total Generating Cost per MWh

The Hydroelectric TGC per MWh was $26.20 for the three months ended September 30, 2017, compared to $31.01 for the same quarter in 2016. The decrease was primarily due to higher SBG-adjusted hydroelectric electricity generation reflecting higher water flows. The Hydroelectric TGC per MWh was $21.74 for the nine months ended September 30, 2017, compared to $23.99 for the same period in 2016. The decrease was primarily due to lower OM&A expenses before the impact of regulatory accounts and lower sustaining capital expenditures.

ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are not measurements in accordance with US GAAP and should not be considered alternative measures to net income, cash flow provided by operating activities, or any other performance measure under US GAAP. OPG believes that these non-GAAP financial measures are effective indicators of its performance and are consistent with the Company's strategic imperatives and related objectives. The definition and calculation of ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are found in the section, *Supplementary Non-GAAP Financial Measures*.

Recent Developments

Ontario's 2017 Long Term Energy Plan

On October 26, 2017, Ontario's Ministry of Energy issued the 2017 Long Term Energy Plan. The Plan is currently being analyzed by OPG but is not expected to significantly impact OPG's business. There are no fundamental changes from the principles in the 2013 Long Term Energy Plan, which include cost effectiveness, reliability, clean energy and community engagement. The 2017 Long Term Energy Plan fully supports nuclear refurbishment projects in Ontario and the extension of commercial operation of all Pickering units to 2024. **[MONITOR & UPDATE DETAILS FOLLOWING RELEASE]**

OEB's Decision on New Regulated Prices **[MONITOR]**

Ontario's Fair Hydro Plan

OPG continues to prepare for its involvement as the Financial Services Manager for Ontario's Fair Hydro Plan (the Fair Hydro Plan) on a commercial basis. Accordingly, the financing entity was established in XX 2017 as the Fair Hydro Trust (the Trust), following the execution of its constating documents. The majority unitholder and beneficiary of the Trust is a wholly-owned subsidiary of OPG. Through this ownership and OPG's control over the key activities of the Trust, the Company will consolidate the Trust for accounting purposes commencing in the fourth quarter of 2017. **[MONITOR]**

In order for the Trust to provide financing for the deferred Global Adjustment costs, the Trust will incur senior debt from capital markets and subordinated debt from OPG. The Trust is structured to be bankruptcy remote and ring fenced from OPG to protect the Company's assets and operations. In support of the Fair Hydro Plan, the following developments have transpired:

- In October 2017, *Ontario Regulation 206/17 General* was amended to establish details of the recovery mechanism for the monthly carrying costs incurred by the Trust from June 1, 2017 to July 31, 2021 payable by the IESO to the Trust. Originally established in June 2017, this regulation provides more details on the funding obligations incurred by the Trust and the fair allocation amount, the determination and collection of clean energy adjustments, the determination of the finance amount, the true up amount, and the regulatory asset, as well as principles and assumptions relating to the financing plan.
- A plan to amend the Company's Articles of Amalgamation to allow for the creation and issuance of Class A shares to be issued to the Province for its equity investment through OPG in the Fair Hydro Plan is in progress. The Province is expected to provide 44 percent of the total funding requirement related to the deferred Global Adjustment costs, which OPG will invest as subordinated debt into the Trust. OPG's Board approval and a Shareholder Resolution are expected later in the year to authorize the amendment.
- OPG is expected to provide five percent of the total funding requirement of the Trust related to the deferred Global Adjustment costs of the Fair Hydro Plan. OPG issued senior notes payable in October 2017 under a short form base shelf prospectus for general corporate purposes and to fund OPG's subordinated debt investment in the Trust. Further details of the debt offering can be found in the section, *Liquidity and Capital Resources* under the heading, *Financing Activities*.

The first set of transactions of the Trust are expected to take place in the fourth quarter of 2017.

Canadian Nuclear Safety Commission Safety Rating for the Darlington GS and the Pickering GS

The Canadian Nuclear Safety Commission (CNSC) publishes an annual report on the safety performance of Canada's nuclear power plants. The report assesses how well plant operators are meeting regulatory requirements and program expectations in the areas of operational performance, safety analysis, radiation protection, waste management and conventional health and safety. On September 8, 2017, the CNSC issued an executive summary of its 2016 annual report. The CNSC gave both the Darlington GS and the Pickering GS the highest possible safety rating of "Fully Satisfactory". The Darlington GS achieved this rating for the eighth consecutive year, while the Pickering GS achieved this rating for the second consecutive year.

CORE BUSINESS, STRATEGY, AND OUTLOOK

The discussion in this section is qualified in its entirety by the cautionary statements included in the section, *Forward-Looking Statements,* at the beginning of the MD&A.

OPG's mission is to provide low cost power in a safe, clean, reliable and sustainable manner for the benefit of customers and its Shareholder. OPG also seeks to pursue, on a commercial basis, generation development projects and other business growth opportunities.

The following sections provide an update to OPG's disclosures in the 2016 annual MD&A related to its four key strategic imperatives – operational excellence, project excellence, financial strength, and social licence. A detailed discussion of these strategic imperatives is included in the 2016 annual MD&A in the section, *Core Business, Strategy, and Outlook*.

Operational Excellence

Operational excellence at OPG is accomplished by the safe and environmentally responsible generation of reliable and cost-effective electricity from the Company's generating assets through a highly trained and engaged workforce.

Electricity Generation Production and Reliability

- As part of the plan to extend Pickering operations, OPG is continuing to undertake the required technical work to confirm that the station's pressure tubes, a key life-limiting component of the station, will remain fit for service for operation to 2024. OPG is also nearing completion of component condition assessments to identify the work required to support the continued operation of the station. The accounting end of life assumptions for the Pickering GS, currently set at the end of 2020, will be reassessed based on the fuel channel analysis and safety case consistent with submissions for the CNSC approval, discussed below. The activities completed to date have had positive results, which will go towards re-confirming Pickering operations past 2020 are technically feasible. The Periodic Safety Review (PSR) is in progress and will confirm that extending operations of the Pickering units will be safe to the public, workers and the environment. The PSR consists of Safety Factor Reports (SFRs), a Global Assessment Report (GAR), and the Integration Improvement Plan (IIP). SFRs have been submitted to the CNSC and the GAR and IIP are on track for CNSC submission in October and November 2017, respectively. Other technical feasibility activities continue to progress as planned. Completion of various technical feasibility assessments are required to reach a high confidence conclusion to allow the station end of life to change for depreciation purposes. OPG's current application with the OEB for new base regulated prices, currently pending the OEB's decision, reflects OPG's plans to extend Pickering operations to 2024 and requests inclusion of the corresponding cost and generation impacts in the determination of the nuclear regulated price.
- OPG's current five-year operating licence for the Pickering GS was approved by the CNSC in 2013 and expires on August 31, 2018. This licence was issued assuming that the station would shut down in 2020. On June 28, 2017, OPG confirmed to the CNSC that it intends to cease commercial operation of all Pickering units on December 31, 2024. On August 28, 2017, OPG submitted a ten-year licence renewal application to the CNSC. The licence term spans the planned extended operations period, through to the end of commercial operation, defueling, dewatering and the start of placing the station in a safe storage state.
- Work continues on the rehabilitation of Unit 2 of the DeCew Falls hydroelectric GS and the rehabilitation and overhaul of Unit 2 of the Lower Notch hydroelectric GS.
- During the third quarter, a new control centre was opened at Saunders GS to merge its operations with Chenaux GS. The new control centre will overlook power production at ten hydroelectric stations along the Madawaska, Ottawa and St. Lawrence rivers.
- As part of the process to decommission the Nanticoke and Lambton generating stations, OPG has begun executing demolition plans that will ensure that the stations are closed safely, securely and in an environmentally responsible manner. The demolition of the Nanticoke coal yard equipment and structures is in progress, with a contract issued in July 2017 for the demolition of the Nanticoke powerhouse and associated structures. Project milestones for the Nanticoke site during the remainder of 2017 include completing the removal of coal yard equipment and structures, demolition of the ash silos, and mobilization of the contractor to prepare for removal of the stacks, powerhouse and associated structures. A competitive bidding process for the demolition of the Lambton GS has been completed, with a contract for the removal of the powerhouse and associated buildings expected to be awarded in 2018. An update of the associated asset retirement obligations related to the Nanticoke and Lambton sites is expected to be finalized in the fourth quarter of 2017.

Environmental Performance

There were no significant changes to environmental legislation affecting the Company during the third quarter of 2017. Disclosures related to the Company's environmental policy and environmental risks can be found in OPG's 2016 annual MD&A.

OPG communicates its environmental performance internally to employees and to external stakeholders, including the Ontario Ministry of the Environment and Climate Change, Environment and Climate Change Canada, the CNSC, and local communities. Details of OPG's environmental performance and initiatives to fulfill the Company's Environmental Policy can be found in OPG's 2016 Sustainability Report, available on the Company's website at www.opg.com. **[MONITOR]**

Project Excellence

OPG is pursuing a number of generation development and other major projects in support of Ontario's electricity planning initiatives. OPG remains focused on delivering projects safely, on time, on budget and with high quality. The status updates for OPG's major projects as at September 30, 2017 are outlined in the following table, with further details below.

Project	Capital expenditures		Approved budget	Expected in-service date	Current status
(millions of dollars)	Year-to-date	Life-to-date			
Darlington Refurbishment	924	4,109	12,800 [1]	First unit - 2020 Last unit - 2026	The setup of specialized tooling and equipment needed for the removal of reactor components was completed in the third quarter of 2017. All feeder tubes have been removed safely, and the pressure tubes have been severed in preparation for their removal. The Re-tube Waste Processing Building will be available for use in the fourth quarter of 2017. The project is tracking on schedule and on budget.
Peter Sutherland Sr. Hydroelectric GS	38	274	300	2017	The station was placed in-service on March 31, 2017, ahead of the originally planned schedule, and is expected to close below the approved budget. Project close-out activities are in progress.
Ranney Falls Hydroelectric GS	17	20	77	2019	Work is progressing on the expanded forebay, forebay wall concrete replacement, powerhouse and spillway areas. The project is tracking on schedule and on budget.
Nanticoke Solar Facility	1	2	107 **[MONITOR]**	2019	Project definition work is continuing, with construction planned to commence in the first quarter of 2018.
Deep Geologic Repository for low and intermediate level radioactive waste (L&ILW)	7 [2]	202 [2]			On August 21, 2017, the federal Minister of Environment and Climate Change requested further information on the project's environmental assessment (EA). OPG is reviewing the new request and will notify the Canadian Environmental Assessment Agency (CEAA) when it has a timeline for submission of that information.

[1] The total project budget of $12.8 billion is for the refurbishment of all four units at the Darlington GS.
[2] Expenditures are charged against the nuclear fixed asset removal and nuclear waste management liabilities (Nuclear Liabilities).

Darlington Refurbishment

The Darlington generating units are approaching their originally designed end-of-life. Refurbishment of the four generating units is expected to extend the operating life of the station by approximately 30 years. OPG commenced the planning of the refurbishment in 2010.

In 2016, the Darlington Refurbishment project transitioned from the planning phase to the execution phase, as OPG commenced the refurbishment of the first unit, Unit 2, in October 2016, as planned. The unit was taken offline on October 15, 2016. De-fuelling of the reactor, the first critical refurbishment activity undertaken once the unit is removed from service, was completed safely in January 2017, with a total of 480 fuel channels de-fuelled. Islanding of Unit 2, the physical separation of the unit under refurbishment from the three operating units, was completed in April 2017, signifying the completion of the first major segment of the project.

The second major segment includes preparatory work to support the removal of feeder tubes and fuel channel assemblies and the removal of reactor components. The preparatory work was completed in the second quarter of 2017. The Re-tube Tooling Platform for hosting the tooling for the removal, inspection, and installation activities and the setup of specialized tooling and equipment needed for the removal and replacement of the reactor components were completed in the third quarter of 2017. The disassembly of reactor components commenced in August 2017, with the removal of all 960 feeder tubes completed safely in September 2017. This was followed by the severing of pressure tubes, with the severing of bellows and the removal of end fittings expected to commence thereafter and through the end of 2017. Other key project activities executed during the second segment include the completion of the primary side steam generator layup, installation of steam generator access ports to support future inspections, continuation of the major turbine generator overhaul and continued execution of the major electrical scope. OPG is also continuing to execute work to support the requirements set out in the CNSC approved IIP for the station.

Once refurbished, Unit 2 is scheduled to be returned to service in the first quarter of 2020, at which time capital expenditures of approximately $4.8 billion are planned to be placed in service. This includes expenditures incurred during the definition and planning phase of the overall project. The project is tracking on schedule and on budget.

With the substantial completion of the Re-tube Waste Processing Building in November 2017, 17 out of 18 pre-requisite projects in support of the execution phase of the project, including construction of facilities, infrastructure upgrades and installation of safety enhancements, have been completed and placed in service. Completion of the Heavy Water Storage and Drum Handling Facility (HWSF) has been delayed due to challenges with construction. OPG suspended the project in the second quarter of 2017 to evaluate the best approach to optimize cost and schedule and complete the project. Construction activities for the HWSF recommenced in the fourth quarter of 2017 following substantial completion of the Re-tube Waste Processing Building. This plan ensures that the necessary resources are available for both projects and, through resource levelling, improves their execution and cost efficiency. The delay in the completion of the HWSF will not impact the overall Darlington Refurbishment project schedule, as the HWSF is not on the project's critical path. This also will not impact the overall project budget of $12.8 billion, as the costs of the HWSF are included in this total figure. The recovery of HWSF costs through regulated prices will be subject to a prudence review by the OEB, which OPG has proposed be conducted as part of a future OEB application.

In addition to the execution of refurbishment activities on Unit 2, OPG is continuing planning activities for the refurbishment of the second unit, Unit 3, and is entering into associated commitments to procure major components that require long lead times. As of September 30, 2017, $70 million has been invested in planning activities related to the refurbishment of the second unit, Unit 3. These planning activities are being undertaken in accordance with the refurbishment project schedule.

The Financial Accountability Office of Ontario has issued a report titled "*An Assessment of the Financial Risks of the Nuclear Refurbishment Plan*". The report assesses both OPG and Bruce Power's refurbishment activities and the method in which those refurbishments and subsequent nuclear generation is provided to the marketplace. The report

concludes that the base case of refurbishing the six units at the Bruce nuclear GS and the four units at the Darlington nuclear GS provide the most cost effective, low emission generation source available to meet Ontario's baseload electricity requirements. This report re-affirms the positive economic and societal benefits associated with a strong nuclear program in the Province. **[MONITOR]**

Ranney Falls Hydroelectric GS

During the third quarter of 2017, OPG continued construction work for a 10 MW single-unit powerhouse on the existing Ranney Falls GS site, as part of the Regulated – Hydroelectric segment. The new unit will replace an existing unit that reached its end of life in 2014. The existing forebay structure demolition has been completed and the upstream cofferdam has been constructed ahead of schedule. Construction continues on the expanded forebay, powerhouse and spillway. Excavation work is substantially complete and forebay wall concrete replacement is in progress. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget.

Nanticoke Solar Facility

The construction of a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands under a Large Renewable Procurement contract with the IESO, through Nanticoke Solar LP, a partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation, is planned to commence in the first quarter of 2018. During the third quarter of 2017, the partnership continued work to obtain approvals and permits required to enable the commencement of construction, and progressed procurement activities for equipment and for engineering and construction services. The facility is expected to be completed in the first quarter of 2019.

Deep Geologic Repository for Low and Intermediate Level Waste

OPG has proposed a deep geologic repository as the preferred solution for the safe long-term management of the L&ILW produced from the continued operation of OPG-owned nuclear generating stations. Agreement has been reached with local municipalities for OPG to develop the L&ILW Deep Geologic Repository (DGR) on lands adjacent to the Western Waste Management Facility (WWMF) in Kincardine, Ontario. The environmental effects of the proposed L&ILW DGR were examined by the CNSC and CEAA-appointed Joint Review Panel (JRP) to meet the requirements of the Canadian Environmental Assessment Act. The JRP submitted its report on the EA to the federal Minister of Environment in May 2015, concluding that, given mitigation, there is unlikely to be significant environmental impact from the project and recommending that the Minister approve the EA. In December 2016, at the request of the federal Minister of Environment and Climate Change, OPG submitted additional information on certain aspects of the EA, including information related to alternate locations for the project. Following its review of OPG's submission and a period of public comment, the CEAA requested further information that OPG subsequently provided in May 2017. In June 2017, the CEAA notified OPG that it had sufficient and adequate information to proceed with the next step of the environmental assessment process and advised that a draft report and updated terms and conditions will be prepared for public review.

On August 21, 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of potential cumulative effects of the project on the Saugeen Ojibway Nations' (SON) physical and cultural heritage, including a description of the potential effects of the project on the Nation's spiritual and cultural connection to the land. OPG is assessing the request and will notify the CEAA when it has determined the timeline for developing a response. The CEAA's draft report for public review will not be issued until this update is provided. The L&ILW DGR at the WWMF site remains OPG's preferred solution for the safe long-term management of the L&ILW.

OPG continues its engagement with the SON toward securing community support for the L&ILW DGR. The in-service date of the L&ILW DGR is expected to be approximately six to seven years from the start of construction.

Financial Strength

As a commercial enterprise, OPG's financial priority is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future growth.

Increase Revenue, Reduce Costs and Achieve Appropriate Return

In May 2016, OPG filed a 5-year application with the OEB for new regulated prices for production from its regulated hydroelectric and nuclear facilities, with a proposed effective date of January 1, 2017. Consistent with the requirements of *Ontario Regulation 53/05*, the application incorporates a rate smoothing proposal that would defer, for future collection, a portion of the approved annual nuclear revenue requirement for the period from January 1, 2017 to the end of the Darlington Refurbishment project, with a view to making changes in OPG's regulated prices more stable year-over-year. The application seeks to ensure that nuclear regulated prices under the rate smoothing approach allow for sufficient cash flow to meet the Company's liquidity needs, support cost effective funding for the Darlington Refurbishment project and other expenditures, and maintain the Company's investment grade credit rating, while taking into account both near-term and future impacts on customers. OPG expects to recognize amounts deferred under rate smoothing as income in the periods to which the underlying approved revenue requirements relate.

The application will further challenge and incentivize OPG to find additional cost reductions and efficiencies within its operations, as a result of greater de-coupling of nuclear and hydroelectric regulated prices from costs and a longer rate-setting period under the OEB's incentive ratemaking framework, which forms the basis for the ratemaking methodologies reflected in the application.

The application seeks an increase in the nuclear rate base, effective in early 2020, to reflect the planned placement in service of approximately $4.8 billion of capital expenditures upon the scheduled return to service of Unit 2 at the Darlington GS as part of the Darlington Refurbishment project and, effective in 2017, an increase in the deemed capital structure applied to the total regulated rate base to 49 percent equity and 51 percent debt, from 45 percent equity and 55 percent debt reflected in the existing regulated prices. The application also requests new rate riders, effective January 1, 2017, to recover or repay the December 31, 2015 balances in all of the Company's OEB-authorized variance and deferral accounts, with the exception of the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the portion of these balances previously approved for recovery or repayment through rate riders that were in effect during 2016.

The OEB's decision on the application, including the effective date of approved new regulated prices, is expected later in 2017. **[MONITOR]**

For generation assets that do not form part of the assets regulated by the OEB, OPG's strategy has been to secure appropriate long-term revenue arrangements. In line with this strategy, virtually all of OPG's non-regulated operating facilities and assets under construction are subject to long-term Energy Supply Agreements (ESAs) or other long-term contracts with the IESO.

Ensure Availability of Cost Effective Funding

In April 2017, DBRS Limited (DBRS) re-affirmed the long-term credit rating on OPG's debt at 'A (low)' and OPG's commercial paper rating at 'R-1 (low)'. All ratings from DBRS have a stable outlook. In July 2017, S&P Global Ratings (S&P) re-affirmed OPG's long-term credit rating at 'BBB+' with a stable outlook. S&P's commercial paper rating for OPG is 'A-1 (low)'.

Social Licence

As the largest electricity generator in Ontario with diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust. OPG is committed to maintaining high standards of public safety and corporate citizenship, including environmental stewardship, transparency, community engagement, and Indigenous relations.

OPG is focused on building long-term, mutually beneficial working relationships with Indigenous communities, businesses and organizations across Ontario, and continues to support procurement, employment and educational opportunities with its Indigenous community partners. The Company seeks to establish these relationships based on a foundation of respect for the languages, customs, and political, social and cultural organizations of the Indigenous communities.

In June 2017, OPG launched an Indigenous Business Engagement (IBE) Initiative. The purpose of this initiative is to increase access to procurement opportunities for Indigenous businesses interested in supplying materials and services to OPG. The IBE Initiative is based on a strategy that will identify opportunities in contracts, scopes of work and business plans for potential Indigenous business engagement; include criteria related to suppliers' ability to engage or partner with Indigenous people or businesses in assessing procurement proposals; and invest in relationships with Indigenous communities by increasing outreach efforts to enhance understanding of how to do business with OPG. OPG has continued to engage with various Indigenous business and communities as well as its suppliers to promote the IBE Initiative. In September 2017, OPG presented the IBE to the Mohawk Council of Akwesanse (Akwesanse). As a result, Akwesanse plans to create a database of businesses in the community that will participate in contracting and supply opportunities with OPG. In September 2017, OPG also hosted a similar presentation to the Williams Treaties First Nations, located proximate to the Pickering and Darlington Nuclear Generating Stations, at the quarterly meeting for these communities.

OPG is developing recruitment plans targeting Indigenous people. In October 2017, OPG participated in five Indigenous-specific career fairs to attract such talent. **[MONITOR]**

OPG has a transportation electrification strategy that will help position OPG as a leader in transportation electrification in Ontario. This strategy is intended to leverage OPG's clean electricity to support action on climate change, create growth opportunities for OPG, and enhance OPG's brand and social licence.

Outlook

The financial performance of OPG's regulated operations is driven, in large part, by the outcome of applications for regulated prices to the OEB. The existing base regulated prices were established by the OEB effective November 1, 2014 based on a forecast of costs and production for the regulated facilities for the 2014 to 2015 period. The future outcome of OPG's current application for new regulated prices, currently pending the OEB's decision, is expected to provide substantial price certainty for the regulated business for the 2017 to 2021 period.

In its application, OPG has requested January 1, 2017 as the effective date for the new regulated prices. In December 2016, the OEB issued an order declaring the existing base regulated prices interim, which preserves the OEB's ability to make the new regulated prices effective as early as January 1, 2017. Considering the timing of OPG's application and OPG's procedural adherence throughout the proceeding, the Company believes that the OEB could make the new regulated prices effective January 1, 2017. This would allow OPG to recover the difference between the approved new regulated prices and the existing regulated prices for the period between January 1, 2017 and the implementation date of the new prices based on the OEB's order. The OEB's decision on the application, including the effective date of the new regulated prices, is expected in the fourth quarter of 2017. **[MONITOR]** The continuation of existing regulated prices until the issuance of the OEB's decision is expected to continue to contribute to lower income, particularly from the Regulated – Nuclear Generation segment, and, excluding the gain on sale of the Company's head office premises and associated parking facility recorded in the second quarter of 2017, lower

ROE Excluding AOCI during 2017, compared to 2016. In large part, this is due to the year-over-year reduction in nuclear electricity generation resulting from the Unit 2 refurbishment outage at the Darlington GS, given that the existing nuclear regulated prices were determined in 2014 based on a higher production forecast that reflected the operation of all four units at the station. As such, the OEB's decision on the effective date of the new regulated prices, as well as the timing of the decision issuance, could have a significant impact on OPG's financial results during 2017.

Nuclear base regulated prices resulting from OPG's current application will be subject to a rate smoothing mechanism that defers collection of a portion of OEB-approved revenues to future periods. As expected, combined with the expiry of rate riders in effect to the end of 2016, a year-over-year reduction in nuclear generation due to the Unit 2 refurbishment outage at the Darlington GS and the continuation of existing regulated prices until such time as new prices are implemented by the OEB, this will result in lower cash flow from operating activities in 2017, compared to 2016. OPG expects to continue to have the necessary financial capacity and sufficient access to cost effective financing sources to continue to fund its capital requirements and other disbursements.

Lower nuclear generation due to the Darlington Refurbishment outages will continue, as planned, to negatively impact the Enterprise TGC metric for the duration of the refurbishment project. Variability in sustaining capital investment expenditures, including major sustaining projects for the hydroelectric operations, also will impact the Enterprise TGC in future periods.

Several OEB-authorized regulatory variance and deferral accounts currently in place contribute to reducing the relative variability of the Company's income and ROE Excluding AOCI. Among others, the regulatory accounts include those related to the revenue impact of variability in water flows and forgone production due to SBG conditions at the regulated hydroelectric stations. As there are no variance or deferral accounts in place related to the impact of generation performance of the nuclear stations on revenue from base regulated prices, the Regulated – Hydroelectric segment generally is expected to produce overall more predictable earnings. OPG continues to operate and maintain its nuclear facilities with a view to optimize their performance and availability, while focusing on improving the overall reliability and predictability of the fleet.

Electricity generated from most of OPG's non-regulated assets is subject to ESAs with the IESO. Based on these agreements, OPG expects the Contracted Generation Portfolio segment to continue to contribute a generally stable level of earnings and cash flow from operations going forward.

OPG's total forecast capital expenditures for the 2017 year are approximately $2.0 billion. This includes amounts for the Darlington Refurbishment project, hydroelectric and other development projects including the completion of the Peter Sutherland Sr. GS and the expansion of the Ranney Falls GS, and sustaining capital investments across the generating fleet. OPG's major projects are discussed in the section, *Project Excellence*.

In addition to the operating and financial performance of the electricity generation business, OPG's results are affected by the earnings on the Nuclear Segregated Funds, which are reported in the Regulated – Nuclear Waste Management segment. While the Nuclear Segregated Funds are managed to achieve, in the long term, the target rate of return based on the discount rate specified in the ONFA, the rates of return earned in a given period can be subject to various external factors including financial market conditions and, for the portion of the Used Fuel Segregated Fund guaranteed by the Province under the ONFA, changes in the Ontario consumer price index (CPI). In the near term, these factors can be volatile and cause fluctuations in the Company's income. This volatility is partially mitigated by the impact of the OEB-authorized Bruce Lease Net Revenues Variance Account and, as discussed below, the funded status of the two segregated funds.

As OPG does not have the right to withdraw surplus amounts from the Nuclear Segregated Funds, OPG limits the amount of Nuclear Segregated Funds assets reported on the balance sheet to the present value of such life cycle funding liability. This reduces the volatility of earnings on the Nuclear Segregated Funds reflected in net income when the funds are in a fully funded or overfunded position. As at September 30, 2017, the Decommissioning

Segregated Fund was overfunded by approximately 23 percent, and the Used Fuel Segregated Fund was marginally overfunded, by less than one percent, based on the 2017 ONFA Reference Plan. Variability in asset performance due to volatility inherent in financial markets and changes in Ontario CPI, or changes in funding liability estimates, may result in either or both funds becoming underfunded in the future.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

Regulated – Nuclear Generation Segment

(millions of dollars) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Revenue	**739**	885	**2,000**	2,631
Fuel expense	**81**	79	**217**	239
Gross margin	**658**	806	**1,783**	2,392
Operations, maintenance and administration	**511**	521	**1,693**	1,665
Depreciation and amortization	**116**	230	**333**	691
Property taxes	**7**	6	**20**	19
Income (loss) before other losses, interest, and income taxes	**24**	49	**(263)**	17
Other losses	**4**	2	**4**	-
Income (loss) before interest and income taxes	**20**	47	**(267)**	17

For the three and nine month periods ended September 30, 2017, the segment earnings decreased by $27 million and $284 million, respectively, compared to the same periods in 2016. The decrease in earnings was expected and primarily due to reduced revenue from the nuclear base regulated price of approximately $24 million and $230 million, respectively. The decrease was partially offset by an associated year-over-year decrease in fuel expense. The decrease in revenue during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, reflected lower electricity generation of 0.4 TWh and 4.0 TWh, respectively, primarily due to the ongoing Unit 2 refurbishment outage at the Darlington GS that began in October 2016, without a corresponding increase in the base regulated price. The existing nuclear base regulated price set by the OEB in 2014 continues to be in effect pending the OEB's decision on OPG's application for new regulated prices, proposed to be effective on January 1, 2017. The existing price does not reflect the lower generation as a result of the Darlington Refurbishment project, as it was set to allow the Company to recover its approved nuclear costs over a higher nuclear production volume, based on the 2014 and 2015 outage profile that did not include a refurbishment outage. The reduction in nuclear electricity generation for the three months ended September 30, 2017 was largely offset by the higher electricity generation from the Pickering GS.

OM&A expenses decreased by $10 million during the third quarter of 2017, compared to the same period in 2016, as a result of a higher materials and supplies obsolescence charge recognized in 2016. OM&A expenses increased by $28 million during the nine months ended September 30, 2017, compared to the same period in 2016, due to planned maintenance activities in 2017.

Depreciation and amortization expense, excluding amortization expense related to regulatory account balances, increased by $16 million and $30 million during the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016, primarily due to new assets in service.

The expiry of an OEB-authorized nuclear rate rider on December 31, 2016 contributed to the decrease in segment revenue for the three and nine month periods ended September 30, 2017, compared to the same periods in 2016. As rate riders allow for recovery of approved balances in OEB-authorized regulatory accounts, this decrease in revenue was largely offset by a decrease in amortization expense related to these balances. There was no rate rider

in effect during the nine months ended September 30, 2017, pending the outcome of OPG's current application to the OEB for new regulated prices.

The Unit Capability Factors for the Darlington and Pickering generating stations were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Unit Capability Factor *(%)* [1]				
Darlington GS	**96.2**	89.6	**82.1**	87.6
Pickering GS	**88.7**	77.3	**83.8**	73.8

[1] The nuclear Unit Capability Factor excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS was excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

The Unit Capability Factor at the Darlington GS increased in the third quarter of 2017, compared to the same quarter in 2016, primarily due to the lower number of planned outage days during the third quarter of 2017. The lower Unit Capability Factor at the Darlington GS for the nine months ended September 30, 2017, compared to the same period in 2016, reflected the higher number of planned outage days, largely driven by constraints related to the transition of the station toward refurbishment.

The increase in Unit Capability Factor at the Pickering GS for the three and nine month periods ended September 30, 2017 was primarily due to outage optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station compared to 2016.

Regulated – Nuclear Waste Management Segment

(millions of dollars) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Revenue	**33**	36	**90**	102
Operations, maintenance and administration	**35**	38	**96**	108
Accretion on nuclear fixed asset removal and nuclear waste management liabilities	**230**	228	**696**	684
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(196)**	(248)	**(579)**	(620)
(Loss) Income before interest and income taxes	**(36)**	18	**(123)**	(70)

The segment loss before interest and income taxes was $36 million and $123 million during the three and nine months ended September 30, 2017, respectively, a decrease in earnings of $54 million and $53 million compared to the same periods in 2016. The decline in earnings was primarily due to lower earnings from the Nuclear Segregated Funds, net of the impact of the impact of the Bruce Lease Net Revenues Variance Account, reflecting higher earnings from market returns on fund assets and the CPI-adjusted rate of return guaranteed by the Province for the portion of the Used Fuel Segregated Fund related to the initial 2.23 million used fuel bundles (committed return) in the third quarter of 2016.

As both the Decommissioning Segregated Fund and the Used Fuel Fund were in an overfunded position during the three and nine months period ended September 30, 2017, compared to the underlying funding liabilities per the approved ONFA Reference Plan, the earnings on the funds during these periods reflected the growth rate in the present value of the funding liabilities and were not impacted by market returns and committed return. The higher earnings on both funds during the three and nine months periods ended September 30, 2016 reflected market returns and committed return, as the Decommissioning Segregated Fund became over 120 percent funded during the third quarter of 2016 while the Used Fuel Fund was underfunded, compared to the corresponding funding liabilities.

Higher market returns and committed return in the third quarter of 2016 in relation to the funding liabilities' growth rate reflected in fund earnings during 2017 resulted in a year-over-year decrease in the amount of earnings on the Nuclear Segregated Funds.

As of December 31, 2016, OPG recorded a decrease of approximately $1,570 million to the Nuclear Liabilities and associated asset retirement costs capitalized as part of the carrying value of the nuclear generating stations. The resulting year-over-year decreases in accretion on fixed asset removal and nuclear waste management liabilities recorded in the Regulated – Nuclear Waste Management segment and depreciation and fuel expenses recorded in the Regulated – Nuclear Generation segment during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, were offset by the impact of the Bruce Lease Net Revenues Variance Account and the Nuclear Liability Deferral Account authorized by the OEB.

Under the current OEB-approved cost recovery methodology, these changes in expenses also are not expected to materially affect OPG's income during the rest of 2017, as they are expected to continue to be largely offset by the impact of the regulatory accounts until such time as the OEB implements corresponding changes to OPG's nuclear regulated prices, and subsequently by the impact of such new regulated prices. Further details on the change in the estimate of the Nuclear Liabilities as of December 31, 2016 are described in OPG's 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Asset Retirement Obligation*. **[MONITOR]**

Regulated – Hydroelectric Segment

(millions of dollars) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Revenue [1]	**327**	350	**1,069**	1,148
Fuel expense	**88**	88	**258**	259
Gross margin	**239**	262	**811**	889
Operations, maintenance and administration	**81**	87	**232**	238
Depreciation and amortization	**34**	56	**103**	169
Property tax	**1**	1	**1**	1
Income before other losses (gains), interest and income taxes	**123**	118	**475**	481
Other losses (gains)	**1**	1	**1**	(19)
Income before interest and income taxes	**122**	117	**474**	500

[1] During the three and nine month periods ended September 30, 2017, the Regulated – Hydroelectric segment revenue included incentive payments of $4 million and $9 million, respectively, related to the OEB-approved hydroelectric incentive mechanism (three and nine month periods ended September 30, 2016 – incentive payments of $6 million and $8 million, respectively). The mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers. The incentive payments are reduced to remove incentive revenues arising in connection with SBG conditions.

The increase in segment income before interest and income taxes of $5 million during the third quarter of 2017, compared to the same quarter in 2016, was primarily the result of a decrease in OM&A expenses, mainly due to the timing of repairs and maintenance work in 2017 and a deferral of outages during the high water period.

The decrease in segment income before interest and income taxes of $26 million during the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to a gain of $22 million recognized during the first quarter of 2016 to reflect the OEB's January 2016 decision to reverse a portion of an earlier capital cost disallowance related to the Niagara Tunnel project expenditures, in response to a motion by OPG. The income impact of OEB-approved variance accounts also contributed to the year-over-year decrease in income for the period. These factors were partially offset by the decrease in OM&A expenses related to the timing of repairs and maintenance work in 2017 and a deferral of outages during the high water period.

The decrease in revenue from the segment for the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was largely due to the expiry of an OEB-authorized rate rider on

December 31, 2016. As the rider allowed for the recovery of approved balances in OEB-authorized regulatory accounts, the resulting reduction in revenue was largely offset by lower amortization expense related to these balances. There was no rate rider in effect during the first nine months of 2017 pending the outcome of OPG's current application to the OEB for new regulated prices.

The Hydroelectric Availability for the stations included in the Regulated – Hydroelectric segment was as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Hydroelectric Availability *(%)*	**87.6**	84.1	**89.0**	89.8

The Hydroelectric Availability in the third quarter of 2017 was higher compared to the same period in 2016, primarily due to a higher number of planned outages in 2016 as a result of the refurbishment of the Sir Adam Beck Pump GS reservoir between April 2016 and February 2017. The marginal decrease in Hydroelectric Availability during the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to a higher number of unplanned outage days at the Northwestern Ontario and Niagara region hydroelectric stations, partially offset by higher availability from the Sir Adam Beck Pump GS.

Contracted Generation Portfolio Segment

(millions of dollars) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Revenue	**141**	149	**431**	431
Fuel expense	**15**	19	**42**	42
Gross margin	**126**	130	**389**	389
Operations, maintenance and administration	**39**	44	**118**	129
Depreciation and amortization	**20**	19	**59**	56
Accretion on fixed asset removal liabilities	**3**	2	**7**	6
Property taxes	**-**	1	**5**	6
Income from investments subject to significant influence	**(11)**	(11)	**(29)**	(28)
Income before other loss, interest and income taxes	**75**	75	**229**	220
Other loss	**-**	1	**-**	1
Income before interest and income taxes	**75**	74	**229**	219

Income before interest and income taxes from the segment increased by $1 million and $10 million during the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016. The increase in earnings for the three months ended September 30, 2017 mainly resulted from revenues from the Peter Sutherland Sr. GS that was placed in-service at the end of the first quarter of 2017 and lower OM&A expenses, partially offset by lower revenue from the Atikokan GS. The decrease in revenue from the Atikokan GS was primarily due to higher revenues in 2016, when the station was called upon to provide the needed support to the electricity system in Northwestern Ontario as a result of an outage at a local transformer station. For the nine months ended September 30, 2017, the increase in earnings was primarily due to lower OM&A expenses. The lower OM&A expenses for the three and nine month periods ended September 30, 2017 were mainly due to the prospective adoption of the full yield curve approach to the estimation of the service and interest cost components of pension and OPEB costs starting in 2017.

The Hydroelectric Availability and the Thermal Equivalent Forced Outage Rate (EFOR) for the Contracted Generation Portfolio segment were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Hydroelectric Availability *(%)*	**66.1**	68.2	**76.9**	79.6
Thermal EFOR *(%)*	**2.6**	2.1	**6.0**	1.3

Lower Hydroelectric Availability during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was primarily due to an increase in the number of planned outage days at the Lower Mattagami River hydroelectric generating stations.

The higher Thermal EFOR during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was primarily due to a higher number of unplanned outage days at a Lennox GS unit as a result of a transmission outage and a generator cooling water system outage in 2017.

Services, Trading, and Other Non-Generation Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue	**9**	15	**36**	52
Fuel expense	**1**	1	**1**	1
Gross margin	**8**	14	**35**	51
Operations, maintenance and administration	**1**	11	**2**	20
Depreciation and amortization	**8**	8	**22**	25
Accretion on fixed asset removal liabilities	**2**	2	**6**	6
Property taxes	**-**	4	**4**	9
(Loss) income before other gains, interest, and income taxes	**(3)**	(11)	**1**	(9)
Other gains	**(2)**	(3)	**(385)**	(5)
Income (loss) before interest and income taxes	**(1)**	(8)	**386**	(4)

Segment earnings improved by $7 million during the third quarter of 2017, compared to the same quarter in 2016. The improvement in earnings was primarily due to lower OM&A expenses reflecting project expenditures incurred in the third quarter of 2016, and OPG's decision, in the fourth quarter of 2016, to proceed with the decommissioning of Lambton GS.

Segment income before interest and income taxes increased by $390 million for the nine months ended September 30, 2017, compared to the same period in 2016. The increase in earnings mainly reflected the gain on the sale of OPG's head office premises and associated parking facility recorded during the second quarter of 2017.

LIQUIDITY AND CAPITAL RESOURCES

OPG's primary sources of liquidity and capital are funds generated from operations, bank financing, credit facilities provided by the Ontario Electricity Financial Corporation (OEFC), long-term corporate debt, and capital market financing. These sources are used for multiple purposes including: to invest in plants and technologies, to undertake major projects, to fund long-term obligations such as contributions to the pension fund and the Nuclear Segregated Funds, to make payments under the OPEB plans, to fund expenditures on Nuclear Liabilities not reimbursable from the Nuclear Segregated Funds, to service and repay long-term debt, to provide general working capital, and to fund OPG's investment in the Fair Hydro Plan.

Changes in cash and cash equivalents for the three and nine month periods ended September 30 are as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Cash and cash equivalents, beginning of period	**242**	295	**186**	464
Cash flow provided by operating activities	**485**	530	**698**	1,211
Cash flow used in investing activities	**(463)**	(390)	**(720)**	(1,253)
Cash flow provided by (used in) financing activities	**16**	(9)	**116**	4
Net increase (decrease)	**38**	131	**94**	(38)
Cash and cash equivalents, end of period	**280**	426	**280**	426

For a discussion of cash flow provided by operating activities and the FFO Adjusted Interest Coverage ratio, refer to the details in the section, *Highlights* under the heading, *Overview of Results*.

Investing Activities

Electricity generation is a capital-intensive business. It requires continued investment in plants and technologies to maintain and improve operating performance including asset reliability, safety and environmental performance, to increase the generating capacity of existing stations, and to invest in the development of new generating stations, emerging technologies and other business growth opportunities.

Cash flow used in investing activities during the third quarter of 2017 was $463 million, compared to $390 million for the same period in 2016. The increase in cash flow used for investing activities mainly resulted from higher expenditures on the Darlington Refurbishment project in the third quarter of 2017.

Cash flow used in investing activities decreased by $533 million for the nine months ended September 30, 2017, compared to the same period in 2016. The decrease in net cash flow used in investing activities was primarily due to the receipt of proceeds from the sale of OPG's head office premises and associated parking facility in the second quarter of 2017 pursuant to a Shareholder Declaration and Shareholder Resolution, and the acquisition of nine million common shares of Hydro One Limited (Hydro One) in the second quarter of 2016, partially offset by higher expenditures on the Darlington Refurbishment project in 2017. OPG acquired the Hydro One shares for investment purposes, to mitigate the risk of future price volatility related to the Company's future share delivery obligations under the collective agreements with the Power Workers' Union and The Society of Energy Professionals.

Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from the sale of head office premises and associated parking facility, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. OPG expects that the amount of designated proceeds to be transferred into the Consolidated Revenue Fund will be largely consistent with the after-tax gain on sale. The transfer is expected to take place later in 2017.

Financing Activities

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. In the second quarter of 2017, OPG renewed and extended the expiry date of both tranches from May 2021 to May 2022. There were no amounts outstanding under the bank credit facility as at September 30, 2017.

There was $160 million of commercial paper outstanding under OPG's commercial paper program as at September 30, 2017.

As at September 30, 2017, OPG also maintained $25 million of short-term, uncommitted overdraft facilities, and a further $463 million of short-term, uncommitted credit facilities, which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other general corporate purposes. As at September 30, 2017, a total of $388 million of Letters of Credit had been issued under these facilities. This included $349 million for the supplementary pension plans, $38 million for general corporate purposes, and $1 million related to the operation of the PEC.

The Company has an agreement to sell an undivided co-ownership interest in its current and future accounts receivable to an independent trust, expiring on November 30, 2018. The maximum amount of co-ownership interest that can be sold under this agreement is $150 million. As at September 30, 2017, no borrowings were issued under this agreement and there were Letters of Credit outstanding under this agreement of $150 million, which were issued in support of OPG's supplementary pension plans.

As at September 30, 2017, Lower Mattagami Energy Limited Partnership (LME) maintained a $400 million bank credit facility to support the funding requirements for the Lower Mattagami River project including support for LME's commercial paper program and the issuance of the Letters of Credit. The facility consists of a $300 million tranche which, in the third quarter of 2017, was extended to mature in August 2022 and a $100 million tranche which, in the third quarter of 2017, was reduced from $200 million and extended to mature in August 2018. As at September 30, 2017, there was no external commercial paper outstanding under LME's commercial paper program. A letter of credit of $55 million was issued in July 2017 and remains outstanding as at September 30, 2017 under the $300 million tranche of the credit facility.

In June 2016, OPG entered into a $700 million general corporate credit facility agreement with the OEFC, which expires on December 31, 2017. In the third quarter of 2017, the agreement was amended to increase the credit facility to $2,350 million and to extend its expiry date to December 31, 2018.

In February 2017, OPG issued senior notes payable to the OEFC totalling $200 million and maturing in February 2047. The effective interest rate and coupon interest rate of these notes was 4.12 percent. In June 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in June 2047. The effective interest rate and coupon interest rate of these notes was 3.65 percent. In August 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in August 2047. The effective interest rate and coupon interest rate of these notes was 3.86 percent. In September 2017, OPG issued senior notes payable to the OEFC totalling $400 million and maturing in September 2047. The effective interest rate and coupon interest rate of these notes was 4.07 percent. As at September 30, 2017, there were outstanding long-term borrowings of $800 million under this credit facility.

In October 2017, OPG issued $500 million of senior notes payable under a Medium Term Note Program. The notes bear a coupon interest rate of 3.32 percent and an effective rate of 3.43 percent, payable semi-annually until maturity on October 4, 2027. The offering was made under OPG's $2 billion short form base shelf prospectus dated September 12, 2017. The net proceeds will be used for general corporate purposes, including the financing of OPG's subordinated debt investment in the Fair Hydro Plan.

As at September 30, 2017, OPG's long-term debt outstanding was $5,482 million, including $628 million due within one year.

OPG continues to evaluate arrangements that would appropriately support the Company's financing needs and capital expenditure programs.

Contractual and Commercial Commitments

Pension Plan Actuarial Valuation

A new actuarial valuation of the OPG registered pension plan was filed with the Financial Services Commission of Ontario in September 2017 with an effective date of January 1, 2017. The annual funding requirements in accordance with the new actuarial valuation are $212 million for 2017, $215 million for 2018, and $219 million for 2019. The next actuarial valuation must have an effective date no later than January 1, 2020.

BALANCE SHEET HIGHLIGHTS

The following section provides highlights of OPG's unaudited interim consolidated financial position using selected balance sheet data:

(millions of dollars) (unaudited)	As At September 30 2017	As At December 31 2016
Property, plant and equipment - net	**20,801**	19,998
The increase was primarily due to capital expenditures on the Darlington Refurbishment project, partially offset by depreciation expense.		
Nuclear fixed asset removal and nuclear waste management funds *(current and non-current portions)*	**16,534**	15,984
The increase was primarily due to earnings on the Nuclear Segregated Funds, partially offset by reimbursements of eligible expenditures on nuclear fixed asset removal and nuclear waste management activities.		
Short-term debt	**160**	2
The increase was due to commercial paper issued under OPG's commercial paper program during the third quarter of 2017.		
Fixed asset removal and nuclear waste management liabilities	**20,075**	19,484
The increase was primarily a result of accretion expense representing the increase in the liabilities due to the passage of time, partially offset by expenditures on nuclear fixed asset removal and waste management activities.		

Off-Balance Sheet Arrangements

In the normal course of operations, OPG engages in a variety of transactions that, under US GAAP, are either not recorded in the Company's interim consolidated financial statements or are recorded in the Company's interim consolidated financial statements using amounts that differ from the full contract amounts. Principal off-balance sheet activities for OPG include guarantees and long-term contracts.

CHANGES IN ACCOUNTING POLICIES AND ESTIMATES

OPG's significant accounting policies are outlined in Note 3 to the audited consolidated financial statements as at and for the year ended December 31, 2016. A discussion of recent accounting pronouncements and change in accounting estimate are included in Note 2 to OPG's unaudited interim consolidated financial statements as at and for the three and nine month periods ended September 30, 2017 under the heading, *Significant Accounting Policies and Estimates*. Disclosure regarding OPG's critical accounting policies is included in OPG's 2016 annual MD&A.

RISK MANAGEMENT

The following provides an update to the discussion of the Company's risks and risk management activities included in OPG's 2016 annual MD&A. As such, the disclosure in this section should be read in conjunction with the *Risk Management* section included in the annual MD&A.

Risks to Achieving Project Excellence

Deep Geologic Repository for Low and Intermediate Level Waste

In August 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of the potential cumulative effects of the DGR project on the physical and cultural heritage of the SON, taking into account the results of the SON Community Process. OPG continues to work with the SON, however the timing and outcome of the SON Community Process and the EA decision by the Minister are uncertain.

Risks to Maintaining Financial Strength

Commodity Markets

Changes in the market price of fuels used to produce electricity can adversely impact OPG's earnings and cash flow from operations.

To manage the risk of unpredictable increases in the price of fuels, the Company has fuel hedging programs, which include fixed price and indexed contracts.

The percentages hedged of OPG's fuel requirements are shown in the following table. These amounts are based on yearly forecasts of generation and supply mix, and as such, are subject to change as these forecasts are updated.

	2017 [1]	2018	2019
Estimated fuel requirements hedged [2]	73%	73%	69%

[1] Based on actual fuel requirements hedged for the nine months ended September 30, 2017 and forecast for the remainder of the year.

[2] Represents the approximate portion of megawatt-hours of expected generation production (and year-end inventory targets) from each type of OPG-operated facility (nuclear, hydroelectric and thermal) for which the Company has entered into contractual arrangements or obligations in order to secure the price of fuel, or which is subject to regulation. In the case of hydroelectric generation, this represents the gross revenue charge and water rental charges. Excess fuel inventories (nuclear and thermal) in a given year are attributed to the next year for the purpose of measuring hedge ratios.

Foreign Exchange

OPG's earnings and cash flow can be affected by movements in the United States dollar (USD) relative to the Canadian dollar.

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are denominated in, or tied to, USD. To manage this risk, OPG periodically employs various financial instruments such as forwards and other

derivative contracts, in accordance with approved risk management policies. As at September 30, 2017, OPG had no foreign exchange contracts outstanding.

Trading

OPG's financial performance can be affected by its trading activities.

OPG's electricity trading operations are closely monitored, with total exposures measured and reported to senior management on a daily basis. The main metric used to measure the financial risk of trading activity is Value at Risk (VaR). VaR is defined as a probabilistic maximum potential future loss expressed in monetary terms for a portfolio based on normal market conditions over a set period of time. For the third quarter of 2017, the VaR utilization ranged between $0.2 million and $0.3 million.

Credit

Deterioration in energy markets counterparty credit and non-performance by suppliers and contractors can adversely impact OPG's earnings and cash flow from operations.

OPG manages its exposure to suppliers or counterparties by evaluating their financial condition and negotiating appropriate collateral or other forms of security. OPG's credit exposure relating to energy markets transactions as at September 30, 2017 was $356 million, including $346 million with the IESO. Management considers the Company's risk exposure relating to electricity sales through the IESO-administered spot market to be low as the IESO oversees the credit worthiness of all market participants. In accordance with the IESO's prudential support requirements, market participants are required to provide collateral to cover funds that they might owe to the market. Of the $10 million remaining exposure as at September 30, 2017, over 95 percent was related to investment grade counterparties.

Fair Hydro Plan

OPG's role in connection with the Fair Hydro Plan could have reputational impacts on the Company.

The *Ontario Fair Hydro Plan Act, 2017* received Royal Assent on June 1, 2017 and its attendant regulations came into force in June, July, and October 2017. **[UPDATE]** The regulations clarify aspects of the structure and program logistics required for OPG, as the Financial Services Manager of the Fair Hydro Plan, to refinance a portion of the Global Adjustment through the Trust. OPG's reputation could potentially be adversely impacted through its involvement with the Fair Hydro Plan and through stakeholder opinions related to this involvement.

Recovery of Pension and OPEB Costs

On September 14, 2017, the OEB issued its final report on the guiding principles and the policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the electricity and natural gas sectors. The report reaffirmed the conclusions of the initial report issued in May 2017, including the establishment of the accrual basis of accounting as the default rate-setting method and the establishment of a variance account to record asymmetric carrying charges in favour of ratepayers on the differences between the accrual costs recovered and cash payments made by a utility for pension and OPEB plans. The report requires OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the Pension & OPEB Cash Versus Accrual Differential Deferral Account that has been in effect since November 1, 2014, until such time as the OEB approves the resumption of the accrual basis of recovery. The future recovery of amounts recorded in the account will be subject to this approval. The report confirmed that OPG would become subject to the carrying charges on the differences between accrual costs and cash payments going back to November 1, 2014, with the charges calculated on the portion of such differences that have been recovered through regulated prices. The carrying charges will be determined at prescribed interest rate set quarterly by the OEB based on the quarterly return of a mid-term corporate bond index yield. This outcome has reduced OPG's risk related to the recovery of actual pension and OPEB accrual costs and the recovery of the balance in the Pension & OPEB Cash Versus Accrual Differential Deferral Account.

The account had a balance of $552 million as at September 30, 2017 and is recognized on the Company's consolidated balance sheet as a regulatory asset. OPG's financial results for the three and nine month periods ended September 30, 2017 were not impacted by the issuance of the OEB's report.

RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One, the IESO and the OEFC. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions are summarized below:

	Three Months Ended September 30			
	2017		2016	
(millions of dollars) (unaudited)	**Revenue**	**Expense**	**Revenue**	**Expense**
Hydro One				
Electricity sales	**2**	**-**	1	-
Services	**-**	**3**	-	3
Dividends	**2**	**-**	-	2
Province of Ontario				
Decommissioning Fund excess funding [1]	**-**	**(44)**	-	201
Used Fuel Fund rate of return guarantee and excess funding [1]	**-**	**(39)**	-	295
Gross revenue charges	**-**	**27**	-	28
ONFA guarantee fee	**-**	**2**	-	2
Other	**-**	**2**	-	-
OEFC				
Gross revenue charges	**-**	**62**	-	57
Interest expense on long-term notes	**-**	**40**	-	42
Income taxes, net of investment tax credits	**-**	**23**	-	28
IESO				
Electricity related revenue	**1,126**	**4**	1,293	7
	1,130	**80**	1,294	665

(millions of dollars) (unaudited)	Nine Months Ended September 30 2017 Revenue	2017 Expense	2016 Revenue	2016 Expense
Hydro One				
Electricity sales	**7**	**-**	4	-
Services	**1**	**8**	1	12
Dividends	**6**	**-**	-	4
Province of Ontario				
Decommissioning Fund excess funding [1]	**-**	**164**	-	137
Used Fuel Fund rate of return guarantee and excess funding [1]	**-**	**217**	-	190
Gross revenue charges	**-**	**84**	-	91
ONFA guarantee fee	**-**	**6**	-	6
Other	**-**	**3**	-	-
OEFC				
Gross revenue charges	**-**	**156**	-	147
Interest expense on long-term notes	**-**	**122**	-	127
Income taxes, net of investment tax credits	**-**	**132**	-	112
IESO				
Electricity related revenue	**3,228**	**11**	3,894	22
	3,242	**903**	3,899	848

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at September 30, 2017 and December 31, 2016, the Nuclear Segregated Funds were reported net of amounts due to the Province of $3,796 million and $3,415 million, respectively. The details of accounting for the Nuclear Segregated Funds are described in OPG's 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

The receivable, available-for-sale securities, payable and long-term debt balances between OPG and its related parties are summarized below:

(millions of dollars) (unaudited)	September 30 2017	December 31 2016
Receivables from related parties		
Hydro One	**1**	1
IESO	**346**	421
OEFC	**3**	1
PEC	**2**	4
Province of Ontario	**5**	2
Available-for-sale securities		
Hydro One shares	**190**	212
Accounts payable and accrued charges		
OEFC	**37**	61
Province of Ontario	**6**	2
IESO	**2**	2
Long-term debt (including current portion)		
Notes payable to OEFC	**3,245**	3,295

OPG holds interest-bearing Province of Ontario bonds in the Nuclear Segregated Funds and the OPG registered pension fund. As at September 30, 2017, the Nuclear Segregated Funds held $1,498 million of interest-bearing Province of Ontario bonds, while the registered pension fund had no such holdings. As at December 31, 2016, the Nuclear Segregated Funds and the registered pension fund held $1,652 million and $284 million of interest-bearing Province of Ontario bonds, respectively. These bonds are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

There have been no related party transactions related to the Fair Hydro Plan and associated financing activities. The first transaction between the Trust and the IESO is expected later in 2017.

INTERNAL CONTROLS OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

The Company maintains a comprehensive system of policies, procedures, and processes that represents its framework for internal controls over financial reporting and for its disclosure controls and procedures (together, ICOFR). There were no changes in the Company's internal control system during the current interim period that has or is reasonably likely to have a material impact to the ICOFR.

QUARTERLY FINANCIAL HIGHLIGHTS

The following tables set out selected financial information from OPG's unaudited interim consolidated financial statements for each of the eight most recently completed quarters.

(millions of dollars - except where noted) *(unaudited)*	**September 30 2017**	**June 30 2017**	**March 31 2017**	**December 31 2016**
Revenue	**1,217**	1,146	1,176	1,388
Net income (loss)	**140**	307	68	(8)
Less: Net income attributable to non-controlling interest	**9**	4	4	5
Net income (loss) attributable to the Shareholder	**131**	303	64	(13)
Per common share, attributable to the Shareholder *(dollars)*	**$0.51**	$1.18	$0.25	($0.05)

(millions of dollars - except where noted) *(unaudited)*	**September 30 2016**	**June 30 2016**	**March 31 2016**	**December 31 2015**
Revenue	1,400	1,387	1,478	1,312
Net income (loss)	198	135	128	(100)
Less: Net income attribute to the non-controlling interest	4	3	5	1
Net income (loss) attributable to the Shareholder	194	132	123	(101)
Per common share, attributable to the Shareholder *(dollars)*	$0.76	$0.51	$0.48	($0.39)

Trends

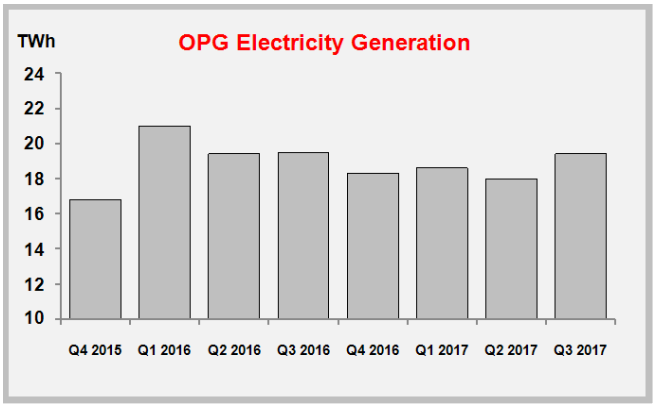
OPG's quarterly results are affected by changes in grid-supplied electricity demand, primarily resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. Weather conditions affect water flows, electricity demand, and prevalence of SBG conditions. Historically, OPG's revenues have been higher in the first

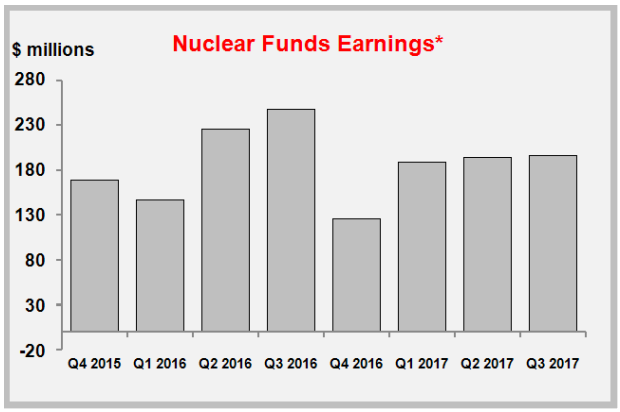
quarter of a fiscal year as a result of winter heating demands and in the third quarter due to air conditioning and cooling demands. The financial impact of forgone production due to SBG conditions at the regulated hydroelectric stations and the financial impact of differences between forecast water flows reflected in OEB-approved regulated prices and the actual water flows are mitigated by regulatory variance accounts authorized by the OEB.

The timing of planned outages at a nuclear generating station during the year can cause variability in year-over-year operating results for partial periods of a fiscal year, including the impact on revenue and OM&A expenses, but is not a significant driver of variability for full fiscal year results.

OPG's electricity generation was reduced as a result of the Unit 2 refurbishment outage at the Darlington GS, which began in October 2016 and is expected to continue until early 2020.

OPG's financial results are also affected by the earnings on the Nuclear Segregated Funds, net of the impact of the Bruce Lease Net Revenues Variance Account.





*net of regulatory variance account

Additional items that affected net income in certain quarters above are described in OPG's 2016 annual MD&A under the section, *Quarterly Financial Highlights*.

SUPPLEMENTARY NON-GAAP FINANCIAL MEASURES

In addition to providing net income and other financial information in accordance with US GAAP, certain non-GAAP financial measures are also presented in OPG's MD&A. These non-GAAP measures do not have any standardized meaning prescribed by US GAAP and, therefore, may not be comparable to similar measures presented by other issuers. OPG utilizes these measures to make operating decisions and assess performance. Readers of the MD&A would utilize these measures in assessing the Company's financial performance from ongoing operations. The Company believes that these indicators are important since they provide additional information about OPG's performance, facilitate comparison of results over different periods, and present measures consistent with the Company's strategies to provide value to the Shareholder, improve cost performance, and ensure availability of cost effective funding. These non-GAAP financial measures have not been presented as an alternative to net income, cash flow provided by operating activities, or any other measure in accordance with US GAAP, but as indicators of operating performance.

The definitions of the non-GAAP financial measures are as follows:

(1) **ROE Excluding AOCI** is defined as net income attributable to the Shareholder divided by average equity attributable to the Shareholder excluding AOCI, for the period. ROE Excluding AOCI is measured over a 12-month period and is calculated as follows:

	Twelve Months Ended	
(millions of dollars – except where noted) (unaudited)	**September 30 2017**	**December 31 2016**
ROE Excluding AOCI		
Net income attributable to the Shareholder	**485**	436
Divided by: Average equity attributable to the Shareholder, excluding AOCI	**11,055**	10,442
ROE Excluding AOCI *(percent)*	**4.4**	4.2

(2) **FFO Adjusted Interest Coverage** is defined as FFO before interest divided by adjusted interest expense. FFO before interest is defined as cash flow provided by operating activities adjusted for interest paid, interest capitalized to fixed and intangible assets, and changes to non-cash working capital balances for the period. Adjusted interest expense is calculated as net interest expense plus interest income, interest capitalized to fixed and intangible assets, interest related to regulatory assets and liabilities, and the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets, for the period.

FFO Adjusted Interest Coverage is measured over a 12-month period and is calculated as follows:

	Twelve Months Ended	
(millions of dollars – except where noted) (unaudited)	**September 30 2017**	**December 31 2016**
FFO before interest		
Cash flow provided by operating activities	**1,082**	1,595
Add: Interest paid	**270**	269
Less: Interest capitalized to fixed and intangible assets	**(161)**	(141)
Less: Changes to non-cash working capital balances	**38**	42
FFO before interest	**1,229**	1,765
Adjusted interest expense		
Net interest expense	**84**	120
Add: Interest income	**8**	7
Add: Interest capitalized to fixed and intangible assets	**161**	141
Add: Interest related to regulatory assets and liabilities	**43**	30
Add: Excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets [1]	**-**	45
Adjusted interest expense	**296**	343
FFO Adjusted Interest Coverage *(times)*	**4.2**	5.1

[1] A value of nil is used in the calculation when interest on pension and OPEB projected benefit obligations is equal to, or lower than, expected return on pension plan assets.

(3) **Enterprise Total Generating Cost per MWh** is used to measure OPG's overall organizational cost performance. Enterprise TGC per MWh is defined as OM&A expenses (excluding the Darlington Refurbishment project and other generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to OPG's electricity generation business), fuel expense for OPG-operated stations including hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures (excluding the Darlington Refurbishment project and other generation development projects) incurred during the period, divided by total electricity generation from OPG-operated generating stations plus electricity generation forgone due to SBG conditions during the period.

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars – except where noted) (unaudited)	**2017**	**2016**	**2017**	**2016**
Enterprise TGC				
Total OM&A expenses	**635**	666	**2,054**	2,061
Total fuel expense	**185**	187	**518**	541
Total capital expenditures	**476**	444	**1,335**	1,162
Less: Darlington Refurbishment capital and OM&A costs	**(328)**	(269)	**(943)**	(717)
Less: Other generation development project capital and OM&A costs	**(17)**	(42)	**(53)**	(121)
Add (Less): OM&A and fuel expenses (refundable through) deferred in regulatory variance and deferral accounts	**4**	35	**(19)**	76
Less: Nuclear fuel expense for non OPG-operated stations	**(13)**	(18)	**(42)**	(50)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**13**	5	**47**	38
Less: OM&A expenses ancillary to electricity generation business	**(4)**	(5)	**(13)**	(17)
Other adjustments	**(3)**	(12)	**(7)**	(15)
	948	991	**2,877**	2,958
Adjusted electricity generation *(TWh)*				
Total OPG electricity generation	**19.4**	19.5	**56.0**	59.9
Adjust for electricity generation forgone due to SBG conditions and OPG's share of electricity generation from co-owned facilities	**0.9**	0.1	**4.2**	3.4
	20.3	19.6	**60.2**	63.3
Enterprise TGC per MWh *($/MWh)* [1]	**46.65**	50.72	**47.77**	46.74

[1] Amounts may not calculate due to rounding.

(4) **Nuclear Total Generating Cost per MWh** is used to measure the cost performance of OPG's nuclear generating assets. Nuclear TGC per MWh is defined as OM&A expenses of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the nuclear electricity generation business), nuclear fuel expense for OPG-operated stations (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs) incurred during the period, divided by nuclear electricity generation for the period.

(millions of dollars – except where noted) (unaudited)	**Three Months Ended September 30**		**Nine Months Ended September 30**	
	2017	**2016**	**2017**	**2016**
Nuclear TGC				
Regulated – Nuclear Generation OM&A expenses	**511**	521	**1,693**	1,665
Regulated – Nuclear Generation fuel expense	**81**	79	**217**	239
Regulated – Nuclear Generation capital expenditures	**409**	339	**1,150**	896
Less: Darlington Refurbishment capital and OM&A costs	**(328)**	(269)	**(943)**	(717)
Add: Regulated – Nuclear Generation OM&A and fuel expenses deferred in regulatory variance and deferral accounts	**5**	31	**6**	84
Less: Nuclear fuel expense for non OPG-operated stations	**(13)**	(18)	**(42)**	(50)
Less: Regulated - Nuclear Generation OM&A expenses ancillary to nuclear electricity generation business	**(1)**	(1)	**(3)**	(4)
Other adjustments	**1**	3	**(1)**	(1)
	665	685	**2,077**	2,112
Nuclear electricity generation (TWh)	**11.3**	11.7	**30.6**	34.6
Nuclear TGC per MWh (*$/MWh*) [1]	**58.75**	58.55	**67.87**	61.07

[1] Amounts may not calculate due to rounding.

(5) **Hydroelectric Total Generating Cost per MWh** is used to measure the cost performance of OPG's hydroelectric generating assets. Hydroelectric TGC per MWh is defined as OM&A expenses of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the hydroelectric electricity generation business), hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding expenditures related to the Peter Sutherland Sr. GS, Ranney Falls GS, and other hydroelectric generation development projects) incurred during the period, divided by total hydroelectric electricity generation plus hydroelectric electricity generation forgone due to SBG conditions during the period. OPG reports hydroelectric gross revenue charge and water rental payments as fuel expense.

(millions of dollars – except where noted) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Hydroelectric TGC				
Regulated – Hydroelectric OM&A expenses	**81**	87	**232**	238
Regulated – Hydroelectric fuel expense	**88**	88	**258**	259
Contracted Generation Portfolio OM&A expenses	**39**	44	**118**	129
Contracted Generation Portfolio fuel expense	**15**	19	**42**	42
Regulated – Hydroelectric and Contracted Generation Portfolio capital expenditures	**56**	92	**141**	231
Less: Regulated – Hydroelectric and Contracted Generation Portfolio generation development project capital and OM&A costs	**(17)**	(41)	**(52)**	(117)
Less: Thermal OM&A and fuel expenses and capital expenditures in the Contracted Generation Portfolio	**(39)**	(51)	**(119)**	(126)
(Less) Add: Regulated – Hydroelectric OM&A and fuel expenses refundable through regulatory variance and deferral accounts	**(1)**	4	**(25)**	(8)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**13**	5	**47**	38
Other adjustments	**(1)**	(1)	**-**	(1)
	234	246	**642**	685
Adjusted hydroelectric electricity generation *(TWh)*				
Regulated – Hydroelectric electricity generation	**7.3**	6.9	**23.5**	22.8
Contracted Generation Portfolio electricity generation	**0.8**	0.9	**1.9**	2.5
Adjust for hydroelectric electricity generation forgone due to SBG conditions and non-hydroelectric electricity generation of the Contracted Generation Portfolio, including OPG's share of electricity generation from co-owned facilities	**0.8**	0.1	**4.1**	3.4
	8.9	7.9	**29.5**	28.7
Hydroelectric TGC per MWh *($/MWh)* [1]	**26.20**	31.01	**21.74**	23.99

[1] Amounts may not calculate due to rounding.

(6) **Gross margin** is defined as revenue less fuel expense.

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ONTARIO POWER GENERATION INC.

INTERIM CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

SEPTEMBER 30, 2017

[DRAFT]

ONTARIO POWER GENERATION

INTERIM CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

(millions of dollars except where noted)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Revenue *(Note 12)*	**1,217**	1,400	**3,539**	4,265
Fuel expense *(Note 12)*	**185**	187	**518**	541
Gross margin	**1,032**	1,213	**3,021**	3,724
Expenses *(Note 12)*				
Operations, maintenance and administration	**635**	666	**2,054**	2,061
Depreciation and amortization	**178**	313	**517**	941
Accretion on fixed asset removal and nuclear waste management liabilities	**235**	232	**709**	696
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(196)**	(248)	**(579)**	(620)
Property taxes	**8**	12	**30**	35
Income from investments subject to significant influence	**(11)**	(11)	**(29)**	(28)
	849	964	**2,702**	3,085
Income before other losses (gains), interest and income taxes	**183**	249	**319**	639
Other losses (gains) *(Note 12)*	**3**	1	**(380)**	(23)
Income before interest and income taxes	**180**	248	**699**	662
Net interest expense *(Note 5)*	**21**	28	**56**	92
Income before income taxes	**159**	220	**643**	570
Income tax expense	**19**	22	**128**	109
Net income	**140**	198	**515**	461
Net income attributable to the Shareholder	**131**	194	**498**	449
Net income attributable to non-controlling interest	**9**	4	**17**	12
Basic and diluted net income per common share *(dollars)*	**0.51**	0.76	**1.94**	1.75
Common shares outstanding *(millions)*	**256.3**	256.3	**256.3**	256.3

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

(millions of dollars)	Three Months Ended September 30 2017	2016	Nine Months Ended September 30 2017	2016
Net income	**140**	198	**515**	461
Other comprehensive income, net of income taxes *(Note 7)*				
Reclassification to income of amounts related to pension and other post-employment benefits [1]	**3**	3	**8**	9
Reclassification to income of losses on derivatives designated as cash flow hedges [2]	**4**	4	**13**	14
Unrealized (loss) gain on available-for-sale securities [3]	**(4)**	-	**(6)**	15
Other comprehensive income for the period	**3**	7	**15**	38
Comprehensive income	**143**	205	**530**	499
Comprehensive income attributable to the Shareholder	**134**	201	**513**	487
Comprehensive income attributable to non-controlling interest	**9**	4	**17**	12

[1] Net of income tax expense of nil and $1 million for the three months ended September 30, 2017 and 2016, respectively. Net of income tax expense of $2 million and $3 million for the nine months ended September 30, 2017 and 2016, respectively.

[2] Net of income tax expense of $1 million for the three months ended September 30, 2017 and 2016. Net of income tax expense of $2 million for the nine months ended September 30, 2017 and 2016.

[3] Net of income tax expense of nil for the three months ended September 30, 2017 and 2016. Net of income tax recovery of $1 million and income tax expense of $5 million for the nine months ended September 30, 2017 and 2016, respectively.

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

Nine Months Ended September 30 *(millions of dollars)*	**2017**	**2016**
Operating activities		
Net income	**515**	461
Adjust for non-cash items:		
Depreciation and amortization	**517**	941
Accretion on fixed asset removal and nuclear waste management liabilities	**709**	696
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(579)**	(620)
Pension and other post-employment benefit costs *(Note 8)*	**339**	351
Deferred income taxes	**50**	(41)
Mark-to-market on derivative instruments	**(4)**	1
Provision for used nuclear fuel and low and intermediate level nuclear waste	**84**	91
Regulatory assets and liabilities	**(97)**	(82)
Provision for materials and supplies	**13**	38
Other gains	**(374)**	(23)
Other	**(35)**	(14)
	1,138	1,799
Contributions to nuclear fixed asset removal and nuclear waste management funds	**-**	(112)
Expenditures on fixed asset removal and nuclear waste management	**(231)**	(189)
Reimbursement of expenditures on nuclear fixed asset removal and nuclear waste management	**59**	49
Contributions to pension funds and expenditures on other post-employment benefits and supplementary pension plans	**(270)**	(331)
Expenditures on restructuring	**(3)**	(3)
Distributions received from investments subject to significant influence	**37**	40
Net changes to other long-term assets and liabilities	**23**	17
Net changes in non-cash working capital balances *(Note 13)*	**(55)**	(59)
Cash flow provided by operating activities	**698**	1,211
Investing activities		
Net proceeds from sale of property, plant and equipment	**484**	-
Purchase of available-for-sale securities	**-**	(213)
Proceeds from deposit note *(Note 4)*	**70**	65
Investment in property, plant and equipment and intangible assets	**(1,274)**	(1,105)
Cash flow used in investing activities	**(720)**	(1,253)
Financing activities		
Issuance of long-term debt *(Note 4)*	**800**	-
Repayment of long-term debt	**(852)**	(2)
Contribution from non-controlling interest	**19**	-
Distribution to non-controlling interest	**(11)**	(11)
Issuance of short-term notes	**1,458**	2,916
Repayment of short-term notes	**(1,298)**	(2,899)
Cash flow provided by financing activities	**116**	4
Net increase (decrease) in cash and cash equivalents	**94**	(38)
Cash and cash equivalents, beginning of period	**186**	464
Cash and cash equivalents, end of period	**280**	426

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

As at *(millions of dollars)*	September 30 2017	December 31 2016
Assets		
Current assets		
Cash and cash equivalents	**280**	186
Available-for-sale securities	**190**	212
Receivables from related parties	**357**	429
Nuclear fixed asset removal and nuclear waste management funds	**19**	24
Fuel inventory	**290**	310
Materials and supplies	**96**	100
Income tax recoverable	**11**	-
Prepaid expenses	**212**	198
Other current assets	**108**	298
	1,563	1,757
Property, plant and equipment	**30,491**	29,315
Less: accumulated depreciation	**9,690**	9,317
	20,801	19,998
Intangible assets	**546**	503
Less: accumulated amortization	**425**	404
	121	99
Other non-current assets		
Nuclear fixed asset removal and nuclear waste management funds	**16,515**	15,960
Long-term materials and supplies	**364**	345
Regulatory assets *(Note 3)*	**6,002**	5,855
Investments subject to significant influence *(Note 14)*	**313**	321
Other long-term assets	**27**	37
	23,221	22,518
	45,706	44,372

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

As at *(millions of dollars)*	September 30 2017	December 31 2016
Liabilities		
Current liabilities		
Accounts payable and accrued charges	**1,144**	1,164
Deferred revenue	**12**	12
Short-term debt	**160**	2
Long-term debt due within one year *(Note 4)*	**628**	1,103
Income taxes payable	**-**	123
	1,944	2,404
Long-term debt *(Note 4)*	**4,840**	4,417
Other non-current liabilities		
Fixed asset removal and nuclear waste management liabilities *(Note 6)*	**20,075**	19,484
Pension liabilities	**2,867**	3,012
Other post-employment benefit liabilities	**2,959**	2,897
Long-term accounts payable and accrued charges	**235**	213
Deferred revenue	**338**	298
Deferred income taxes	**890**	829
Regulatory liabilities *(Note 3)*	**510**	310
	27,874	27,043
Equity		
Common shares [1]	**5,126**	5,126
Retained earnings	**6,034**	5,534
Accumulated other comprehensive loss *(Note 7)*	**(277)**	(295)
Equity attributable to the Shareholder	**10,883**	10,365
Equity attributable to non-controlling interest	**165**	143
Total equity	**11,048**	10,508
	45,706	44,372

[1] 256,300,010 common shares outstanding at a stated value of $5,126 million as at September 30, 2017 and December 31, 2016.

Commitments and Contingencies *(Notes 4, 10 and 11)*

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY (UNAUDITED)

Nine Months Ended September 30 *(millions of dollars)*	**2017**	**2016**
Common shares	**5,126**	5,126
Retained earnings		
Balance at beginning of period	**5,534**	5,098
Net income attributable to the Shareholder	**498**	449
Reclassification of non-controlling interest on change in ownership interest *(Note 15)*	**2**	-
Balance at end of period	**6,034**	5,547
Accumulated other comprehensive loss, net of income taxes		
Balance at beginning of period	**(295)**	(319)
Other comprehensive income	**15**	38
Reclassification of non-controlling interest on change in ownership interest *(Note 15)*	**3**	-
Balance at end of period	**(277)**	(281)
Equity attributable to the Shareholder	**10,883**	10,392
Equity attributable to non-controlling interest		
Balance at beginning of period	**143**	140
Equity contribution from non-controlling interest *(Note 15)*	**21**	-
Reclassification of non-controlling interest on change in ownership interest *(Note 15)*	**(5)**	-
Distribution to non-controlling interest	**(11)**	(11)
Income attributable to non-controlling interest	**17**	12
Balance at end of period	**165**	141
Total equity	**11,048**	10,533

See accompanying notes to the interim consolidated financial statements

NOTES TO THE INTERIM CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

For the three and nine months ended September 30, 2017 and 2016

1. BASIS OF PRESENTATION

These interim consolidated financial statements for the three and nine months ended September 30, 2017 and 2016 include the accounts of Ontario Power Generation Inc. (OPG or the Company) and its subsidiaries. The Company consolidates its interest in entities over which it is able to exercise control and attributes the results to its sole shareholder, the Province of Ontario (Province). Interests owned by other parties are reflected as non-controlling interest. These interim consolidated financial statements have been prepared and presented in accordance with United States generally accepted accounting principles (US GAAP). These interim consolidated financial statements do not contain all of the disclosures required by US GAAP for annual financial statements. Accordingly, they should be read in conjunction with the annual consolidated financial statements of the Company as at and for the year ended December 31, 2016. All dollar amounts are presented in Canadian dollars.

Certain of the 2016 comparative amounts have been reclassified from financial statements previously presented to conform to the 2017 interim consolidated financial statement presentation.

Use of Management Estimates

The preparation of consolidated financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the interim consolidated financial statements, and the reported amounts of revenues and expenses for the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in the period incurred. Significant estimates are included in the determination of pension and other post-employment benefit (OPEB) balances, asset retirement obligations and associated asset retirement costs capitalized as part of property, plant and equipment, income taxes (including deferred income taxes), contingencies, regulatory assets and liabilities, valuation of derivative instruments and investments in segregated funds, depreciation and amortization expenses, and inventories. Actual results may differ significantly from these estimates.

2. SIGNIFICANT ACCOUNTING POLICIES AND ESTIMATES

Change in Accounting Estimate

Pension and Other Post-Employment Benefits

Effective January 1, 2017, OPG changed the method used to estimate the service and interest cost components of pension and OPEB costs. OPG adopted a full yield curve approach to the estimation of these cost components, by applying the specific spot rates along the yield curve used in the determination of the projected benefit obligations to the relevant projected cash flows. Under the previous method, these components of pension and OPEB costs were calculated using the same single weighted-average discount rates as reflected in the calculation of the benefit obligations. This change in the method was accounted for prospectively, as a change in estimate. The resulting reduction in pension and OPEB costs is estimated at approximately $35 million and $105 million for the three and nine months ended September 30, 2017, respectively. Approximately 90 percent of this reduction in pension and OPEB costs was attributed to the Company's regulated business segments and therefore was offset by the impact of regulatory variance and deferral accounts authorized by the Ontario Energy Board (OEB).

Recent Accounting Pronouncements Not Yet Adopted

Revenue from Contracts with Customers [**MONITOR**]

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09, *Revenue from Contracts with Customers* (Topic 606), which supersedes nearly all existing revenue recognition guidance, including industry-specific guidance, under US GAAP. The core principle of Topic 606 is to recognize revenues when promised goods or services are transferred to customers in an amount that reflects the consideration to which an entity expects to be entitled for those goods or services. Either a full retrospective application or a modified retrospective application is required for annual periods beginning on or after January 1, 2018, including interim periods within that year. Early adoption is permitted.

As part of the project to implement the new revenue standard, OPG is continuing to assess the impact of the standard on accounting for the Company's revenue streams and consolidated financial statements. OPG's major revenue streams include regulated generation revenue from base regulated prices and rate riders established by the OEB, as well as revenue from generation assets under long-term contractual arrangements with the Independent Electricity System Operator (IESO). In March 2017, the American Institute of Certified Public Accountants (AICPA) issued Revenue Recognition Implementation Issue #13-1*, Scope Clarification Regarding Tariff Sales to Regulated Customers*. The draft implementation guidance was developed by the AICPA Power & Utilities task force. This draft guidance concludes that tariff-based revenue from the provision of regulated utility service to a utility's customers is within the scope of Topic 606. OPG has completed its analysis of the impact of Topic 606 on its accounting for generation revenue from base regulated prices and long-term contractual arrangements with the IESO, and has not identified any material differences in the timing or quantum of the recognition of revenue based on the analysis performed to date. The Company continues to work on its assessment of the impact of Topic 606 on its other revenue streams.

The Company currently expects to apply the new revenue standard in its 2018 first quarter interim financial statements and is in the process of concluding on the method of adoption.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost

In March 2017, the FASB issued ASU No. 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. Under the new guidance, employers that sponsor defined benefit plans for pensions and/or other postretirement benefits are required to present the service cost component of net periodic benefit cost in the same statement of income line item as other employee compensation costs arising from services rendered during the period. The other components of the net periodic benefit cost are to be presented separately from the line item that includes the service cost and outside of any subtotal of income from operations, if such a subtotal is presented. In addition, the new guidance requires that only the service cost component of net benefit cost be eligible for capitalization.

This guidance is effective for fiscal years beginning after December 15, 2017, including interim periods of those years. The guidance is not expected to have a material impact on OPG's consolidated financial statements, as OPG currently capitalizes only the service cost component of post-retirement benefits costs. Additionally, OPG already includes the service cost component of post-retirement benefit costs with other compensation costs, within the operations, maintenance and administration expenses line item in the consolidated statements of income, and does not show a subtotal of income from operations. As such, the new guidance is not expected to affect the presentation of OPG's consolidated financial statements.

3. REGULATORY ASSETS AND LIABILITIES

The regulatory assets and liabilities recorded as at September 30, 2017 and December 31, 2016 are as follows:

(millions of dollars)	**September 30 2017**	**December 31 2016**
Regulatory assets		
Variance and deferral accounts authorized by the OEB		
Pension and OPEB Cost Variance Account	**716**	716
Pension & OPEB Cash Versus Accrual Differential Deferral Account *(Note 8)*	**552**	497
Hydroelectric Surplus Baseload Generation Variance Account	**327**	210
Bruce Lease Net Revenues Variance Account	**131**	95
Other variance and deferral accounts	**137**	107
	1,863	1,625
Pension and OPEB Regulatory Asset *(Note 8)*	**3,260**	3,392
Deferred Income Taxes	**879**	838
Total regulatory assets	**6,002**	5,855
Regulatory liabilities		
Variance and deferral accounts authorized by the OEB		
Hydroelectric Water Conditions Variance Account	**143**	51
Impact Resulting from Changes in Station End-of-Life Dates Deferral Account	**124**	71
Other variance and deferral accounts	**243**	188
Total regulatory liabilities	**510**	310

[**MONITOR**] OPG's May 2016 application with the OEB for new regulated prices included a request for new rate riders to recover or repay the December 31, 2015 balances in all of the Company's OEB-authorized variance and deferral accounts, with the exception of the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the portion of these balances previously approved for recovery or repayment through rate riders in effect during 2016. The application also requested the continuation of all applicable existing variance and deferral accounts. In March 2017, the OEB approved a settlement agreement reached by OPG and intervenors on a limited set of issues in the application (Settlement Agreement). Among the settled issues, the agreement provided for the continuation of all applicable existing variance and deferral accounts and accepted a number of variance and deferral account balances for recovery, as requested in OPG's application. The periods of recovery or repayment for the accepted variance and deferral account balances are excluded from the scope of the Settlement Agreement. The Settlement Agreement did not impact OPG's financial results for the three and nine months ended September 30, 2017. The final arguments were completed in the second quarter of 2017. The OEB's decision is expected in the fourth quarter of 2017.

As at September 30, 2017 and December 31, 2016, regulatory assets for other variance and deferral accounts included amounts for the Nuclear Deferral and Variance Over/Under Recovery Variance Account, the Nuclear Liability Deferral Account, the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account, the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account, and the Nuclear Development Variance Account. As at September 30, 2017 and December 31, 2016, regulatory liabilities for other variance and deferral accounts included the amounts for the Pension & OPEB Cash Payment Variance Account, the Capacity Refurbishment Variance Account, the Ancillary Services Net Revenue Variance Account, the Income and Other Taxes Variance Account and the Hydroelectric Incentive Mechanism Variance Account.

4. LONG-TERM DEBT

Long-term debt consists of the following:

(millions of dollars)	**September 30 2017**	**December 31 2016**
Notes payable to the Ontario Electricity Financial Corporation	**3,245**	3,295
UMH Energy Partnership	**182**	184
PSS Generating Station Limited Partnership	**245**	245
Lower Mattagami Energy Limited Partnership	**1,795**	1,795
Other	**15**	15
	5,482	5,534
Less: bond issuance fees	**(14)**	(14)
Less: due within one year	**(628)**	(1,103)
Long-term debt	**4,840**	4,417

In the fourth quarter of 2015, PSS Generating Station Limited Partnership (PSS), a subsidiary of OPG, issued long-term debt totalling $245 million in support of the Peter Sutherland Sr. Generating Station (GS) project. The majority of the debt proceeds, totalling $180 million, were invested in a structured deposit note with staggered maturity dates ranging from January 2016 to April 2017. As at September 30, 2017, the deposit note has matured.

In June 2016, OPG entered into a $700 million general corporate credit facility agreement with the Ontario Electricity Financial Corporation (OEFC), which expires on December 31, 2017. In the third quarter of 2017, the agreement was amended with the credit facility increased to $2,350 million and expiry date extended to December 31, 2018.

In February 2017, OPG issued senior notes payable to the OEFC totalling $200 million and maturing in February 2047. The effective interest rate and coupon interest rate of these notes was 4.12 percent. In June 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in June 2047. The effective interest rate and coupon interest rate of these notes was 3.65 percent. In August 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in August 2047. The effective interest rate and coupon interest rate of these notes was 3.86 percent. In September 2017, OPG issued senior notes payable to the OEFC totalling $400 million and maturing in September 2047. The effective interest rate and coupon interest rate of these notes was 4.07 percent.

In October 2017, OPG issued $500 million of senior notes payable under a Medium Term Note Program. The notes bear a coupon interest rate of 3.32 percent and an effective rate of 3.43 percent, payable semi-annually until maturity on October 4, 2027. The offering was made under OPG's $2 billion short form base shelf prospectus dated September 12, 2017.

5. SHORT-TERM DEBT AND NET INTEREST EXPENSE

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. In the second quarter of 2017, OPG renewed and extended the expiry date of both tranches from May 2021 to May 2022. As at September 30, 2017, there were no amounts outstanding under the bank credit facility. There was $160 million commercial paper outstanding under OPG's commercial paper program as at September 30, 2017.

As at September 30, 2017, the Lower Mattagami Energy Limited Partnership (LME) maintained a $400 million bank credit facility to support the funding requirements for the Lower Mattagami River project including support for LME's commercial paper program. The facility consists of a $300 million tranche maturing in August 2022 and a $100 million tranche maturing in August 2018. As at September 30, 2017, there was no external commercial paper

outstanding under LME's commercial paper program. There were also no amounts outstanding under LME's bank credit facility as at September 30, 2017. A letter of credit of $55 million was issued in July 2017 under the first tranche of the credit facility.

As at September 30, 2017, OPG maintained $25 million of short-term, uncommitted overdraft facilities and $463 million of short-term, uncommitted credit facilities, which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other general corporate purposes. As at September 30, 2017, a total of $388 million of Letters of Credit had been issued under these facilities. This included $349 million for the supplementary pension plans, $38 million for general corporate purposes, and $1 million related to the operation of the Portlands Energy Centre (PEC), a jointly controlled entity in which OPG holds a 50 percent interest.

The Company has an agreement to sell an undivided co-ownership interest in its current and future accounts receivable to an independent trust. The maximum amount of co-ownership interest that can be sold under this agreement is $150 million, expiring on November 30, 2018. As at September 30, 2017, there were Letters of Credit outstanding under this agreement of $150 million, which were issued in support of OPG's supplementary pension plans.

UMH Energy Partnership has entered into an $8 million short-term, uncommitted overdraft facility and $16 million of irrevocable, standby Letters of Credit facilities in support of its operations. As at September 30, 2017, total Letters of Credit of $14 million had been issued under these facilities.

The following table summarizes the net interest expense:

(millions of dollars)	**Three Months Ended September 30**		**Nine Months Ended September 30**	
	2017	**2016**	**2017**	**2016**
Interest on long-term debt	**74**	73	**215**	217
Interest on short-term debt	**-**	-	**2**	2
Interest income	**(4)**	(1)	**(6)**	(5)
Interest capitalized to property, plant and equipment and intangible assets	**(39)**	(36)	**(121)**	(101)
Interest related to regulatory assets and liabilities [1]	**(10)**	(8)	**(34)**	(21)
Net interest expense	**21**	28	**56**	92

[1] Includes interest to recognize the cost of financing related to regulatory variance and deferral accounts, as authorized by the OEB, and interest deferred in the Bruce Lease Net Revenues Variance Account, the Capacity Refurbishment Variance Account, and the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account.

6. FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT LIABILITIES

The liabilities for fixed asset removal and nuclear waste management on a present value basis as at September 30, 2017 and December 31, 2016 consist of the following:

(millions of dollars)	**September 30 2017**	**December 31 2016**
Liability for nuclear used fuel management	**11,690**	11,292
Liability for nuclear decommissioning and nuclear low and intermediate level waste management	**8,009**	7,811
Liability for non-nuclear fixed asset removal	**376**	381
Fixed asset removal and nuclear waste management liabilities	**20,075**	19,484

7. ACCUMULATED OTHER COMPREHENSIVE LOSS

The changes in the balance of each component of accumulated other comprehensive loss (AOCL), are as follows:

	Nine Months Ended September 30, 2017			
(millions of dollars)	**Unrealized Losses on Cash Flow Hedges [1]**	**Pension and OPEB [1]**	**Available-for-sale Securities [1]**	**Total [1]**
AOCL, beginning of period	**(87)**	**(207)**	**(1)**	**(295)**
Unrealized loss on available-for-sale securities	**-**	**-**	**(6)**	**(6)**
Amounts reclassified from AOCL	**13**	**8**	**-**	**21**
Other comprehensive income for the period	**13**	**8**	**(6)**	**15**
Reclassification of non-controlling interest on change in ownership interest *(Note 15)*	**3**	**-**	**-**	**3**
AOCL, end of period	**(71)**	**(199)**	**(7)**	**(277)**

[1] All amounts are net of income taxes.

	Nine Months Ended September 30, 2016			
(millions of dollars)	**Unrealized Losses on Cash Flow Hedges [1]**	**Pension and OPEB [1]**	**Available-for-sale Securities [1]**	**Total [1]**
AOCL, beginning of period	(106)	(213)	-	(319)
Unrealized gain on available-for-sale securities	-	-	15	15
Amounts reclassified from AOCL	14	9	-	23
Other comprehensive income for the period	14	9	15	38
AOCL, end of period	(92)	(204)	15	(281)

[1] All amounts are net of income taxes.

The significant amounts reclassified out of each component of AOCL, net of income taxes, during the three and nine months ended September 30, 2017 are as follows:

(millions of dollars)	**Amount Reclassified from AOCL Three Months Ended September 30, 2017**	**Nine Months Ended September 30, 2017**	**Statement of Income Line Item**
Amortization of losses from cash flow hedges			
Losses	**5**	**15**	Net interest expense
Income tax recovery	**(1)**	**(2)**	Income tax expense
	4	**13**	
Amortization of amounts related to pension and OPEB			
Actuarial losses	**3**	**10**	See (1) below
Income tax recovery	**-**	**(2)**	Income tax expense
	3	**8**	
Total reclassifications for the period	**7**	**21**	

[1] These AOCL components are included in the computation of pension and OPEB costs (see Note 8 for additional details).

The significant amounts reclassified out of each component of AOCL, net of income taxes, during the three and nine months ended September 30, 2016 are as follows:

(millions of dollars)	**Amount Reclassified from AOCL Three Months Ended September 30, 2016**	**Nine Months Ended September 30, 2016**	**Statement of Income Line Item**
Amortization of losses from cash flow hedges			
Losses	5	16	Net interest expense
Income tax recovery	(1)	(2)	Income tax expense
	4	14	
Amortization of amounts related to pension and OPEB			
Actuarial losses	4	12	See (1) below
Income tax recovery	(1)	(3)	Income tax expense
	3	9	
Total reclassifications for the period	7	23	

[1] These AOCL components are included in the computation of pension and OPEB costs (see Note 8 for additional details).

8. PENSION AND OTHER POST-EMPLOYMENT BENEFITS

OPG's pension and OPEB costs for the three months ended September 30, 2017 and 2016 are as follows:

	Registered Pension Plans		Supplementary Pension Plans		OPEB	
(millions of dollars)	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**
Components of Cost Recognized for the period						
Current service costs	**68**	70	**2**	2	**17**	16
Interest on projected benefit obligation	**138**	158	**2**	3	**27**	34
Expected return on plan assets, net of expenses	**(191)**	(185)	**-**	-	**-**	-
Amortization of net actuarial loss [1]	**45**	49	**2**	1	**-**	5
Cost recognized [2]	**60**	92	**6**	6	**44**	55

[1] The amortization of net actuarial loss is recognized as an increase to other comprehensive income. This increase for the three months ended September 30, 2017 was partially offset by a decrease in the Pension and OPEB Regulatory Asset of $44 million (three months ended September 30, 2016 – $51 million).

[2] These pension and OPEB costs for the three months ended September 30, 2017 exclude the net addition of costs of $3 million from the recognition of changes in the regulatory assets for the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB Cash Payment Variance Account (three months ended September 30, 2016 – net reduction of costs of $35 million).

OPG's pension and OPEB costs for the nine months ended September 30, 2017 and 2016 are as follows:

	Registered Pension Plans		Supplementary Pension Plans		OPEB	
(millions of dollars)	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**
Components of Cost Recognized						
Current service costs	**205**	208	**5**	5	**51**	50
Interest on projected benefit obligation	**411**	475	**8**	9	**81**	100
Expected return on plan assets, net of expenses	**(574)**	(552)	**-**	-	**-**	-
Amortization of net actuarial loss [1]	**137**	145	**5**	3	**-**	15
Cost recognized [2]	**179**	276	**18**	17	**132**	165

[1] The amortization of net actuarial loss is recognized as an increase to other comprehensive income. This increase for the nine months ended September 30, 2017 was partially offset by a decrease in the Pension and OPEB Regulatory Asset of $132 million (nine months ended September 30, 2016 – $151 million).

[2] These pension and OPEB costs for the nine months ended September 30, 2017 exclude the net addition of costs of $10 million from the recognition of changes in the regulatory assets for the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB Cash Payment Variance Account (nine months ended September 30, 2016 − net reduction of costs of $107 million).

A new actuarial valuation of the OPG registered pension plan was filed with the Financial Services Commission of Ontario in September 2017 with an effective date of January 1, 2017. The annual funding requirements in accordance with the new actuarial valuation are $212 million for 2017, $215 million for 2018, and $219 million for 2019.

9. RISK MANAGEMENT AND DERIVATIVES

OPG is exposed to risks related to changes in market interest rates on debt expected to be issued in the future and movements in foreign currency that affect the Company's assets, liabilities, and forecasted transactions. Select derivative instruments are used to manage such risks. Derivatives are used as hedging instruments, as well as for trading purposes.

Interest rate risk is the risk that the value of assets and liabilities can change due to movements in related interest rates. Interest rate risk for OPG arises with the need to refinance existing debt and/or undertake new financing. The management of these risks includes using derivatives to hedge the exposure in accordance with corporate risk management policies. OPG periodically uses interest rate swap agreements to mitigate elements of interest rate risk exposure associated with anticipated financing.

OPG's financial results are exposed to volatility in the Canadian/United States (US) foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are denominated in, or tied to, US dollars. OPG enters into foreign exchange derivatives and agreements with major financial institutions, when appropriate, in order to manage the Company's exposure to foreign currency movements.

The majority of OPG's revenues are derived from sales through the IESO administered spot market. Market participants in the IESO spot market provide collateral in accordance with the IESO prudential support requirements to cover funds that they might owe to the market. Although the credit exposure to the IESO represents a significant portion of OPG's accounts receivable, the Company's management accepts this risk due to the IESO's primary role in the Ontario electricity market. The remaining receivables exposure is to a diverse group of generally high quality counterparties. OPG's allowance for doubtful accounts as at September 30, 2017 was less than $1 million. OPG's fair value derivatives totalled a net liability of $16 million as at September 30, 2017 (December 31, 2016 – $24 million).

Existing pre-tax net losses of $20 million deferred in AOCL as at September 30, 2017 are expected to be reclassified to net income within the next 12 months.

10. FAIR VALUE MEASUREMENTS

The fair value of financial instruments traded in active markets is based on quoted market prices at the interim consolidated balance sheet dates. A market is regarded as active if quoted prices are readily and regularly available from an exchange, dealer, broker, industry group, pricing service, or regulatory agency, and those prices represent actual and regularly occurring market transactions on an arm's length basis. The quoted market price used for financial assets held by OPG is the current bid price. These instruments are included in Level 1 and are comprised primarily of equity investments and fund investments. The fair value hierarchy groups financial instruments into three levels, based on the significance of inputs used in measuring the fair value of the assets and liabilities.

For financial instruments for which quoted market prices are not directly available, fair values are estimated using forward price curves developed from observable market prices or rates. The estimation of fair value may include the use of valuation techniques or models, based wherever possible on assumptions supported by observable market prices or rates prevailing at the interim consolidated balance sheet dates. This is the case for over-the-counter derivatives and securities, which include energy commodity derivatives, foreign exchange derivatives, interest rate swap derivatives, and fund investments. Pooled fund investments are valued at the unit values supplied by the pooled fund administrators. The unit values represent the underlying net assets at fair values, determined using closing market prices. Valuation models use general assumptions and market data and therefore do not reflect the specific risks and other factors that would affect a particular instrument's fair value. The methodologies used for calculating the fair value adjustments are reviewed on an ongoing basis to ensure that they remain appropriate. If all significant inputs required to fair value an instrument are observable, the instrument is included in Level 2.

If one or more of the significant inputs is not based on observable market data, the instrument is included in Level 3. Specific valuation techniques are used to value these instruments. Significant Level 3 inputs include: recent comparable transactions, comparable benchmark information, bid/ask spread of similar transactions, and other relevant factors.

Certain alternative investments are measured at fair value by their investment managers using net asset value (NAV). Investments measured at NAV as a practical expedient for determining their fair value are excluded from the fair value hierarchy.

Transfers into, out of, or between levels are deemed to have occurred on the date of the event or change in circumstances that caused the transfer to occur.

The following is a summary of OPG's financial instruments and their fair value as at September 30, 2017 and December 31, 2016:

	Fair Value		Carrying Value [1]		
(millions of dollars)	**2017**	**2016**	**2017**	**2016**	**Balance Sheet Line Item**
Nuclear Segregated Funds (includes current portion) [2]	**16,534**	15,984	**16,534**	15,984	Nuclear fixed asset removal and nuclear waste management funds
Investment in Hydro One shares	**190**	212	**190**	212	Available-for-sale securities
Payable related to cash flow hedges	**(42)**	(48)	**(42)**	(48)	Long-term accounts payable and accrued charges
Long-term debt (includes current portion)	**(5,859)**	(6,033)	**(5,482)**	(5,520)	Long-term debt
Other financial instruments	**(11)**	(18)	**(11)**	(18)	Various

[1] The carrying values of other financial instruments included in cash and cash equivalents, receivables from related parties, other current assets, short-term debt, and accounts payable and accrued charges approximate their fair values due to the immediate or short-term maturity of these financial instruments.

[2] The Nuclear Segregated Funds are comprised of the Decommissioning Segregated Fund and the Used Fuel Segregated Fund.

The fair value of long-term debt instruments is determined based on a conventional pricing model, which is a function of future cash flows, the current market yield curve and term to maturity. These inputs are considered Level 2 inputs.

The following tables present financial assets and financial liabilities measured at fair value in accordance with the fair value hierarchy as at September 30, 2017 and December 31, 2016:

	September 30, 2017			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Used Fuel Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	**5,879**	**4,498**	**-**	**10,377**
Investments measured at NAV [1]				**1,231**
				11,608
Due to Province				**(2,155)**
Used Fuel Segregated Fund, net				**9,453**
Decommissioning Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	**4,363**	**3,343**	**-**	**7,706**
Investments measured at NAV [1]				**1,016**
				8,722
Due to Province				**(1,641)**
Decommissioning Segregated Fund, net				**7,081**
Investment in available-for-sale securities [2]	**190**	**-**	**-**	**190**
Other financial assets	**4**	**3**	**7**	**14**
Liabilities				
Other financial liabilities	**(22)**	**(3)**	**-**	**(25)**

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to amounts presented on the interim consolidated balance sheets.

(millions of dollars)	December 31, 2016 Level 1	Level 2	Level 3	Total
Assets				
Used Fuel Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	5,602	4,394	-	9,996
Investments measured at NAV [1]				1,086
				11,082
Due to Province				(1,938)
Used Fuel Segregated Fund, net				9,144
Decommissioning Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	4,171	3,243	-	7,414
Investments measured at NAV [1]				903
				8,317
Due to Province				(1,477)
Decommissioning Segregated Fund, net				6,840
Investment in available-for-sale securities	212	-	-	212
Other financial assets	6	2	9	17
Liabilities				
Other financial liabilities	(29)	(6)	-	(35)

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to amounts presented on the interim consolidated balance sheets.

During the nine months ended September 30, 2017, there were no transfers between Level 1 and Level 2. In addition, there were no transfers into or out of Level 3.

The following table presents the changes in OPG's net assets measured at fair value that are classified as Level 3 for the three months ended September 30, 2017:

(millions of dollars)	Other financial instruments
Opening balance, July 1, 2017	**9**
Realized losses included in revenue	**(4)**
Purchases	**2**
Closing balance, September 30, 2017	**7**

The following table presents the changes in OPG's net assets measured at fair value that are classified as Level 3 for the nine months ended September 30, 2017:

(millions of dollars)	Other financial instruments
Opening balance, January 1, 2017	**9**
Unrealized losses included in revenue	**(2)**
Realized losses included in revenue	**(7)**
Purchases	**7**
Closing balance, September 30, 2017	**7**

Nuclear Segregated Funds

The fair value of the investments within the Nuclear Segregated Funds' alternative investment portfolio is determined using appropriate valuation techniques, such as recent arm's length market transactions, references to current fair values of other instruments that are substantially the same, discounted cash flow analyses, third-party independent appraisals, valuation multiples, or other valuation methods. Any control, size, liquidity or other discount premiums on the investments are considered in the determination of fair value. Alternative investments are measured at fair value using NAV as a practical expedient.

The process of valuing investments for which no published market price exists is based on inherent uncertainties and the resulting values may differ from values that would have been used had a ready market existed for these investments. The values may also differ from the prices at which the investments may be sold.

The following are the classes of investments within the Nuclear Segregated Funds that are reported on the basis of NAV as at September 30, 2017:

(millions of dollars except where noted)	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice
Alternative Investments				
Infrastructure	**1,276**	**835**	**n/a**	**n/a**
Real Estate	**892**	**465**	**n/a**	**n/a**
Agriculture	**78**	**106**	**n/a**	**n/a**
Pooled Funds				
Short-term Investments	**12**	**n/a**	**Daily**	**1 - 5 Days**
Fixed Income	**643**	**n/a**	**Daily**	**1 - 5 Days**
Equity	**890**	**n/a**	**Daily**	**1 - 5 Days**
Total	**3,791**	**1,406**		

The fair value of the pooled funds is classified as Level 2. Infrastructure, real estate and agriculture investments are measured using NAV as a practical expedient for determining their fair value.

Infrastructure

This class includes investments in funds whose investment objective is to generate a combination of long-term capital appreciation and current income, generally through investments such as energy, transportation and utilities. The fair values of investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in partners' capital and/or underlying investments held by subsidiaries of an infrastructure fund. The investments in the respective infrastructure funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests/shares to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Distributions from each infrastructure fund will be received based on the operations of the underlying investments and/or as the underlying investments of the infrastructure funds are liquidated. It is not possible to estimate when the underlying assets of the infrastructure funds will be liquidated. However, the infrastructure funds have a maturity end period ranging from 2019 to 2025.

Real Estate

This class includes investments in institutional-grade real estate property. The investment objective is to provide a stable level of income with the opportunity for long-term capital appreciation. The fair values of the investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in these investments. The partnership investments are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests to another party, as stipulated in the partnership agreement. For investments in private real estate corporations, shares may be redeemed through a pre-established redemption process. It is not possible to estimate when the underlying assets in this class will be liquidated.

Agriculture

This class includes a diversified portfolio of global farmland and timberland investments. The investment objective is to provide a differentiated return source, income yield, and inflation protection. The fair values of the investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in these investments. The investments are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests/shares to another party, as stipulated in the partnership agreements and/or shareholders' agreements.

Pooled Funds

This class represents investments in pooled funds, which primarily include a diversified portfolio of fixed income securities, issued mainly by Canadian corporations, and diversified portfolios of Emerging Market listed equity. The investment objective of the pooled funds is to achieve capital appreciation and income through professionally managed portfolios. The fair value of the investments in this class has been estimated using NAV per share of the investments. There are no significant restrictions on the ability to sell the investments in this class.

11. COMMITMENTS AND CONTINGENCIES

Litigation

On August 9, 2006, a Notice of Action and Statement of Claim filed with the Ontario Superior Court of Justice in the amount of $500 million was served against OPG and Bruce Power L.P. (Bruce Power) by British Energy Limited and British Energy International Holdings Limited (together British Energy). The action is for contribution and indemnity of any amounts British Energy was liable for in an arbitration against it by some of the owners of Bruce Power regarding an alleged breach of British Energy's representations and warranties to the claimants when they purchased British Energy's interest in Bruce Power (the Arbitration). Both the action and the Arbitration relate to corrosion to a steam generator unit discovered after OPG leased the Bruce nuclear generating stations to Bruce Power.

In 2012, the arbitrator found that British Energy was liable to the claimants for some of the damages they claimed. The final settlement amount was valued by British Energy at $71 million. In September 2014, British Energy amended its Statement of Claim (Amended Claim) to reduce the claim amount to $100 million to reflect that the purchasers of British Energy's interest in Bruce Power did not receive the full damages they originally claimed in the Arbitration. British Energy also added an allegation to its Amended Claim that OPG breached a covenant to maintain the steam generator between the time of the initial agreement to lease and the effective date of the lease in accordance with "Good Utility Practices".

In November 2016, British Energy obtained consent to a timetable for the remaining steps in the litigation, pursuant to which the matter must be set down for trial by December 31, 2018. OPG has delivered a statement of defence in accordance with an extension of the original June 30, 2017 delivery deadline set out in the timetable.

Various other legal proceedings are pending against OPG or its subsidiaries covering a wide range of matters that arise in the ordinary course of business activities.

Each of these matters is subject to various uncertainties. Some of these matters may be resolved unfavourably. While it is not possible to determine the ultimate outcome of the various pending actions, it is the Company's belief that their resolution is not likely to have a material adverse impact on its financial position.

Guarantees

The Company and its joint venture partners have jointly guaranteed the financial performance of jointly owned entities related primarily to the payment of liabilities. As at September 30, 2017, the total amount of guarantees OPG provided to these entities was $82 million (December 31, 2016 − $83 million). OPG may terminate some of these

guarantees within a short time frame by providing written notice to the counterparties at any time. Other guarantees have terms ending between 2019 and 2029. As at September 30, 2017, the potential impact of the fair value of these guarantees to income has been estimated to be negligible and OPG does not expect to make any payments associated with these guarantees.

Contractual and Commercial Commitments

OPG's contractual obligations and commercial commitments as at September 30, 2017 are as follows:

(millions of dollars)	**2017** [1]	**2018**	**2019**	**2020**	**2021**	**Thereafter**	**Total**
Fuel supply agreements	52	169	96	76	62	98	553
Contributions to the OPG registered pension plan [2]	23	215	219	-	-	-	457
Long-term debt repayment	251	398	368	663	413	3,389	5,482
Interest on long-term debt	49	244	225	203	175	3,167	4,063
Commitments related to Darlington Refurbishment [3]	530	-	-	-	-	-	530
Commitments related to Peter Sutherland Sr. GS project	7	1	-	-	-	-	8
Commitments related to Ranney Falls GS project	9	29	5	-	-	-	43
Operating licences	10	40	41	24	28	115	258
Operating lease obligations	8	27	25	25	23	93	201
Unconditional purchase obligations	15	59	58	56	5	-	193
Accounts payable and accrued charges	844	8	-	-	-	16	868
Other	35	43	30	2	1	65	176
Total	1,833	1,233	1,067	1,049	707	6,943	12,832

[1] Represents amounts for the remainder of the year.

[2] The pension contributions include ongoing funding requirements and additional funding requirements towards the deficit, in accordance with the actuarial valuation of the OPG registered pension plan as at January 1, 2017. The next actuarial valuation of the OPG registered pension plan must have an effective date no later than January 1, 2020. The pension contributions are affected by various factors including market performance, changes in actuarial assumptions, plan experience, changes in the pension regulatory environment, and the timing of funding valuations. Funding requirements after 2019 are excluded due to significant variability in the assumptions required to project the timing of future cash flows. The amount of OPG's additional, voluntary contribution, if any, is revisited from time to time.

[3] Represents estimated currently committed costs to close the project, including accruals for completed work, demobilization of project staff and cancellation of existing contracts and material orders.

Contractual and commercial commitments as noted exclude certain purchase orders, as they represent purchase authorizations rather than legally binding contracts, and are subject to change without significant penalties.

12. BUSINESS SEGMENTS

Segment Income (Loss) for the Three Months Ended September 30, 2017 *(millions of dollars)*	Nuclear Generation	Regulated Nuclear Waste Manage-ment	Hydro-electric	Unregulated Contracted Generation Portfolio	Unregulated Services, Trading, and Other Non-Generation	Elimination	Total
Revenue	**739**	**33**	**327**	**141**	**9**	**(32)**	**1,217**
Fuel expense	**81**	**-**	**88**	**15**	**1**	**-**	**185**
Gross margin	**658**	**33**	**239**	**126**	**8**	**(32)**	**1,032**
Operations, maintenance and administration	**511**	**35**	**81**	**39**	**1**	**(32)**	**635**
Depreciation and amortization	**116**	**-**	**34**	**20**	**8**	**-**	**178**
Accretion on fixed asset removal and nuclear waste management liabilities	**-**	**230**	**-**	**3**	**2**	**-**	**235**
Earnings on nuclear fixed asset removal and nuclear waste management funds	**-**	**(196)**	**-**	**-**	**-**	**-**	**(196)**
Property taxes	**7**	**-**	**1**	**-**	**-**	**-**	**8**
Income from investments subject to significant influence	**-**	**-**	**-**	**(11)**	**-**	**-**	**(11)**
Other losses (gains)	**4**	**-**	**1**	**-**	**(2)**	**-**	**3**
Income (Loss) before interest and income taxes	**20**	**(36)**	**122**	**75**	**(1)**	**-**	**180**

Segment Income (Loss) for the Three Months Ended September 30, 2016 *(millions of dollars)*	Nuclear Generation	Regulated Nuclear Waste Manage-ment	Hydro-electric	Unregulated Contracted Generation Portfolio	Unregulated Services, Trading, and Other Non-Generation	Elimination	Total
Revenue	885	36	350	149	15	(35)	1,400
Fuel expense	79	-	88	19	1	-	187
Gross margin	806	36	262	130	14	(35)	1,213
Operations, maintenance and administration	521	38	87	44	11	(35)	666
Depreciation and amortization	230	-	56	19	8	-	313
Accretion on fixed asset removal and nuclear waste management liabilities	-	228	-	2	2	-	232
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(248)	-	-	-	-	(248)
Property taxes	6	-	1	1	4	-	12
Income from investments subject to significant influence	-	-	-	(11)	-	-	(11)
Other losses (gains)	2	-	1	1	(3)	-	1
Income (Loss) before interest and income taxes	47	18	117	74	(8)	-	248

Segment Income (Loss) for the Nine Months Ended September 30, 2017 *(millions of dollars)*	Nuclear Generation	Regulated Nuclear Waste Manage-ment	Hydro-electric	Unregulated Contracted Generation Portfolio	Unregulated Services, Trading, and Other Non-Generation	Elimination	Total
Revenue	**2,000**	**90**	**1,069**	**431**	**36**	**(87)**	**3,539**
Fuel expense	**217**	**-**	**258**	**42**	**1**	**-**	**518**
Gross margin	**1,783**	**90**	**811**	**389**	**35**	**(87)**	**3,021**
Operations, maintenance and administration	**1,693**	**96**	**232**	**118**	**2**	**(87)**	**2,054**
Depreciation and amortization	**333**	**-**	**103**	**59**	**22**	**-**	**517**
Accretion on fixed asset removal and nuclear waste management liabilities	**-**	**696**	**-**	**7**	**6**	**-**	**709**
Earnings on nuclear fixed asset removal and nuclear waste management funds	**-**	**(579)**	**-**	**-**	**-**	**-**	**(579)**
Property taxes	**20**	**-**	**1**	**5**	**4**	**-**	**30**
Income from investments subject to significant influence	**-**	**-**	**-**	**(29)**	**-**	**-**	**(29)**
Other losses (gains)	**4**	**-**	**1**	**-**	**(385)**	**-**	**(380)**
(Loss) Income before interest and income taxes	**(267)**	**(123)**	**474**	**229**	**386**	**-**	**699**

Segment Income (Loss) for the Nine Months Ended September 30, 2016 *(millions of dollars)*	Nuclear Generation	Regulated Nuclear Waste Manage-ment	Hydro-electric	Unregulated Contracted Generation Portfolio	Unregulated Services, Trading, and Other Non-Generation	Elimination	Total
Revenue	2,631	102	1,148	431	52	(99)	4,265
Fuel expense	239	-	259	42	1	-	541
Gross margin	2,392	102	889	389	51	(99)	3,724
Operations, maintenance and administration	1,665	108	238	129	20	(99)	2,061
Depreciation and amortization	691	-	169	56	25	-	941
Accretion on fixed asset removal and nuclear waste management liabilities	-	684	-	6	6	-	696
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(620)	-	-	-	-	(620)
Property taxes	19	-	1	6	9	-	35
Income from investments subject to significant influence	-	-	-	(28)	-	-	(28)
Other (gains) losses	-	-	(19)	1	(5)	-	(23)
Income (Loss) before interest and income taxes	17	(70)	500	219	(4)	-	662

Shareholder Declaration and Shareholder Resolution to Sell Certain Non-Core Real Estate Property

In December 2015, OPG received a Shareholder Declaration and a Shareholder Resolution that required the Company to sell its head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street in Toronto, Ontario. In December 2016, a purchase and sale agreement was executed, and the sale was completed in April 2017. A gain on sale of $283 million, which is net of tax effects of $95 million, was recognized in net income upon completion of the transaction for the nine months ended September 30, 2017. The pre-tax gain on sale was recorded as an item of Other gains in the interim consolidated statement of income in the Services, Trading and Other Non-Generation segment. Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. OPG is working with the Ontario Ministry of Finance to finalize the amount of designated proceeds to be transferred into the Province's Consolidated Revenue Fund. [**MONITOR**]

13. NET CHANGES IN NON-CASH WORKING CAPITAL BALANCES

(millions of dollars)	Nine Months Ended September 30 2017	2016
Receivables from related parties	**72**	107
Prepaid expenses	**(18)**	(52)
Other current assets	**10**	(7)
Fuel inventory	**20**	41
Income taxes payable	**(92)**	49
Materials and supplies	**4**	(2)
Accounts payable and accrued charges	**(51)**	(195)
	(55)	(59)

14. INVESTMENTS SUBJECT TO SIGNIFICANT INFLUENCE

Investments subject to significant influence consist of OPG's 50 percent ownership interest in the jointly controlled entities of the PEC gas-fired combined cycle generating station and the Brighton Beach gas-fired combined cycle generating station (Brighton Beach), which are accounted for using the equity method. Details of the balances as at September 30, 2017 and December 31, 2016 are as follows:

(millions of dollars)	September 30 2017	December 31 2016
PEC		
Current assets	**19**	18
Long-term assets	**244**	256
Current liabilities	**(9)**	(8)
Long-term liabilities	**(5)**	(5)
Brighton Beach		
Current assets	**5**	5
Long-term assets	**162**	168
Current liabilities	**(17)**	(16)
Long-term liabilities	**(8)**	(7)
Long-term debt	**(78)**	(90)
Investments subject to significant influence	**313**	321

15. NON-CONTROLLING INTEREST

PSS Generating Station LP

PSS is a limited partnership between OPG, Coral Rapids Power Corporation (CRP), and PSS Generating Station Inc. (PSS GS Inc.). The principal business of the partnership is the development, construction, ownership, operation and maintenance of the 28 MW Peter Sutherland Sr. hydroelectric GS on the New Post Creek. OPG and PSS GS Inc. are general partners and CRP is a limited partner in the partnership. CRP is a wholly owned subsidiary of the Taykwa Tagamou Nation.

The Peter Sutherland Sr. GS was placed in-service in March 2017 and, in April 2017, CRP increased its interest in PSS to 33 percent under the partnership agreement, by making contributions of $21 million, reducing OPG's interest to 67 percent. As a result of the contributions made by OPG and CRP, PSS has met the criteria of having sufficient equity at risk to finance its activities, and ceased being classified as a variable interest entity during the second quarter of 2017. OPG continues to consolidate the results of PSS in its consolidated financial statements. CRP's 33 percent interest in PSS is reported as non-controlling interest. As a result of CRP increasing its interest in the partnership, PSS' AOCL and partner's deficit were proportionately allocated to CRP as a reduction to its non-controlling interest as of September 30, 2017.

ONTARIO POWER GENERATION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

2017 THIRD QUARTER REPORT

[DRAFT]

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ONTARIO POWER GENERATION

ONTARIO POWER GENERATION INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) should be read in conjunction with the unaudited interim consolidated financial statements and accompanying notes of Ontario Power Generation Inc. (OPG or Company) as at and for the three and nine months ended September 30, 2017. OPG's unaudited interim consolidated financial statements are prepared in accordance with United States generally accepted accounting principles (US GAAP) and are presented in Canadian dollars.

For a complete description of OPG's corporate strategies, risk management, corporate governance, and the effect of critical accounting policies and estimates on OPG's results of operations and financial condition, this MD&A should also be read in conjunction with OPG's audited consolidated financial statements, accompanying notes, the Annual Information Form, and the MD&A as at and for the year ended December 31, 2016.

As required by *Ontario Regulation 395/11*, as amended, a regulation under the *Financial Administration Act* (Ontario), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. In 2014, the Ontario Securities Commission approved an exemption which allows OPG to apply US GAAP up to January 1, 2019. The term of the exemption is subject to certain conditions, which may result in the expiry of the exemption prior to January 1, 2019. For details, refer to the section, *Critical Accounting Policies and Estimates* under the heading, *Exemptive Relief for Reporting under US GAAP,* in OPG's 2016 annual MD&A. This MD&A is dated November 9, 2017.

FORWARD-LOOKING STATEMENTS

The MD&A contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could", and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

All forward-looking statements involve inherent assumptions, risks, and uncertainties, including those set out in the section, *Risk Management,* and forecasts discussed in the section, *Core Business, Strategy, and Outlook.* All forward-looking statements could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's generating station performance and availability, fuel costs, surplus baseload generation (SBG), cost of fixed asset removal and nuclear waste management, performance and earnings of investment funds, refurbishment of existing facilities, development and construction of new facilities, pension and other post-employment benefit (OPEB) obligations and funds, income taxes, proposed new legislation, the ongoing evolution of Ontario's electricity industry, environmental and other regulatory requirements, health, safety and environmental developments, business continuity events, the weather, financing and liquidity, applications to the Ontario Energy Board (OEB) for regulatory prices, the impact of regulatory decisions by the OEB, and forecasts of earnings, cash flows, Funds from Operations (FFO) Adjusted Interest Coverage, Return on Common Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI), Total Generating Cost (TGC) and capital expenditures. Accordingly, undue reliance should not be placed on any forward-looking statement. The forward-looking statements included in this MD&A are made only as of the date of this MD&A. Except as required by applicable securities laws, OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events, or otherwise.

THE COMPANY

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG was established under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (Province or Shareholder).

As at September 30, 2017, OPG's electricity generation portfolio had an in-service capacity of 16,210 megawatts (MW). OPG operates two nuclear generating stations, 66 hydroelectric generating stations, three thermal generating stations, and one wind power turbine. In addition, OPG and TransCanada Energy Ltd. co-own the 550 MW Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS). OPG and ATCO Power Canada Ltd. co-own the 560 MW Brighton Beach gas-fired combined cycle GS (Brighton Beach). OPG's 50 percent share of the in-service capacity and generation volume of these co-owned facilities is included in the generation portfolio statistics set out in this report. The income from the co-owned facilities is accounted for using the equity method of accounting, and OPG's share of income is presented as income from investments subject to significant influence in the Contracted Generation Portfolio segment.

OPG also owns two other nuclear generating stations, the Bruce A GS and the Bruce B GS, which are leased on a long-term basis to Bruce Power LP (Bruce Power). Income from these leased stations is included in revenue under the Regulated – Nuclear Generation segment. The leased stations are not included in the generation portfolio statistics set out in this report.

All of OPG's owned and co-owned generating facilities are located in Ontario. OPG does not operate PEC, Brighton Beach, the Bruce A GS and the Bruce B GS.

A description of OPG's segments is provided in OPG's 2016 annual MD&A in the section, *Business Segments*.

In-Service Generating Capacity

OPG's in-service generating capacity by business segment as at September 30, 2017 and December 31, 2016 was as follows:

	As at	
(MW)	**September 30 2017**	**December 31 2016**
Regulated – Nuclear Generation [1]	**5,728**	5,728
Regulated – Hydroelectric	**6,426**	6,421
Contracted Generation Portfolio [2]	**4,056**	4,028
Total	**16,210**	16,177

[1] The in-service generating capacity as of September 30, 2017 and December 31, 2016 excludes Unit 2 of the Darlington GS. The unit, which has a generating capacity of 878 MW, was taken offline in mid-October 2016 and is currently undergoing refurbishment.

[2] Includes OPG's share of in-service generating capacity of 275 MW for PEC and 280 MW for Brighton Beach.

During the nine months ended September 30, 2017, the total in-service capacity increased by 33 MW. The increase was primarily due to the completion of the Peter Sutherland Sr. hydroelectric GS, which was placed in-service at the end of the first quarter of 2017, and the upgrade of Unit 10 of the Sir Adam Beck 1 hydroelectric GS, which was completed in June 2017.

HIGHLIGHTS

Overview of Results

This section provides an overview of OPG's unaudited interim consolidated operating results. Significant factors which contributed to OPG's results during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, are discussed below.

(millions of dollars – except where noted) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Revenue	**1,217**	1,400	**3,539**	4,265
Fuel expense	**185**	187	**518**	541
Gross margin	**1,032**	1,213	**3,021**	3,724
Operations, maintenance and administration	**635**	666	**2,054**	2,061
Depreciation and amortization	**178**	313	**517**	941
Accretion on fixed asset removal and nuclear waste management liabilities	**235**	232	**709**	696
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(196)**	(248)	**(579)**	(620)
Income from investments subject to significant influence	**(11)**	(11)	**(29)**	(28)
Property taxes	**8**	12	**30**	35
	849	964	**2,702**	3,085
Income before other losses (gains), interest and income taxes	**183**	249	**319**	639
Other losses (gains)	**3**	1	**(380)**	(23)
Income before interest and income taxes	**180**	248	**699**	662
Net interest expense	**21**	28	**56**	92
Income before income taxes	**159**	220	**643**	570
Income tax expense	**19**	22	**128**	109
Net income	**140**	198	**515**	461
Net income attributable to the Shareholder	**131**	194	**498**	449
Net income attributable to non-controlling interest [1]	**9**	4	**17**	12
Electricity production (TWh) [2]	**19.4**	19.5	**56.0**	59.9
Cash flow provided by operating activities	**485**	530	**698**	1,211

[1] Relates to the 25 percent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in the Lower Mattagami Limited Partnership, the 33 percent interest of Coral Rapids Power Corporation, a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership, and the 10 percent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP.

[2] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

Commented [A1]:
Wondering if this should be 437?
Since:
Q3 9-mos ended – Q2 6-mos ended = 698-261 = 437

Was Q2 "6-month ended June 30" number for Cash flow provided by operating activities revised?

Third Quarter

Net income attributable to the Shareholder was $131 million for the third quarter of 2017, a decrease of $63 million compared to the same quarter in 2016. Income before interest and income taxes for the third quarter of 2017 was $180 million, a decrease of $68 million compared to the same quarter in 2016.

Significant factors that reduced income before interest and income taxes:

- Lower earnings from the nuclear base regulated price of approximately $24 million reflecting lower electricity generation of 0.4 terawatt hours (TWh) from the Regulated – Nuclear Generation segment and the continuation of existing base regulated prices set by the OEB in 2014. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS since October 2016, largely offset by an increase in generation from Pickering GS. The increase in generation from the Pickering GS was primarily due to outage optimization, favourable unit conditions and execution of planned outage work. The base regulated prices set in 2014 continue to be in effect pending the OEB's decision on OPG's current application for new regulated prices, expected later in 2017. **[MONITOR]** The existing nuclear base regulated price was set to allow the Company to recover its approved nuclear costs over a higher nuclear production volume, based on the 2014 and 2015 outage profile that did not include a refurbishment outage. OPG has requested January 1, 2017 as the effective date of the new regulated prices.
- Lower earnings on the nuclear fixed asset removal and nuclear waste management funds (Nuclear Segregated Funds) of $52 million.
- Higher depreciation and amortization expense of $16 million in the Regulated – Nuclear Generation segment, excluding amortization expense related to balances in OEB-authorized regulatory variance and deferral accounts (regulatory accounts), primarily due to new assets in service.

Commented [A2]: If approved by OEB (during Q4), would this result in a higher regulated price and a revenue/net income pick up for 2017 reported in OPG's Q4?

The expiry of rate riders for the recovery of approved balances in OEB-authorized regulatory accounts on December 31, 2016 contributed to the decrease in revenue for the three months ended September 30, 2017, compared to the same period in 2016, but was largely offset by a decrease in the amortization expense related to these balances. OPG has requested new rate riders in its current application to the OEB for new regulated prices, with a proposed effective date of January 1, 2017.

Significant factor that increased income before interest and income taxes:

- Lower operations, maintenance and administration (OM&A) expenses of $31 million, mainly in the Regulated – Nuclear Generation segment, as a result of a higher materials and supplies obsolescence charge recognized in the third quarter of 2016, Services, Trading and Other Non-Generation segment due to project expenditures incurred in the third quarter of 2016, and Regulated – Hydroelectric segment due to the timing of repairs and maintenance work in 2017 and a deferral of outages during the high water period.

Net interest expense decreased by $7 million during the third quarter of 2017, compared to the same quarter in 2016, primarily due to a higher amount of interest costs capitalized for the Darlington Refurbishment project expenditures and a higher amount of interest costs deferred in OEB-authorized regulatory accounts.

Income tax expense for the three months ended September 30, 2017 was $19 million, compared to $22 million for the same period in 2016. The decrease in income tax expense was primarily due to lower income before taxes and a higher change in reserves from the resolution of uncertainties, partially offset by a lower amount of tax expense deferred in regulatory assets.

Year-To-Date

Net income attributable to the Shareholder was $498 million for the first nine months of 2017, an increase of $49 million compared to the same period in 2016. Income before interest and income taxes for the first nine months of 2017 was $699 million, an increase of $37 million compared to the same period in 2016.

Significant factor that increased income before interest and income taxes:

- Higher earnings of $390 million from the Services, Trading, and Other Non-Generation segment, primarily reflecting the gain on sale of OPG's head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street that was recognized in the second quarter of 2017. The sale of the

assets was required by a Shareholder Declaration and a Shareholder Resolution. The gain on sale was $283 million, which is net of tax effects of $95 million.

Significant factors that reduced income before interest and income taxes:

- Lower earnings from the nuclear base regulated price of approximately $230 million, partially offset by a decrease in nuclear fuel expense of $22 million, reflecting lower electricity generation of 4.0 TWh from the Regulated – Nuclear Generation segment and the continuation of existing base regulated prices set by the OEB in 2014. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS, partially offset by an increase in generation from Pickering GS.
- Lower earnings on the Nuclear Segregated Funds of $41 million.
- Higher depreciation and amortization expense of $30 million in the Regulated – Nuclear Generation segment, excluding amortization expense related to regulatory account balances, primarily due to new assets in service.
- A gain of $22 million recorded in the first quarter of 2016 to reflect the OEB's decision on OPG's motion asking the OEB to review and vary parts of its November 2014 decision on OPG's regulated prices.

The expiry of rate riders for the recovery of approved balances in OEB-authorized regulatory accounts on December 31, 2016 contributed to the decrease in revenue for the nine months ended September 30, 2017, compared to the same period in 2016, but was primarily offset by a decrease in the amortization expense related to these balances.

Net interest expense decreased by $36 million for the nine months ended September 30, 2017, compared to the same period in 2016, primarily due to a higher amount of interest costs capitalized for the Darlington Refurbishment project expenditures and a higher amount of interest costs deferred in OEB-authorized regulatory accounts.

Commented [A3]: Does this imply there were interest costs related to Darlington Refurb previously (same quarter previous year), that were not capitalized, but were able to be capitalized this year?

Income tax expense for the nine months ended September 30, 2017 was $128 million, compared to $109 million for the same period in 2016. The increase in income tax expense was primarily due to higher income before income taxes.

Segment Results

The following table summarizes OPG's income before interest and income taxes by business segment. A detailed discussion of OPG's performance by reportable segment is included in the section, *Discussion of Operating Results by Business Segment*.

(millions of dollars)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Income (loss) before interest and income taxes				
Regulated – Nuclear Generation	**20**	47	**(267)**	17
Regulated – Hydroelectric	**122**	117	**474**	500
Contracted Generation Portfolio	**75**	74	**229**	219
Total electricity generation business segments	**217**	238	**436**	736
Regulated – Nuclear Waste Management	**(36)**	18	**(123)**	(70)
Services, Trading, and Other Non-Generation	**(1)**	(8)	**386**	(4)
	180	248	**699**	662

Electricity Generation

Electricity generation for the three and nine month periods ended September 30, 2017 and 2016 was as follows:

(TWh)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Regulated – Nuclear Generation	**11.3**	11.7	**30.6**	34.6
Regulated – Hydroelectric	**7.3**	6.9	**23.5**	22.8
Contracted Generation Portfolio [1]	**0.8**	0.9	**1.9**	2.5
Total OPG electricity generation	**19.4**	19.5	**56.0**	59.9
Total electricity generation by all other generators in Ontario [2]	**16.6**	19.5	**51.7**	53.8

[1] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.
[2] Non-OPG generation is calculated as the Ontario electricity demand plus net exports, as published by the Independent Electricity System Operator (IESO), minus OPG electricity generation.

Total OPG electricity generation decreased by 0.1 TWh during the third quarter of 2017, compared to the same quarter in 2016, and by 3.9 TWh during the nine months ended September 30, 2017, compared to the same period in 2016. As expected, the lower electricity generation from the Regulated – Nuclear Generation segment was primarily the result of the removal from service of Unit 2 at the Darlington GS for the duration of the unit's refurbishment, which began in October 2016. This decrease in electricity generation was largely offset by an increase in generation from the Pickering GS, primarily due to outage optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station, and higher hydroelectric generation from the Regulated – Hydroelectric segment.

The higher electricity generation of 0.4 TWh and 0.7 TWh from the Regulated – Hydroelectric segment for the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016, was due to higher water flows primarily on the eastern Ontario river systems, net of water spilled as a result of SBG conditions, discussed below.

The lower electricity generation of 0.6 TWh from the Contracted Generation Portfolio segment for the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to higher SBG conditions. The electricity generation from the Contracted Generation Portfolio segment for the three months ended September 30, 2017 was comparable to the same period in 2016.

OPG's operating results are impacted by changes in grid-supplied electricity demand resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. For the three and nine month periods ended September 30, 2017, Ontario's electricity demand as reported by the IESO was 33.6 TWh and 98.5 TWh, respectively, compared to 36.7 TWh and 103.8 TWh for the same periods in 2016, respectively, excluding electricity exports out of the province.

Power that is surplus to the Ontario market is managed by the IESO, mainly through generation reductions at hydroelectric, other grid-connected renewable resources and nuclear stations. Reducing hydroelectric production is the first measure used by the IESO to manage SBG conditions. Low demand conditions in Ontario continued to be prevalent in 2017, resulting in forgone hydroelectric generation for OPG of 1.1 TWh and 4.5 TWh due to SBG conditions in the three and nine month periods ended September 30, 2017, respectively, compared to 0.5 TWh and 3.9 TWh during the same periods in 2016, respectively. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions during these periods was offset by the impact of a regulatory variance account authorized by the OEB. OPG did not forgo any electricity production at its nuclear stations due to SBG conditions.

Average Sales Prices

The majority of OPG's generation is from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments. The same base regulated prices for electricity generated by these segments, authorized by the OEB effective November 1, 2014, were in effect during the first nine months of 2017 as in 2016. These prices will remain in effect until such time as the OEB approves new regulated prices based on OPG's current application. **[MONITOR]** The base regulated prices established in 2014 are discussed in OPG's 2016 annual MD&A in the section, *Revenue Mechanisms for Regulated and Non-Regulated Generation*.

The average sales price for the Regulated – Nuclear Generation segment was 5.8 cents per kilowatt hour (¢/kWh) during the three and nine month periods ended September 30, 2017, respectively, compared to 6.9 ¢/kWh during the same periods in 2016. The decrease in the average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized nuclear rate rider of $10.84 per megawatt hour (MWh) for the recovery of variance and deferral account balances. The average sales price for the Regulated – Hydroelectric segment was 4.1 ¢/kWh during the three and nine month periods ended September 30, 2017, respectively, compared to 4.4 ¢/kWh during the same periods in 2016. The decrease in the average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized regulated hydroelectric rate rider of $3.19/MWh for the recovery of variance and deferral account balances. The rate riders were established to recover approved balances recorded in the variance and deferral accounts in prior years. As such, the year-over-year changes in revenue from the rate riders were largely offset by changes in amortization expense related to these balances. There were no rate riders in effect during the nine months ended September 30, 2017 for either nuclear or regulated hydroelectric generation, pending the outcome of OPG's current application with the OEB for new regulated prices.

Cash Flow from Operations

Cash flow provided by operating activities was $485 million for the three months ended September 30, 2017 and $698 million for the nine months ended September 30, 2017, compared to $530 million and $1,211 million for the same periods in 2016, respectively. The decrease in cash flow provided by operating activities was expected and primarily due to lower generation revenue receipts reflecting lower generation from the Regulated – Nuclear Generation segment as a result of the ongoing refurbishment of Unit 2 at the Darlington GS and the expiry, on December 31, 2016, of the OEB-authorized rate riders for nuclear and regulated hydroelectric generation. The decrease in cash flow during the nine months ended September 30, 2017 was also due to higher income tax instalments.

The decrease in cash flow provided by operating activities for the three and nine month periods ended September 30, 2017 was partly offset by lower OM&A expenditures and lower contributions to the Used Fuel Segregated Fund in 2017. Both the Used Fuel Segregated Fund and the Decommissioning Segregated Fund were determined to be fully funded based on an updated estimate of OPG's nuclear waste management and nuclear facilities decommissioning obligations pursuant to a reference plan approved by the Province, for years 2017 to 2021, under the Ontario Nuclear Funds Agreement (ONFA), effective January 1, 2017. Pursuant to the ONFA, the reference plan is required to be updated at least once every five years. Contributions to either or both of the Nuclear Segregated Funds may be required in the future should the funds be in an underfunded position at the time of the next ONFA reference plan update. The year-over-year decrease in cash flow also was partially offset by the payment of a supplemental rent rebate to Bruce Power in the first quarter of 2016 in relation to a period in 2015. The lease agreement for the Bruce nuclear generating stations was amended in late 2015 to eliminate this rebate provision going forward.

Return on Common Equity Excluding Accumulated Other Comprehensive Income

ROE Excluding AOCI is an indicator of OPG's performance consistent with the Company's strategy to provide value to the Shareholder. ROE Excluding AOCI is measured over a 12-month period.

ROE Excluding AOCI was 4.4 percent for the 12 months ended September 30, 2017, compared to 4.2 percent for the 12 months ended December 31, 2016. The increase was primarily due to higher net income attributable to the Shareholder for the 12 months ended September 30, 2017, which reflected the gain on sale of OPG's head office premises and associated parking facility recorded in the second quarter of 2017, partially offset by the lower earnings from the decrease in nuclear electricity generation reflecting the Unit 2 refurbishment outage at the Darlington GS without a corresponding increase in the nuclear base regulated price, as expected. The lower nuclear generation as a result of the refurbishment outage will continue to negatively affect OPG's ROE Excluding AOCI until such time as new regulated prices are approved by the OEB, anticipated in the fourth quarter of 2017. **[MONITOR]**

Funds from Operations Adjusted Interest Coverage

FFO Adjusted Interest Coverage is an indicator of OPG's ability to meet interest obligations from operating cash flows. The indicator is measured over a 12-month period. FFO Adjusted Interest Coverage for the 12 months ended September 30, 2017 was 4.2 times, compared to 5.1 times for the 12 months ended December 31, 2016. FFO Adjusted Interest Coverage in 2017 reflected a year-over-year decrease in FFO before interest due to lower cash flow provided by operating activities, partially offset by the impact of a lower adjusted interest expense due to a decrease in the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets.

The decrease in the excess of interest on pension and OPEB benefit obligations over expected return on pension plan assets in the nine months of 2017 was primarily due to the change in the method used to estimate the interest cost and service cost components of pension and OPEB costs. Effective January 1, 2017, OPG adopted a full yield curve approach to the estimation of these cost components, by applying the specific spot rates along the yield curve used in the determination of the projected benefit obligations to the relevant projected cash flows. Under the previous method, these components of pension and OPEB costs were calculated using the same single weighted-average discount rates as reflected in the calculation of the benefit obligations. This change in the method was accounted for prospectively, as a change in estimate. The resulting reduction in pension and OPEB costs for the three and nine month periods ended September 30, 2017 did not have a material impact on net income as it was largely offset by the impact of OEB-authorized variance and deferral accounts in the regulated business segments. Further details on the full yield curve approach can be found in the 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Pension and Other Post-Employment Benefits*.

Enterprise Total Generating Cost per MWh

The Enterprise TGC per MWh decreased to $46.65 for the three months ended September 30, 2017, compared to $50.72 for the same quarter in 2016. The decrease was mainly due to lower OM&A expenses before the impact of regulatory accounts and higher SBG-adjusted hydroelectric generation reflecting higher water flows.

The Enterprise TGC per MWh was $47.77 for the nine months ended September 30, 2017, an increase compared to $46.74 for the same period in 2016. The increase was expected and mainly a result of lower electricity generation due to the Unit 2 refurbishment outage at the Darlington GS, largely offset by lower OM&A expenses before the impact of regulatory accounts and higher SBG-adjusted hydroelectric generation reflecting higher water flows.

If Unit 2 at the Darlington GS was not currently undergoing refurbishment and had continued to operate in a manner consistent with the performance of the remaining units at the Darlington GS, adjusting for generation constraints on these units related to the transition of the station toward refurbishment, the Enterprise TGC would have been approximately $4 per MWh lower for both the three and nine month periods ended September 30, 2017. This sensitivity was calculated using the estimated incremental electricity and associated fuel cost that are expected to have resulted in the absence of the refurbishment.

Nuclear Total Generating Cost per MWh

The Nuclear TGC per MWh was $58.75 for the three months ended September 30, 2017, which was comparable to $58.55 for the same quarter in 2016. For the three months ended September 30, 2017, the higher generation at the Pickering GS and the impact of lower OM&A expenses before the impact of regulatory accounts was mostly offset by the expected decrease in nuclear electricity generation reflecting the Unit 2 refurbishment outage at the Darlington GS and higher sustaining capital expenditures. The Nuclear TGC per MWh was $67.87 for the nine months ended September 30, 2017, compared to $61.07 for the same period in 2016. The increase in the Nuclear TGC per MWh for the nine months ended September 30, 2017 was expected and primarily due to the decrease in nuclear electricity generation, partially offset by lower OM&A expenses before the impact of regulatory accounts.

Hydroelectric Total Generating Cost per MWh

The Hydroelectric TGC per MWh was $26.20 for the three months ended September 30, 2017, compared to $31.01 for the same quarter in 2016. The decrease was primarily due to higher SBG-adjusted hydroelectric electricity generation reflecting higher water flows. The Hydroelectric TGC per MWh was $21.74 for the nine months ended September 30, 2017, compared to $23.99 for the same period in 2016. The decrease was primarily due to lower OM&A expenses before the impact of regulatory accounts and lower sustaining capital expenditures.

ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are not measurements in accordance with US GAAP and should not be considered alternative measures to net income, cash flow provided by operating activities, or any other performance measure under US GAAP. OPG believes that these non-GAAP financial measures are effective indicators of its performance and are consistent with the Company's strategic imperatives and related objectives. The definition and calculation of ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are found in the section, *Supplementary Non-GAAP Financial Measures*.

Recent Developments

Ontario's 2017 Long Term Energy Plan

On October 26, 2017, Ontario's Ministry of Energy issued the 2017 Long Term Energy Plan. The Plan is currently being analyzed by OPG but is not expected to significantly impact OPG's business. There are no fundamental changes from the principles in the 2013 Long Term Energy Plan, which include cost effectiveness, reliability, clean energy and community engagement. The 2017 Long Term Energy Plan fully supports nuclear refurbishment projects in Ontario and the extension of commercial operation of all Pickering units to 2024. **[MONITOR & UPDATE DETAILS FOLLOWING RELEASE]**

OEB's Decision on New Regulated Prices **[MONITOR]**

Ontario's Fair Hydro Plan

OPG continues to prepare for its involvement as the Financial Services Manager for Ontario's Fair Hydro Plan (the Fair Hydro Plan) on a commercial basis. Accordingly, the financing entity was established in XX 2017 as the Fair Hydro Trust (the Trust), following the execution of its constating documents. The majority unitholder and beneficiary of the Trust is a wholly-owned subsidiary of OPG. Through this ownership and OPG's control over the key activities of the Trust, the Company will consolidate the Trust for accounting purposes commencing in the fourth quarter of 2017. **[MONITOR]**

In order for the Trust to provide financing for the deferred Global Adjustment costs, the Trust will incur senior debt from capital markets and subordinated debt from OPG. The Trust is structured to be bankruptcy remote and ring fenced from OPG to protect the Company's assets and operations. In support of the Fair Hydro Plan, the following developments have transpired:

Commented [A4]: Please confirm if there are 3 organizations:
There's OPG,
There's 'the Trust'
And also there's a 'wholly-owned subsidiary of OPG'.

- In October 2017, *Ontario Regulation 206/17 General* was amended to establish details of the recovery mechanism for the monthly carrying costs incurred by the Trust from June 1, 2017 to July 31, 2021 payable by the IESO to the Trust. Originally established in June 2017, this regulation provides more details on the funding obligations incurred by the Trust and the fair allocation amount, the determination and collection of clean energy adjustments, the determination of the finance amount, the true up amount, and the regulatory asset, as well as principles and assumptions relating to the financing plan.
- A plan to amend the Company's Articles of Amalgamation to allow for the creation and issuance of Class A shares to be issued to the Province for its equity investment through OPG in the Fair Hydro Plan is in progress. The Province is expected to provide 44 percent of the total funding requirement related to the deferred Global Adjustment costs, which OPG will invest as subordinated debt into the Trust. OPG's Board approval and a Shareholder Resolution are expected later in the year to authorize the amendment.
- OPG is expected to provide five percent of the total funding requirement of the Trust related to the deferred Global Adjustment costs of the Fair Hydro Plan. OPG issued senior notes payable in October 2017 under a short form base shelf prospectus for general corporate purposes and to fund OPG's subordinated debt investment in the Trust. Further details of the debt offering can be found in the section, *Liquidity and Capital Resources* under the heading, *Financing Activities*.

Commented [A5]: Are any other details available to be released at this time?

The first set of transactions of the Trust are expected to take place in the fourth quarter of 2017.

Canadian Nuclear Safety Commission Safety Rating for the Darlington GS and the Pickering GS

The Canadian Nuclear Safety Commission (CNSC) publishes an annual report on the safety performance of Canada's nuclear power plants. The report assesses how well plant operators are meeting regulatory requirements and program expectations in the areas of operational performance, safety analysis, radiation protection, waste management and conventional health and safety. On September 8, 2017, the CNSC issued an executive summary of its 2016 annual report. The CNSC gave both the Darlington GS and the Pickering GS the highest possible safety rating of "Fully Satisfactory". The Darlington GS achieved this rating for the eighth consecutive year, while the Pickering GS achieved this rating for the second consecutive year.

CORE BUSINESS, STRATEGY, AND OUTLOOK

The discussion in this section is qualified in its entirety by the cautionary statements included in the section, *Forward-Looking Statements,* at the beginning of the MD&A.

OPG's mission is to provide low cost power in a safe, clean, reliable and sustainable manner for the benefit of customers and its Shareholder. OPG also seeks to pursue, on a commercial basis, generation development projects and other business growth opportunities.

The following sections provide an update to OPG's disclosures in the 2016 annual MD&A related to its four key strategic imperatives – operational excellence, project excellence, financial strength, and social licence. A detailed discussion of these strategic imperatives is included in the 2016 annual MD&A in the section, *Core Business, Strategy, and Outlook*.

Operational Excellence

Operational excellence at OPG is accomplished by the safe and environmentally responsible generation of reliable and cost-effective electricity from the Company's generating assets through a highly trained and engaged workforce.

Electricity Generation Production and Reliability

- As part of the plan to extend Pickering operations, OPG is continuing to undertake the required technical work to confirm that the station's pressure tubes, a key life-limiting component of the station, will remain fit for service for operation to 2024. OPG is also nearing completion of component condition assessments to identify the work required to support the continued operation of the station. The accounting end of life assumptions for the Pickering GS, currently set at the end of 2020, will be reassessed based on the fuel channel analysis and safety case consistent with submissions for the CNSC approval, discussed below. The activities completed to date have had positive results, which will go towards re-confirming Pickering operations past 2020 are technically feasible. The Periodic Safety Review (PSR) is in progress and will confirm that extending operations of the Pickering units will be safe to the public, workers and the environment. The PSR consists of Safety Factor Reports (SFRs), a Global Assessment Report (GAR), and the Integration Improvement Plan (IIP). SFRs have been submitted to the CNSC and the GAR and IIP are on track for CNSC submission in October and November 2017, respectively. Other technical feasibility activities continue to progress as planned. Completion of various technical feasibility assessments are required to reach a high confidence conclusion to allow the station end of life to change for depreciation purposes. OPG's current application with the OEB for new base regulated prices, currently pending the OEB's decision, reflects OPG's plans to extend Pickering operations to 2024 and requests inclusion of the corresponding cost and generation impacts in the determination of the nuclear regulated price.
- OPG's current five-year operating licence for the Pickering GS was approved by the CNSC in 2013 and expires on August 31, 2018. This licence was issued assuming that the station would shut down in 2020. On June 28, 2017, OPG confirmed to the CNSC that it intends to cease commercial operation of all Pickering units on December 31, 2024. On August 28, 2017, OPG submitted a ten-year licence renewal application to the CNSC. The licence term spans the planned extended operations period, through to the end of commercial operation, defueling, dewatering and the start of placing the station in a safe storage state.
- Work continues on the rehabilitation of Unit 2 of the DeCew Falls hydroelectric GS and the rehabilitation and overhaul of Unit 2 of the Lower Notch hydroelectric GS.
- During the third quarter, a new control centre was opened at Saunders GS to merge its operations with Chenaux GS. The new control centre will overlook power production at ten hydroelectric stations along the Madawaska, Ottawa and St. Lawrence rivers.
- As part of the process to decommission the Nanticoke and Lambton generating stations, OPG has begun executing demolition plans that will ensure that the stations are closed safely, securely and in an environmentally responsible manner. The demolition of the Nanticoke coal yard equipment and structures is in progress, with a contract issued in July 2017 for the demolition of the Nanticoke powerhouse and associated structures. Project milestones for the Nanticoke site during the remainder of 2017 include completing the removal of coal yard equipment and structures, demolition of the ash silos, and mobilization of the contractor to prepare for removal of the stacks, powerhouse and associated structures. A competitive bidding process for the demolition of the Lambton GS has been completed, with a contract for the removal of the powerhouse and associated buildings expected to be awarded in 2018. An update of the associated asset retirement obligations related to the Nanticoke and Lambton sites is expected to be finalized in the fourth quarter of 2017.

Environmental Performance

There were no significant changes to environmental legislation affecting the Company during the third quarter of 2017. Disclosures related to the Company's environmental policy and environmental risks can be found in OPG's 2016 annual MD&A.

OPG communicates its environmental performance internally to employees and to external stakeholders, including the Ontario Ministry of the Environment and Climate Change, Environment and Climate Change Canada, the CNSC, and local communities. Details of OPG's environmental performance and initiatives to fulfill the Company's Environmental Policy can be found in OPG's 2016 Sustainability Report, available on the Company's website at www.opg.com. **[MONITOR]**

Project Excellence

OPG is pursuing a number of generation development and other major projects in support of Ontario's electricity planning initiatives. OPG remains focused on delivering projects safely, on time, on budget and with high quality. The status updates for OPG's major projects as at September 30, 2017 are outlined in the following table, with further details below.

Project	Capital expenditures		Approved budget	Expected in-service date	Current status
(millions of dollars)	**Year-to-date**	**Life-to-date**			
Darlington Refurbishment	924	4,109	12,800 [1]	First unit - 2020 Last unit - 2026	The setup of specialized tooling and equipment needed for the removal of reactor components was completed in the third quarter of 2017. All feeder tubes have been removed safely, and the pressure tubes have been severed in preparation for their removal. The Re-tube Waste Processing Building will be available for use in the fourth quarter of 2017. The project is tracking on schedule and on budget.
Peter Sutherland Sr. Hydroelectric GS	38	274	300	2017	The station was placed in-service on March 31, 2017, ahead of the originally planned schedule, and is expected to close below the approved budget. Project close-out activities are in progress.
Ranney Falls Hydroelectric GS	17	20	77	2019	Work is progressing on the expanded forebay, forebay wall concrete replacement, powerhouse and spillway areas. The project is tracking on schedule and on budget.
Nanticoke Solar Facility	1	2	107 **[MONITOR]**	2019	Project definition work is continuing, with construction planned to commence in the first quarter of 2018.
Deep Geologic Repository for low and intermediate level radioactive waste (L&ILW)	7 [2]	202 [2]			On August 21, 2017, the federal Minister of Environment and Climate Change requested further information on the project's environmental assessment (EA). OPG is reviewing the new request and will notify the Canadian Environmental Assessment Agency (CEAA) when it has a timeline for submission of that information.

[1] The total project budget of $12.8 billion is for the refurbishment of all four units at the Darlington GS.
[2] Expenditures are charged against the nuclear fixed asset removal and nuclear waste management liabilities (Nuclear Liabilities).

Commented [A6]: Does this imply that only 700M further is anticipated to be spent by the time Unit 2 gets completed? (Eg. 4.8B in Capital Expenditure)

Eg. from above:
"Once refurbished, Unit 2 is scheduled to be returned to service in the first quarter of 2020, at which time capital expenditures of approximately $4.8 billion are planned to be placed in service."

Darlington Refurbishment

The Darlington generating units are approaching their originally designed end-of-life. Refurbishment of the four generating units is expected to extend the operating life of the station by approximately 30 years. OPG commenced the planning of the refurbishment in 2010.

In 2016, the Darlington Refurbishment project transitioned from the planning phase to the execution phase, as OPG commenced the refurbishment of the first unit, Unit 2, in October 2016, as planned. The unit was taken offline on October 15, 2016. De-fuelling of the reactor, the first critical refurbishment activity undertaken once the unit is removed from service, was completed safely in January 2017, with a total of 480 fuel channels de-fuelled. Islanding of Unit 2, the physical separation of the unit under refurbishment from the three operating units, was completed in April 2017, signifying the completion of the first major segment of the project.

The second major segment includes preparatory work to support the removal of feeder tubes and fuel channel assemblies and the removal of reactor components. The preparatory work was completed in the second quarter of 2017. The Re-tube Tooling Platform for hosting the tooling for the removal, inspection, and installation activities and the setup of specialized tooling and equipment needed for the removal and replacement of the reactor components were completed in the third quarter of 2017. The disassembly of reactor components commenced in August 2017, with the removal of all 960 feeder tubes completed safely in September 2017. This was followed by the severing of pressure tubes, with the severing of bellows and the removal of end fittings expected to commence thereafter and through the end of 2017. Other key project activities executed during the second segment include the completion of the primary side steam generator layup, installation of steam generator access ports to support future inspections, continuation of the major turbine generator overhaul and continued execution of the major electrical scope. OPG is also continuing to execute work to support the requirements set out in the CNSC approved IIP for the station.

Once refurbished, Unit 2 is scheduled to be returned to service in the first quarter of 2020, at which time capital expenditures of approximately $4.8 billion are planned to be placed in service. This includes expenditures incurred during the definition and planning phase of the overall project. The project is tracking on schedule and on budget.

With the substantial completion of the Re-tube Waste Processing Building in November 2017, 17 out of 18 pre-requisite projects in support of the execution phase of the project, including construction of facilities, infrastructure upgrades and installation of safety enhancements, have been completed and placed in service. Completion of the Heavy Water Storage and Drum Handling Facility (HWSF) has been delayed due to challenges with construction. OPG suspended the project in the second quarter of 2017 to evaluate the best approach to optimize cost and schedule and complete the project. Construction activities for the HWSF recommenced in the fourth quarter of 2017 following substantial completion of the Re-tube Waste Processing Building. This plan ensures that the necessary resources are available for both projects and, through resource levelling, improves their execution and cost efficiency. The delay in the completion of the HWSF will not impact the overall Darlington Refurbishment project schedule, as the HWSF is not on the project's critical path. This also will not impact the overall project budget of $12.8 billion, as the costs of the HWSF [and potential over runs] are included in this total figure. The recovery of HWSF costs through regulated prices will be subject to a prudence review by the OEB, which OPG has proposed be conducted as part of a future OEB application.

Commented [A7]: The understanding is that if HWSF is over budget, but it will still be within the 12.8B envelope.

In addition to the execution of refurbishment activities on Unit 2, OPG is continuing planning activities for the refurbishment of the second unit, Unit 3, and is entering into associated commitments to procure major components that require long lead times. As of September 30, 2017, $70 million has been invested in planning activities related to the refurbishment of the second unit, Unit 3. These planning activities are being undertaken in accordance with the refurbishment project schedule.

The Financial Accountability Office of Ontario has issued a report titled "*An Assessment of the Financial Risks of the Nuclear Refurbishment Plan*". The report assesses both OPG and Bruce Power's refurbishment activities and the method in which those refurbishments and subsequent nuclear generation is provided to the marketplace. The report

concludes that the base case of refurbishing the six units at the Bruce nuclear GS and the four units at the Darlington nuclear GS provide the most cost effective, low emission generation source available to meet Ontario's baseload electricity requirements. This report re-affirms the positive economic and societal benefits associated with a strong nuclear program in the Province. **[MONITOR]**

Commented [A8]: Not yet released.

Ranney Falls Hydroelectric GS

During the third quarter of 2017, OPG continued construction work for a 10 MW single-unit powerhouse on the existing Ranney Falls GS site, as part of the Regulated – Hydroelectric segment. The new unit will replace an existing unit that reached its end of life in 2014. The existing forebay structure demolition has been completed and the upstream cofferdam has been constructed ahead of schedule. Construction continues on the expanded forebay, powerhouse and spillway. Excavation work is substantially complete and forebay wall concrete replacement is in progress. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget.

Nanticoke Solar Facility

The construction of a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands under a Large Renewable Procurement contract with the IESO, through Nanticoke Solar LP, a partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation, is planned to commence in the first quarter of 2018. During the third quarter of 2017, the partnership continued work to obtain approvals and permits required to enable the commencement of construction, and progressed procurement activities for equipment and for engineering and construction services. The facility is expected to be completed in the first quarter of 2019.

Deep Geologic Repository for Low and Intermediate Level Waste

OPG has proposed a deep geologic repository as the preferred solution for the safe long-term management of the L&ILW produced from the continued operation of OPG-owned nuclear generating stations. Agreement has been reached with local municipalities for OPG to develop the L&ILW Deep Geologic Repository (DGR) on lands adjacent to the Western Waste Management Facility (WWMF) in Kincardine, Ontario. The environmental effects of the proposed L&ILW DGR were examined by the CNSC and CEAA-appointed Joint Review Panel (JRP) to meet the requirements of the Canadian Environmental Assessment Act. The JRP submitted its report on the EA to the federal Minister of Environment in May 2015, concluding that, given mitigation, there is unlikely to be significant environmental impact from the project and recommending that the Minister approve the EA. In December 2016, at the request of the federal Minister of Environment and Climate Change, OPG submitted additional information on certain aspects of the EA, including information related to alternate locations for the project. Following its review of OPG's submission and a period of public comment, the CEAA requested further information that OPG subsequently provided in May 2017. In June 2017, the CEAA notified OPG that it had sufficient and adequate information to proceed with the next step of the environmental assessment process and advised that a draft report and updated terms and conditions will be prepared for public review.

On August 21, 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of potential cumulative effects of the project on the Saugeen Ojibway Nations' (SON) physical and cultural heritage, including a description of the potential effects of the project on the Nation's spiritual and cultural connection to the land. OPG is assessing the request and will notify the CEAA when it has determined the timeline for developing a response. The CEAA's draft report for public review will not be issued until this update is provided. The L&ILW DGR at the WWMF site remains OPG's preferred solution for the safe long-term management of the L&ILW.

OPG continues its engagement with the SON toward securing community support for the L&ILW DGR. The in-service date of the L&ILW DGR is expected to be approximately six to seven years from the start of construction.

Financial Strength

As a commercial enterprise, OPG's financial priority is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future growth.

Increase Revenue, Reduce Costs and Achieve Appropriate Return

In May 2016, OPG filed a 5-year application with the OEB for new regulated prices for production from its regulated hydroelectric and nuclear facilities, with a proposed effective date of January 1, 2017. Consistent with the requirements of *Ontario Regulation 53/05*, the application incorporates a rate smoothing proposal that would defer, for future collection, a portion of the approved annual nuclear revenue requirement for the period from January 1, 2017 to the end of the Darlington Refurbishment project, with a view to making changes in OPG's regulated prices more stable year-over-year. The application seeks to ensure that nuclear regulated prices under the rate smoothing approach allow for sufficient cash flow to meet the Company's liquidity needs, support cost effective funding for the Darlington Refurbishment project and other expenditures, and maintain the Company's investment grade credit rating, while taking into account both near-term and future impacts on customers. OPG expects to recognize amounts deferred under rate smoothing as income in the periods to which the underlying approved revenue requirements relate.

The application will further challenge and incentivize OPG to find additional cost reductions and efficiencies within its operations, as a result of greater de-coupling of nuclear and hydroelectric regulated prices from costs and a longer rate-setting period under the OEB's incentive ratemaking framework, which forms the basis for the ratemaking methodologies reflected in the application.

The application seeks an increase in the nuclear rate base, effective in early 2020, to reflect the planned placement in service of approximately $4.8 billion of capital expenditures upon the scheduled return to service of Unit 2 at the Darlington GS as part of the Darlington Refurbishment project and, effective in 2017, an increase in the deemed capital structure applied to the total regulated rate base to 49 percent equity and 51 percent debt, from 45 percent equity and 55 percent debt reflected in the existing regulated prices. The application also requests new rate riders, effective January 1, 2017, to recover or repay the December 31, 2015 balances in all of the Company's OEB-authorized variance and deferral accounts, with the exception of the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the portion of these balances previously approved for recovery or repayment through rate riders that were in effect during 2016.

The OEB's decision on the application, including the effective date of approved new regulated prices, is expected later in 2017. **[MONITOR]**

For generation assets that do not form part of the assets regulated by the OEB, OPG's strategy has been to secure appropriate long-term revenue arrangements. In line with this strategy, virtually all of OPG's non-regulated operating facilities and assets under construction are subject to long-term Energy Supply Agreements (ESAs) or other long-term contracts with the IESO.

Ensure Availability of Cost Effective Funding

In April 2017, DBRS Limited (DBRS) re-affirmed the long-term credit rating on OPG's debt at 'A (low)' and OPG's commercial paper rating at 'R-1 (low)'. All ratings from DBRS have a stable outlook. In July 2017, S&P Global Ratings (S&P) re-affirmed OPG's long-term credit rating at 'BBB+' with a stable outlook. S&P's commercial paper rating for OPG is 'A-1 (low)'.

Social Licence

As the largest electricity generator in Ontario with diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust. OPG is committed to maintaining high standards of public safety and corporate citizenship, including environmental stewardship, transparency, community engagement, and Indigenous relations.

OPG is focused on building long-term, mutually beneficial working relationships with Indigenous communities, businesses and organizations across Ontario, and continues to support procurement, employment and educational opportunities with its Indigenous community partners. The Company seeks to establish these relationships based on a foundation of respect for the languages, customs, and political, social and cultural organizations of the Indigenous communities.

In June 2017, OPG launched an Indigenous Business Engagement (IBE) Initiative. The purpose of this initiative is to increase access to procurement opportunities for Indigenous businesses interested in supplying materials and services to OPG. The IBE Initiative is based on a strategy that will identify opportunities in contracts, scopes of work and business plans for potential Indigenous business engagement; include criteria related to suppliers' ability to engage or partner with Indigenous people or businesses in assessing procurement proposals; and invest in relationships with Indigenous communities by increasing outreach efforts to enhance understanding of how to do business with OPG. OPG has continued to engage with various Indigenous business and communities as well as its suppliers to promote the IBE Initiative. In September 2017, OPG presented the IBE to the Mohawk Council of Akwesanse (Akwesanse). As a result, Akwesanse plans to create a database of businesses in the community that will participate in contracting and supply opportunities with OPG. In September 2017, OPG also hosted a similar presentation to the Williams Treaties First Nations, located proximate to the Pickering and Darlington Nuclear Generating Stations, at the quarterly meeting for these communities.

OPG is developing recruitment plans targeting Indigenous people. In October 2017, OPG participated in five Indigenous-specific career fairs to attract such talent. **[MONITOR]**

OPG has a transportation electrification strategy that will help position OPG as a leader in transportation electrification in Ontario. This strategy is intended to leverage OPG's clean electricity to support action on climate change, create growth opportunities for OPG, and enhance OPG's brand and social licence.

Outlook

The financial performance of OPG's regulated operations is driven, in large part, by the outcome of applications for regulated prices to the OEB. The existing base regulated prices were established by the OEB effective November 1, 2014 based on a forecast of costs and production for the regulated facilities for the 2014 to 2015 period. The future outcome of OPG's current application for new regulated prices, currently pending the OEB's decision, is expected to provide substantial price certainty for the regulated business for the 2017 to 2021 period.

In its application, OPG has requested January 1, 2017 as the effective date for the new regulated prices. In December 2016, the OEB issued an order declaring the existing base regulated prices interim, which preserves the OEB's ability to make the new regulated prices effective as early as January 1, 2017. Considering the timing of OPG's application and OPG's procedural adherence throughout the proceeding, the Company believes that the OEB could make the new regulated prices effective January 1, 2017. This would allow OPG to recover the difference between the approved new regulated prices and the existing regulated prices for the period between January 1, 2017 and the implementation date of the new prices based on the OEB's order. The OEB's decision on the application, including the effective date of the new regulated prices, is expected in the fourth quarter of 2017. **[MONITOR]** The continuation of existing regulated prices until the issuance of the OEB's decision is expected to continue to contribute to lower income, particularly from the Regulated – Nuclear Generation segment, and, excluding the gain on sale of the Company's head office premises and associated parking facility recorded in the second quarter of 2017, lower

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Commented [A10]: Typo: license

Commented [A11]: Does this deal with OPG owned fleet and other vehicles, or in line with the infrastructure for EV vehicles.

Can further details be provided in particular on the point of 'creating growth opportunities for OPG'.

ROE Excluding AOCI during 2017, compared to 2016. In large part, this is due to the year-over-year reduction in nuclear electricity generation resulting from the Unit 2 refurbishment outage at the Darlington GS, given that the existing nuclear regulated prices were determined in 2014 based on a higher production forecast that reflected the operation of all four units at the station. As such, the OEB's decision on the effective date of the new regulated prices, as well as the timing of the decision issuance, could have a significant impact on OPG's financial results during 2017.

Nuclear base regulated prices resulting from OPG's current application will be subject to a rate smoothing mechanism that defers collection of a portion of OEB-approved revenues to future periods. As expected, combined with the expiry of rate riders in effect to the end of 2016, a year-over-year reduction in nuclear generation due to the Unit 2 refurbishment outage at the Darlington GS and the continuation of existing regulated prices until such time as new prices are implemented by the OEB, this will result in lower cash flow from operating activities in 2017, compared to 2016. OPG expects to continue to have the necessary financial capacity and sufficient access to cost effective financing sources to continue to fund its capital requirements and other disbursements.

Lower nuclear generation due to the Darlington Refurbishment outages will continue, as planned, to negatively impact the Enterprise TGC metric for the duration of the refurbishment project. Variability in sustaining capital investment expenditures, including major sustaining projects for the hydroelectric operations, also will impact the Enterprise TGC in future periods.

Several OEB-authorized regulatory variance and deferral accounts currently in place contribute to reducing the relative variability of the Company's income and ROE Excluding AOCI. Among others, the regulatory accounts include those related to the revenue impact of variability in water flows and forgone production due to SBG conditions at the regulated hydroelectric stations. As there are no variance or deferral accounts in place related to the impact of generation performance of the nuclear stations on revenue from base regulated prices, the Regulated – Hydroelectric segment generally is expected to produce overall more predictable earnings. OPG continues to operate and maintain its nuclear facilities with a view to optimize their performance and availability, while focusing on improving the overall reliability and predictability of the fleet.

Electricity generated from most of OPG's non-regulated assets is subject to ESAs with the IESO. Based on these agreements, OPG expects the Contracted Generation Portfolio segment to continue to contribute a generally stable level of earnings and cash flow from operations going forward.

OPG's total forecast capital expenditures for the 2017 year are approximately $2.0 billion. This includes amounts for the Darlington Refurbishment project, hydroelectric and other development projects including the completion of the Peter Sutherland Sr. GS and the expansion of the Ranney Falls GS, and sustaining capital investments across the generating fleet. OPG's major projects are discussed in the section, *Project Excellence*.

In addition to the operating and financial performance of the electricity generation business, OPG's results are affected by the earnings on the Nuclear Segregated Funds, which are reported in the Regulated – Nuclear Waste Management segment. While the Nuclear Segregated Funds are managed to achieve, in the long term, the target rate of return based on the discount rate specified in the ONFA, the rates of return earned in a given period can be subject to various external factors including financial market conditions and, for the portion of the Used Fuel Segregated Fund guaranteed by the Province under the ONFA, changes in the Ontario consumer price index (CPI). In the near term, these factors can be volatile and cause fluctuations in the Company's income. This volatility is partially mitigated by the impact of the OEB-authorized Bruce Lease Net Revenues Variance Account and, as discussed below, the funded status of the two segregated funds.

As OPG does not have the right to withdraw surplus amounts from the Nuclear Segregated Funds, OPG limits the amount of Nuclear Segregated Funds assets reported on the balance sheet to the present value of such life cycle funding liability. This reduces the volatility of earnings on the Nuclear Segregated Funds reflected in net income when the funds are in a fully funded or overfunded position. As at September 30, 2017, the Decommissioning

Segregated Fund was overfunded by approximately 23 percent, and the Used Fuel Segregated Fund was marginally overfunded, by less than one percent, based on the 2017 ONFA Reference Plan. Variability in asset performance due to volatility inherent in financial markets and changes in Ontario CPI, or changes in funding liability estimates, may result in either or both funds becoming underfunded in the future.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

Regulated – Nuclear Generation Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue	**739**	885	**2,000**	2,631
Fuel expense	**81**	79	**217**	239
Gross margin	**658**	806	**1,783**	2,392
Operations, maintenance and administration	**511**	521	**1,693**	1,665
Depreciation and amortization	**116**	230	**333**	691
Property taxes	**7**	6	**20**	19
Income (loss) before other losses, interest, and income taxes	**24**	49	**(263)**	17
Other losses	**4**	2	**4**	-
Income (loss) before interest and income taxes	**20**	47	**(267)**	17

For the three and nine month periods ended September 30, 2017, the segment earnings decreased by $27 million and $284 million, respectively, compared to the same periods in 2016. The decrease in earnings was expected and primarily due to reduced revenue from the nuclear base regulated price of approximately $24 million and $230 million, respectively. The decrease was partially offset by an associated year-over-year decrease in fuel expense. The decrease in revenue during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, reflected lower electricity generation of 0.4 TWh and 4.0 TWh, respectively, primarily due to the ongoing Unit 2 refurbishment outage at the Darlington GS that began in October 2016, without a corresponding increase in the base regulated price. The existing nuclear base regulated price set by the OEB in 2014 continues to be in effect pending the OEB's decision on OPG's application for new regulated prices, proposed to be effective on January 1, 2017. The existing price does not reflect the lower generation as a result of the Darlington Refurbishment project, as it was set to allow the Company to recover its approved nuclear costs over a higher nuclear production volume, based on the 2014 and 2015 outage profile that did not include a refurbishment outage. The reduction in nuclear electricity generation for the three months ended September 30, 2017 was largely offset by the higher electricity generation from the Pickering GS.

OM&A expenses decreased by $10 million during the third quarter of 2017, compared to the same period in 2016, as a result of a higher materials and supplies obsolescence charge recognized in 2016. OM&A expenses increased by $28 million during the nine months ended September 30, 2017, compared to the same period in 2016, due to planned maintenance activities in 2017.

Depreciation and amortization expense, excluding amortization expense related to regulatory account balances, increased by $16 million and $30 million during the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016, primarily due to new assets in service.

The expiry of an OEB-authorized nuclear rate rider on December 31, 2016 contributed to the decrease in segment revenue for the three and nine month periods ended September 30, 2017, compared to the same periods in 2016. As rate riders allow for recovery of approved balances in OEB-authorized regulatory accounts, this decrease in revenue was largely offset by a decrease in amortization expense related to these balances. There was no rate rider

in effect during the nine months ended September 30, 2017, pending the outcome of OPG's current application to the OEB for new regulated prices.

The Unit Capability Factors for the Darlington and Pickering generating stations were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Unit Capability Factor *(%)* [1]				
Darlington GS	**96.2**	89.6	**82.1**	87.6
Pickering GS	**88.7**	77.3	**83.8**	73.8

[1] The nuclear Unit Capability Factor excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS was excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

The Unit Capability Factor at the Darlington GS increased in the third quarter of 2017, compared to the same quarter in 2016, primarily due to the lower number of planned outage days during the third quarter of 2017. The lower Unit Capability Factor at the Darlington GS for the nine months ended September 30, 2017, compared to the same period in 2016, reflected the higher number of planned outage days, largely driven by constraints related to the transition of the station toward refurbishment.

The increase in Unit Capability Factor at the Pickering GS for the three and nine month periods ended September 30, 2017 was primarily due to outage optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station compared to 2016.

Regulated – Nuclear Waste Management Segment

(millions of dollars) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Revenue	**33**	36	**90**	102
Operations, maintenance and administration	**35**	38	**96**	108
Accretion on nuclear fixed asset removal and nuclear waste management liabilities	**230**	228	**696**	684
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(196)**	(248)	**(579)**	(620)
(Loss) Income before interest and income taxes	**(36)**	18	**(123)**	(70)

The segment loss before interest and income taxes was $36 million and $123 million during the three and nine months ended September 30, 2017, respectively, a decrease in earnings of $54 million and $53 million compared to the same periods in 2016. The decline in earnings was primarily due to lower earnings from the Nuclear Segregated Funds, net of the impact of the impact of the Bruce Lease Net Revenues Variance Account, reflecting higher earnings from market returns on fund assets and the CPI-adjusted rate of return guaranteed by the Province for the portion of the Used Fuel Segregated Fund related to the initial 2.23 million used fuel bundles (committed return) in the third quarter of 2016.

As both the Decommissioning Segregated Fund and the Used Fuel Fund were in an overfunded position during the three and nine months period ended September 30, 2017, compared to the underlying funding liabilities per the approved ONFA Reference Plan, the earnings on the funds during these periods reflected the growth rate in the present value of the funding liabilities and were not impacted by market returns and committed return. The higher earnings on both funds during the three and nine months periods ended September 30, 2016 reflected market returns and committed return, as the Decommissioning Segregated Fund became over 120 percent funded during the third quarter of 2016 while the Used Fuel Fund was underfunded, compared to the corresponding funding liabilities.

Higher market returns and committed return in the third quarter of 2016 in relation to the funding liabilities' growth rate reflected in fund earnings during 2017 resulted in a year-over-year decrease in the amount of earnings on the Nuclear Segregated Funds.

As of December 31, 2016, OPG recorded a decrease of approximately $1,570 million to the Nuclear Liabilities and associated asset retirement costs capitalized as part of the carrying value of the nuclear generating stations. The resulting year-over-year decreases in accretion on fixed asset removal and nuclear waste management liabilities recorded in the Regulated – Nuclear Waste Management segment and depreciation and fuel expenses recorded in the Regulated – Nuclear Generation segment during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, were offset by the impact of the Bruce Lease Net Revenues Variance Account and the Nuclear Liability Deferral Account authorized by the OEB.

Under the current OEB-approved cost recovery methodology, these changes in expenses also are not expected to materially affect OPG's income during the rest of 2017, as they are expected to continue to be largely offset by the impact of the regulatory accounts until such time as the OEB implements corresponding changes to OPG's nuclear regulated prices, and subsequently by the impact of such new regulated prices. Further details on the change in the estimate of the Nuclear Liabilities as of December 31, 2016 are described in OPG's 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Asset Retirement Obligation*. **[MONITOR]**

Regulated – Hydroelectric Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue [1]	**327**	350	**1,069**	1,148
Fuel expense	**88**	88	**258**	259
Gross margin	**239**	262	**811**	889
Operations, maintenance and administration	**81**	87	**232**	238
Depreciation and amortization	**34**	56	**103**	169
Property tax	**1**	1	**1**	1
Income before other losses (gains), interest and income taxes	**123**	118	**475**	481
Other losses (gains)	**1**	1	**1**	(19)
Income before interest and income taxes	**122**	117	**474**	500

[1] During the three and nine month periods ended September 30, 2017, the Regulated – Hydroelectric segment revenue included incentive payments of $4 million and $9 million, respectively, related to the OEB-approved hydroelectric incentive mechanism (three and nine month periods ended September 30, 2016 – incentive payments of $6 million and $8 million, respectively). The mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers. The incentive payments are reduced to remove incentive revenues arising in connection with SBG conditions.

The increase in segment income before interest and income taxes of $5 million during the third quarter of 2017, compared to the same quarter in 2016, was primarily the result of a decrease in OM&A expenses, mainly due to the timing of repairs and maintenance work in 2017 and a deferral of outages during the high water period.

The decrease in segment income before interest and income taxes of $26 million during the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to a gain of $22 million recognized during the first quarter of 2016 to reflect the OEB's January 2016 decision to reverse a portion of an earlier capital cost disallowance related to the Niagara Tunnel project expenditures, in response to a motion by OPG. The income impact of OEB-approved variance accounts also contributed to the year-over-year decrease in income for the period. These factors were partially offset by the decrease in OM&A expenses related to the timing of repairs and maintenance work in 2017 and a deferral of outages during the high water period.

The decrease in revenue from the segment for the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was largely due to the expiry of an OEB-authorized rate rider on

December 31, 2016. As the rider allowed for the recovery of approved balances in OEB-authorized regulatory accounts, the resulting reduction in revenue was largely offset by lower amortization expense related to these balances. There was no rate rider in effect during the first nine months of 2017 pending the outcome of OPG's current application to the OEB for new regulated prices.

The Hydroelectric Availability for the stations included in the Regulated – Hydroelectric segment was as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Hydroelectric Availability *(%)*	**87.6**	84.1	**89.0**	89.8

The Hydroelectric Availability in the third quarter of 2017 was higher compared to the same period in 2016, primarily due to a higher number of planned outages in 2016 as a result of the refurbishment of the Sir Adam Beck Pump GS reservoir between April 2016 and February 2017. The marginal decrease in Hydroelectric Availability during the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to a higher number of unplanned outage days at the Northwestern Ontario and Niagara region hydroelectric stations, partially offset by higher availability from the Sir Adam Beck Pump GS.

Contracted Generation Portfolio Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue	**141**	149	**431**	431
Fuel expense	**15**	19	**42**	42
Gross margin	**126**	130	**389**	389
Operations, maintenance and administration	**39**	44	**118**	129
Depreciation and amortization	**20**	19	**59**	56
Accretion on fixed asset removal liabilities	**3**	2	**7**	6
Property taxes	**-**	1	**5**	6
Income from investments subject to significant influence	**(11)**	(11)	**(29)**	(28)
Income before other loss, interest and income taxes	**75**	75	**229**	220
Other loss	**-**	1	**-**	1
Income before interest and income taxes	**75**	74	**229**	219

Income before interest and income taxes from the segment increased by $1 million and $10 million during the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016. The increase in earnings for the three months ended September 30, 2017 mainly resulted from revenues from the Peter Sutherland Sr. GS that was placed in-service at the end of the first quarter of 2017 and lower OM&A expenses, partially offset by lower revenue from the Atikokan GS. The decrease in revenue from the Atikokan GS was primarily due to higher revenues in 2016, when the station was called upon to provide the needed support to the electricity system in Northwestern Ontario as a result of an outage at a local transformer station. For the nine months ended September 30, 2017, the increase in earnings was primarily due to lower OM&A expenses. The lower OM&A expenses for the three and nine month periods ended September 30, 2017 were mainly due to the prospective adoption of the full yield curve approach to the estimation of the service and interest cost components of pension and OPEB costs starting in 2017.

The Hydroelectric Availability and the Thermal Equivalent Forced Outage Rate (EFOR) for the Contracted Generation Portfolio segment were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Hydroelectric Availability *(%)*	**66.1**	68.2	**76.9**	79.6
Thermal EFOR *(%)*	**2.6**	2.1	**6.0**	1.3

Lower Hydroelectric Availability during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was primarily due to an increase in the number of planned outage days at the Lower Mattagami River hydroelectric generating stations.

The higher Thermal EFOR during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was primarily due to a higher number of unplanned outage days at a Lennox GS unit as a result of a transmission outage and a generator cooling water system outage in 2017.

Services, Trading, and Other Non-Generation Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue	**9**	15	**36**	52
Fuel expense	**1**	1	**1**	1
Gross margin	**8**	14	**35**	51
Operations, maintenance and administration	**1**	11	**2**	20
Depreciation and amortization	**8**	8	**22**	25
Accretion on fixed asset removal liabilities	**2**	2	**6**	6
Property taxes	**-**	4	**4**	9
(Loss) income before other gains, interest, and income taxes	**(3)**	(11)	**1**	(9)
Other gains	**(2)**	(3)	**(385)**	(5)
Income (loss) before interest and income taxes	**(1)**	(8)	**386**	(4)

Segment earnings improved by $7 million during the third quarter of 2017, compared to the same quarter in 2016. The improvement in earnings was primarily due to lower OM&A expenses reflecting project expenditures incurred in the third quarter of 2016, and OPG's decision, in the fourth quarter of 2016, to proceed with the decommissioning of Lambton GS.

Segment income before interest and income taxes increased by $390 million for the nine months ended September 30, 2017, compared to the same period in 2016. The increase in earnings mainly reflected the gain on the sale of OPG's head office premises and associated parking facility recorded during the second quarter of 2017.

LIQUIDITY AND CAPITAL RESOURCES

OPG's primary sources of liquidity and capital are funds generated from operations, bank financing, credit facilities provided by the Ontario Electricity Financial Corporation (OEFC), long-term corporate debt, and capital market financing. These sources are used for multiple purposes including: to invest in plants and technologies, to undertake major projects, to fund long-term obligations such as contributions to the pension fund and the Nuclear Segregated Funds, to make payments under the OPEB plans, to fund expenditures on Nuclear Liabilities not reimbursable from the Nuclear Segregated Funds, to service and repay long-term debt, to provide general working capital, and to fund OPG's investment in the Fair Hydro Plan.

Changes in cash and cash equivalents for the three and nine month periods ended September 30 are as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Cash and cash equivalents, beginning of period	**242**	295	**186**	464
Cash flow provided by operating activities	**485**	530	**698**	1,211
Cash flow used in investing activities	**(463)**	(390)	**(720)**	(1,253)
Cash flow provided by (used in) financing activities	**16**	(9)	**116**	4
Net increase (decrease)	**38**	131	**94**	(38)
Cash and cash equivalents, end of period	**280**	426	**280**	426

For a discussion of cash flow provided by operating activities and the FFO Adjusted Interest Coverage ratio, refer to the details in the section, *Highlights* under the heading, *Overview of Results*.

Investing Activities

Electricity generation is a capital-intensive business. It requires continued investment in plants and technologies to maintain and improve operating performance including asset reliability, safety and environmental performance, to increase the generating capacity of existing stations, and to invest in the development of new generating stations, emerging technologies and other business growth opportunities.

Cash flow used in investing activities during the third quarter of 2017 was $463 million, compared to $390 million for the same period in 2016. The increase in cash flow used for investing activities mainly resulted from higher expenditures on the Darlington Refurbishment project in the third quarter of 2017.

Cash flow used in investing activities decreased by $533 million for the nine months ended September 30, 2017, compared to the same period in 2016. The decrease in net cash flow used in investing activities was primarily due to the receipt of proceeds from the sale of OPG's head office premises and associated parking facility in the second quarter of 2017 pursuant to a Shareholder Declaration and Shareholder Resolution, and the acquisition of nine million common shares of Hydro One Limited (Hydro One) in the second quarter of 2016, partially offset by higher expenditures on the Darlington Refurbishment project in 2017. OPG acquired the Hydro One shares for investment purposes, to mitigate the risk of future price volatility related to the Company's future share delivery obligations under the collective agreements with the Power Workers' Union and The Society of Energy Professionals.

Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from the sale of head office premises and associated parking facility, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. OPG expects that the amount of designated proceeds to be transferred into the Consolidated Revenue Fund will be largely consistent with the after-tax gain on sale. The transfer is expected to take place later in 2017.

Financing Activities

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. In the second quarter of 2017, OPG renewed and extended the expiry date of both tranches from May 2021 to May 2022. There were no amounts outstanding under the bank credit facility as at September 30, 2017.

There was $160 million of commercial paper outstanding under OPG's commercial paper program as at September 30, 2017.

As at September 30, 2017, OPG also maintained $25 million of short-term, uncommitted overdraft facilities, and a further $463 million of short-term, uncommitted credit facilities, which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other general corporate purposes. As at September 30, 2017, a total of $388 million of Letters of Credit had been issued under these facilities. This included $349 million for the supplementary pension plans, $38 million for general corporate purposes, and $1 million related to the operation of the PEC.

The Company has an agreement to sell an undivided co-ownership interest in its current and future accounts receivable to an independent trust, expiring on November 30, 2018. The maximum amount of co-ownership interest that can be sold under this agreement is $150 million. As at September 30, 2017, no borrowings were issued under this agreement and there were Letters of Credit outstanding under this agreement of $150 million, which were issued in support of OPG's supplementary pension plans.

As at September 30, 2017, Lower Mattagami Energy Limited Partnership (LME) maintained a $400 million bank credit facility to support the funding requirements for the Lower Mattagami River project including support for LME's commercial paper program and the issuance of the Letters of Credit. The facility consists of a $300 million tranche which, in the third quarter of 2017, was extended to mature in August 2022 and a $100 million tranche which, in the third quarter of 2017, was reduced from $200 million and extended to mature in August 2018. As at September 30, 2017, there was no external commercial paper outstanding under LME's commercial paper program. A letter of credit of $55 million was issued in July 2017 and remains outstanding as at September 30, 2017 under the $300 million tranche of the credit facility.

In June 2016, OPG entered into a $700 million general corporate credit facility agreement with the OEFC, which expires on December 31, 2017. In the third quarter of 2017, the agreement was amended to increase the credit facility to $2,350 million and to extend its expiry date to December 31, 2018.

In February 2017, OPG issued senior notes payable to the OEFC totalling $200 million and maturing in February 2047. The effective interest rate and coupon interest rate of these notes was 4.12 percent. In June 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in June 2047. The effective interest rate and coupon interest rate of these notes was 3.65 percent. In August 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in August 2047. The effective interest rate and coupon interest rate of these notes was 3.86 percent. In September 2017, OPG issued senior notes payable to the OEFC totalling $400 million and maturing in September 2047. The effective interest rate and coupon interest rate of these notes was 4.07 percent. As at September 30, 2017, there were outstanding long-term borrowings of $800 million under this credit facility.

In October 2017, OPG issued $500 million of senior notes payable under a Medium Term Note Program. The notes bear a coupon interest rate of 3.32 percent and an effective rate of 3.43 percent, payable semi-annually until maturity on October 4, 2027. The offering was made under OPG's $2 billion short form base shelf prospectus dated September 12, 2017. The net proceeds will be used for general corporate purposes, including the financing of OPG's subordinated debt investment in the Fair Hydro Plan.

As at September 30, 2017, OPG's long-term debt outstanding was $5,482 million, including $628 million due within one year.

OPG continues to evaluate arrangements that would appropriately support the Company's financing needs and capital expenditure programs.

Contractual and Commercial Commitments

Pension Plan Actuarial Valuation

A new actuarial valuation of the OPG registered pension plan was filed with the Financial Services Commission of Ontario in September 2017 with an effective date of January 1, 2017. The annual funding requirements in accordance with the new actuarial valuation are $212 million for 2017, $215 million for 2018, and $219 million for 2019. The next actuarial valuation must have an effective date no later than January 1, 2020.

BALANCE SHEET HIGHLIGHTS

The following section provides highlights of OPG's unaudited interim consolidated financial position using selected balance sheet data:

(millions of dollars) (unaudited)	As At September 30 2017	As At December 31 2016
Property, plant and equipment - net	**20,801**	19,998
The increase was primarily due to capital expenditures on the Darlington Refurbishment project, partially offset by depreciation expense.		
Nuclear fixed asset removal and nuclear waste management funds *(current and non-current portions)*	**16,534**	15,984
The increase was primarily due to earnings on the Nuclear Segregated Funds, partially offset by reimbursements of eligible expenditures on nuclear fixed asset removal and nuclear waste management activities.		
Short-term debt	**160**	2
The increase was due to commercial paper issued under OPG's commercial paper program during the third quarter of 2017.		
Fixed asset removal and nuclear waste management liabilities	**20,075**	19,484
The increase was primarily a result of accretion expense representing the increase in the liabilities due to the passage of time, partially offset by expenditures on nuclear fixed asset removal and waste management activities.		

Off-Balance Sheet Arrangements

In the normal course of operations, OPG engages in a variety of transactions that, under US GAAP, are either not recorded in the Company's interim consolidated financial statements or are recorded in the Company's interim consolidated financial statements using amounts that differ from the full contract amounts. Principal off-balance sheet activities for OPG include guarantees and long-term contracts.

CHANGES IN ACCOUNTING POLICIES AND ESTIMATES

OPG's significant accounting policies are outlined in Note 3 to the audited consolidated financial statements as at and for the year ended December 31, 2016. A discussion of recent accounting pronouncements and change in accounting estimate are included in Note 2 to OPG's unaudited interim consolidated financial statements as at and for the three and nine month periods ended September 30, 2017 under the heading, *Significant Accounting Policies and Estimates*. Disclosure regarding OPG's critical accounting policies is included in OPG's 2016 annual MD&A.

RISK MANAGEMENT

The following provides an update to the discussion of the Company's risks and risk management activities included in OPG's 2016 annual MD&A. As such, the disclosure in this section should be read in conjunction with the *Risk Management* section included in the annual MD&A.

Risks to Achieving Project Excellence

Deep Geologic Repository for Low and Intermediate Level Waste

In August 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of the potential cumulative effects of the DGR project on the physical and cultural heritage of the SON, taking into account the results of the SON Community Process. OPG continues to work with the SON, however the timing and outcome of the SON Community Process and the EA decision by the Minister are uncertain.

Risks to Maintaining Financial Strength

Commodity Markets

Changes in the market price of fuels used to produce electricity can adversely impact OPG's earnings and cash flow from operations.

To manage the risk of unpredictable increases in the price of fuels, the Company has fuel hedging programs, which include fixed price and indexed contracts.

The percentages hedged of OPG's fuel requirements are shown in the following table. These amounts are based on yearly forecasts of generation and supply mix, and as such, are subject to change as these forecasts are updated.

	2017 [1]	2018	2019
Estimated fuel requirements hedged [2]	73%	73%	69%

[1] Based on actual fuel requirements hedged for the nine months ended September 30, 2017 and forecast for the remainder of the year.

[2] Represents the approximate portion of megawatt-hours of expected generation production (and year-end inventory targets) from each type of OPG-operated facility (nuclear, hydroelectric and thermal) for which the Company has entered into contractual arrangements or obligations in order to secure the price of fuel, or which is subject to regulation. In the case of hydroelectric generation, this represents the gross revenue charge and water rental charges. Excess fuel inventories (nuclear and thermal) in a given year are attributed to the next year for the purpose of measuring hedge ratios.

Foreign Exchange

OPG's earnings and cash flow can be affected by movements in the United States dollar (USD) relative to the Canadian dollar.

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are denominated in, or tied to, USD. To manage this risk, OPG periodically employs various financial instruments such as forwards and other

derivative contracts, in accordance with approved risk management policies. As at September 30, 2017, OPG had no foreign exchange contracts outstanding.

Trading

OPG's financial performance can be affected by its trading activities.

OPG's electricity trading operations are closely monitored, with total exposures measured and reported to senior management on a daily basis. The main metric used to measure the financial risk of trading activity is Value at Risk (VaR). VaR is defined as a probabilistic maximum potential future loss expressed in monetary terms for a portfolio based on normal market conditions over a set period of time. For the third quarter of 2017, the VaR utilization ranged between $0.2 million and $0.3 million.

Credit

Deterioration in energy markets counterparty credit and non-performance by suppliers and contractors can adversely impact OPG's earnings and cash flow from operations.

OPG manages its exposure to suppliers or counterparties by evaluating their financial condition and negotiating appropriate collateral or other forms of security. OPG's credit exposure relating to energy markets transactions as at September 30, 2017 was $356 million, including $346 million with the IESO. Management considers the Company's risk exposure relating to electricity sales through the IESO-administered spot market to be low as the IESO oversees the credit worthiness of all market participants. In accordance with the IESO's prudential support requirements, market participants are required to provide collateral to cover funds that they might owe to the market. Of the $10 million remaining exposure as at September 30, 2017, over 95 percent was related to investment grade counterparties.

Fair Hydro Plan

OPG's role in connection with the Fair Hydro Plan could have reputational impacts on the Company.

The *Ontario Fair Hydro Plan Act, 2017* received Royal Assent on June 1, 2017 and its attendant regulations came into force in June, July, and October 2017. **[UPDATE]** The regulations clarify aspects of the structure and program logistics required for OPG, as the Financial Services Manager of the Fair Hydro Plan, to refinance a portion of the Global Adjustment through the Trust. OPG's reputation could potentially be adversely impacted through its involvement with the Fair Hydro Plan and through stakeholder opinions related to this involvement.

Recovery of Pension and OPEB Costs

On September 14, 2017, the OEB issued its final report on the guiding principles and the policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the electricity and natural gas sectors. The report reaffirmed the conclusions of the initial report issued in May 2017, including the establishment of the accrual basis of accounting as the default rate-setting method and the establishment of a variance account to record asymmetric carrying charges in favour of ratepayers on the differences between the accrual costs recovered and cash payments made by a utility for pension and OPEB plans. The report requires OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the Pension & OPEB Cash Versus Accrual Differential Deferral Account that has been in effect since November 1, 2014, until such time as the OEB approves the resumption of the accrual basis of recovery. The future recovery of amounts recorded in the account will be subject to this approval. The report confirmed that OPG would become subject to the carrying charges on the differences between accrual costs and cash payments going back to November 1, 2014, with the charges calculated on the portion of such differences that have been recovered through regulated prices. The carrying charges will be determined at prescribed interest rate set quarterly by the OEB based on the quarterly return of a mid-term corporate bond index yield. This outcome has reduced OPG's risk related to the recovery of actual pension and OPEB accrual costs and the recovery of the balance in the Pension & OPEB Cash Versus Accrual Differential Deferral Account.

The account had a balance of $552 million as at September 30, 2017 and is recognized on the Company's consolidated balance sheet as a regulatory asset. OPG's financial results for the three and nine month periods ended September 30, 2017 were not impacted by the issuance of the OEB's report.

RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One, the IESO and the OEFC. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions are summarized below:

	Three Months Ended September 30			
	2017		2016	
(millions of dollars) (unaudited)	**Revenue**	**Expense**	**Revenue**	**Expense**
Hydro One				
Electricity sales	**2**	**-**	1	-
Services	**-**	**3**	-	3
Dividends	**2**	**-**	-	2
Province of Ontario				
Decommissioning Fund excess funding [1]	**-**	**(44)**	-	201
Used Fuel Fund rate of return guarantee and excess funding [1]	**-**	**(39)**	-	295
Gross revenue charges	**-**	**27**	-	28
ONFA guarantee fee	**-**	**2**	-	2
Other	**-**	**2**	-	-
OEFC				
Gross revenue charges	**-**	**62**	-	57
Interest expense on long-term notes	**-**	**40**	-	42
Income taxes, net of investment tax credits	**-**	**23**	-	28
IESO				
Electricity related revenue	**1,126**	**4**	1,293	7
	1,130	**80**	1,294	665

(millions of dollars) (unaudited)	Nine Months Ended September 30 2017 Revenue	2017 Expense	2016 Revenue	2016 Expense
Hydro One				
Electricity sales	**7**	**-**	4	-
Services	**1**	**8**	1	12
Dividends	**6**	**-**	-	4
Province of Ontario				
Decommissioning Fund excess funding [1]	**-**	**164**	-	137
Used Fuel Fund rate of return guarantee and excess funding [1]	**-**	**217**	-	190
Gross revenue charges	**-**	**84**	-	91
ONFA guarantee fee	**-**	**6**	-	6
Other	**-**	**3**	-	-
OEFC				
Gross revenue charges	**-**	**156**	-	147
Interest expense on long-term notes	**-**	**122**	-	127
Income taxes, net of investment tax credits	**-**	**132**	-	112
IESO				
Electricity related revenue	**3,228**	**11**	3,894	22
	3,242	**903**	3,899	848

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at September 30, 2017 and December 31, 2016, the Nuclear Segregated Funds were reported net of amounts due to the Province of $3,796 million and $3,415 million, respectively. The details of accounting for the Nuclear Segregated Funds are described in OPG's 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

The receivable, available-for-sale securities, payable and long-term debt balances between OPG and its related parties are summarized below:

(millions of dollars) (unaudited)	September 30 2017	December 31 2016
Receivables from related parties		
Hydro One	**1**	1
IESO	**346**	421
OEFC	**3**	1
PEC	**2**	4
Province of Ontario	**5**	2
Available-for-sale securities		
Hydro One shares	**190**	212
Accounts payable and accrued charges		
OEFC	**37**	61
Province of Ontario	**6**	2
IESO	**2**	2
Long-term debt (including current portion)		
Notes payable to OEFC	**3,245**	3,295

OPG holds interest-bearing Province of Ontario bonds in the Nuclear Segregated Funds and the OPG registered pension fund. As at September 30, 2017, the Nuclear Segregated Funds held $1,498 million of interest-bearing Province of Ontario bonds, while the registered pension fund had no such holdings. As at December 31, 2016, the Nuclear Segregated Funds and the registered pension fund held $1,652 million and $284 million of interest-bearing Province of Ontario bonds, respectively. These bonds are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

There have been no related party transactions related to the Fair Hydro Plan and associated financing activities. The first transaction between the Trust and the IESO is expected later in 2017.

INTERNAL CONTROLS OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

The Company maintains a comprehensive system of policies, procedures, and processes that represents its framework for internal controls over financial reporting and for its disclosure controls and procedures (together, ICOFR). There were no changes in the Company's internal control system during the current interim period that has or is reasonably likely to have a material impact to the ICOFR.

QUARTERLY FINANCIAL HIGHLIGHTS

The following tables set out selected financial information from OPG's unaudited interim consolidated financial statements for each of the eight most recently completed quarters.

(millions of dollars - except where noted) (unaudited)	**September 30 2017**	**June 30 2017**	**March 31 2017**	**December 31 2016**
Revenue	**1,217**	1,146	1,176	1,388
Net income (loss)	**140**	307	68	(8)
Less: Net income attributable to non-controlling interest	**9**	4	4	5
Net income (loss) attributable to the Shareholder	**131**	303	64	(13)
Per common share, attributable to the Shareholder *(dollars)*	**$0.51**	$1.18	$0.25	($0.05)

(millions of dollars - except where noted) (unaudited)	**September 30 2016**	**June 30 2016**	**March 31 2016**	**December 31 2015**
Revenue	1,400	1,387	1,478	1,312
Net income (loss)	198	135	128	(100)
Less: Net income attribute to the non-controlling interest	4	3	5	1
Net income (loss) attributable to the Shareholder	194	132	123	(101)
Per common share, attributable to the Shareholder *(dollars)*	$0.76	$0.51	$0.48	($0.39)

Trends

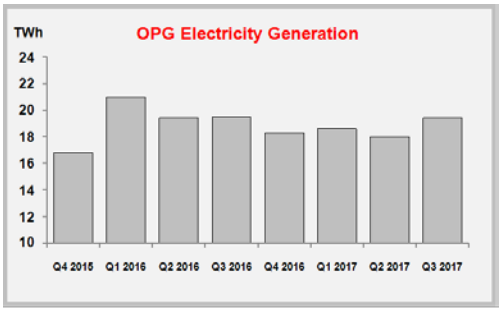
OPG's quarterly results are affected by changes in grid-supplied electricity demand, primarily resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. Weather conditions affect water flows, electricity demand, and prevalence of SBG conditions. Historically, OPG's revenues have been higher in the first

quarter of a fiscal year as a result of winter heating demands and in the third quarter due to air conditioning and cooling demands. The financial impact of forgone production due to SBG conditions at the regulated hydroelectric stations and the financial impact of differences between forecast water flows reflected in OEB-approved regulated prices and the actual water flows are mitigated by regulatory variance accounts authorized by the OEB.

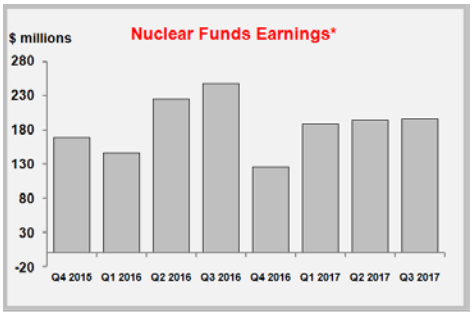
The timing of planned outages at a nuclear generating station during the year can cause variability in year-over-year operating results for partial periods of a fiscal year, including the impact on revenue and OM&A expenses, but is not a significant driver of variability for full fiscal year results.

OPG's electricity generation was reduced as a result of the Unit 2 refurbishment outage at the Darlington GS, which began in October 2016 and is expected to continue until early 2020.

OPG's financial results are also affected by the earnings on the Nuclear Segregated Funds, net of the impact of the Bruce Lease Net Revenues Variance Account.



Additional items that affected net income in certain quarters above are described in OPG's 2016 annual MD&A under



*net of regulatory variance account

the section, *Quarterly Financial Highlights*.

SUPPLEMENTARY NON-GAAP FINANCIAL MEASURES

In addition to providing net income and other financial information in accordance with US GAAP, certain non-GAAP financial measures are also presented in OPG's MD&A. These non-GAAP measures do not have any standardized meaning prescribed by US GAAP and, therefore, may not be comparable to similar measures presented by other issuers. OPG utilizes these measures to make operating decisions and assess performance. Readers of the MD&A would utilize these measures in assessing the Company's financial performance from ongoing operations. The Company believes that these indicators are important since they provide additional information about OPG's performance, facilitate comparison of results over different periods, and present measures consistent with the Company's strategies to provide value to the Shareholder, improve cost performance, and ensure availability of cost effective funding. These non-GAAP financial measures have not been presented as an alternative to net income, cash flow provided by operating activities, or any other measure in accordance with US GAAP, but as indicators of operating performance.

The definitions of the non-GAAP financial measures are as follows:

(1) **ROE Excluding AOCI** is defined as net income attributable to the Shareholder divided by average equity attributable to the Shareholder excluding AOCI, for the period. ROE Excluding AOCI is measured over a 12-month period and is calculated as follows:

	Twelve Months Ended	
(millions of dollars – except where noted) (unaudited)	**September 30 2017**	**December 31 2016**
ROE Excluding AOCI		
Net income attributable to the Shareholder	**485**	436
Divided by: Average equity attributable to the Shareholder, excluding AOCI	**11,055**	10,442
ROE Excluding AOCI *(percent)*	**4.4**	4.2

(2) **FFO Adjusted Interest Coverage** is defined as FFO before interest divided by adjusted interest expense. FFO before interest is defined as cash flow provided by operating activities adjusted for interest paid, interest capitalized to fixed and intangible assets, and changes to non-cash working capital balances for the period. Adjusted interest expense is calculated as net interest expense plus interest income, interest capitalized to fixed and intangible assets, interest related to regulatory assets and liabilities, and the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets, for the period.

FFO Adjusted Interest Coverage is measured over a 12-month period and is calculated as follows:

	Twelve Months Ended	
(millions of dollars – except where noted) (unaudited)	**September 30 2017**	**December 31 2016**
FFO before interest		
Cash flow provided by operating activities	**1,082**	1,595
Add: Interest paid	**270**	269
Less: Interest capitalized to fixed and intangible assets	**(161)**	(141)
Less: Changes to non-cash working capital balances	**38**	42
FFO before interest	**1,229**	1,765
Adjusted interest expense		
Net interest expense	**84**	120
Add: Interest income	**8**	7
Add: Interest capitalized to fixed and intangible assets	**161**	141
Add: Interest related to regulatory assets and liabilities	**43**	30
Add: Excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets [1]	**-**	45
Adjusted interest expense	**296**	343
FFO Adjusted Interest Coverage *(times)*	**4.2**	5.1

[1] A value of nil is used in the calculation when interest on pension and OPEB projected benefit obligations is equal to, or lower than, expected return on pension plan assets.

(3) **Enterprise Total Generating Cost per MWh** is used to measure OPG's overall organizational cost performance. Enterprise TGC per MWh is defined as OM&A expenses (excluding the Darlington Refurbishment project and other generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to OPG's electricity generation business), fuel expense for OPG-operated stations including hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures (excluding the Darlington Refurbishment project and other generation development projects) incurred during the period, divided by total electricity generation from OPG-operated generating stations plus electricity generation forgone due to SBG conditions during the period.

(millions of dollars – except where noted) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Enterprise TGC				
Total OM&A expenses	**635**	666	**2,054**	2,061
Total fuel expense	**185**	187	**518**	541
Total capital expenditures	**476**	444	**1,335**	1,162
Less: Darlington Refurbishment capital and OM&A costs	**(328)**	(269)	**(943)**	(717)
Less: Other generation development project capital and OM&A costs	**(17)**	(42)	**(53)**	(121)
Add (Less): OM&A and fuel expenses (refundable through) deferred in regulatory variance and deferral accounts	**4**	35	**(19)**	76
Less: Nuclear fuel expense for non OPG-operated stations	**(13)**	(18)	**(42)**	(50)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**13**	5	**47**	38
Less: OM&A expenses ancillary to electricity generation business	**(4)**	(5)	**(13)**	(17)
Other adjustments	**(3)**	(12)	**(7)**	(15)
	948	991	**2,877**	2,958
Adjusted electricity generation *(TWh)*				
Total OPG electricity generation	**19.4**	19.5	**56.0**	59.9
Adjust for electricity generation forgone due to SBG conditions and OPG's share of electricity generation from co-owned facilities	**0.9**	0.1	**4.2**	3.4
	20.3	19.6	**60.2**	63.3
Enterprise TGC per MWh *($/MWh)* [1]	**46.65**	50.72	**47.77**	46.74

[1] Amounts may not calculate due to rounding.

(4) **Nuclear Total Generating Cost per MWh** is used to measure the cost performance of OPG's nuclear generating assets. Nuclear TGC per MWh is defined as OM&A expenses of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the nuclear electricity generation business), nuclear fuel expense for OPG-operated stations (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs) incurred during the period, divided by nuclear electricity generation for the period.

(millions of dollars – except where noted) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Nuclear TGC				
Regulated – Nuclear Generation OM&A expenses	**511**	521	**1,693**	1,665
Regulated – Nuclear Generation fuel expense	**81**	79	**217**	239
Regulated – Nuclear Generation capital expenditures	**409**	339	**1,150**	896
Less: Darlington Refurbishment capital and OM&A costs	**(328)**	(269)	**(943)**	(717)
Add: Regulated – Nuclear Generation OM&A and fuel expenses deferred in regulatory variance and deferral accounts	**5**	31	**6**	84
Less: Nuclear fuel expense for non OPG-operated stations	**(13)**	(18)	**(42)**	(50)
Less: Regulated - Nuclear Generation OM&A expenses ancillary to nuclear electricity generation business	**(1)**	(1)	**(3)**	(4)
Other adjustments	**1**	3	**(1)**	(1)
	665	685	**2,077**	2,112
Nuclear electricity generation (TWh)	**11.3**	11.7	**30.6**	34.6
Nuclear TGC per MWh (*$/MWh*) [1]	**58.75**	58.55	**67.87**	61.07

[1] Amounts may not calculate due to rounding.

(5) **Hydroelectric Total Generating Cost per MWh** is used to measure the cost performance of OPG's hydroelectric generating assets. Hydroelectric TGC per MWh is defined as OM&A expenses of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the hydroelectric electricity generation business), hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding expenditures related to the Peter Sutherland Sr. GS, Ranney Falls GS, and other hydroelectric generation development projects) incurred during the period, divided by total hydroelectric electricity generation plus hydroelectric electricity generation forgone due to SBG conditions during the period. OPG reports hydroelectric gross revenue charge and water rental payments as fuel expense.

(millions of dollars – except where noted) (unaudited)	**Three Months Ended September 30**		**Nine Months Ended September 30**	
	2017	**2016**	**2017**	**2016**
Hydroelectric TGC				
Regulated – Hydroelectric OM&A expenses	**81**	87	**232**	238
Regulated – Hydroelectric fuel expense	**88**	88	**258**	259
Contracted Generation Portfolio OM&A expenses	**39**	44	**118**	129
Contracted Generation Portfolio fuel expense	**15**	19	**42**	42
Regulated – Hydroelectric and Contracted Generation Portfolio capital expenditures	**56**	92	**141**	231
Less: Regulated – Hydroelectric and Contracted Generation Portfolio generation development project capital and OM&A costs	**(17)**	(41)	**(52)**	(117)
Less: Thermal OM&A and fuel expenses and capital expenditures in the Contracted Generation Portfolio	**(39)**	(51)	**(119)**	(126)
(Less) Add: Regulated – Hydroelectric OM&A and fuel expenses refundable through regulatory variance and deferral accounts	**(1)**	4	**(25)**	(8)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**13**	5	**47**	38
Other adjustments	**(1)**	(1)	**-**	(1)
	234	246	**642**	685
Adjusted hydroelectric electricity generation *(TWh)*				
Regulated – Hydroelectric electricity generation	**7.3**	6.9	**23.5**	22.8
Contracted Generation Portfolio electricity generation	**0.8**	0.9	**1.9**	2.5
Adjust for hydroelectric electricity generation forgone due to SBG conditions and non-hydroelectric electricity generation of the Contracted Generation Portfolio, including OPG's share of electricity generation from co-owned facilities	**0.8**	0.1	**4.1**	3.4
	8.9	7.9	**29.5**	28.7
Hydroelectric TGC per MWh *($/MWh)* [1]	**26.20**	31.01	**21.74**	23.99

[1] Amounts may not calculate due to rounding.

(6) **Gross margin** is defined as revenue less fuel expense.

For further information, please contact: Investor Relations 416-592-6700

webmaster@opg.com

Media Relations 416-592-4008

1-877-592-4008

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www.sedar.com

Follow-up Questions to Ontario Power Generation September Monthly Report

1. The Pickering Unit 6 planned outage deferral to 2018 boosts net income in 2017-18. As a result, is this expected to lower net income in 2018-19, and if so by how much?
2. How is the lower-than-planned headcount expected to affect OPG financial performance going forward? Is the shortfall mainly due to hiring delays or other factors as well?
3. What were the changes in corporate provisions related to – as noted in the gross margins change explanation?
4. Does OPG have an estimate of when the 2018-2020 Business Plan will be available?

Follow-up Question to Ontario Power Generation Q3 Financial Report

1. OPG's MDA notes the impact on operating results of embedded generation (page 7). Is this, and more generally other distributed energy resources, e.g., energy storage, demand response, that are discussed in the 2017 Long Term Energy Report expected to have material impacts on OPG's operational results over the near to medium-term?

Corporate Electricity Finance Division/Electricity Finance Branch

October 30, 2017

From:	John Kim
To:	Ronald Kwan
Cc:	Usman Zahid
Subject:	FW: OPG Q4 2017 Submission to Province
Date:	Monday, February 26, 2018 5:37:43 PM
Attachments:	Q4 2017 OPG FS PROVINCE MAILING Feb 16_EFB_v3 [Version to Be Reviewed].docx Q4 2017 MD&A - DRAFT - Feb 16 - PROVINCE MAILING_EFB_v3 [Version to Be Reviewed].docx 2017 AIF - DRAFT - Feb 16 - PROVINCE MAILING_EFB_v3 [Version to Be Reviewed].docx

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Hi Ron,

Would you have any issues adding these edits to your comments (or vice versa)?

Thanks,

John

From: John Kim
Sent: Saturday, February 24, 2018 11:31 AM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Usman Zahid <Usman.Zahid@ofina.on.ca>; Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>; Darren Scanlan <Darren.Scanlan@ofina.on.ca>
Subject: RE: OPG Q4 2017 Submission to Province

Hi Ron,

Pls. see attached. No issue on the NR.

Thanks,

John

Z:\Users\CEF\Hydro 2018\OPG\Financials\Q4 2017

From: HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
Sent: February-16-18 5:11 PM
To: Shruti.Talwar@ontario.ca; Manu.Sud@ontario.ca; John Kim <John.Kim@ofina.on.ca>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: GORE Michael -FIN & C CTRL <michael.gore@opg.com>; PAN Rebecca -FIN & C CTRL <rebecca.pan@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>
Subject: OPG Q4 2017 Submission to Province

Hi All,

Please find attached OPG's draft Q4 2017 Financial Results Press Release, Management's Discussion and Analysis (MD&A), Annual Information Form (AIF) and Financial Statements for the Province's review.

We would greatly appreciate comments on the above **no later than Thursday, Feb 22nd**.

These documents will be filed with the Ontario Securities Commission on **Thursday, March 8th** following OPG's Board of Directors meeting.

Kindly forward all comments directly to Philip Ho – philip.ho@opg.com.

To assist the review process, the following are the key items in the Q4 2017 MD&A:

Highlights	
Recent Developments	MD&A p.13-19
OEB's Decision on OPG's Application for New Regulated Prices	MD&A p.13-15
Darlington Refurbishment	MD&A p.16-17; 28-30
Ontario's Fair Hydro Plan	MD&A p.17-18

Philip Ho, CPA, CA | Senior Manager, External Reporting & Accounting Policy | Ontario Power Generation
700 University Avenue, Toronto ON M5G 1X6 | Phone: (416) 592-3320| E-mail: philip.ho@opg.com

ONTARIO POWER GENERATION INC.

CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2017

[DRAFT]

STATEMENT OF MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL INFORMATION

Ontario Power Generation Inc.'s (OPG) management is responsible for the presentation and preparation of the annual consolidated financial statements and Management's Discussion and Analysis (MD&A).

The consolidated financial statements have been prepared in accordance with United States generally accepted accounting principles (US GAAP). The MD&A has been prepared in accordance with the requirements of securities regulators, including National Instrument 51-102 of the Canadian Securities Administrators and its related published requirements.

The consolidated financial statements and information in the MD&A necessarily include amounts based on informed judgments and estimates of the expected effects of current events and transactions with appropriate consideration to materiality. Something is considered material if it is reasonably expected to have a significant impact on the Company's earnings, cash flow, value of an asset or liability, or reputation. In addition, in preparing the financial information, we must interpret the requirements described above, make determinations as to the relevancy of information to be included, and make estimates and assumptions that affect the reported information. The MD&A also includes information regarding the impact of current transactions and events, sources of liquidity and capital resources, operating trends, and risks and uncertainties. Actual results in the future may differ materially from our present assessment of this information because future events and circumstances may not occur as expected.

In meeting our responsibility for the reliability of the financial information, we maintain and rely on a comprehensive system of internal controls and internal audits, including organizational and procedural controls and internal controls over financial reporting. Our system of internal controls includes: written communication of our policies and procedures governing corporate conduct and risk management; comprehensive business planning; effective segregation of duties; delegation of authority and personal accountability; careful selection and training of personnel; and accounting policies, which we regularly update. This structure ensures appropriate internal controls over transactions, assets and records. We also regularly test internal controls. These controls and testing are designed to provide us with reasonable assurance that the financial records are reliable for preparing financial statements and other financial information, assets are safeguarded against unauthorized use or disposition, liabilities are recognized, and we are in compliance with all regulatory requirements.

Management, including the President and Chief Executive Officer (CEO) and the Chief Financial Officer (CFO), is responsible for maintaining disclosure controls and procedures (DC&P) and internal controls over financial reporting (ICOFR). DC&P is designed to provide reasonable assurance that all relevant information is gathered and reported to senior management, including the President and CEO and the CFO, on a timely basis so that appropriate decisions can be made regarding public disclosure. ICOFR is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements in accordance with US GAAP.

An evaluation of the effectiveness of the design and operation of OPG's DC&P and ICOFR was conducted as of December 31, 2017. Accordingly, we, as OPG's President and CEO and CFO, will certify OPG's annual disclosure documents filed with the Ontario Securities Commission, which includes attesting to the design and effectiveness of OPG's DC&P and ICOFR.

The Board of Directors, based on recommendations from its Audit and Risk Committee, reviews and approves the consolidated financial statements and the MD&A, and oversees management's responsibilities for the presentation and preparation of financial information, maintenance of appropriate internal controls, management and control of major areas of financial risk, and assessment of significant and related party transactions.

The consolidated financial statements have been audited by Ernst & Young LLP, independent external auditors appointed by the Board of Directors. The Independent Auditors' Report outlines the auditors' responsibilities and the scope of their examination and their opinion on OPG's consolidated financial statements. The independent external auditors, as confirmed by the Audit and Risk Committee, had direct and full access to the Audit and Risk Committee, with and without the presence of management, to discuss their audit and their findings therefrom, as to the integrity of OPG's financial reporting and the effectiveness of the system of internal controls.

Jeff Lyash
President and Chief Executive Officer

Ken Hartwick
Chief Financial Officer and Senior Vice President – Finance

March 8, 2018

INDEPENDENT
AUDITORS' REPORT

To the Shareholder of Ontario Power Generation Inc.

We have audited the accompanying consolidated financial statements of Ontario Power Generation Inc., which comprise the consolidated balance sheets as at December 31, 2017 and 2016, and the consolidated statements of income, comprehensive income, cash flows and changes in shareholder's equity for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with United States generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Ontario Power Generation Inc. as at December 31, 2017 and 2016, and the results of its operations and its cash flows for the years then ended in accordance with United States generally accepted accounting principles.

Toronto, Canada

March 8, 2018

Ernst & Young LLP

Chartered Professional Accountants,
Licensed Public Accountants

CONSOLIDATED STATEMENTS OF INCOME

Years Ended December 31 *(millions of dollars except where noted)*	**2017**	**2016**
Revenue *(Note 17)*	**5,158**	5,653
Fuel expense *(Note 17)*	**689**	727
Gross margin	**4,469**	4,926
Operations, maintenance and administration *(Note 17)*	**2,824**	2,747
Depreciation and amortization *(Note 4)*	**679**	1,257
Accretion on fixed asset removal and nuclear waste management liabilities *(Note 8)*	**960**	929
Earnings on nuclear fixed asset removal and nuclear waste management funds *(Note 8)*	**(801)**	(746)
Earnings from Fair Hydro Trust *(Note 17)*	**(1)**	-
Income from investments subject to significant influence	**(38)**	(37)
Property taxes	**40**	46
Restructuring	**-**	6
	3,663	4,202
Income before other gains, interest and income taxes	**806**	724
Other gains *(Note 17)*	**379**	17
Income before interest and income taxes	**1,185**	741
Net interest expense *(Note 6)*	**95**	120
Income before income taxes	**1,090**	621
Income tax expense *(Note 9)*	**209**	168
Net income	**881**	453
Net income attributable to the Shareholder	**860**	436
Net income attributable to non-controlling interest	**21**	17
Basic and diluted net income per common share *(dollars) (Note 15)*	**3.35**	1.70

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Years Ended December 31 *(millions of dollars)*	2017	2016
Net income	**881**	453
Other comprehensive income, net of income taxes *(Note 10)*		
Actuarial loss on re-measurement of liabilities for pension and other post-employment benefits [1]	**(23)**	(6)
Reclassification to income of amounts related to pension and other post-employment benefits [2]	**10**	12
Reclassification to income of losses on derivatives designated as cash flow hedges [3]	**18**	19
Unrealized loss on available-for-sale securities [4]	**(8)**	(1)
Other comprehensive (loss) income for the year	**(3)**	24
Comprehensive income	**878**	477
Comprehensive income attributable to the Shareholder	**857**	460
Comprehensive income attributable to non-controlling interest	**21**	17

[1] Net of income tax recovery of $7 million and $2 million for 2017 and 2016, respectively.
[2] Net of income tax expenses of $3 million and $4 million for 2017 and 2016, respectively.
[3] Net of income tax expenses of $2 million for each of 2017 and 2016.
[4] Net of income tax recovery of $2 million and nil for 2017 and 2016, respectively.

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31 *(millions of dollars)*	2017	2016
Operating activities		
Net income	**881**	453
Adjust for non-cash items:		
Depreciation and amortization *(Note 4)*	**679**	1,257
Accretion on fixed asset removal and nuclear waste management liabilities	**960**	929
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(801)**	(746)
Pension and other post-employment benefit costs *(Note 11)*	**412**	464
Deferred income taxes	**19**	(36)
Mark-to-market on derivative instruments	**(3)**	3
Provision for used nuclear fuel and low and intermediate level nuclear waste	**116**	118
Regulatory assets and liabilities	**(558)**	(170)
Provision for materials and supplies	**33**	42
Other gains	**(371)**	-
Other	**1**	(25)
	1,368	2,289
Contributions to nuclear fixed asset removal and nuclear waste management funds	**-**	(150)
Expenditures on fixed asset removal and nuclear waste management	**(313)**	(275)
Reimbursement of eligible expenditures on nuclear fixed asset removal and nuclear waste management	**79**	70
Contributions to pension funds and expenditures on other post-employment benefits and supplementary pension plans	**(322)**	(363)
Expenditures on restructuring	**(4)**	(6)
Distributions received from investments subject to significant influence	**50**	52
Net changes to other long-term assets and liabilities	**32**	20
Net changes to non-cash working capital balances *(Note 18)*	**54**	180
Cash flow provided by operating activities	**944**	1,817
Investing activities		
Acquisition of Fair Hydro Trust financing receivables *(Notes 3 and 19)*	**(1,179)**	-
Purchase of available-for-sale securities	**-**	(213)
Proceeds from deposit note	**70**	110
Net proceeds from sale of property, plant and equipment	**484**	-
Investment in property, plant and equipment and intangible assets	**(1,853)**	(1,816)
Cash flow used in investing activities	**(2,478)**	(1,919)
Financing activities		
Issuance of Class A shares *(Note 14)*	**519**	-
Issuance of long-term debt *(Note 6)*	**1,301**	334
Repayment of long-term debt	**(1,103)**	(273)
Issuance of long-term debt by Fair Hydro Trust *(Note 6)*	**601**	-
Distribution to non-controlling interest	**(15)**	(14)
Capital contribution from non-controlling interest	**19**	-
Issuance of short-term notes	**1,960**	3,108
Repayment of short-term debt	**(1,700)**	(3,331)
Cash flow provided by (used in) financing activities	**1,582**	(176)
Net increase (decrease) in cash and cash equivalents	**48**	(278)
Cash and cash equivalents, beginning of year	**186**	464
Cash and cash equivalents, end of year	**234**	186

See accompanying notes to the consolidated financial statements

CONSOLIDATED BALANCE SHEETS

As at December 31 *(millions of dollars)*	2017	2016
Assets		
Current assets		
Cash and cash equivalents [1]	**234**	186
Available-for-sale securities	**188**	212
Receivables from related parties *(Note 19)*	**369**	429
Nuclear fixed asset removal and nuclear waste management funds *(Notes 8 and 17)*	**23**	24
Fuel inventory *(Note 17)*	**309**	310
Materials and supplies *(Note 17)*	**103**	100
Prepaid expenses	**192**	198
Other current assets	**146**	298
	1,564	1,757
Property, plant and equipment *(Notes 4 and 17)*	**29,950**	29,315
Less: accumulated depreciation	**8,628**	9,317
	21,322	19,998
Intangible assets *(Notes 4 and 17)*	**565**	503
Less: accumulated amortization	**432**	404
	133	99
Other assets		
Nuclear fixed asset removal and nuclear waste management funds *(Notes 8 and 17)*	**16,701**	15,960
Financing receivables *(Note 19)*	**1,179**	-
Long-term materials and supplies *(Note 17)*	**355**	345
Regulatory assets *(Note 5)*	**7,231**	5,855
Investments subject to significant influence *(Note 20)*	**309**	321
Other long-term assets	**28**	37
	25,803	22,518
	48,822	44,372

[1] Includes $4 million restricted for Fair Hydro Trust purposes.

See accompanying notes to the consolidated financial statements

CONSOLIDATED BALANCE SHEETS

As at December 31 *(millions of dollars)*	2017	2016
Liabilities		
Current liabilities		
Accounts payable and accrued charges *(Note 19)*	**1,228**	1,164
Short-term debt *(Note 7)*	**260**	2
Deferred revenue due within one year	**12**	12
Long-term debt due within one year *(Note 6)*	**398**	1,103
Income taxes payable	**80**	123
	1,978	2,404
Long-term debt *(Notes 6 and 17)*	**5,921**	4,417
Other liabilities		
Fixed asset removal and nuclear waste management liabilities *(Notes 8 and 17)*	**20,421**	19,484
Pension liabilities *(Note 11)*	**3,423**	3,012
Other post-employment benefit liabilities *(Note 11)*	**3,092**	2,897
Long-term accounts payable and accrued charges	**252**	213
Deferred revenue	**351**	298
Deferred income taxes *(Note 9)*	**879**	829
Regulatory liabilities *(Note 5)*	**594**	310
	29,012	27,043
Equity		
Common shares [1] *(Note 14)*	**5,126**	5,126
Class A shares [2] *(Note 14)*	**519**	-
Retained earnings	**6,396**	5,534
Accumulated other comprehensive loss *(Note 10)*	**(295)**	(295)
Equity attributable to the Shareholder	**11,746**	10,365
Equity attributable to non-controlling interest *(Note 22)*	**165**	143
Total equity	**11,911**	10,508
	48,822	44,372

[1] 256,300,010 common shares outstanding at a stated value of $5,126 million as at December 31, 2017 and December 31, 2016.

[2] 12,217,616 Class A shares outstanding at a stated value of $519 million as at December 31, 2017.

Commitments and Contingencies *(Notes 6, 9, 11 and 16)*

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY

Years Ended December 31 *(millions of dollars)*	**2017**	**2016**
Common shares	**5,126**	5,126
Class A shares *(Note 14)*	**519**	-
Retained earnings		
Balance at beginning of year	**5,534**	5,098
Net income attributable to the Shareholder	**860**	436
Reclassification of non-controlling interest on change in ownership interest *(Note 22)*	**2**	-
Balance at end of year	**6,396**	5,534
Accumulated other comprehensive loss, net of income taxes		
Balance at beginning of year	**(295)**	(319)
Other comprehensive (loss) income	**(3)**	24
Reclassification of non-controlling interest on change in ownership interest *(Note 22)*	**3**	-
Balance at end of year	**(295)**	(295)
Equity attributable to the Shareholder	**11,746**	10,365
Equity attributable to non-controlling interest		
Balance at beginning of year	**143**	140
Equity contribution from non-controlling interest *(Note 22)*	**21**	-
Reclassification of non-controlling interest on change in ownership interest *(Note 22)*	**(5)**	-
Distribution to non-controlling interest	**(15)**	(14)
Income attributable to non-controlling interest	**21**	17
Balance at end of year	**165**	143
Total equity	**11,911**	10,508

See accompanying notes to the consolidated financial statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the years ended December 31, 2017 and 2016

1. DESCRIPTION OF BUSINESS

Ontario Power Generation Inc. (OPG or the Company) was incorporated on December 1, 1998 pursuant to the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the Province or the Shareholder). OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario.

2. BASIS OF PRESENTATION

These consolidated financial statements have been prepared and presented in accordance with United States generally accepted accounting principles (US GAAP).

As required by *Ontario Regulation 395/11,* as amended, under the *Financial Administration Act* (Ontario), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. Since January 1, 2012, OPG also has received exemptive relief from the Ontario Securities Commission (OSC) from the requirements of section 3.2 of National Instrument 52-107, *Acceptable Accounting Policies and Auditing Standards*. The exemption allows OPG to file consolidated financial statements based on US GAAP, rather than International Financial Reporting Standards (IFRS), without becoming a US Securities and Exchange Commission registrant, or issuing public debt.

The current OSC exemption, received in 2014, will terminate on the earliest of the following:

- January 1, 2019
- The financial year that commences after OPG ceases to have activities subject to rate regulation
- The effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within IFRS specific to entities with rate-regulated activities.

All dollar amounts are presented in Canadian dollars, except in tabular format where noted. Certain of the 2016 comparative amounts have been reclassified from financial statements previously presented to conform to the 2017 consolidated financial statement presentation.

3. SIGNIFICANT ACCOUNTING POLICIES AND ESTIMATES

Consolidation

The consolidated financial statements of the Company include the accounts of OPG and its majority-owned subsidiaries, and variable interest entities (VIEs) where OPG is the primary beneficiary. All significant intercompany balances and intercompany transactions have been eliminated on consolidation.

Where OPG does not control an investment, but has significant influence over operating and financing policies of the investee, the investment is accounted for under the equity method. OPG co-owns the Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS) with TransCanada Energy Ltd. and co-owns the Brighton Beach gas-fired combined cycle GS (Brighton Beach) with ATCO Power Canada Ltd. OPG accounts for its 50 percent ownership interest in each of these jointly controlled entities using the equity method.

Variable Interest Entities

OPG performs ongoing analysis to assess whether it holds any VIEs. VIEs of which OPG is deemed to be the primary beneficiary are consolidated. The primary beneficiary of a VIE has both the power to direct the activities of the entity that most significantly impact its economic performance and the obligation to absorb losses of the entity that could potentially be significant to the Company. In circumstances where OPG is not deemed to be the primary beneficiary, the VIE is not recorded in OPG's consolidated financial statements.

Nuclear Waste Management Organization (NWMO)

In 2002, OPG and other Canadian nuclear waste producers established a separately incorporated NWMO in accordance with the *Nuclear Fuel Waste Act* (Canada) (NFWA). The primary long-term mandate of the NWMO is to implement an approach to address the long-term management of used nuclear fuel in Canada. In addition to the above mandate, the NWMO currently provides project management services for OPG's proposed Deep Geologic Repository (DGR) for the long-term management of low and intermediate level waste (L&ILW) and certain other nuclear life cycle liability management services. OPG has the majority of voting rights at the NWMO Board of Directors' and members' level. The NFWA requires the nuclear fuel waste owners to establish and make payments into trust funds for the purpose of funding the implementation of the long-term nuclear used fuel management plan in accordance with the NFWA. OPG provides over 90 percent of NWMO's funding, primarily towards the design and implementation of Canada's Adaptive Phased Management plan for the long-term management of nuclear used fuel. As a result, OPG is expected to absorb a majority of the NWMO's expected losses through future funding in the event of any shortfall. Therefore, OPG holds a variable interest in the NWMO, of which it is the primary beneficiary. Accordingly, the applicable amounts in the accounts of the NWMO, after elimination of all significant intercompany transactions, are consolidated.

Fair Hydro Trust

On March 2, 2017, the Province announced Ontario's Fair Hydro Plan (the Fair Hydro Plan) aimed at reducing electricity bills for eligible~~all~~ residential customers, and as many as half a million farm and~~,~~ small businesses ~~and other eligible consumers~~ (Specified Consumers) in the province on average by 25 percent. The rate reduction is inclusive of an eight percent rebate equivalent to the provincial portion of the harmonized sales tax granted by the Ontario government in January 2017. As part of the Fair Hydro Plan, a portion of the Global Adjustment costs ~~resulting from the Fair Hydro Plan shortfall~~ will be refinanced over a longer time period. The Global Adjustment includes the difference between Ontario's electricity market clearing price used to dispatch generation and the prices paid to contracted and regulated generators in the province, and the cost of conservation and demand management programs. On June 1, 2017, the *Ontario Fair Hydro Plan Act, 2017* (the Fair Hydro Act or the Act) received Royal Assent and the associated general regulation came into force in June 2017. Effective May 1, 2017, the Independent Electricity System Operator (IESO) began to defer a portion of the Global Adjustment costs. The Act allows for the IESO to transfer a portion of the balance in the variance account to a financing entity that will fund the deferral in exchange for the right to recover the balance and associated financing and other costs from Specified Consumers in the future (Investment Interest).

In December 2017, the Fair Hydro Trust (the Trust) was established as the financing entity contemplated by the Fair Hydro Act. Immediately after the establishment, OPG entered into a management agreement with the Trust which conveys to OPG all of the powers and duties of managing the Trust, including determining whether to acquire Investment Interests from the IESO related to the shortfall from the rate reduction mandated by the Fair Hydro Act, negotiating and executing all agreements, fulfilling all reporting requirements, and administering all of its day-to-day activities. In addition to the powers and duties delegated to OPG as manager under the management agreement, OPG is also required to comply with its duties as Financial Services Manager under the Fair Hydro Act and the regulations.

The Trust is essentially all debt funded and has minimal equity at risk to finance its activities. As part of the funding structure of the Trust, concurrent with every issuance of senior debt, it is expected that OPG will purchase subordinated debt of the Trust in an aggregate amount equal to, but no more than 49 percent of all of the required funding. The subordination level may vary over time, but must at least equal to, or be greater than 35 percent of all outstanding debt. Approximately 90 percent of such amount is expected to be funded through equity investments in OPG by the Province, with the remainder being funded from OPG's available funds, including all or a portion of the proceeds from OPG's medium term notes program. Based on management's assessment, it is concluded that OPG holds a variable interest in the Trust through its ownership of the most subordinated debt, of which it is the primary beneficiary. Accordingly, the applicable amounts in the accounts of the Trust, after elimination of all significant intercompany transactions, have been consolidated by OPG.

PSS Generating Station Limited Partnership (PSS or the Partnership)

As at December 31, 2017, PSS has recognized sufficient level of income and has eliminated deficits within the partnership. Hence, the Partnership has met the criteria of having sufficient equity at risk to finance its activities, and ceased being classified as a variable interest entity. Since OPG is the primary beneficiary of PSS, it continues to consolidate the Partnership.

Use of Management Estimates

The preparation of consolidated financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the consolidated financial statements, and the reported amounts of revenues and expenses for the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in the period incurred. Significant estimates are included in the determination of pension and other post-employment benefit (OPEB) balances, asset retirement obligations (AROs) and associated asset retirement costs capitalized as part of property, plant and equipment (PP&E), income taxes (including deferred income taxes), contingencies, regulatory assets and liabilities, valuation of investments in segregated funds, depreciation and amortization expenses. Actual results may differ significantly from these estimates.

Cash and Cash Equivalents and Short-Term Investments

Cash and cash equivalents include cash on deposit and money market securities with a maturity of less than 90 days on the date of purchase. All other money market securities with a maturity on the date of purchase that is greater than 90 days, but less than one year, are recorded as short-term investments and classified as current assets. These securities are valued at the lower of cost and market.

Inventories

Inventories, consisting of fuel and materials and supplies, are measured at the lower of cost and net realizable value. Cost is determined as weighted average cost for fuel inventory and average cost for materials and supplies.

Property, Plant and Equipment, Intangible Assets and Depreciation and Amortization

PP&E and intangible assets are recorded at cost. Interest costs incurred during construction and development are capitalized as part of the cost of the asset based on the interest rates on OPG's long-term debt. Expenditures for replacements of major components are capitalized.

Depreciation and amortization rates for the various classes of assets are based on their estimated service lives. Asset removal costs that have not been specifically provided for in current or previous periods are charged to operations, maintenance and administration (OM&A) expenses when incurred. Repairs and maintenance costs also are expensed when incurred.

PP&E are depreciated on a straight-line basis, except for computers, which are depreciated on a declining balance basis. Intangible assets, which consist of major application software, are amortized on a straight-line basis.

As at December 31, 2017, the amortization periods of PP&E and intangible assets are as follows:

Nuclear generating stations and major components	15 to 74 years [1]
Thermal generating stations and major components	5 to 50 years
Hydroelectric generating stations and major components	10 to 100 years
Administration and service facilities	10 to 50 years
Computers – declining balance	12% to 40% per year
Major application software	5 years
Service equipment	5 to 10 years

[1] As at December 31, 2017, the end of station life for depreciation purposes for the Darlington, Pickering, Bruce A and Bruce B nuclear generating stations ranged between 2022 and 2061. Major components are depreciated over the lesser of the station life and the life of the components.

Asset Impairment

Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. The review is based on the presence of impairment indicators such as the future economic benefit of the assets and external market conditions. The net carrying amount of assets is considered impaired if it exceeds the sum of the estimated undiscounted cash flows expected to result from the asset's use and eventual disposition. In cases where the sum of the undiscounted expected future cash flows is less than the carrying amount, an impairment loss is recognized. This loss equals the amount by which the carrying amount exceeds the fair value. Fair value is determined using expected discounted cash flows when quoted market prices are not available. The impairment is recognized in income in the period in which it is identified.

The carrying values of investments accounted for under the equity method are reviewed annually for the presence of any indicators of impairment. If an impairment exists and is determined to be other-than-temporary, an impairment charge is recognized. This charge equals the amount by which the carrying value exceeds the investment's fair value.

Rate Regulated Accounting

The *Ontario Energy Board Act, 1998* and *Ontario Regulation 53/05* provide that OPG receives regulated prices for electricity generated from the Sir Adam Beck 1, 2 and Pump hydroelectric generating stations, the DeCew Falls 1 and 2 hydroelectric generating stations, the R.H. Saunders Hydroelectric GS, the 48 hydroelectric generating stations prescribed for rate regulation effective in 2014, and the Pickering and Darlington nuclear generating stations (collectively, prescribed facilities or regulated facilities). OPG's regulated prices for these facilities are determined by the Ontario Energy Board (OEB).

The OEB is a self-funding Crown corporation. Its mandate and authority come from the *Ontario Energy Board Act, 1998,* the *Electricity Act, 1998*, and a number of other provincial statutes. The OEB is an independent, quasi-judicial tribunal that reports to the Legislature of the Province through the Ontario Ministry of Energy. It regulates market participants in Ontario's natural gas and electricity industries. The OEB carries out its regulatory functions through public hearings and other more informal processes such as consultations.

US GAAP recognizes that rate regulation can create economic benefits and obligations that are required by the regulator to be obtained from, or settled with, the customers. When the Company assesses that there is sufficient assurance that incurred costs in respect of the regulated facilities will be recovered in the future, those costs are deferred and reported as a regulatory asset. When the Company is required to refund amounts to customers in the future in respect of the regulated facilities, including amounts related to costs that have not been incurred but for which the OEB has provided recovery through regulated prices, the Company records a regulatory liability.

Certain of the regulatory assets and liabilities recognized by the Company relate to variance and deferral accounts authorized by the OEB, including those authorized pursuant to *Ontario Regulation 53/05*. Variance and deferral accounts typically capture differences between actual costs and revenues and the corresponding forecast amounts

approved by the OEB in setting regulated prices, or record the impact of items not reflected in the approved regulated prices. The measurement of these regulatory assets and liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of *Ontario Regulation 53/05* and the OEB's decisions. The estimates and assumptions made in the interpretation of the regulation and the OEB's decisions are reviewed as part of the OEB's regulatory process.

Regulatory assets and liabilities for variance and deferral account balances approved by the OEB for inclusion in regulated prices are amortized based on approved recovery or repayment periods. Disallowed balances are charged to operations in the period that the corresponding OEB decision is issued.

Regulatory assets and liabilities for variance and deferral account balances approved by the OEB are classified as current if they are expected to be recovered from, or refunded to, customers within 12 months of the end of the reporting period, based on recovery or repayment periods authorized by the OEB. All other regulatory asset and liability balances are classified as non-current on the consolidated balance sheets.

In addition to regulatory assets and liabilities for variance and deferral accounts, OPG recognizes regulatory assets and liabilities for unamortized amounts recorded in accumulated other comprehensive income (AOCI) in respect of pension and OPEB obligations, and deferred income taxes, in order to reflect the expected recovery or repayment of these amounts through future regulated prices charged to customers. There are measurement uncertainties related to these balances due to the assumptions made in the determination of pension and OPEB obligations and deferred income taxes that are attributed to rate regulated business segments.

The regulatory asset for unamortized pension and OPEB amounts recorded in AOCI has reflected the OEB's use, since April 1, 2008, of the accrual basis of accounting for including pension and OPEB amounts in approved regulated prices for OPG. This is also the manner in which these costs are recognized in OPG's consolidated financial statements. Therefore, unamortized amounts in respect of OPG's pension and OPEB plans recognized in AOCI generally would not be reflected in regulated prices until they have been reclassified from AOCI and recognized as amortization components of the benefit costs for these plans. The regulatory asset is reversed as underlying unamortized balances are amortized as components of the benefit cost.

In setting OPG's regulated prices effective November 1, 2014, the OEB limited amounts for pension and OPEB costs allowed in the approved revenue requirements to the regulated business portion of the Company's cash expenditures on its pension and OPEB plans. It is the Company's position that this decision by the OEB does not constitute a change in the basis of rate recovery for OPG's pension and OPEB costs. This position is based on the OEB's establishment of the Pension & OPEB Cash Versus Accrual Differential Deferral Account pursuant to its November 2014 decision, and the expectation expressed by the OEB in that decision that a transition from the accrual basis of recovery for OPG, if required, would be addressed in a future OPG rate proceeding, informed by the outcome of an OEB generic proceeding related to the regulatory treatment and recovery of pension and OPEB costs. Effective November 1, 2014, the Pension & OPEB Cash Versus Accrual Differential Deferral Account records the difference between OPG's actual pension and OPEB costs for the regulated business determined using the accrual method applied in OPG's audited consolidated financial statements and OPG's corresponding actual cash expenditures for these plans. The OEB's November 2014 decision indicated that the future recovery, if any, of amounts recorded in the deferral account would be subject to the outcome of an OEB generic proceeding on the regulatory treatment and recovery of pension and OPEB costs. In May 2015, the OEB began a consultation process to develop standard principles to guide its future review of pension and OPEB costs of rate regulated utilities in the electricity and natural gas sectors, including establishing appropriate regulatory mechanisms for cost recovery. The consultation is continuing. On September 14, 2017, the OEB issued its final report on the guiding principles and the policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the Ontario electricity and natural gas sectors. The report establishes the accrual basis of accounting as the method of determining pension and OPEB amounts for rate-setting purposes, unless the OEB finds that this method does not result in just and reasonable rates in the circumstances of a particular utility.

In consideration of the above factors, the Company continues to believe that there is sufficient likelihood that unamortized pension and OPEB amounts that have not yet been reclassified from AOCI will be included in future regulated prices or in an OEB-authorized deferral or variance account for future recovery, as they are recognized in benefit costs. Therefore, the Company continues to recognize a regulatory asset for these unamortized amounts and also has recognized a regulatory asset for the balance of the Pension & OPEB Cash Versus Accrual Differential Deferral Account discussed in Note 5.

See Notes 5, 8, 9, and 11 for additional disclosures related to the OEB's decisions, regulatory assets and liabilities, and rate regulated accounting.

Revenue Recognition

All of OPG's electricity generation is offered into the real-time energy spot market administered by the IESO. Revenue is recognized as electricity is generated and metered to the IESO.

Revenue Recognition – Regulated Generation

Energy revenue generated from OPG's regulated facilities is based on regulated prices determined by the OEB that include a base regulated price and, as applicable, rate riders for the recovery or repayment of approved variance and deferral account balances.

The base regulated prices in effect during 2016 were established by the OEB's November 2014 decision and December 2014 order, using a forecast cost-of-service rate-setting methodology based on the OEB-approved revenue requirements, taking into account the OEB-approved forecasts of production and operating costs for the regulated facilities for 2014 and 2015 and a return on rate base. Rate base is a regulatory construct that, for OPG, represents the average net level of investment in regulated fixed and intangible assets in-service and an allowance for working capital. The revenues from the regulated hydroelectric facilities are also subject to the OEB-approved hydroelectric incentive mechanism. This mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers.

The rate riders in effect during 2016 were established by the OEB in its October 2015 order on OPG's application to recover balances in most of the Company's authorized variance and deferral accounts as at December 31, 2014. The OEB-authorized variance and deferral accounts are discussed in Note 5.

The OEB's decision and order on OPG's May 2016 five-year application for new regulated prices for its nuclear and regulated hydroelectric generation was issued on December 28, 2017, following a public hearing process. The OEB set an effective date for OPG's new regulated prices of June 1, 2017. OPG had requested an effective date of January 1, 2017 and has filed a motion with the OEB in January 2018 to review and vary this aspect of the OEB's December 2017 decision. [**MONITOR**] See Note 5 for further information on OPG's May 2016 application.

Revenue Recognition – Non-regulated Generation and Other Revenue

The electricity generation from OPG's non-regulated assets receives the Ontario electricity spot market price, except where an energy supply agreement (ESA) with the IESO or another contractual agreement is in place. As at December 31, 2017, most of OPG's operating non-regulated assets are subject to an ESA. Revenue from the generating stations subject to an ESA is recognized in accordance with the terms of the agreement.

OPG also sells into, and purchases from, interconnected markets of other provinces and the northeast and midwest regions of the US. All contracts that are not designated as hedges are recorded on the consolidated balance sheets at market value, with gains or losses recorded in the consolidated statements of income. Gains and losses on energy trading contracts (including those to be physically settled) are recorded on a net basis in the consolidated statements of income. Accordingly, power purchases of $15 million were netted against revenue in 2017 (2016 – $19 million).

OPG derives non-energy revenue under the terms of a lease arrangement and associated agreements with Bruce Power L.P. (Bruce Power) related to the Bruce nuclear generating stations. This includes lease revenue and revenue from heavy water sales, detritiation services and waste management services. OPG's net revenues from the lease of these stations and related agreements, including a portion of heavy water sales, are credited to customers and therefore have reduced regulated prices for the generation from the nuclear facilities owned and operated by OPG. The minimum lease payments are recognized in revenue on a straight-line basis over the term of the lease.

In addition, non-energy revenue includes isotope sales, real estate rentals and other service revenues. Revenues from these activities are recognized as services are provided, or as products are delivered, in accordance with the terms stipulated in the respective contracts.

Fixed Asset Removal and Nuclear Waste Management Liabilities

OPG recognizes AROs for fixed asset removal and nuclear waste management, discounted for the time value of money. OPG estimates both the amount and timing of future cash expenditures based on the plans for fixed asset removal and nuclear waste management. The liabilities are initially recorded at their estimated fair value, which is based on a discounted value of the expected costs to be paid.

On an ongoing basis, the liabilities for nuclear fixed asset removal and nuclear waste management (Nuclear Liabilities) are increased by the present value of the incremental (variable) cost portion for the nuclear waste generated each year, with the corresponding amounts charged to OM&A expenses. Variable expenses relating to L&ILW are charged to OM&A expenses. Variable expenses relating to the management and storage of nuclear used fuel are charged to fuel expense. The liabilities may also be adjusted due to changes in the estimated amount or timing of the underlying future cash flows, with resulting changes in the related asset retirement costs capitalized as part of the carrying amount of the related fixed assets in service. A comprehensive reassessment of all underlying assumptions and baseline cost estimates for the Nuclear Liabilities is performed periodically. Changes in the Nuclear Liabilities resulting from changes in assumptions or estimates that impact the amount or timing of the originally estimated undiscounted future cash flows are recorded as an adjustment to the liabilities. Upward revisions in the Nuclear Liabilities represent the present value of increases in future undiscounted cash flows determined using a current credit-adjusted risk-free rate. Downward revisions in the Nuclear Liabilities represent the present value of decreases in future undiscounted cash flows determined using the weighted average discount rate reflected in the existing liability. Upon settlement of the liabilities, a gain or loss would be recorded.

Accretion arises because the fixed asset removal and nuclear waste management liabilities are reported on a net present value basis. Accretion expense is the increase in the carrying amount of the liabilities due to the passage of time.

The asset retirement cost is capitalized by increasing the carrying value of the related fixed assets in service. The capitalized cost is depreciated over the remaining service life of the related fixed assets and is included in depreciation and amortization expenses.

OPG has no legal obligation associated with the decommissioning of its hydroelectric generating facilities and the costs cannot be reasonably estimated because of the long service life of these assets. With either maintenance efforts or rebuilding, the water control structures are assumed to be used for the foreseeable future. Accordingly, OPG has not recognized a liability for the decommissioning of its hydroelectric generating facilities.

Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

Pursuant to the Ontario Nuclear Funds Agreement (ONFA) between OPG and the Province, OPG has established and sets aside funds in a Used Fuel Segregated Fund and a Decommissioning Segregated Fund (together the Nuclear Segregated Funds). The Used Fuel Segregated Fund is intended to fund expenditures associated with the long-term management of radioactive used nuclear fuel bundles and certain costs of used fuel storage incurred after the nuclear stations are shut down, while the Decommissioning Segregated Fund was established to fund the costs

of nuclear fixed asset removal and long-term L&ILW management, and certain costs of used fuel storage incurred after the nuclear stations are shut down. OPG's funding obligations and resulting contributions to the Nuclear Segregated Funds are determined based on periodically updated reference plans approved by the Province under the ONFA. OPG maintains the Nuclear Segregated Funds in third-party custodial and trust accounts that are segregated from the rest of OPG's assets.

OPG's investments in the Nuclear Segregated Funds and the corresponding amounts payable to/receivable from the Province are classified as held-for-trading. The Nuclear Segregated Funds are measured at fair value based on the bid prices of the underlying equity and fixed income securities, and, in the case of the alternative investment portfolio, using appropriate valuation techniques as outlined in Note 13, with realized and unrealized gains and losses recognized in OPG's consolidated statements of income.

Financing Receivables

Financing receivables consist of the current and irrevocable right of the Fair Hydro Trust to collect payments from Specified Consumers in the future in accordance with the Fair Hydro Act and associated general regulation. These amounts are measured at the transaction price entered into with the IESO on market terms upon acquisition and subsequently measured on an amortized cost basis. The basis of amortization follows the effective interest method.

Derivatives

All derivatives, including embedded derivatives that must be separately accounted for, generally are classified as held-for-trading and recorded at fair value in the consolidated balance sheets. Transaction costs are expensed as incurred for financial instruments classified or designated as held-for-trading.

Derivatives qualify for hedge accounting if they meet stringent documentation requirements, and if the derivative instrument that is designated as a hedge is expected to effectively hedge the identified risk throughout the life of the hedged item. At the inception of a hedging relationship, OPG documents the relationship between the hedging instrument and the hedged item, its risk management objective, and its strategy for undertaking the hedge. A documented assessment is made, both at the inception of a hedge and on an ongoing basis, of whether or not the derivatives that are used in hedging transactions are highly effective in offsetting the changes attributable to the hedged risks in the fair values or cash flows of the hedged items.

All derivative contracts not designated as hedges are recorded on the consolidated balance sheets as derivative assets or liabilities at fair value, with changes in the fair value recorded in the revenue of the Services, Trading, and Other Non-Generation segment. Refer to Note 12 for a discussion of OPG's risk exposures and the derivative instruments used to manage these risks.

Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly arm's-length transaction between market participants at the measurement date. Fair value measurements are required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model. OPG uses a fair value hierarchy, grouping assets and liabilities into three levels based on the relative objectivity of the inputs used to measure fair value, with Level 1 representing the most objective. Refer to Note 13 for a discussion of fair value measurements and the fair value hierarchy.

Available-for-Sale Securities

Available-for-sale (AFS) securities are measured at fair value, with unrealized gains and losses due to changes in fair value recognized in other comprehensive income (OCI). Gains and losses are realized and included in net income when the securities are sold or awarded. Related transaction costs are expensed as incurred, and dividend income

is included in net income in the period dividends are declared. Equity securities are initially measured at the transaction price.

Research and Development

Research and development costs are expensed as incurred. Research and development costs incurred to discharge long-term obligations for which specific provisions have already been made, such as the Nuclear Liabilities, are charged to the related liability.

Leases

Leases are evaluated and classified as either operating or capital leases for financial reporting purposes. Capital leases, which transfer substantially all of the risks and benefits incidental to ownership of the leased item, are capitalized at the inception of the lease at the fair value of the leased property or, if lower, at the present value of the minimum lease payments. Capital leases are depreciated over the shorter of the estimated useful life of the asset and the lease term.

Leases where the lessor retains substantially all the risks and benefits incidental to ownership of the asset are classified as operating leases. Operating lease payments, other than contingent rentals, are recognized as an expense in the consolidated statements of income on a straight-line basis over the lease term. Where the amount of rent expense recognized is different from the actual operating lease payment, other than contingent rentals, the difference is deferred and included as assets or liabilities on the consolidated balance sheets.

Pension and Other Post-Employment Benefits

OPG's post-employment benefit programs consist of a contributory defined benefit registered pension plan, a defined benefit supplementary pension plan, and other post-retirement benefits (OPRB) including group life insurance and health care benefits, and long-term disability (LTD) benefits. Post-employment benefit programs are also provided by the NWMO, which is consolidated into OPG's financial results. Unless otherwise noted, information on the Company's post-employment benefit programs is presented on a consolidated basis.

OPG accrues its obligations under pension and OPEB plans in accordance with US GAAP. The obligations for pension and OPRB are determined using the projected benefit method pro-rated on service. The obligation for LTD benefits is determined using the projected benefit method on a terminal basis. Pension and OPEB obligations are impacted by factors including interest rates, adjustments arising from plan amendments, demographic assumptions, experience gains or losses, salary levels, inflation, and health care cost escalation assumptions. Pension and OPEB costs and obligations are determined annually by independent actuaries using management's best estimate assumptions.

Assumptions are significant inputs to actuarial models that measure pension and OPEB obligations and related effects on operations. Discount rate, inflation rate, and changes in salary levels are three critical assumptions in the determination of benefit costs and obligations. In addition, the expected long-term rate of return on plan assets is a critical assumption in the determination of registered pension plan cost and the health care cost trend rate is a critical assumption in the determination of OPEB cost and obligations. These assumptions, as well as other assumptions involving demographic factors such as retirement age, mortality, and employee turnover, are evaluated periodically by management in consultation with independent actuaries. During the evaluation process, the assumptions are updated to reflect past experience and expectations for the future. Actual results in any given year will often differ from actuarial assumptions because of economic and other factors giving rise to actuarial gains and losses. In accordance with US GAAP, for pension and OPRB, the impact of these updates and differences on the respective benefit obligations is accumulated and amortized over future periods. For LTD benefits, the impact of these updates and differences is immediately recognized as OPEB costs in the period incurred.

The discount rates, which are representative of AA corporate bond yields, are used to calculate the present value of the expected future cash flows on the measurement date in order to determine the projected benefit obligations for the Company's employee benefit plans. A lower discount rate increases the benefit obligations and increases benefit costs. The expected rate of return on plan assets is based on the pension fund's asset allocation and the expected return considering long-term risks and returns associated with each asset class within the plan portfolio. A lower expected rate of return on plan assets increases pension cost.

Pension fund assets include equity securities, corporate and government debt securities, pooled funds, real estate, infrastructure, and other investments. These assets are managed by professional investment managers. The pension fund does not invest in equity or debt securities issued by OPG. Pension fund assets are valued using market-related values for purposes of determining the amortization of actuarial gains or losses and the expected return on plan assets. The market-related value recognizes gains and losses on equity assets relative to a six percent assumed real return over a five-year period.

Pension and OPEB costs include current service costs, interest costs on the obligations, the expected return on pension plan assets, adjustments for plan amendments, and adjustments for actuarial gains or losses, which result from changes in assumptions and experience gains and losses. Past service costs or credits arising from pension and OPRB plan amendments are amortized on a straight-line basis over the expected average remaining service life to full eligibility of the employees covered by the corresponding plan. Past service costs or credits arising from amendments to LTD benefits are immediately recognized as OPEB costs in the period incurred. Due to the long-term nature of pension and OPRB liabilities, the excess of the net cumulative unamortized gain or loss, over 10 percent of the greater of the benefit obligation and the market-related value of the plan assets (the corridor), is amortized over the expected average remaining service life of the employees, which represents the period during which the associated economic benefits are expected to be realized by the Company. Actuarial gains or losses for LTD benefits are immediately recognized as OPEB costs in the period incurred.

OPG recognizes the funded status of its defined benefit plans on the consolidated balance sheets. The funded status is measured as the difference between the fair value of plan assets and the benefit obligation, on a plan-by-plan basis.

Actuarial gains or losses and past service costs or credits arising during the year that are not recognized immediately as components of benefit costs are recognized as increases or decreases in OCI, net of income taxes. These unamortized amounts in AOCI are subsequently reclassified and recognized as components of pension and OPRB costs as described above.

OPG records an offsetting regulatory asset or liability for the portion of the adjustments to AOCI that is attributable to the regulated operations in order to reflect the expected recovery or refund of these amounts through future regulated prices charged to customers. For the recoverable or refundable portion attributable to regulated operations, OPG records a corresponding change in this regulatory asset or liability for the amount of the increases or decreases in OCI and for the amounts reclassified from AOCI into benefit costs during the period.

When the recognition of the transfer of employees and employee-related benefits gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement. A curtailment is the loss by employees of the right to earn future benefits under the plan. A settlement is the discharge of a plan's liability.

Income Taxes and Investment Tax Credits

OPG is exempt from income taxes under the *Income Tax Act* (Canada). However, under the *Electricity Act, 1998*, OPG is required to make payments in lieu of corporate income taxes to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by the *Electricity Act, 1998* and related regulations. This results in OPG paying taxes similar to those imposed under the federal and Ontario tax acts.

OPG's operations are complex and the computation of the provision for income taxes involves interpretation of the various tax statutes and regulations. OPG has taken certain filing positions in calculating the amount of its income tax provision. These filing positions may be challenged on audit by the Ontario Ministry of Finance and some of them possibly disallowed, resulting in a potential significant change in OPG's tax provision upon reassessment. A change in the tax provision upon reassessment impacting regulated operations may be recoverable from or refundable to customers through the Income and Other Taxes Variance Account authorized by the OEB.

OPG follows the liability method of accounting for income taxes. Under the liability method, deferred income tax assets and liabilities are determined based on differences between the accounting and tax bases of assets and liabilities. Deferred amounts are measured using the enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect of a change in tax rates on deferred income tax assets and liabilities is included in income in the period the change is enacted.

If management determines that it is more likely than not that some, or all, of a deferred income tax asset will not be realized, a valuation allowance is recorded to report the balance at the amount expected to be realized.

OPG recognizes deferred income taxes associated with its regulated operations and records an offsetting regulatory asset or liability for the deferred income taxes that are expected to be recovered or refunded through future regulated prices charged to customers.

Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return and investment tax credits are recorded only when the more likely than not recognition threshold is satisfied. Tax benefits and investment tax credits recognized are measured at the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement.

Investment tax credits are recorded as a reduction to income tax expense. OPG classifies interest and penalties associated with unrecognized income tax benefits as income tax expense.

Change in Accounting Estimates

Change in Nuclear Liabilities Estimate

In the fourth quarter of 2017, OPG achieved sufficient confidence in the Company's plans to pursue the continued safe and reliable operation of two units at the Pickering GS to 2022 and the four remaining units to 2024. This resulted in a change to the useful lives for the Pickering GS, for the purposes of calculating depreciation. Effective December 31, 2017, the change to the estimated service live of the Pickering GS has been reflected in an increase to the estimate of the Nuclear Liabilities of $188 million, and a corresponding changes in the carrying value of the nuclear generating stations to which the liabilities relate. The increase in the liabilities is primarily due to higher fixed costs associated with the Used Fuel Disposal and L&ILW Storage programs, discounted using the current credit-adjusted risk-free rate of 2.94 percent.

OPG filed an application with the OEB (EB-2018-0002) on December 29, 2017 to seek approval to establish a deferral account to record, from January 1, 2018 until the effective date of the OEB's next payment amounts order, the revenue requirement impact of changes to nuclear liabilities and depreciation and amortization expense resulting from changes to station end-of-life dates for OPG's Pickering prescribed nuclear facilities that were effective December 31, 2017. On January 31, 2018 the OEB issued an interim order (EB-2018-0002) for the establishment of the Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account, pending the outcome of the proceeding.

Pension and Other Post-Employment Benefits

Effective January 1, 2017, OPG changed the method used to estimate the service and interest cost components of pension and OPEB costs. OPG adopted a full yield curve approach to the estimation of these cost components, by applying the specific spot rates along the yield curve used in the determination of the projected benefit obligations to the relevant projected cash flows. Under the previous method, these components of pension and OPEB costs were calculated using the same single weighted-average discount rates as reflected in the calculation of the benefit obligations. This change in the method was accounted for prospectively, as a change in estimate. The resulting reduction in pension and OPEB costs is estimated at approximately $135 million in 2017. Approximately 90 percent of this reduction in pension and OPEB costs was attributed to the Company's regulated business segments and therefore was offset by the impact of regulatory variance and deferral accounts authorized by the OEB. This change does not affect the measurement of the total benefit obligation as the change in the current service and interest cost components from the previous method will be offset by a corresponding change in the actuarial gain and loss recorded in AOCI.

Pension Plan Actuarial Valuation

A new actuarial valuation of the OPG registered pension plan was filed with the Financial Services Commission of Ontario in September 2017 with an effective date of January 1, 2017. The annual funding requirements in accordance with the new actuarial valuation are $212 million for 2017, $215 million for 2018, and $219 million for 2019.

Recent Accounting Pronouncements Not Yet Adopted

Revenue from Contracts with Customers

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09, *Revenue from Contracts with Customers* (Topic 606), which supersedes nearly all existing revenue recognition guidance, including industry-specific guidance, under US GAAP. The core principle of Topic 606 is to recognize revenues when promised goods or services are transferred to customers in an amount that reflects the consideration to which an entity expects to be entitled for those goods or services. Either a full retrospective application or a modified retrospective application is required for annual periods beginning on or after January 1, 2018, including interim periods within that year. Early adoption is permitted.

OPG has assessed the impact of the standard on accounting for the Company's revenue streams and consolidated financial statements. OPG's major revenue streams include regulated generation revenue from base regulated prices and rate riders established by the OEB, as well as revenue from generation assets under long-term contractual arrangements with the IESO. OPG has completed its analyses of the impact of Topic 606 on all of its revenue streams, and has not identified any material differences in the timing or amount of revenue recognition for these streams.

The Company will apply the new revenue standard in its 2018 first quarter interim financial statements and is in the process of evaluating the additional disclosures required under the new standard.

Lease Accounting

In February 2016, the FASB issued ASU No. 2016-02, *Leases* (Topic 842). The update includes comprehensive changes to existing guidance for lease accounting, particularly for lessees, and aims to increase transparency and comparability among organizations by requiring the recognition of lease assets and lease liabilities on the balance sheet. The standard is effective for annual periods beginning after December 15, 2018, including interim periods within that year.

Under the current guidance, entities are required to use a modified retrospective approach for leases that exist, or are entered into, after the beginning of the earliest comparative period presented in the financial statements of the period of adoption. Under this method, Topic 842 would effectively be implemented by recognizing any adjustments stemming from the transition, as of beginning of the earliest comparative period presented in the entities' financial statements. Full retrospective application is prohibited. In January 2018, the FASB issued a proposed ASU wherein entities would be able to utilize an additional optional transition method of recording the cumulative impact of adopting the new lease standard to the opening balance in the initial period of adoption; with comparative periods continuing to be presented in accordance with the existing leasing standard, Topic 840 - *Leases*, including disclosures. [**MONITOR**] The Company will continue to monitor the status of this proposed ASU.

The FASB also issued ASU No. 2018-01, *Land Easement Practical Expedient for Transition to Topic 842* in January 2018. The amendments therein allows an entity to choose not to evaluate under Topic 842 land easements that exist or expired before the entity's adoption of the new leasing standard and that were not previously accounted for as leases under Topic 840.

The Company continues to implement and execute a comprehensive project governance framework, which comprises a Steering Committee, Implementation & Stakeholder Committee, Project Management Office, and various working groups in order to evaluate the implement the new standard. The working groups are represented by cross functional finance and non-finance stakeholders who will support the financial and operational implementation of the standard. The Company continues to evaluate the impact of the new leasing standard on its consolidated financial statements.

Recognition and Measurement of Financial Assets and Financial Liabilities

In January 2016, the FASB issued ASU No. 2016-01, *Financial Instruments – Overall: Recognition and Measurement of Financial Assets and Financial Liabilities*. Under the updated guidance, entities will have to measure equity investments at fair value and recognize any changes in fair value in net income. The update will be effective for OPG's 2018 fiscal year, including interim periods. As a result of this update, effective January 1, 2018, the AFS classification for securities will no longer be available, with any unrealized gains and losses related to such securities recognized in net income instead of OCI. Any unrealized gains and losses for AFS securities reported by OPG in AOCI as of the end of 2017 will be reclassified to retained earnings as of January 1, 2018. OPG's Hydro One share holdings are currently the Company's only AFS securities. As at December 31, 2017, these shares are valued on the consolidated balance sheet at $188 million (December 31, 2016 − $212 million), for which a loss of $8 million (2016 − $1 million) has been recorded in AOCI. OPG continues to evaluate whether the new standard will have any further impact on its consolidated financial statements.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost

In March 2017, the FASB issued ASU No. 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. Under the new guidance, employers that sponsor defined benefit plans for pensions and/or other postretirement benefits are required to present the service cost component of net periodic benefit cost in the same statement of income line item as other employee compensation costs arising from services rendered during the period. The other components of the net periodic benefit cost are to be presented separately from the line item that includes the service cost and outside of any subtotal of income from operations, if such a subtotal is presented. In addition, the new guidance requires that only the service cost component of net benefit cost be eligible for capitalization.

This guidance is effective for fiscal years beginning after December 15, 2017, including interim periods of those years. The guidance is not expected to have a material impact on OPG's consolidated financial statements, as OPG currently capitalizes only the service cost component of post-retirement benefits costs. Additionally, OPG already includes the service cost component of post-retirement benefit costs with other compensation costs, within the OM&A expenses line item in the consolidated statements of income, and does not show a subtotal of income from operations. As such, the new guidance is not expected to affect the presentation of OPG's consolidated financial statements.

4. PROPERTY, PLANT AND EQUIPMENT, INTANGIBLE ASSETS AND DEPRECIATION AND AMORTIZATION

PP&E as at December 31 consist of the following:

(millions of dollars)	**2017**	**2016**
Nuclear generating stations	**11,985**	11,057
Regulated hydroelectric generating stations	**9,566**	9,430
Contracted generation portfolio generating stations	**3,935**	3,751
Other property, plant and equipment	**372**	1,595
Construction in progress	**4,092**	3,482
	29,950	29,315
Less: accumulated depreciation		
Generating stations	**8,480**	7,948
Other property, plant and equipment	**148**	1,369
	8,628	9,317
	21,322	19,998

Construction in progress as at December 31 consists of the following:

(millions of dollars)	**2017**	**2016**
Darlington Refurbishment	**3,507**	2,563
Peter Sutherland Sr. GS	**17**	236
Other	**568**	683
	4,092	3,482

Intangible assets as at December 31 consist of the following:

(millions of dollars)	**2017**	**2016**
Nuclear generating stations	**122**	122
Regulated hydroelectric generating stations	**6**	7
Contracted generation portfolio generating stations	**5**	4
Computer software and other intangible assets	**393**	350
Development in progress	**39**	20
	565	503
Less: accumulated amortization		
Generating stations	**123**	120
Computer software and other intangible assets	**309**	284
	432	404
	133	99

Depreciation and amortization expenses, including amounts recognized in regulatory variance and deferral accounts authorized by the OEB, for the years ended December 31 consist of the following:

(millions of dollars)	**2017**	**2016**
Depreciation	**649**	602
Amortization of intangible assets	**30**	27
Amounts recognized in regulatory variance and deferral accounts	**-**	26
Amortization of regulatory assets and liabilities *(Note 5)*	**-**	602
	679	1,257

Interest capitalized to construction in progress during 2017 was $162 million (2016 – $141 million), at an average rate of five percent (2016 – five percent).

5. REGULATORY ASSETS AND LIABILITIES

OPG's May 2016 application with the OEB for new regulated prices included a request for new rate riders to recover or repay the December 31, 2015 balances in all of the Company's OEB-authorized variance and deferral accounts, with the exception of the Pension & OPEB Cash Versus Accrual Differential Deferral Account, less amounts previously approved for recovery or repayment for these accounts in 2016. The application also requested the continuation of all applicable existing variance and deferral accounts. In March 2017, the OEB approved a settlement agreement reached by OPG and intervenors on a limited set of issues in the application (Settlement Agreement). Among the settled issues, the agreement provided for the continuation of all applicable existing variance and deferral accounts and accepted a number of variance and deferral account balances for recovery, as requested in OPG's application. The periods of recovery or repayment for the accepted variance and deferral account balances were excluded from the scope of the Settlement Agreement.

In the OEB's December 2017 Decision and Order, the OEB accepted all applicable variance and deferral account balances for recovery that were not already accepted as part of the partial Settlement Agreement that was reached by OPG and intervenors. That OEB-approved Settlement Agreement also provided for the continuation of all applicable existing variance and deferral accounts effective June 1, 2017. The December 2017 decision and order allows for recovery of $305 million recorded in certain variance and deferral accounts as at December 31, 2015, without adjustments. OPG's draft Payment Amounts Order proposed the recovery period to be January 1, 2019 to December 31, 2021.

Consistent with the effective date of the OEB's December 2017 decision and order, for the period from January 1, 2017 to May 31, 2017, OPG continued to record additions to the existing variance and deferral accounts for the nuclear and regulated hydroelectric facilities pursuant to the OEB's previous decisions and orders. These additions reflected differences between actual and forecast amounts embedded in the regulated prices in effect prior to June 1, 2017.

In its December 2017 decision and order on OPG's rate application, the OEB granted OPG approval to request disposal of applicable audited deferral and variance account balances, including the Pension & OPEB Cash Versus Accrual Differential Account, in calendar year 2018. Under the requirements of US GAAP, the period of deferring amounts recorded in the Pension & OPEB Cash Versus Accrual Differential Deferral Account must not exceed five years from the time that they were incurred. Accordingly, such amounts recorded during November 2014 must begin to be recovered no later than November 2019 and must be fully recovered within 20 years of November 2014 or OPG will be required to write off the regulatory asset for these amounts.

The regulatory assets and liabilities recorded as at December 31 are as follows:

(millions of dollars)	**2017**	**2016**
Regulatory assets		
Variance and deferral accounts authorized by the OEB		
Pension and OPEB Cost Variance Account	**716**	716
Pension & OPEB Cash Versus Accrual Differential Deferral Account *(Note 11)*	**614**	497
Hydroelectric Surplus Baseload Generation Variance Account	**360**	210
Bruce Lease Net Revenues Variance Account	**121**	95
Other variance and deferral accounts	**124**	107
	1,935	1,625
Interim Period Revenue Shortfall Account	**544**	-
Pension and OPEB Regulatory Asset *(Note 11)*	**3,855**	3,392
Deferred Income Taxes	**897**	838
Total regulatory assets	**7,231**	5,855
Regulatory liabilities		
Variance and deferral accounts authorized by the OEB		
Hydroelectric Water Conditions Variance Account	**150**	51
Pension & OPEB Cash Variance Account	**140**	58
Impacts Resulting from Changes in Station End-of-Life Dates Deferral Account	**103**	71
Rate Smoothing Deferral Account	**63**	-
Other variance and deferral accounts	**138**	130
Total regulatory liabilities	**594**	310

The changes in the regulatory assets and liabilities during 2017 and 2016 are as follows:

(millions of dollars)	Pension and OPEB Cost Vari-ance	Pension & OPEB Cash vs Accrual Differen-tial Deferral	Hydro-electric Surplus Baseload Genera-tion Variance	Bruce Lease Net Reve-nues Variance	Water Condit-ions variance	Pension & OPEB Cash	Impact Resulting from Changes in Station End-of-Life Dates Deferral Account	Rate Smooth-ing Deferral Account	Other Vari-ance and Deferral (net)	Interim Period Revenue Shortfall Account	Pension and OPEB Regula-tory Asset	Deferred Income Taxes
Net regulatory assets (liabilities) January 1, 2016	865	315	114	95	(23)	28	-	-	260	-	3,362	792
Increase (decrease)	-	182	126	143	(33)	(86)	(71)	-	-	-	30	46
Interest	-	-	2	-	(1)	-	0	-	1	-	-	-
Amortization	(149)	-	(32)	(143)	6	-	0	-	(284)	-	-	-
Net regulatory assets (liabilities) December 31, 2016	716	497	210	95	(51)	(58)	(71)	-	(23)	-	3,392	838
Increase (decrease)	**-**	**117**	**146**	**25**	**(98)**	**(81)**	**(32)**	**(62)**	**10**	**544**	**463**	**59**
Interest	**-**	**-**	**4**	**1**	**(1)**	**(1)**	**0**	**(1)**	**(1)**	**-**	**-**	**-**
Net regulatory assets (liabilities) December 31, 2017	**716**	**614**	**360**	**121**	**(150)**	**(140)**	**(103)**	**(63)**	**(14)**	**544**	**3,855**	**897**

Pension and OPEB Cost Variance Account

As authorized by the OEB, for the period from March 1, 2011 to October 30, 2014, the Pension and OPEB Cost Variance Account recorded the differences between OPG's actual pension and OPEB costs for the regulated business determined on an accrual basis and related tax impacts, and corresponding forecast amounts reflected in the regulated prices then in effect. In its November 2014 decision, the OEB determined that the pension and OPEB amounts reflected in OPG's regulated prices established by that decision effective November 1, 2014 would be limited to the Company's estimated minimum contributions to its registered pension plan and a forecast of OPG's expenditures on the OPEB and supplementary pension plans. As such, the OEB ordered the Pension and OPEB Cost Variance Account to record only amortization beginning on November 1, 2014.

In its October 2015 order, the OEB approved the continuation of the previously authorized recovery of 10/12 of the account balance as at December 31, 2012 over a 144-month period to December 31, 2024. Amounts recorded in the account in 2013 and 2014 were approved for recovery over a 72-month period to June 30, 2021 by the OEB's October 2015 order. In OPG's draft payment amounts order, the recovery period was adjusted to extend beyond June 30, 2021 and December 31, 2024 to account for the break in recovery of the account in the 2017 and 2018 periods as proposed by OPG.

Pension & OPEB Cash Versus Accrual Differential Deferral Account

In its November 2014 decision and December 2014 order, the OEB established the Pension & OPEB Cash Versus Accrual Differential Deferral Account. Effective November 1, 2014, this deferral account records the difference between OPG's actual pension and OPEB costs for the regulated business determined on an accrual basis under US GAAP and OPG's corresponding actual cash expenditures for these plans. The balance in the account as at

December 31, 2017 represents the excess of costs calculated using the accrual basis over the cash basis for the period from November 1, 2014 to December 31, 2017. The Company has recognized the amount set aside in the deferral account as a regulatory asset.

The OEB's November 2014 decision indicated that the future recovery, if any, of amounts recorded in the deferral account would be subject to the outcome of the OEB generic proceeding on the regulatory treatment and recovery of pension and OPEB costs. On September 14, 2017, the OEB issued its final report on the guiding principles and the policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the Ontario electricity and natural gas sectors. The report establishes the accrual basis of accounting as the method of determining pension and OPEB amounts for rate-setting purposes, unless the OEB finds that this method does not result in just and reasonable rates in the circumstances of a particular utility. The OEB's September 2017 report and the OEB's December 2017 decision on OPG's application for new regulated prices require OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the Pension & OPEB Cash to Accrual Differential Deferral Account in effect since November 1, 2014, until such time as the OEB approves resumption of the accrual basis of recovery.

Consistent with the expectations set out in the OEB's December 2017 decision, in 2018, OPG plans to file an application with the OEB requesting disposition of the Pension & OPEB Cash Versus Accrual Differential Deferral Account balance.

Hydroelectric Surplus Baseload Generation Variance Account

The Hydroelectric Surplus Baseload Generation Variance Account records the impact of forgone production at OPG's regulated hydroelectric facilities due to surplus baseload generation conditions.

In its December 2017 Decision and Order, the OEB approved the disposition of the Hydroelectric Surplus Baseload Generation Variance Account balance as at December 31, 2015, as proposed. OPG has proposed a recovery period of January 1, 2019 to December 31, 2021.

Bruce Lease Net Revenues Variance Account

In accordance with *Ontario Regulation 53/05*, the OEB is required to include the difference between OPG's revenues and costs associated with the two nuclear generating stations on lease to Bruce Power in the determination of the regulated prices for production from OPG's regulated nuclear facilities. Based on *Ontario Regulation 53/05* requirements, the OEB has established a variance account that captures differences between OPG's actual revenues and costs related to these stations and the corresponding forecasts included in approved nuclear regulated prices, including the costs associated with OPG's Nuclear Liabilities and the earnings from the portion of the Nuclear Segregated Funds related to the Bruce stations.

In 2013, the OEB ordered the portion of the balance in the Bruce Lease Net Revenues Variance Account related to the impact of the derivative liability embedded in the terms of the lease agreement between OPG and Bruce Power related to the Bruce nuclear generating stations (Bruce Lease) in effect prior to December 2015 to be recovered on the basis of OPG's expected rent rebate payments to Bruce Power and associated income tax impacts. The OEB's October 2015 order reaffirmed this approach and included, in amounts authorized for recovery over the period to the end of 2016, amounts for the derivative liability. In December 2015, as a result of amendments to the Bruce Lease, OPG reversed the derivative liability, with a corresponding reduction to the regulatory asset for the Bruce Lease Net Revenue Variance Account. Amounts collected from customers for the derivative liability for periods after its reversal are subject to refund in the future and have been recognized as a regulatory liability as part of the variance account balance.

The regulatory asset balance for the Bruce Lease Net Revenues Variance Account as at December 31, 2017 reflects a net amount of $190 million recoverable from customers for non-derivative variances recorded in 2015 through 2017, which is partially offset by a liability of $69 million to customers for amounts recovered for the derivative liability

since its reversal in December 2015. Non-derivative amounts recorded during 2017 included those arising from the adjustment to the Nuclear Liabilities and related changes to the estimated service lives of OPG's nuclear stations, for accounting purposes, effective December 31, 2015 and the updated 2017 ONFA reference plan approved by the province.

In its December 2017 Decision and Order, the OEB approved the disposition of the Bruce Lease Net Revenues Account balance as at December 31, 2015, as proposed. OPG has proposed a recovery period of January 1, 2019 to December 31, 2021.

Interim Period Revenue Shortfall Account

The Interim Period Revenue Shortfall regulatory asset records the revenue shortfall between proposed Nuclear and Regulated Hydroelectric rates and existing Nuclear and Regulated Hydroelectric rates from June 1, 2017 through December 31 2017 based on actual production. The recovery of this account is expected to begin January 1, 2019 through to December 31, 2021. [**UPDATE**]

Pension and OPEB Regulatory Asset

The Pension and OPEB Regulatory Asset represents unamortized amounts in respect of OPG's pension and OPEB plans that have been recognized in OCI and not yet reclassified into the amortization component of the benefit costs in respect of these plans. These amounts are expected to be recovered from customers through future regulated prices. The regulatory asset is reversed as underlying unamortized balances are amortized as components of benefit costs. For further details, refer to Note 3 under the heading, *Rate Regulated Accounting*. The AOCI amounts related to pension and OPEB plans are presented in Note 11.

Deferred Income Taxes

OPG is required to record a regulatory asset or liability for the deferred income taxes that are expected to be recovered or refunded through future regulated prices charged to customers for generation from OPG's regulated facilities. In addition, OPG is required to recognize a deferred income tax liability or asset for the regulatory asset or liability for the amount of deferred income taxes expected to be included in future regulated prices and paid to, or recovered, from customers. Income taxes are discussed in Note 9.

Hydroelectric Water Conditions Variance Account

The Hydroelectric Water Conditions Variance Account captures the impact of differences in regulated hydroelectric electricity production due to differences between forecast water conditions underlying the production forecast approved by the OEB in setting regulated hydroelectric prices, and the actual water conditions.

In its December 2017 Decision and Order, the OEB approved the disposition of the Hydroelectric Water Conditions Variance Account balance as at December 31, 2015, as proposed. OPG has proposed a recovery period of January 1, 2019 to December 31, 2021.

Pension & OPEB Cash Payment Variance Account

The Pension & OPEB Cash Payment Variance Account was approved in EB-2013-0321 and continued in EB-2014-0370. The account records the difference between OPG's actual registered pension plan contributions and OPEB plan payments (including the long-term disability benefit plan) attributed to the prescribed generating facilities, and such forecast amounts reflected in the revenue requirement approved by the OEB.

In its December 2017 Decision and Order, the OEB approved the disposition of the Pension & OPEB Cash Payment Variance Account balance as at December 31, 2015, as proposed. OPG has proposed a recovery period of January 1, 2019 to December 31, 2021.

Impact Resulting from Changes in Station End-of-Life Dates Deferral Account

In December 2015, as required by the OEB's previous decisions and orders, OPG applied to the OEB for an accounting order to establish a new deferral account to record the revenue requirement impact on the Pickering and Darlington nuclear generating stations of changes to the Nuclear Liabilities and depreciation expense arising from extensions in the estimated useful lives of OPG's nuclear stations, for accounting purposes, effective December 31, 2015. These impacts were not reflected in the existing regulated prices. In March 2016, the OEB issued its final decision and order establishing the requested account, the Impact Resulting from Changes in Station End-of-Life Dates Deferral Account, effective January 1, 2016. The deferral account recorded these impacts until new regulated prices reflecting the above changes came into effect on June 1, 2017.

The extensions to the estimated useful lives of OPG's nuclear generating stations effective December 31, 2015, for accounting purposes, included those of the Bruce A GS and the Bruce B GS to reflect the estimated end-of-life dates per the updated refurbishment agreement between the IESO and Bruce Power announced in December 2015, a one-year extension for the Darlington GS to reflect the approval of the refurbishment schedule in 2015, and an extension of less than one year for the Pickering GS. To reflect these changes, OPG recognized a total increase of $2,330 million in the Nuclear Liabilities and a corresponding increase in the related asset retirement costs capitalized to PP&E, effective December 31, 2015.

Rate Smoothing Deferral Account

In accordance with section 5.5 of *Ontario Regulation 53/05*, OPG shall establish a Rate Smoothing Deferral Account. This account shall record, for each respective year, the difference between: (i) the total annual revenue requirement for the prescribed nuclear facilities approved by the OEB; and, (ii) the portion of that revenue requirement in (i) that is used in connection with setting the approved nuclear payment amounts in each year.

Consistent with the requirements of *Ontario Regulation 53/05*, OPG's overall production weighted payment amounts will be smoothed, with a resulting portion of the approved annual nuclear revenue requirements for the 2017-2021 period deferred in the Rate Smoothing Deferral Account for future collection. The non-deferred portion of each year's nuclear revenue requirement will be divided by the OEB-approved forecast of OPG's nuclear electricity generation for the corresponding year to determine the base nuclear regulated price. Per the regulation, the deferral account records interest at a long-term debt rate reflecting OPG's cost of long-term borrowing approved by the OEB, compounded annually. The regulation also requires the OEB to authorize recovery of the balance in the account on a straight line basis over a period not to exceed ten years following the end of the Darlington Refurbishment project. OPG recognizes positive amounts deferred under rate smoothing as an increase in net regulatory assets and an increase in revenue in the period to which the underlying approved revenue requirement relates. Negative amounts determined under rate smoothing are correspondingly recorded as a decrease in net regulatory assets and a decrease to revenue.

On January 17, 2018, OPG submitted a draft payment amounts order to the OEB that proposed nuclear base regulated prices for each year of the 2017-2021 period. The proposed regulated prices reflected the December 2017 decision's findings in calculating the 2017-2021 nuclear revenue requirements and reflected a rate smoothing proposal developed by OPG in accordance with *Ontario Regulation 53/05* and OEB's direction. As at December 31, 2017 OPG recorded a liability of $63 million and is expected to have a regulatory asset balance of approximately $750 million by 2021.

Other Variance and Deferral Accounts

Regulatory assets

As at December 31, 2017 and 2016, regulatory assets for Other variance and deferral accounts included amounts for the Nuclear Liability Deferral Account, the Nuclear and Hydroelectric Deferral and Variance Over/Under Recovery Variance Account, the Nuclear Development Account, and the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account and the Fitness for Duty Deferral Account.

Pursuant to *Ontario Regulation 53/05*, the Nuclear Liability Deferral Account has been authorized by the OEB in connection with changes to OPG's liabilities for nuclear used fuel management and nuclear decommissioning and L&ILW management associated with the nuclear facilities owned and operated by OPG, which are comprised of the Pickering and Darlington nuclear generating stations. The deferral account records the revenue requirement impact associated with the changes in these liabilities arising from an approved reference plan, in accordance with the terms of the ONFA.

The Nuclear and Hydroelectric Deferral and Variance Over/Under Recovery Variance Accounts records any shortfall or over-recovery of the approved variance and deferral account balances due to differences between actual and forecast nuclear and hydroelectric production respectively.

The Nuclear Development Variance Account records variances between the actual non-capital costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities and the corresponding forecasts reflected in the regulated prices approved by the OEB.

The Fitness for Duty Deferral Account was approved by the OEB in the EB-2016-0152 Decision and order, effective June 1, 2017. The account shall record the costs related to implementing the Canadian Nuclear Safety Commission (CNSC) Fitness for Duty program. The Fitness for Duty program is a drug, alcohol, psychological and physical testing program for employees in nuclear facilities, which is anticipated to be a license requirement of the CNSC.

Regulatory liabilities

As at December 31, 2017 and 2016, regulatory liabilities for Other variance and deferral accounts included amounts for the Ancillary Services Net Revenue Variance Account, the Income and Other Taxes Variance Account, the Hydroelectric Incentive Mechanism Variance Account, the SR&ED ITC Variance Account and the Capacity Refurbishment Variance Account.

The Ancillary Services Net Revenue Variance Account has been authorized by the OEB to capture differences between actual nuclear and regulated hydroelectric ancillary services net revenue and the forecast amounts of such revenue approved by the OEB in setting regulated prices.

The Income and Other Taxes Variance Account includes deviations in income taxes for the regulated business, from those approved by the OEB in setting regulated prices, caused by changes in tax rates and rules, as well as reassessments.

The Hydroelectric Incentive Mechanism Variance Account records a credit to customers equal to 50 percent of OPG's hydroelectric incentive mechanism revenues above a specified threshold for the regulated hydroelectric facilities.

As at December 31, 2017, regulatory liabilities for Other variance and deferral accounts also included the SR&ED ITC Variance Account and the Capacity Refurbishment Variance Account. The SR&ED ITC Variance Account was approved by the OEB in its EB-2016-0152 Decision, effective June 1, 2017. This account will record the tax expense impact for the nuclear facilities as a result of the difference between actual SR&ED ITCs (attributed to the nuclear facilities) as determined after any tax audits and the forecast SR&ED ITCs included in the nuclear revenue requirement approved by the OEB. Pursuant to *Ontario Regulation 53/05*, the OEB has authorized the Capacity Refurbishment Variance Account. The account captures variances from the forecasts reflected in the regulated prices for capital and non-capital costs incurred to increase the output of, refurbish, or add operating capacity to one or more of the regulated facilities. The balance in the account as at December 31, 2017 includes variances related to

the refurbishment of the Darlington nuclear generating station, life extension initiatives at the Pickering nuclear generation station, and other projects.

6. LONG-TERM DEBT AND NET INTEREST EXPENSE

Long-term debt consists of the following as at December 31: [1]

(millions of dollars)	**2017**	**2016**
Notes payable to the OEFC [2]		
Senior Notes		
bear interest at rates ranging from 3.12% to 5.44%; maturity dates ranging from 2018 to 2047	**3,195**	3,295
Medium Term Note Program [3]		
Senior Notes		
3.32% due 2027	**500**	-
UMH Energy Partnership [4]		
Senior Notes		
7.86% due 2041	**181**	184
PSS Generating Station Limited Partnership [5]		
Senior Notes		
4.90% due 2067	**245**	245
Lower Mattagami Energy Limited Partnership [6]		
Senior Notes		
bear interest at rates ranging from 2.4% to 5.26%; maturity dates ranging from 2021 to 2052	**1,595**	1,795
Fair Hydro Trust [7]		
Senior notes		
2.32% due 2019	**601**	-
Other	**19**	15
	6,336	5,534
Less: bond issuance fees	**(17)**	(14)
Less: due within one year	**(398)**	(1,103)
Long-term debt	**5,921**	4,417

[1] The interest rates disclosed reflect the effective interest rate of the debt, except for the Fair Hydro Trust notes which reflect the weighted average interest rate during the period the notes were outstanding from December 21 to December 31, 2017.

[2] OEFC is entitled to receive in full amounts owing in respect of the senior debt.

[3] These notes are direct unsecured obligations of OPG and rank *pari passu* with all other OPG's unsubordinated and unsecured obligations.

[4] These notes are secured by the assets of the Upper Mattagami and Hound Chute project. Principal repayments of $3 million per year are made on a semi-annual basis until maturity in 2041, at which time the remaining principal balance of $116 million becomes due.

[5] These notes are secured by the assets of the Peter Sutherland Sr. GS project. The notes have an interest-only feature until 2025 and will be amortized with blended semi-annual principal and interest payments thereafter until maturity in 2067, at which time the remaining principal balance of $49 million becomes due.

[6] These notes are secured by the assets of the Lower Mattagami River project, including existing and new operating facilities.

[7] The notes were issued under an $800 million two-year revolving warehouse facility discussed below and are secured by the assets of the Fair Hydro Trust.

In June 2016, OPG entered into a $700 million general corporate credit facility agreement with the OEFC, which expired on December 31, 2017. In September 2017, the agreement was amended, with the credit facility increased to $2,350 million and the expiry date extended to December 31, 2018. As of December 31, 2017, $800 million were outstanding from the credit facility.

In February 2017, OPG issued senior notes payable to the OEFC totalling $200 million and maturing in February 2047. The effective interest rate and coupon interest rate of these notes was 4.12 percent. In June 2017,

OPG issued senior notes payable to the OEFC totalling $100 million and maturing in June 2047. The effective interest rate and coupon interest rate of these notes was 3.65 percent. In August 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in August 2047. The effective interest rate and coupon interest rate of these notes was 3.86 percent. In September 2017, OPG issued senior notes payable to the OEFC totalling
$400 million and maturing in September 2047. The effective interest rate and coupon interest rate of these notes was 4.07 percent.

In October 2017, OPG issued $500 million of senior notes payable under a Medium Term Note Program. The notes bear a coupon interest rate of 3.32 percent and an effective rate of 3.43 percent, payable semi-annually until maturity in October 2027. The offering was made under OPG's $2 billion short form base shelf prospectus filed in September 2017.

In 2015, PSS, a subsidiary of OPG, issued long-term debt totalling $245 million in support of the Peter Sutherland Sr. Generating Station (GS) project. The majority of the debt proceeds, totalling $180 million, were invested in a structured deposit note with staggered maturity dates ranging from January 2016 to April 2017. As at December 31, 2017, the deposit note had matured.

In October 2016, Lower Mattagami Energy Limited Partnership (LME) issued senior notes totalling $220 million maturing in October 2026. The effective interest rate and coupon interest rate of these notes were 2.40 percent and 2.31 percent, respectively.

In December 2017, the Trust entered into an $800 million revolving warehouse facility agreement with an expiry date of December 21, 2019. As at December 31, 2017, there were outstanding senior notes of $601 million under this credit facility, which were used to finance 51 percent of the Trust's funding requirement for the acquisition of the first tranche of Investment Interest from the IESO in December 2017. The outstanding balance has been classified as long-term debt to reflect the terms and substance of the facility agreement. The interest incurred on this debt is recorded within Earnings from Fair Hydro Trust on the consolidated statements of income. Please refer to Note 17 for additional information on Fair Hydro Trust's financial information.

In February 2018, the Trust issued $500 million of senior notes payable with a coupon interest rate of 3.36 percent and an effective interest rate of 3.42 percent, payable semi-annually until maturity on May 15, 2033. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility issued by the Trust in December 2017. By the end of the first quarter of 2018, the Trust is expected to acquire another tranche of Investment Interest from the IESO, which it expects to fund using its revolving warehouse facility. **[MONITOR]**

The following table summarizes the net interest expense:

(millions of dollars)	December 31 **2017**	**2016**
Interest on long-term debt	**289**	290
Interest on short-term debt	**7**	8
Interest income	**(9)**	(7)
Interest capitalized to property, plant and equipment and intangible assets	**(162)**	(141)
Interest related to regulatory assets and liabilities [1]	**(30)**	(30)
Net interest expense	**95**	120

[1] Includes interest to recognize the cost of financing related to regulatory variance and deferral accounts, as authorized by the OEB, and interest deferred in the Bruce Lease Net Revenues Variance Account, the Capacity Refurbishment Variance Account, and the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account.

Interest paid in 2017 was $258 million (2016 – $269 million), of which $ 251 million (2016 – $261 million) relates to interest paid on long-term debt.

The net book value of the pledged assets of PSS, UMH, LME, and Lower Mattagami Limited Partnership against their debt as at December 31, 2017 was $3,645 million (2016 – $3,510 million).

7. SHORT-TERM DEBT

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. During 2017, OPG renewed and extended the expiry date of both tranches to May 2022. There were no amounts outstanding under the bank credit facility. There was $100 million of commercial paper outstanding under OPG's commercial paper program as at December 31, 2017. The Commercial paper program is used to provide short-term funding requirement for the Company, at rates of approximately one percent and are less than one year in duration.

As at December 31, 2017, the LME maintained a $400 million bank credit facility to support the funding requirements for the Lower Mattagami River project including support for LME's commercial paper program. The facility consists of a $300 million tranche maturing in August 2022 and a $100 million tranche maturing in August 2018. As at December 31, 2017, there was $160 million commercial paper outstanding under LME's commercial paper program (December 31, 2016 – nil). A letter of credit of $55 million was issued in July 2017 and remains outstanding as at December 31, 2017 under the first tranche of LME's credit facility.

As at December 31, 2017, OPG maintained $25 million of short-term, uncommitted overdraft facilities and $468 million of short-term, uncommitted credit facilities, which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other general corporate purposes. As at December 31, 2017, a total of $390 million of Letters of Credit had been issued under these facilities. This included $353 million for the supplementary pension plans, $36 million for general corporate purposes, and $1 million related to the operation of the PEC.

The Company has an agreement to sell an undivided co-ownership interest in its current and future accounts receivable to an independent trust. The maximum amount of co-ownership interest that can be sold under this agreement is $150 million, expiring on November 30, 2018. As at December 31, 2017, there were Letters of Credit outstanding under this agreement of $150 million (December 31, 2016 – $150 million), which were issued in support of OPG's supplementary pension plans.

UMH Energy Partnership has entered into an $8 million short-term, uncommitted overdraft facility and $16 million of irrevocable, standby Letters of Credit facilities in support of its operations. As at December 31, 2017, total Letters of Credit of $15 million had been issued under these facilities.

8. NUCLEAR FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT FUND AND FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT LIABILITIES

The liabilities for fixed asset removal and nuclear waste management on a present value basis as December 31, consist of the following:

(millions of dollars)	**2017**	**2016**
Liability for nuclear used fuel management	**11,970**	11,292
Liability for nuclear decommissioning and nuclear low and intermediate level waste management	**8,107**	7,811
Liability for non-nuclear fixed asset removal	**344**	381
Fixed asset removal and nuclear waste management liabilities	**20,421**	19,484

The changes in the fixed asset removal and nuclear waste management liabilities for the years ended December 31 are as follows:

(millions of dollars)	**2017**	**2016**
Liabilities, beginning of year	**19,484**	20,169
Increase in liabilities due to accretion [1]	**974**	1,024
Decrease in liabilities resulting from the ONFA reference plan update process	**-**	(1,567)
Net change in liabilities reflecting changes to the estimated useful lives *(Note 3)*	**158**	-
Increase in liabilities due to changes in estimates of nuclear used fuel and nuclear waste management expenses and other expenses [1]	**118**	133
Liabilities settled by expenditures on fixed asset removal and nuclear waste management	**(313)**	(275)
Liabilities, end of year	**20,421**	19,484

[1] Amounts shown exclude the impact of regulatory variance and deferral accounts.

OPG's fixed asset removal and nuclear waste management liabilities are comprised of expected costs to be incurred up to and beyond termination of operations and the closure of nuclear and thermal generating facilities, and other facilities. Costs will be incurred for activities such as preparation for safe storage and safe storage of the nuclear stations, dismantlement, demolition and disposal of facilities and equipment, remediation and restoration of sites, and the ongoing and long-term management of nuclear used fuel and L&ILW material.

The determination of the accrual for fixed asset removal and nuclear waste management costs requires significant assumptions since these programs are long-term in nature. The most recent comprehensive update of the cost estimates for the Nuclear Liabilities is contained in the 2017−2021 ONFA reference plan, which was finalized and approved by the Province in the fourth quarter of 2016 (2017 ONFA Reference Plan).

For the purposes of calculating OPG's Nuclear Liabilities, as at December 31, 2017, consistent with the current accounting end-of-life assumptions, nuclear station decommissioning activities are projected to occur over approximately the next 80 years. The estimates for the Nuclear Liabilities include cash flow estimates for decommissioning the nuclear stations for approximately 40 years after stations are shut down and to 2088 for placement of used fuel into the assumed long-term disposal repository, followed by extended monitoring.

The significant assumptions underlying operational, technical, and economic factors used in the calculation of the accrued Nuclear Liabilities are subject to periodic review. Changes to these assumptions, including changes to assumptions on the timing of the nuclear waste programs including construction of waste disposal facilities, station end-of-life dates, waste disposal methods, financial indicators, or the technology employed, may result in significant changes to the value of the accrued liabilities. With programs of this long-term duration and the evolving technology to handle the nuclear waste, there is a significant degree of inherent uncertainty surrounding the measurement of the costs for these programs. These costs may increase or decrease over time.

Liability for Nuclear Used Fuel Management Costs

The liability for nuclear used fuel management represents the cost of managing the highly radioactive used nuclear fuel bundles. The federal NFWA, proclaimed into force in 2002, required that Canada's nuclear fuel waste owners form a nuclear waste management organization, and that each waste owner establish a trust fund for used fuel management costs as specified in the NFWA. This organization, the NWMO, is responsible for the design and implementation of Canada's plan for the long-term management of nuclear used fuel waste. To estimate its liability for nuclear used fuel management costs, OPG has adopted an approach consistent with the Adaptive Phased Management concept approved by the Government of Canada, which assumes a deep geologic repository as part of the long-term management of nuclear used fuel, with an in-service date of 2043 at the earliest.

Liability for Nuclear Decommissioning and L&ILW Management Costs

The liability for nuclear decommissioning and L&ILW management represents the estimated costs of decommissioning the nuclear generating stations after the end of their service lives, as well as the cost of managing L&ILW generated by the stations. The significant assumptions used in estimating future nuclear fixed asset removal costs include a deferred dismantlement basis for decommissioning of the stations, whereby the reactors will be de-watered and de-fueled immediately after the station has ceased operations and thereafter will remain in a safe state condition for a 30-year period, prior to an approximate 10-year dismantlement period.

The life cycle costs of L&ILW management include the costs of processing and storage of such radioactive wastes during and following the operation of the nuclear stations, as well as the costs of the ultimate long-term management of these wastes. The current assumptions used to establish the accrued costs for the management of L&ILW include an L&ILW DGR to be owned and operated by OPG. Agreement was previously reached with local municipalities for OPG to develop a deep geologic repository for the long-term management of L&ILW adjacent to OPG's Western Waste Management Facility in Kincardine, Ontario.

Liability for Non-Nuclear Fixed Asset Removal Costs

The liability for non-nuclear fixed asset removal primarily represents the estimated costs of decommissioning OPG's thermal generating stations at the end of their services lives. The liability is based on third-party cost estimates following an in-depth review of plant sites and an assessment of required clean-up and restoration activities completed in 2017.

OPG performed a revaluation of the liability for non-nuclear fixed asset removal as at December 31, 2017. OPG recognized a decrease in the non-nuclear fixed asset removal liabilities of approximately $30 million, resulting in an decrease in asset retirement costs of $18 million capitalized as part of the carrying value of PP&E, and a gain of $12 million recorded to net income in 2017.

Ontario Nuclear Funds Agreement

In accordance with the ONFA, OPG sets aside and invests funds that are held in segregated custodian and trustee accounts specifically for discharging its life cycle obligation for nuclear decommissioning and long-term nuclear waste management. The Used Fuel Segregated Fund and the Decommissioning Segregated Fund were established under the ONFA for this purpose. OPG makes contributions to the Nuclear Segregated Funds based on the approved ONFA reference plan in effect. ONFA reference plans are subject to approval by the Province.

Since inception, OPG has been making quarterly payments to the Used Fuel Segregated Fund over the assumed lives of its nuclear generating stations, as specified in the ONFA, including contributions to the NFWA Trust established by OPG pursuant to the NFWA. The NFWA Trust forms part of the Used Fuel Segregated Fund, with any OPG contributions to the Used Fuel Segregated Fund, as well as any portion of the fund currently not in the trust, being able to be applied towards the NFWA Trust's annual contribution requirements pursuant to the NFWA. As a result, required funding of the Used Fuel Segregated Fund for 2017 was nil (2016 – $150 million). ONFA

requirements have resulted in the majority of the underlying used fuel management obligation being funded through OPG contributions over the initial estimated useful lives of the nuclear generating stations assumed in the ONFA, which did not reflect subsequent extensions to the nuclear station lives to reflect refurbishment and life extension decisions.

OPG has not been required to make contributions to the Decommissioning Segregated Fund, which was fully funded at its inception through an initial contribution made by the Province and, taking into account asset performance and changes in underlying funding obligation over time, at the time of every subsequent approved ONFA reference plan.

The 2017 ONFA Reference Plan was approved by the Province in December 2016, with an effective date of January 1, 2017. Based on the funded status of the Used Fuel Segregated Fund and the Decommissioning Segregated Fund reflecting the life cycle liability estimates per the 2017 ONFA Reference Plan, no overall contributions to either fund are currently required starting in 2017. Contributions may be required in the future should either or both of the funds be in an underfunded position when a new reference plan is prepared.

The *Nuclear Safety and Control Act* (Canada) requires OPG to have sufficient funds available to discharge its existing nuclear waste management and nuclear facilities decommissioning obligations. As required by the terms of the ONFA, the Province has provided a Provincial Guarantee to the CNSC since 2003, on behalf of OPG. The Provincial Guarantee provides for any shortfall between the CNSC consolidated financial guarantee requirement and the value of the Nuclear Segregated Funds. OPG pays the Province an annual guarantee fee of 0.5 percent of the amount of the Provincial Guarantee. The value of the Provincial Guarantee amount in effect through to the end of 2017 was $1,551 million. Based on this guarantee amount, OPG paid a guarantee fee of $8 million to the Province for each of 2017 and 2016.

Commented [DS1]: Realize that these financial statements are only through Dec. 31, 2017, but to be safe, wanted to flag the CNSC decision in November 2017 such that the Province no longer provides a Provincial Guarantee as of Jan. 1, 2018.

The investments in the Nuclear Segregated Funds include a diversified portfolio of equities and fixed income securities that are invested across geographic markets, as well as investments in infrastructure, real estate, and agriculture. The Nuclear Segregated Funds are invested to fund long-term liability requirements and, as such, the portfolio asset mix is structured to achieve the required return over a long-term horizon. While short-term fluctuations in market value will occur, managing the long-term return of the Nuclear Segregated Funds remains the primary goal. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

Decommissioning Segregated Fund

Under the ONFA, OPG is wholly responsible for cost estimate changes and investment returns in the Decommissioning Segregated Fund. As at December 31, 2017 and 2016, the Decommissioning Segregated Fund was in an overfunded position.

Upon termination of the ONFA, the Province has the sole right to any excess funds in the Decommissioning Segregated Fund, which is the excess of the fair market value of the fund's assets over the underlying estimated future costs, as per the most recently approved ONFA reference plan. Accordingly, when the Decommissioning Segregated Fund is overfunded, OPG limits the fund earnings recognized in the consolidated financial statements by recording an amount due to the Province, such that the asset recognized for the fund on the consolidated balance sheet is equal to the cost estimate of the liability based on the most recently approved ONFA reference plan. Additionally, OPG recognizes the portion of the surplus that it may direct to the Used Fuel Segregated Fund, which is possible when the surplus in the Decommissioning Segregated Fund is such that the underlying liabilities, as defined by the most recently approved ONFA reference plan, are at least 120 percent funded. In those circumstances, OPG may direct, at the time a new reference plan is approved, up to 50 percent of the surplus over 120 percent to the Used Fuel Segregated Fund, with the OEFC entitled to a distribution of an equal amount. Therefore, when the Decommissioning Segregated Fund is at least 120 percent funded, OPG recognizes 50 percent of the excess greater than 120 percent in income, up to the amount by which the Used Fuel Segregated Fund is underfunded. Based on the 2017 ONFA Reference Plan, the Used Fuel Segregated Fund was in a marginally overfunded position as at December 31, 2016, for the first time since inception. As a result, OPG recognized a due to the Province amount

such that the Decommissioning Segregated Fund asset on the consolidated balance sheet as at December 31, 2017 and 2016 was limited to the value of the underlying liability per the 2017 ONFA Reference Plan. The payable to the Province may be reduced in subsequent periods in the event that the Decommissioning Segregated Fund earns less than its target rate of return, a new ONFA reference plan is approved with a higher underlying funding liability, or the Used Fuel Segregated Fund changes to an underfunded status. When the Decommissioning Segregated Fund is underfunded, the earnings on the fund reflect actual fund returns based on the market value of the assets.

When the Decommissioning Segregated Fund is in an overfunded status at less than 120 percent, OPG recognized its annual earnings on the fund at 3.25 percent plus the long-term Ontario Consumer Price Index (CPI) specified in the most recently approved ONFA reference plan, which is the rate of growth in the underlying funding liability. The same treatment is applied to the Decommissioning Segregated Fund when it is in an overfunded status at greater than 120 percent, if the Used Fuel Segregated Fund is fully funded.

Used Fuel Segregated Fund

OPG is responsible for cost increases in the funding liability for used fuel waste management under the ONFA, subject to specified graduated liability thresholds, pursuant to which the Province limits OPG's total financial exposure for the first 2.23 million nuclear used fuel bundles at approximately $15.7 billion in present value dollars as at December 31, 2017. The graduated liability thresholds do not apply to used fuel bundles beyond the 2.23 million threshold.

Under the ONFA, the Province guarantees OPG's annual return in the Used Fuel Segregated Fund at 3.25 percent plus the change in the Ontario CPI, as defined by ONFA, for funding related to the first 2.23 million used fuel bundles, (committed return). OPG recognizes the committed return on the Used Fuel Segregated Fund as Earnings on the Nuclear Segregated Funds. The difference between the committed return and the actual market return determined based on the fair value of the fund assets related to the first 2.23 million used fuel bundles is recorded as due to or due from the Province. This amount due to or due from the Province represents the amount that would be paid to or received from the Province if the committed return were to be settled as at the consolidated balance sheets date. The 2.23 million threshold represents the estimated total life cycle fuel bundles based on the initial estimated useful lives of the nuclear stations assumed in the ONFA.

As prescribed under the ONFA, OPG's contributions for fuel bundles in excess of 2.23 million are not subject to the rate of return guaranteed by the Province, and earn a return based on changes in the market value of the assets of the Used Fuel Segregated Fund.

If there is a surplus in the Used Fuel Segregated Fund such that the liabilities, as defined by the most recently approved ONFA reference plan, are at least 110 percent funded, the Province, has the right, at any time, to access the excess amount greater than 110 percent. Upon termination of the ONFA, the Province is entitled to any surplus in the fund, which is the excess of the fair market value of the Used Fuel Segregated Fund assets over the estimated future costs, as per the most recently approved ONFA reference plan. Neither OPG nor the Province has a right to direct any amounts from the Used Fuel Segregated Fund to the Decommissioning Segregated Fund. Therefore, when the Used Fuel Fund is overfunded, OPG limits the earnings it recognizes by recording an amount due to the Province, such that the asset recognized for the fund on the consolidated balance sheets is equal to the cost estimate of the liability per the most recently approved ONFA reference plan. This results in OPG recognizing annual earnings on the fund at 3.25 percent plus the long-term Ontario CPI specified in the most recently approved ONFA reference plan, which is the rate of growth in the underlying funding liability, when the fund is overfunded.

As at December 31, 2017, the Used Fuel Segregated Fund was marginally overfunded in accordance with the 2017 ONFA Reference Plan, and OPG recognized a due to the Province amount of $55 million such that the asset recognized for the fund was limited to the value of the underlying funding liability. This payable to the Province may be reduced in subsequent periods in the event that the Used Fuel Segregated Fund earns less than its target rate of return or in the event that a new ONFA reference plan is approved with a higher underlying funding liability.

Nuclear Segregated Funds

The nuclear fixed asset removal and nuclear waste management funds as at December 31 consist of the following:

(millions of dollars)	Fair Value 2017	2016
Decommissioning Segregated Fund	**9,099**	8,317
Due to Province – Decommissioning Segregated Fund	**(1,933)**	(1,477)
	7,166	6,840
Used Fuel Segregated Fund [1]	**12,087**	11,082
Due to Province – Used Fuel Segregated Fund	**(2,529)**	(1,938)
	9,558	9,144
Total Nuclear Segregated Funds	**16,724**	15,984
Less: current portion	**23**	24
Non-current Nuclear Segregated Funds	**16,701**	15,960

[1] The Ontario NFWA Trust represents $3,882 million as at December 31, 2017 (2016 – $3,688 million) of the Used Fuel Segregated Fund on a fair value basis.

The fair value of the securities invested in the Nuclear Segregated Funds as at December 31 is as follows:

(millions of dollars)	Fair Value 2017	2016
Cash and cash equivalents and short-term investments	**227**	354
Alternative investments	**2,357**	1,989
Pooled funds	**1,713**	1,329
Marketable equity securities	**10,457**	9,503
Fixed income securities	**6,405**	6,181
Net receivables/payables	**27**	43
	21,186	19,399
Due to Province	**(4,462)**	(3,415)
	16,724	15,984

The historical cost, gross unrealized aggregate appreciation and depreciation of investment, gross unrealized foreign exchange gains, and fair value of the Nuclear Segregated Funds as at December 31, 2017 and 2016 are summarized as follows:

	2017		
(millions of dollars)	**Decommissioning Segregated Fund**	**Used Fuel Segregated Fund**	**Total**
Historical cost	**7,327**	**9,902**	**17,229**
Gross unrealized gains (losses)			
Aggregate appreciation	**1,789**	**2,188**	**3,977**
Aggregate depreciation	**(134)**	**(180)**	**(314)**
Foreign exchange	**117**	**177**	**294**
	9,099	**12,087**	**21,186**
Due to Province	**(1,933)**	**(2,529)**	**(4,462)**
Total fair value	**7,166**	**9,558**	**16,724**
Less: current portion	**5**	**18**	**23**
Non-current fair value	**7,161**	**9,540**	**16,701**

	2016		
(millions of dollars)	**Decommissioning Segregated Fund**	**Used Fuel Segregated Fund**	**Total**
Historical cost	6,896	9,385	16,281
Gross unrealized gains (losses)			
Aggregate appreciation	1,326	1,564	2,890
Aggregate depreciation	(165)	(222)	(387)
Foreign exchange	260	355	615
	8,317	11,082	19,399
Due to Province	(1,477)	(1,938)	(3,415)
Total fair value	6,840	9,144	15,984
Less: current portion	8	16	24
Non-current fair value	6,832	9,128	15,960

Net realized and unrealized gains or losses from investments for the years ended December 31, 2017 and 2016 are summarized as follows:

(millions of dollars)	2017 Decommissioning Segregated Fund	2017 Used Fuel Segregated Fund	2017 Total
Net realized gains			
Realized gains excluding foreign exchange	**198**	**245**	**443**
Realized foreign exchange gains	**54**	**65**	**119**
Net realized gains	**252**	**310**	**562**
Net unrealized gains			
Unrealized gains excluding foreign exchange	**494**	**666**	**1,160**
Unrealized foreign exchange losses	**(143)**	**(178)**	**(321)**
Net unrealized gains	**351**	**488**	**839**

(millions of dollars)	2016 Decommissioning Segregated Fund	2016 Used Fuel Segregated Fund	2016 Total
Net realized gains			
Realized gains excluding foreign exchange	84	180	264
Realized foreign exchange gains	30	41	71
Net realized gains	114	221	335
Net unrealized gains			
Unrealized gains excluding foreign exchange	360	442	802
Unrealized foreign exchange losses	(165)	(216)	(381)
Net unrealized gains	195	226	421

The change in the Nuclear Segregated Funds for the years ended December 31 is as follows:

(millions of dollars)	Fair Value 2017	Fair Value 2016
Decommissioning Segregated Fund, beginning of year	**6,840**	6,549
Increase in fund due to return on investments	**807**	505
Decrease in fund due to reimbursement of eligible expenditures	**(25)**	(22)
Increase in due to Province	**(456)**	(192)
Decommissioning Segregated Fund, end of year	**7,166**	6,840
Used Fuel Segregated Fund, beginning of year	**9,144**	8,587
Increase in fund due to contributions made	**-**	150
Increase in fund due to return on investments	**1,059**	690
Decrease in fund due to reimbursement of eligible expenditures	**(54)**	(48)
Increase in due to Province	**(591)**	(235)
Used Fuel Segregated Fund, end of year	**9,558**	9,144

The earnings from the Nuclear Segregated Funds during 2017 and 2016 were impacted by the Bruce Lease Net Revenues Variance Account authorized by the OEB. The earnings on the Nuclear Segregated Funds for the years ended December 31 are as follows:

(millions of dollars)	**2017**	**2016**
Decommissioning Segregated Fund	**351**	313
Used Fuel Segregated Fund	**468**	455
Bruce Lease Net Revenues Variance Account	**(18)**	(22)
Total earnings	**801**	746

9. INCOME TAXES

OPG follows the liability method of accounting for income taxes. The Company records an offsetting regulatory asset or liability for the deferred income taxes that are expected to be recovered or refunded through future regulated prices charged to customers for generation from OPG's regulated facilities.

A reconciliation between the statutory and the effective rate of income taxes is as follows:

(millions of dollars)	**2017**	**2016**
Income before income taxes	**1,090**	621
Combined Canadian federal and provincial statutory enacted income tax rates	**26.5%**	26.5%
Statutory income tax rates applied to accounting income	**289**	165
(Decrease) increase in income taxes resulting from:		
Income tax (recovery) expense deferred in regulatory assets and liabilities	**(20)**	65
Scientific Research and Experimental Development investment tax credits	**(47)**	(48)
Manufacturing and processing credit	**(16)**	(9)
Other	**3**	(5)
	(80)	3
Income tax expense	**209**	168
Effective rate of income taxes	**19.1%**	27.0%

Significant components of the income tax expense are presented in the table below:

(millions of dollars)	**2017**	**2016**
Current income tax expense	**190**	204
Deferred income tax expense (recovery)	**19**	(36)
Income tax expense	**209**	168

The income tax effects of temporary differences that give rise to deferred income tax assets and liabilities as at December 31 are as follows:

(millions of dollars)	**2017**	**2016**
Deferred income tax assets:		
Fixed asset removal and nuclear waste management liabilities	**5,096**	4,861
Other assets and liabilities	**2,057**	1,813
	7,153	6,674
Deferred income tax liabilities:		
Property, plant and equipment and intangible assets	**(1,923)**	(1,807)
Nuclear fixed asset removal and nuclear waste management funds	**(4,181)**	(3,996)
Other assets and liabilities	**(1,928)**	(1,700)
	(8,032)	(7,503)
Net deferred income tax liabilities	**(879)**	(829)

During 2017, OPG recorded an increase in the deferred income tax liability for the income taxes that are expected to be recovered or refunded through regulated prices charged to customers of $59 million (2016 – $46 million). Since these deferred income taxes are expected to be refunded through future regulated prices, OPG recorded a corresponding increase to the regulatory asset for deferred income taxes. As a result, the deferred income tax expense for 2017 and 2016 was not impacted.

The following table summarizes the deferred income tax liabilities recorded for the rate regulated operations that are expected to be recovered through future regulated prices:

(millions of dollars)	**2017**	**2016**
January 1:		
Deferred income tax liabilities on temporary differences related to regulated operations	**627**	592
Deferred income tax liabilities on temporary differences related to the regulatory asset for the deferred income tax liabilities	**211**	200
	838	792
Changes during the year:		
Increase in deferred income tax liabilities on temporary differences related to regulated operations	**44**	35
Increase in deferred income tax liabilities on temporary differences related to the regulatory asset for the deferred income tax liabilities	**15**	11
Balance as at December 31	**897**	838

The tax benefit associated with an income tax position is recognized only when it is more likely than not that such a position will be sustained upon examination by the taxing authorities based on the technical merits of the position. The current and deferred income tax benefit is equal to the largest amount, considering possible settlement outcomes, that is greater than 50 percent likely of being realized upon settlement with the taxing authorities.

A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

(millions of dollars)	**2017**	**2016**
Unrecognized tax benefits, beginning of year	**77**	72
Additions based on tax positions related to the current year	**21**	19
Additions for tax positions of prior years	**-**	2
Reductions for tax positions of prior years	**(20)**	(16)
Unrecognized tax benefits, end of year	**78**	77

As at December 31, 2017, OPG's unrecognized tax benefits were $78 million (2016 – $77 million), excluding interest and penalties, all of which, if recognized, would affect OPG's effective tax rate. Changes in unrecognized tax benefits over the next 12 months cannot be predicted with certainty.

OPG recognizes interest and penalties related to unrecognized tax benefits as income tax expense. As at December 31, 2017, OPG had recorded interest on unrecognized tax benefits of $8 million (2016 – $8 million). OPG considers its significant tax jurisdiction to be Canada. OPG remains subject to income tax examination for years after 2013.

OPG paid $195 million in income taxes (net of tax refunds) during 2017 (2016 – $98 million).

10. ACCUMULATED OTHER COMPREHENSIVE LOSS

The changes in the balance of each component of accumulated other comprehensive loss (AOCL), net of income taxes, are as follows:

	2017			
(millions of dollars)	**Unrealized Gains and Losses on Cash Flow Hedges [1]**	**Pension and OPEB [1]**	**Available-for-sale Securities [1]**	**Total [1]**
AOCL, beginning of year	**(87)**	**(207)**	**(1)**	**(295)**
Actuarial loss on re-measurement of liabilities for pension and OPEB	**-**	**(23)**	**-**	**(23)**
Unrealized loss on available-for-sale securities	**-**	**-**	**(8)**	**(8)**
Amounts reclassified from AOCL	**18**	**10**	**-**	**28**
Other comprehensive income (loss) for the year	**18**	**(13)**	**(8)**	**(3)**
Reclassification of non-controlling interest on change in ownership interest *(Note 22)*	**3**	**-**	**-**	**3**
AOCL, end of year	**(66)**	**(220)**	**(9)**	**(295)**

[1] All amounts are net of income taxes.

	2016			
(millions of dollars)	**Unrealized Gains and Losses on Cash Flow Hedges [1]**	**Pension and OPEB [1]**	**Available-for-sale Securities [1]**	**Total [1]**
AOCL, beginning of year	(106)	(213)	-	(319)
Actuarial loss on re-measurement of liabilities for pension and OPEB	-	(6)	-	(6)
Unrealized loss on available-for-sale securities	-	-	(1)	(1)
Amounts reclassified from AOCL	19	12	-	31
Other comprehensive income (loss) for the year	19	6	(1)	24
AOCL, end of year	(87)	(207)	(1)	(295)

[1] All amounts are net of income taxes.

The significant amounts reclassified out of each component of AOCL, net of income taxes, during December 31, 2017 and 2016 are as follows:

	Amount Reclassified from AOCL		
(millions of dollars)	**2017**	**2016**	**Statement of Income Line Item**
Amortization of losses from cash flow hedges			
Losses	**20**	21	Net interest expense
Income tax recovery	**(2)**	(2)	Income tax expense
	18	19	
Amortization of amounts related to pension and OPEB			
Actuarial losses and past service costs	**13**	16	See (1) below
Income tax recovery	**(3)**	(4)	Income tax expense
	10	12	
Total reclassifications for the year	**28**	31	

[1] These AOCL components are included in the computation of pension and OPEB costs (see Note 11 for additional details).

11. PENSION AND OTHER POST-EMPLOYMENT BENEFITS

Fund Assets

The OPG registered pension fund investment guidelines are stated in an approved Statement of Investment Policies and Procedures (SIPP). The SIPP is reviewed and approved by the Audit and Risk Committee of OPG's Board of Directors at least annually and includes a discussion of investment objectives and expectations, asset mix and rebalancing, and the basis for measuring the performance of the pension fund assets.

In accordance with the SIPP, investment allocation decisions are made with a view to achieve OPG's objective of meeting obligations of the plan as they come due. The pension fund assets are invested in four categories of asset classes. The first category is liability hedging assets, which are intended to hedge the inflation and interest rate sensitivity of the plan liabilities. The second category is return enhancing assets, which are intended to obtain higher investment returns compared to the returns expected for liability hedging assets. The third category is real assets, which offer exposure to the combined characteristics of liability hedging and return enhancing assets. The fourth category is return diversifying strategies, which are intended to improve the overall return of the pension fund while mitigating the downside market risk.

To achieve the above objective, OPG has adopted the following target strategic asset allocation:

	Target
Asset Class	
Liability Hedging Assets	34%
Return Enhancing Assets	31%
Real Assets	20%
Return Diversifying Assets	15%

The plan may use derivatives for risk management or strategic purposes, where such activity is consistent with the plan's investment objectives.

Significant Concentrations of Risk in Fund Assets

The assets of the pension fund are diversified to limit the impact of any individual investment. The pension fund is diversified across multiple asset classes. Fixed income securities are diversified among Canadian government bonds, government agency bonds, real return bonds, and corporate bonds. Equity securities are diversified across

Canadian, US, and Global stocks. There are also real estate, infrastructure, and agriculture portfolios that represent approximately 12 percent of the total pension fund assets as at December 31, 2017. Investments in the above asset classes are further diversified across funds, investment managers, strategies, vintages, sectors and geographies, depending on the specific characteristics of each asset class.

Credit risk with respect to the pension fund's fixed income securities is managed by risk tolerance guidelines, which requires that fixed income securities comply with various investment constraints that ensure prudent diversification and prescribed minimum required credit rating quality. Credit risk, as it relates to the pension fund's derivatives, is managed through the use of International Swap and Derivatives Association documentation and counterparty management performed by the fund's investment managers.

Risk Management

Risk management oversight with respect to the pension fund includes, but is not limited to, the following activities:

- Periodic asset/liability management and strategic asset allocation studies
- Monitoring of funding levels and funding ratios
- Monitoring compliance with asset allocation guidelines and investment management agreements
- Monitoring asset class performance against asset class benchmarks
- Monitoring investment manager performance against benchmarks
- Monitoring of risk tolerance guidelines

Expected Rate of Return on Plan Assets

The expected rate of return on plan assets is based on the fund's asset allocation, as well as the return expectations considering long-term risks and returns associated with each asset class within the plan portfolio. The asset management decisions consider the economic liabilities of the plan.

Fair Value Measurements

OPG is required to classify fair value measurements using a fair value hierarchy. This hierarchy groups financial instruments into three levels, based on the significance of inputs used in measuring the fair value of the assets and liabilities. Refer to Note 13 for a detailed discussion of fair value measurements and the fair value hierarchy.

The following tables present pension plan assets measured at fair value in accordance with the fair value hierarchy:

	December 31, 2017			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Cash and cash equivalents	**377**	**-**	**-**	**377**
Short-term investments	**-**	**9**	**-**	**9**
Fixed income				
Corporate debt securities	**-**	**521**	**-**	**521**
Government bonds	**-**	**3,476**	**-**	**3,476**
Equities				
Canadian	**1,441**	**329**	**-**	**1,770**
US	**1,551**	**-**	**-**	**1,551**
Global	**1,681**	**-**	**-**	**1,681**
Pooled funds	**459**	**105**	**-**	**564**
Other	**15**	**-**	**-**	**15**
	5,524	**4,440**	**-**	**9,964**
Investments measured at NAV [1]				**4,221**
				14,185 [2]

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to the total fair value of plan assets presented in tables following.

[2] The table above excludes pension fund receivables and payables.

	December 31, 2016			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Cash and cash equivalents	690	-	-	690
Fixed income				
Corporate debt securities	-	407	-	407
Government bonds	-	3,483	-	3,483
Equities				
Canadian	1,449	291	-	1,740
US	1,495	-	-	1,495
Global	1,643	-	-	1,643
Pooled funds	118	413	-	531
	5,395	4,594	-	9,989
Investments measured at NAV [1]				3,504
				13,493 [2]

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to the total fair value of plan assets presented in tables following.

[2] The table above excludes pension fund receivables and payables.

Plan Costs and Liabilities

Details of OPG's pension and OPEB obligations, pension fund assets and costs are presented in the following tables:

	Registered and Supplementary Pension Plans		Other Post-Employment Benefits	
	2017	**2016**	**2017**	**2016**
Weighted Average Assumptions – Benefit Obligations at Year-End				
Discount rate for projected benefit obligation	**3.57 %**	3.90 %	**3.60 %**	3.94 %
Salary schedule escalation rate - initial rate [1]	**1.90 %**	1.80 %	**1.90 %**	1.80 %
- thereafter	**2.50 %**	2.50 %	**2.50 %**	2.50 %
Rate of cost of living increase to pensions	**2.00 %**	2.00 %	**n/a**	n/a
Initial health care trend rate	**n/a**	n/a	**5.80 %**	5.90 %
Ultimate health care trend rate	**n/a**	n/a	**4.32 %**	4.32 %
Year ultimate health care trend rate reached	**n/a**	n/a	**2030**	2030
Rate of increase in disability benefits	**n/a**	n/a	**2.00 %**	2.00 %

[1] Per year to December 31, 2021.

	Registered and Supplementary Pension Plans		Other Post-Employment Benefits	
	2017	**2016**	**2017**	**2016**
Weighted Average Assumptions – Costs for the Year				
Expected return on plan assets, net of expenses	**6.00 %**	6.00 %	**n/a**	n/a
Discount rate for projected benefit obligation	**3.90 %**	4.10 %	**3.94 %**	4.13 %
Discount rate for current service cost	**4.15 %**	4.10 %	**4.03 %**	4.13 %
Discount rate for interest on projected benefit obligation	**3.37 %**	4.10 %	**3.53 %**	4.13 %
Discount rate for interest on current service cost	**3.95 %**	4.10 %	**3.85 %**	4.13 %
Salary schedule escalation rate - initial rate [1]	**1.80 %**	1.60 %	**1.80 %**	1.60 %
- thereafter	**2.50 %**	2.50 %	**2.50 %**	2.50 %
Rate of cost of living increase to pensions	**2.00 %**	2.00 %	**n/a**	n/a
Initial health care trend rate	**n/a**	n/a	**5.90 %**	6.00 %
Ultimate health care trend rate	**n/a**	n/a	**4.32 %**	4.33 %
Year ultimate health care trend rate reached	**n/a**	n/a	**2030**	2030
Rate of increase in disability benefits	**n/a**	n/a	**2.00 %**	2.00 %
Expected average remaining service life for employees (years)	**12**	12	**13**	13

[1] Per year to December 31, 2021.

(millions of dollars)	Registered Pension Plans 2017	2016	Supplementary Pension Plans 2017	2016	Other Post-Employment Benefits 2017	2016
Components of Cost Recognized for the year						
Current service costs	**274**	277	**7**	7	**67**	67
Interest on projected benefit obligation	**548**	634	**11**	12	**106**	133
Expected return on plan assets, net of expenses	**(766)**	(734)	**-**	-	**-**	-
Amortization of past service costs [1]	**-**	-	**-**	-	**1**	1
Amortization of net actuarial loss [1]	**183**	192	**6**	4	**-**	19
Recognition of LTD net actuarial loss (gain)	**-**	**-**	**-**	**-**	**11**	(52)
Costs recognized [2]	**239**	369	**24**	23	**185**	168

[1] The amortization of past service costs and net actuarial loss was recognized as an increase to OCI. This increase was partially offset by the impact of the Pension and OPEB Regulatory Asset discussed in Note 5.

[2] Excludes the impact of regulatory variance and deferral accounts discussed in Note 5.

Total benefit costs, including the impact of the Pension & OPEB Cash Payment Variance Account and the Pension & OPEB Cash Versus Accrual Differential Deferral Account, for the years ended December 31 are as follows:

(millions of dollars)	2017	2016
Registered pension plans	**239**	369
Supplementary pension plans	**24**	23
Other post-employment benefits	**185**	168
Pension & OPEB Cash Payment Variance Account *(Note 5)*	**81**	86
Pension & OPEB Cash Versus Accrual Differential Deferral Account *(Note 5)*	**(117)**	(182)
Pension and other post-employment benefit costs	**412**	464

The pension and OPEB obligations and the pension fund assets measured as at December 31 are as follows:

(millions of dollars)	Registered Pension Plans 2017	2016	Supplementary Pension Plans 2017	2016	Other Post-Employment Benefits 2017	2016
Change in Plan Assets						
Fair value of plan assets at beginning of year	**13,506**	13,160	**-**	-	**-**	-
Contributions by employer	**214**	255	**14**	15	**94**	93
Contributions by employees	**97**	85	**-**	-	**-**	-
Actual return on plan assets, net of expenses	**1,207**	714	**-**	-	**-**	-
Benefit payments	**(761)**	(708)	**(14)**	(15)	**(94)**	(93)
Fair value of plan assets at end of year	**14,263**	13,506	**-**	-	**-**	-
Change in Projected Benefit Obligations						
Projected benefit obligations at beginning of year	**16,199**	15,475	**336**	299	**2,992**	3,188
Employer current service costs	**274**	277	**7**	7	**67**	67
Contributions by employees	**97**	85	**-**	-	**-**	-
Interest on projected benefit obligation	**548**	634	**11**	12	**106**	133
Benefit payments	**(761)**	(708)	**(14)**	(15)	**(94)**	(93)
Net actuarial loss (gain)	**987**	436	**16**	33	**119**	(303)
Projected benefit obligations at end of year	**17,344**	16,199	**356**	336	**3,190**	2,992
Funded status – deficit at end of year	**(3,081)**	(2,693)	**(356)**	(336)	**(3,190)**	(2,992)

The following table provides the pension and OPEB liabilities and their classification on the consolidated balance sheets as at December 31:

(millions of dollars)	Registered Pension Plans 2017	2016	Supplementary Pension Plans 2017	2016	Other Post-Employment Benefits 2017	2016
Current liabilities	**-**	-	**(14)**	(17)	**(98)**	(95)
Non-current liabilities	**(3,081)**	(2,693)	**(342)**	(319)	**(3,092)**	(2,897)
Total liabilities	**(3,081)**	(2,693)	**(356)**	(336)	**(3,190)**	(2,992)

The accumulated benefit obligations for the registered pension plans and supplementary pension plans as at December 31, 2017 are $16,005 million and $333 million, respectively (2016 – $14,909 million and $293 million, respectively). The accumulated benefit obligation differs from the projected benefit obligation in that the accumulated benefit obligation includes no assumption about future compensation levels.

The following table provides the components of OPG's OCI related to pension and OPEB plans and the offsetting Pension and OPEB Regulatory Asset, discussed in Note 5, for the years ended December 31, on a pre-tax basis:

(millions of dollars)	Registered Pension Plans 2017	Registered Pension Plans 2016	Supplementary Pension Plans 2017	Supplementary Pension Plans 2016	Other Post-Employment Benefits 2017	Other Post-Employment Benefits 2016
Changes in plan assets and benefit obligations recognized in OCI						
Current year net actuarial loss (gain)	**546**	456	**16**	33	**108**	(251)
Amortization of net actuarial loss	**(183)**	(192)	**(6)**	(4)	**-**	(19)
Amortization of past service costs	**-**	-	**-**	-	**(1)**	(1)
Total decrease (increase) in OCI	**363**	264	**10**	29	**107**	(271)
Less: increase (decrease) in Pension and OPEB Regulatory Asset *(Note 5)*	**352**	253	**9**	27	**102**	(250)
Net decrease (increase) in OCI (pre-tax)	**11**	11	**1**	2	**5**	(21)

The following table provides the components of OPG's AOCL and the offsetting Pension and OPEB Regulatory Asset that have not yet been recognized as components of benefit costs as at December 31, on a pre-tax basis:

(millions of dollars)	Registered Pension Plans 2017	Registered Pension Plans 2016	Supplementary Pension Plans 2017	Supplementary Pension Plans 2016	Other Post-Employment Benefits 2017	Other Post-Employment Benefits 2016
Unamortized amounts recognized in AOCL						
Past service costs	**-**	-	**-**	-	**4**	5
Net actuarial loss	**3,650**	3,287	**116**	106	**378**	270
Total recognized in AOCL	**3,650**	3,287	**116**	106	**382**	275
Less: Pension and OPEB Regulatory Asset *(Note 5)*	**3,391**	3,039	**109**	100	**355**	253
Net recognized in AOCL (pre-tax)	**259**	248	**7**	6	**27**	22

The following table provides the components of OPG's AOCL and the offsetting Pension and OPEB Regulatory Asset as at December 31 (included in the table above) that are expected to be amortized as components of benefit costs and recognized as increases to OCI and reductions in the Pension and OPEB Regulatory Asset in 2018, on a pre-tax basis:

(millions of dollars)	Registered Pension Plans	Supplementary Pension Plans	Other Post-Employment Benefits
Past service costs	**-**	**-**	**1**
Net actuarial loss	**198**	**7**	**6**
Total increase in OCI	**198**	**7**	**7**
Less: estimated decrease in Pension and OPEB Regulatory Asset	**184**	**6**	**6**
Net increase in OCI (pre-tax)	**14**	**1**	**1**

The most recently filed actuarial valuation, for funding purposes, of the OPG registered pension plan, as at January 1, 2017, was filed with the FSCO in September 2017. The next filed funding valuation must have an effective date no later than January 1, 2020. For 2018, OPG's required contribution to its registered pension plan is expected to be $215 million. The amount of OPG's additional, voluntary contribution, if any, is revisited from time to time. OPG will continue to assess the requirements for contributions to the pension plan.

The supplementary pension plans are not funded, but are secured by Letters of Credit totalling $353 million as at December 31, 2017 (2016 – $349 million).

Estimated future benefit payments to participants in the pension and OPEB plans based on the assumptions used to measure the benefit obligations as at December 31, 2017 are as follows:

(millions of dollars)	Registered Pension Plans	Supplementary Pension Plans	Other Post-Employment Benefits
2018	676	15	98
2019	696	15	101
2020	722	15	105
2021	747	16	108
2022	764	16	111
2023 through 2027	4,397	86	633

A one percent increase or decrease in the health care trend rate would result in an increase in the current service and interest components of the 2017 OPEB costs of $40 million (2016 – $45 million) or a decrease in the service and interest components of the 2017 OPEB costs of $29 million (2016 – $33 million). A one percent increase or decrease in the health care trend rate would result in an increase in the projected OPEB obligation as at December 31, 2017 of $592 million (2016 – $560 million) or a decrease in the projected OPEB obligation as at December 31, 2017 of $451 million (2016 – $426 million).

12. RISK MANAGEMENT AND DERIVATIVES

OPG is exposed to risks related to changes in market interest rates on debt expected to be issued in the future and movements in foreign currency that affect the Company's assets, liabilities, and forecasted transactions. Select derivative instruments are used to manage such risks. Derivatives are used as hedging instruments, as well as for trading purposes.

Interest rate risk is the risk that the value of assets and liabilities can change due to movements in related interest rates. Interest rate risk for OPG arises with the need to refinance existing debt and/or undertake new financing. The management of these risks includes using derivatives to hedge the exposure in accordance with corporate risk management policies. OPG periodically uses interest rate swap agreements to mitigate elements of interest rate risk exposure associated with anticipated financing.

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are denominated in, or tied to, US dollars. OPG enters into foreign exchange derivatives and agreements with major financial institutions, when appropriate, in order to manage the Company's exposure to foreign currency movements.

The majority of OPG's revenues are derived from sales through the IESO administered spot market. Market participants in the IESO spot market provide collateral in accordance with the IESO prudential support requirements to cover funds that they might owe to the market. Although the credit exposure to the IESO represents a significant portion of OPG's accounts receivable, the Company's management accepts this risk due to the IESO's primary role in the Ontario electricity market. The remaining receivables exposure is to a diverse group of generally high quality counterparties. OPG's allowance for doubtful accounts as at December 31, 2017 was less than $1 million. OPG's fair value derivatives totalled a net liability of $20 million as at December 31, 2017 (December 31, 2016 − $24 million).

The following table shows the pre-tax amounts related to derivatives recorded in AOCL and net income for the years ended December 31:

(millions of dollars)	**2017**	**2016**
Cash flow hedges (recorded in AOCL)		
Reclassification of losses to net interest expense	**19**	21
Commodity derivatives (recorded in net income)		
Realized losses in revenue	**(9)**	(12)
Unrealized gains (losses) in revenue	**3**	(3)

Existing pre-tax net losses of $19 million deferred in AOCL as at December 31, 2017 are expected to be reclassified to net income within the next 12 months.

13. FAIR VALUE MEASUREMENTS

OPG is required to classify fair value measurements using a fair value hierarchy. This hierarchy groups financial assets and liabilities into three levels, based on the inputs used in measuring the fair value of the financial assets and liabilities. The fair value hierarchy has the following levels:

- Level 1: Valuation of inputs is based on unadjusted quoted market prices observed in active markets for identical assets or liabilities.
- Level 2: Valuation is based on inputs other than quoted prices under Level 1 that are observable for the asset or liability, either directly or indirectly.
- Level 3: Valuation is based on inputs for the asset or liability that are not based on observable market data.

The fair value of financial instruments traded in active markets is based on quoted market prices as at the consolidated balance sheet dates. A market is regarded as active if quoted prices are readily and regularly available from an exchange, dealer, broker, industry group, pricing service, or regulatory agency, and those prices represent actual and regularly occurring market transactions on an arm's length basis. The quoted market price used for financial assets held by OPG is the current bid price. These instruments are included in Level 1 and are comprised primarily of equity investments and fund investments.

For financial instruments for which quoted market prices are not directly available, fair values are estimated using forward price curves developed from observable market prices or rates. The estimation of fair value may include the use of valuation techniques or models, based wherever possible on assumptions supported by observable market prices or rates prevailing as at the consolidated balance sheet dates. This is the case for over-the-counter derivatives and securities, which include energy commodity derivatives, foreign exchange derivatives, interest rate swap derivatives, and fund investments. Pooled fund investments are valued at the unit values supplied by the pooled fund administrators. The unit values represent the underlying net assets at fair values, determined using closing market prices. Valuation models use general assumptions and market data and therefore do not reflect the specific risks and other factors that would affect a particular instrument's fair value. The methodologies used for calculating the fair value adjustments are reviewed on an ongoing basis to ensure that they remain appropriate. If all significant inputs required to fair value an instrument are observable, the instrument is included in Level 2.

The following is a summary of OPG's financial instruments and their fair value as at December 31, 2017 and December 31, 2016:

	Fair Value		Carrying Value [1]		
(millions of dollars)	**2017**	**2016**	**2017**	**2016**	**Balance Sheet Line Item**
Nuclear Segregated Funds (includes current portion) [2]	**16,724**	15,984	**16,724**	15,984	Nuclear fixed asset removal and nuclear waste management funds
Financing receivables	**1,179**	-	**1,179**	-	Financing receivables
Investment in Hydro One shares	**188**	212	**188**	212	Available-for-sale securities
Payable related to cash flow hedges	**(40)**	(48)	**(40)**	(48)	Long-term accounts payable and accrued charges
Long-term debt (includes current portion and medium) term notes)	**(6,835)**	(6,033)	**(5,735)**	(5,520)	Long-term debt
Long-term debt – Fair Hydro Trust	**(601)**	-	**(601)**	-	Long-term debt
Other financial instruments	**(16)**	(18)	**(16)**	(18)	Various

[1] The carrying values of other financial instruments included in cash and cash equivalents, receivables from related parties, other current assets, short-term debt, and accounts payable and accrued charges approximate their fair values due to the immediate or short-term maturity of these financial instruments.

[2] The Nuclear Segregated Funds are comprised of the Decommissioning Segregated Fund and the Used Fuel Segregated Fund.

The fair value of long-term debt instruments is determined based on a conventional pricing model, which is a function of future cash flows, the current market yield curve and term to maturity. These inputs are considered Level 2 inputs.

The fair value of the Trust debt and Medium Term Note Program debt (included in the Long-term debt line above) are based on unadjusted quoted active market prices, which are considered Level 1 inputs. All other long-term debt instruments is determined based on a conventional pricing model, which is a function of future cash flows, the current market yield curve and term to maturity. These inputs are considered Level 2 inputs. For the financing receivables related to the Investment Interest acquired from the IESO, fair value is estimated to equal the fair value of the underlying debt due to the direct relationship of the asset, and the debt instruments that financed the acquisition. The financing receivables are funded by both the senior and subordinated debt issued by the Trust. The long-term debt ranks as senior notes and has inputs that are based on unadjusted quoted active market prices, which are considered Level 1 inputs, while the portion funded by the subordinated debt has inputs that are based on indicative pricing from the market, which are considered Level 2 inputs.

If one or more of the significant inputs is not based on observable market data, the instrument is included in Level 3. Specific valuation techniques are used to value these instruments. Significant Level 3 inputs include: recent comparable transactions, comparable benchmark information, bid/ask spread of similar transactions, and other relevant factors.

Transfers into, out of, or between levels are deemed to have occurred on the date of the event or change in circumstances that caused the transfer to occur.

The following tables present financial assets and financial liabilities measured at fair value in accordance with the fair value hierarchy as at December 31, 2017 and December 31, 2016:

	December 31, 2017			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Used Fuel Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	**6,090**	**4,705**	**-**	**10,795**
Investments measured at NAV [1]				**1,292**
				12,087
Due to Province				**(2,529)**
Used Fuel Segregated Fund, net				**9,558**
Decommissioning Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	**4,547**	**3,487**	**-**	**8,034**
Investments measured at NAV [1]				**1,065**
				9,099
Due to Province				**(1,933)**
Decommissioning Segregated Fund, net				**7,166**
Investment in available-for-sale securities	**188**	**-**	**-**	**188**
Other financial assets	**5**	**3**	**6**	**14**
Liabilities				
Other financial liabilities	**(28)**	**(2)**	**-**	**(30)**

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to amounts presented on the consolidated balance sheets.

(millions of dollars)	December 31, 2016 Level 1	Level 2	Level 3	Total
Assets				
Used Fuel Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	5,602	4,394	-	9,996
Investments measured at NAV [1]				1,086
				11,082
Due to Province				(1,938)
Used Fuel Segregated Fund, net				9,144
Decommissioning Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	4,171	3,243	-	7,414
Investments measured at NAV [1]				903
				8,317
Due to Province				(1,477)
Decommissioning Segregated Fund, net				6,840
Investments in available-for-sale securities	212	-	-	212
Other financial assets	6	2	9	17
Liabilities				
Other financial liabilities	(29)	(6)	-	(35)

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to amounts presented on the consolidated balance sheets.

During the year ended December 31, 2017, there were no transfers between Level 1 and Level 2. In addition, there were no transfers into or out of Level 3.

The following table presents the changes in OPG's net assets measured at fair value that are classified as Level 3 financial instruments.

(millions of dollars)	Other financial instruments
Opening balance, January 1 2017	**9**
Unrealized losses included in revenue	**(3)**
Realized losses included in revenue	**(9)**
Purchases	**9**
Closing balance, December 31, 2017	**6**

Nuclear Segregated Funds

The fair value of the investments within the Nuclear Segregated Funds' alternative investment portfolio is determined using appropriate valuation techniques, such as recent arm's length market transactions, references to current fair values of other instruments that are substantially the same, discounted cash flow analyses, third-party independent appraisals, valuation multiples, or other valuation methods. Any control, size, liquidity or other discount premiums on the investments are considered in the determination of fair value. Alternative investments are measured at fair value using NAV as a practical expedient.

The process of valuing investments for which no published market price exists is based on inherent uncertainties and the resulting values may differ from values that would have been used had a ready market existed for these investments. The values may also differ from the prices at which the investments may be sold.

The following are the classes of investments within the Nuclear Segregated Funds that are reported on the basis of NAV as at December 31, 2017:

(millions of dollars except where noted)	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice
Alternative Investments				
Infrastructure	**1,330**	**798**	**n/a**	**n/a**
Real Estate	**936**	**440**	**n/a**	**n/a**
Agriculture	**90**	**97**	**n/a**	**n/a**
Pooled Funds				
Short-term Investments	**32**	**n/a**	**Daily**	**1 - 5 Days**
Fixed Income	**729**	**n/a**	**Daily**	**1 - 5 Days**
Equity	**952**	**n/a**	**Daily**	**1 - 5 Days**
Total	**4,069**	**1,335**		

The fair value of the pooled funds is classified as Level 2. Infrastructure, real estate and agriculture investments are measured using NAV as a practical expedient for determining their fair value.

Infrastructure

This asset class includes investments in funds and assets with an objective to generate a combination of long-term capital appreciation and current income, generally through private investments in sectors such as energy, transportation, communication and utilities. The fair values of investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in these investments. The investments in its respective funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests/shares to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Distributions from each infrastructure fund will be received based on the operations of the underlying investments and/or as the underlying investments of the infrastructure funds are liquidated. It is not possible to estimate when the underlying assets in this asset class will be liquidated.

Real Estate

This asset class includes investments in funds and assets with an objective is to generate a combination of long-term capital appreciation and current income, generally through investments in institutional-grade real estate property. The fair values of the investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in these investments. The investments in its respective funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Distributions from each real estate fund will be received based on the operations of the underlying investments and/or as the underlying investments of the real estate funds are liquidated. For investments in private real estate corporations, shares may be redeemed through a pre-established redemption process. It is not possible to estimate when the underlying assets in this asset class will be liquidated.

Agriculture

This asset class includes investments in funds and assets with an objective to provide a differentiated return source, income yield, and inflation protection, generally through private investments inglobal farmland and timberland. The fair values of the investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in these investments. The investments in its respective funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests/shares to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Distributions from each fund will be received based on the operations of the underlying investments and/or as the underlying investments of the funds are liquidated. It is not possible to estimate when the underlying assets in this asset class will be liquidated.

Pooled Funds

This asset class represents investments in pooled funds, which primarily include a diversified portfolio of fixed income securities, issued mainly by Canadian corporations, and diversified portfolios of Emerging Market listed equity. The investment objective of the pooled funds is to achieve capital appreciation and income through professionally managed portfolios. The fair value of the investments in this class has been estimated using NAV per share of the investments. There are no significant restrictions on the ability to sell the investments in this class.

14. SHARE CAPITAL

Common Shares

As at December 31, 2017 and 2016, OPG had 256,300,010 common shares issued and outstanding at a stated value of $5,126 million. OPG is authorized to issue an unlimited number of common shares without nominal or par value. Any issue of new shares is subject to the consent of OPG's shareholder.

Class A Shares

The Company's Articles of Amalgamation were amended effective December 1, 2017 to allow for the creation and issuance of non-voting Class A shares to the Province in exchange for its equity injections in OPG to be used solely for its investment in the Trust. All of the outstanding shares are owned directly by the Province and OPG is authorized to issue an unlimited number of Class A shares without nominal or par value. The Class A and common shares rank equally as to dividends on a share for share basis, and all dividends declared by OPG shall be declared in equal amounts per share on all outstanding shares without preference or distinction. Upon the liquidation, dissolution or wind-up of OPG, whether voluntary or involuntary, the holders of Class A shares and common shares are entitled to share equally, on a share for share basis, in all distributions of property and assets without preference or distinction. Any issue of new shares is subject to the consent of the Province. OPG is entitled to redeem outstanding shares in connection with the repayment of the Trust's debt or other purposes as may be approved by OPG's Board of Directors.

In December 2017, OPG issued 12,217,616 Class A shares at a price of $42.46 per share to the Province for its equity injection in OPG, generating proceeds of $519 million, which was used to fund 44 percent of the total funding requirement of the Trust's acquisition of Investment Interest from the IESO.

15. EARNINGS PER COMMON SHARE

Basic and diluted earnings per common share is calculated by dividing net income attributable to the Shareholder of OPG by the weighted average number of common shares outstanding.

Class A shares are included in the weighted average number of common shares outstanding. The weighted average number of shares outstanding as at December 31, 2017 was 256.7 million (2016 – 256.3 million). There were no dilutive securities during the years ended December 31, 2017 and 2016.

16. COMMITMENTS AND CONTINGENCIES

Litigation

On August 9, 2006, a Notice of Action and Statement of Claim filed with the Ontario Superior Court of Justice in the amount of $500 million was served against OPG and Bruce Power by British Energy Limited and British Energy International Holdings Limited (together British Energy). The action is for contribution and indemnity of any amounts British Energy was liable for in an arbitration against it by some of the owners of Bruce Power regarding an alleged breach of British Energy's representations and warranties to the claimants when they purchased British Energy's interest in Bruce Power (the Arbitration). Both the action and the Arbitration relate to corrosion to a steam generator unit discovered after OPG leased the Bruce nuclear generating stations to Bruce Power.

In 2012, the arbitrator found that British Energy was liable to the claimants for some of the damages they claimed. The final settlement amount was valued by British Energy at $71 million. In September 2014, British Energy amended its Statement of Claim (Amended Claim) to reduce the claim amount to $100 million to reflect that the purchasers of British Energy's interest in Bruce Power did not receive the full damages they originally claimed in the Arbitration. British Energy also added an allegation to its Amended Claim that OPG breached a covenant to maintain the steam generator between the time of the initial agreement to lease and the effective date of the lease in accordance with "Good Utility Practices".

In November 2016, British Energy obtained consent from Ontario Superior Court of Justice to a timetable for the remaining steps in the litigation, pursuant to which the matter must be set down for trial by December 31, 2018. OPG has delivered a statement of defence in accordance with an extension of the original June 30, 2017 delivery deadline set up in the timetable. [**MONITOR**]

Various other legal proceedings are pending against OPG or its subsidiaries covering a wide range of matters that arise in the ordinary course of business activities.

Each of these matters is subject to various uncertainties. Some of these matters may be resolved unfavourably. While it is not possible to determine the ultimate outcome of the various pending actions, it is the Company's belief that their resolution is not likely to have a material adverse impact on its financial position.

Guarantees

The Company and its joint venture partners have jointly guaranteed the financial performance of jointly owned entities related primarily to the payment of liabilities. As at December 31, 2017, the total amount of guarantees OPG provided to these entities was $82 million (December 31, 2016 − $83 million). OPG may terminate some of these guarantees within a short time frame by providing written notice to the counterparties at any time. Other guarantees have terms ending between 2019 and 2029. As at December 31, 2017, the potential impact of the fair value of these guarantees to income has been estimated to be negligible and OPG does not expect to make any payments associated with these guarantees.

Contractual Obligations

OPG's contractual obligations as at December 31, 2017, are as follows:

(millions of dollars)	2018	2019	2020	2021	2022	Thereafter	Total
Fuel supply agreements	158	125	115	88	67	67	620
Contributions to the OPG registered pension plan [1]	215	219	-	-	-	-	434
OPG long-term debt repayment	398	368	663	413	172	3,721	5,735
Interest on OPG long-term debt	244	226	204	175	161	3,006	4,016
Fair Hydro Trust senior debt repayment [2]	-	601	-	-	-	-	601
Interest on Fair Hydro Trust senior debt	15	15	-	-	-	-	30
Commitments related to Darlington Refurbishment project [3]	473	-	-	-	-	-	473
Commitments related to Ranney Falls GS project	29	5	-	-	-	-	34
Operating licences	40	41	24	28	28	87	248
Operating lease obligations	28	24	24	22	22	79	199
Unconditional purchase obligations	59	58	56	5	-	-	178
Accounts payable and accrued charges	957	8	-	-	-	16	981
Other	57	30	2	1	1	64	155
Total	2,673	1,720	1,088	732	451	7,040	13,704

[1] The pension contributions include ongoing funding requirements and additional funding requirements towards the deficit, in accordance with the actuarial valuation of the OPG registered pension plan as at January 1, 2017. The next actuarial valuation of the OPG registered pension plan must have an effective date no later than January 1, 2020. The pension contributions are affected by various factors including market performance, changes in actuarial assumptions, plan experience, changes in the pension regulatory environment, and the timing of funding valuations. Funding requirements after 2019 are excluded due to significant variability in the assumptions required to project the timing of future cash flows. The amount of OPG's additional, voluntary contribution, if any, is revisited from time to time.

[2] The notes were issued by the Fair Hydro Trust under an $800 million two-year revolving warehouse facility in December 2017. In February 2018, the Trust issued $500 million of senior notes payable to repay the majority of the outstanding balance of the revolving warehouse facility.

[3] Represents estimated currently committed costs to close the project, including accruals for completed work, demobilization of project staff and cancellation of existing contracts and material orders.

Other Commitments

Collective Agreements

As of December 31, 2017, OPG had approximately 9,212 regular employees. Most of OPG's regular employees are represented by two unions:

- **The PWU** – This union represents approximately 4,849 OPG employees or approximately 53 percent of OPG's regular workforce as at December 31, 2017. Union membership includes operators, technicians, skilled trades, clerical, and security personnel. The current collective agreement between OPG and the PWU has a three-year term, expiring on March 31, 2018.
- **The Society** – This union represents approximately 3,259 OPG employees or approximately 35 percent of OPG's regular workforce as at December 31, 2017. Union membership includes supervisors, professional engineers, scientists, and other professionals. The current collective agreement between OPG and The Society has a three-year term, expiring on December 31, 2018.

In addition to the regular workforce, construction work is performed through 19 craft unions with established bargaining rights at OPG facilities. These bargaining rights are established either through the Electrical Power Systems Construction Association or directly with OPG. Collective agreements between the Company and its construction unions are negotiated either directly or through EPSCA. All of these collective agreements currently have multi-year terms, expiring on April 30, 2020.

17. BUSINESS SEGMENTS

Effective in the fourth quarter of 2017, OPG has the following six reportable business segments:

- Regulated – Nuclear Generation
- Regulated – Nuclear Waste Management
- Regulated – Hydroelectric
- Contracted Generation Portfolio
- Services, Trading, and Other Non-Generation
- Fair Hydro Trust

Regulated – Nuclear Generation Segment

The Regulated – Nuclear Generation business segment operates in Ontario, generating and selling electricity from the Pickering GS and the Darlington GS, both owned and operated by OPG. The business segment also includes revenue under the terms of a long-term lease arrangement and related agreements with Bruce Power related to the Bruce nuclear generating stations. This revenue includes lease revenue, fees for nuclear waste management, and revenue from heavy water sales and detritiation services. The segment also earns revenue from isotope sales and ancillary services supplied by OPG-operated nuclear stations. Ancillary revenues are earned through voltage control and reactive support. Revenues under the agreements with Bruce Power, including a portion of heavy water sales, and from isotope sales and ancillary services are included by the OEB as a credit to customers in the determination of the regulated prices for production from OPG's nuclear facilities, which has had the effect of reducing these prices.

Regulated – Nuclear Waste Management Segment

OPG's Regulated – Nuclear Waste Management segment reports the results of the Company's operations associated with the management of nuclear used fuel and L&ILW, the decommissioning of OPG's nuclear generating stations including the stations on lease to Bruce Power and other waste management facilities, the management of the Nuclear Segregated Funds, and related activities including the inspection and maintenance of the waste storage facilities. Accordingly, accretion expense, which is the increase in the Nuclear Liabilities carried on the consolidated balance sheets in present value terms due to passage of time, and earnings from the Nuclear Segregated Funds are reported under this segment.

As the nuclear generating stations operate over time, OPG incurs incremental costs related to used nuclear fuel and low and intermediate level wastes, which increase the Nuclear Liabilities. OPG charges these incremental costs to current operations in the Regulated – Nuclear Generation segment to reflect the cost of producing energy from the Pickering and Darlington nuclear generating stations and earning revenue under the Bruce Lease and related agreements. Since the incremental costs increase the Nuclear Liabilities in the Regulated – Nuclear Waste Management segment, OPG records an inter-segment charge between the Regulated – Nuclear Generation and the Regulated – Nuclear Waste Management segments. The impact of the inter-segment charge is eliminated in the consolidated statements of income and balance sheets.

The Regulated – Nuclear Waste Management segment is considered rate regulated because OPG's costs associated with the Nuclear Liabilities have been included in the determination of regulated prices for production from the Pickering and Darlington nuclear generating stations, in accordance with the methodology applied by the OEB since its 2008 decision on OPG's first application for regulated prices.

Regulated – Hydroelectric Segment

OPG's Regulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from most of the Company's hydroelectric generating stations. The business segment includes the results of the Sir Adam Beck 1, 2 and Pump generating stations, the DeCew Falls 1 and 2 generating stations, and the R.H. Saunders GS

that were prescribed for rate regulation prior to 2014, and the 48 hydroelectric stations prescribed for rate regulation effective in 2014.

In addition, the business segment includes ancillary and other revenues from OPG's regulated hydroelectric stations. Ancillary revenues are earned through offering available generating capacity as operating reserve and through the supply of other ancillary services including voltage control and reactive support, certified black start facilities, regulation service, and other services. These ancillary revenues and other revenues are included by the OEB as a credit to ratepayers in the determination of the regulated prices for production from OPG's prescribed hydroelectric facilities, which has had the effect of reducing these prices.

Contracted Generation Portfolio Segment

The Contracted Generation Portfolio business segment operates in Ontario, generating and selling electricity from the Company's generating stations that are not prescribed for rate regulation. The segment primarily includes generating facilities that are under an ESA with the IESO or other long-term contracts.

The Contracted Generation Portfolio segment also includes OPG's share of equity income from its 50 percent ownership interests in the PEC and Brighton Beach stations.

The business segment also includes ancillary revenues and other revenues from the stations included in the segment, which are earned through offering available generating capacity as operating reserve, and the supply of other ancillary services including voltage control and reactive support, certified black start facilities, regulation service, and other services.

Services, Trading, and Other Non-Generation Segment

The Services, Trading, and Other Non-Generation segment is a non-generation segment that is not subject to rate regulation. It includes the revenue and expenses related to OPG's trading and other non-hedging activities. As part of these activities, OPG transacts with counterparties in Ontario and neighbouring energy markets in predominantly short-term trading activities of typically one year or less in duration. These activities relate to electricity that is purchased and sold at the Ontario border, financial energy trades, financial risk management energy product revenues, and sales of energy-related products. In addition, OPG has a wholly owned trading subsidiary that transacts solely in the US market. The results of this subsidiary are reported in this segment. All contracts that are not designated as hedges are recorded as assets or liabilities at fair value on the consolidated balance sheets with changes in fair value recorded in the revenue of this segment. In addition, the segment includes revenue from real estate rentals and non-regulated services, non-regulated business development activities, and, prior to OPG's decision to decommission the stations, preservation costs related to the former coal-fired Lambton GS and the Nanticoke GS sites.

OM&A expenses of the generation business segments include an inter-segment service fee for the use of certain PP&E and intangible assets held within Service, Trading, and Other Non-Generation segment. The total service fee is recorded as a reduction to the segment's OM&A expenses.

The service fee included in OM&A expenses by segment in 2017 and 2016 was as follows:

(millions of dollars)	**2017**	**2016**
Regulated – Nuclear Generation	**36**	34
Regulated – Hydroelectric	**7**	7
Contracted Generation Portfolio	**4**	4
Reduction to Services, Trading, and Other Non-Generation	**47**	45

Fair Hydro Trust Segment

The Trust was established on December 20, 2017 and was established as a non-generation segment that is not subject to rate regulation. It includes OPG's earnings from the Trust, which includes the financial results of the Trust, as well as revenues and expenses related to OPG's role as Financial Services Manager of the Fair Hydro Trust and holder of subordinated debt issued by the Trust. Revenues include recovery of related to third-party costs and fees for financial management and ongoing administration services. OM&A expenses include incurred third-party and other recoverable incurred costs related to the management and administration of the Trust. Net interest expense (income) include interest income from OPG's investment in subordinated debt of the Trust of up to 49 percent of the Trust's total outstanding debt, partially offset by interest costs on debt issued by OPG to fund five percent of the subordinated investment in the Trust.

The earnings from the Trust is comprised of the following:

For the year ended December 31 *(millions of dollars)*	**2017**
Revenues	**(8)**
OM&A expenses	**8**
Net interest expense (income)	**(1)**
Earnings from Fair Hydro Trust	**(1)**

Segment Income (Loss) for the Year Ended December 31, 2017 *(millions of dollars)*	Nuclear Generation	Regulated Nuclear Waste Management	Hydro-Electric	Unregulated Contracted Generation Portfolio	Unregulated Services, Trading, and Other Non-Generation	Fair Hydro Trust	Elimination	Total
Revenue	**3,095**	**121**	**1,436**	**579**	**43**	**-**	**(116)**	**5,158**
Fuel expense	**284**	**-**	**351**	**53**	**1**	**-**	**-**	**689**
Gross margin	**2,811**	**121**	**1,085**	**526**	**42**	**-**	**(116)**	**4,469**
Operations, maintenance and administration	**2,293**	**129**	**330**	**169**	**18**	**1**	**(116)**	**2,824**
Depreciation and amortization	**431**	**-**	**139**	**79**	**30**	**-**	**-**	**679**
Accretion on fixed asset removal and nuclear waste management liabilities	**-**	**943**	**-**	**9**	**8**	**-**	**-**	**960**
Earnings on nuclear fixed asset removal and nuclear waste management funds	**-**	**(801)**	**-**	**-**	**-**	**-**	**-**	**(801)**
Earnings from Fair Hydro Trust						**(1)**		**(1)**
Income from investments subject to significant influence	**-**	**-**	**-**	**(38)**	**-**	**-**	**-**	**(38)**
Property taxes	**26**	**-**	**1**	**7**	**6**	**-**	**-**	**40**
Other (gains) losses	**4**	**-**	**1**	**-**	**(384)**	**-**	**-**	**(379)**
Income (loss) before interest and income taxes	**57**	**(150)**	**614**	**300**	**364**	**-**	**-**	**1,185**
Net interest expense								**95**
Income before income taxes								**1,090**
Income tax expense								**209**
Net income								**881**

Segment Income (Loss) for the Year Ended December 31, 2016 *(millions of dollars)*	Nuclear Generation	Regulated Nuclear Waste Management	Hydroelectric	Unregulated Contracted Generation Portfolio	Unregulated Services, Trading, and Other Non-Generation	Elimination	Total
Revenue	3,481	138	1,527	573	68	(134)	5,653
Fuel expense	315	-	353	58	1	-	727
Gross margin	3,166	138	1,174	515	67	(134)	4,926
Operations, maintenance and administration	2,210	146	325	178	22	(134)	2,747
Depreciation and amortization	925	-	225	75	32	-	1,257
Accretion on fixed asset removal and nuclear waste management liabilities	-	912	-	9	8	-	929
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(746)	-	-	-	-	(746)
Income from investments to significant influence	-	-	-	(37)	-	-	(37)
Property taxes	26	-	1	7	12	-	46
Restructuring	-	-	-	-	6	-	6
Other (gains) losses	1	-	(19)	1	-	-	(17)
Income (loss) before interest and taxes	4	(174)	642	282	(13)	-	741
Net interest expense							120
Income before income taxes							621
Income tax expense							168
Net income							453

Selected Consolidated Balance Sheet information as at December 31, 2017 *(millions of dollars)*	Nuclear Gener-ation	Regulated Nuclear Waste Manage-ment	Hydro-electric	Unregulated Contracted Generation Portfolio	Unregulated Services, Trading, and Other Non-Generation	Fair Hydro Trust	Total
Segment property, plant and equipment in-service, net	**6,167**	**-**	**7,359**	**3,480**	**224**	**-**	**17,230**
Segment construction in progress	**3,839**	**-**	**157**	**78**	**18**	**-**	**4,092**
Segment property, plant and equipment, net	**10,006**	**-**	**7,516**	**3,558**	**242**	**-**	**21,322**
Segment intangible assets in-service, net	**4**	**-**	**1**	**5**	**84**	**-**	**94**
Segment development in progress	**16**	**-**	**-**	**-**	**23**	**-**	**39**
Segment intangible assets, net	**20**	**-**	**1**	**5**	**107**	**-**	**133**
Segment fuel inventory	**265**	**-**	**-**	**44**	**-**	**-**	**309**
Segment materials and supplies inventory, net:							
Current	**102**	**-**	**-**	**1**	**-**	**-**	**103**
Long-term	**351**	**-**	**-**	**4**	**-**	**-**	**355**
Nuclear fixed asset removal and nuclear waste management funds (current and non-current portions)	**-**	**16,724**	**-**	**-**	**-**	**-**	**16,724**
Financing receivables Fair Hydro Trust	**-**	**-**	**-**	**-**	**-**	**1,179**	**1,179**
Fixed asset removal and nuclear waste liabilities	**-**	**(20,077)**	**-**	**(151)**	**(193)**	**-**	**(20,421)**

Selected Consolidated Balance Sheet Information as at December 31, 2016 *(millions of dollars)*	Nuclear Generation	Regulated Nuclear Waste Management	Hydro-electric	Unregulated Contracted Generation Portfolio	Unregulated Services, Trading, and Other Non-Generation	Total
Segment property, plant and equipment in-service, net	5,653	-	7,355	3,282	226	16,516
Segment construction in progress	2,988	-	166	301	27	3,482
Segment property, plant and equipment, net	8,641	-	7,521	3,583	253	19,998
Segment intangible assets in-service, net	7	-	2	4	66	79
Segment development in progress	3	-	-	1	16	20
Segment intangible assets, net	10	-	2	5	82	99
Segment fuel inventory	276	-	-	34	-	310
Segment materials and supplies inventory, net:						
Current	99	-	-	1	-	100
Long-term	340	-	1	4	-	345
Nuclear fixed asset removal and nuclear waste management funds (current and non-current portions)	-	15,984	-	-	-	15,984
Fixed asset removal and nuclear waste management liabilities	-	(19,103)	-	(160)	(221)	(19,484)

Selected Capital Expenditure Information	Regulated		Unregulated				
(millions of dollars)	**Nuclear Generation**	**Nuclear Waste Manage-ment**	**Hydro-electric**	**Contracted Generation Portfolio**	**Services, Trading, and Other Non-Generation**	**Fair Hydro Trust**	**Total**
Year ended December 31, 2017							
Investment in property, plant and equipment, and intangible assets	**1,631**	**-**	**148**	**73**	**74**	**-**	**1,926**
Year ended December 31, 2016							
Investment in property, plant and equipment, and intangible assets	1,338	-	132	198	36	-	1,704

Shareholder Declarations and Shareholder Resolutions to Sell Certain Non-Core Real Estate Properties

In December 2015, OPG received a Shareholder Declaration and a Shareholder Resolution requiring the Company to sell its head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street in Toronto, Ontario. The sale was completed in April 2017 with a gain on sale of $283 million, which is net of tax effects of $95 million, recognized in net income during the year ended December 31, 2017. The pre-tax gain on sale was recorded as an item of Other gains in the consolidated statement of income in the Services, Trading and Other Non-Generation segment. Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. The amount of designated proceeds transferred into the Consolidated Revenue Fund ~~will~~ are expected to approximate ~~be equal to~~ the after-tax gain on sale. [**MONITOR**] The transfer is expected to take place ~~as early as~~ in the first quarter of 2018, through a special dividend authorized by OPG's Board of Directors in March 2018. **[MONITOR]**

Commented [DS2]: The amount of designated proceeds will be determined by regulation and therefore uncertain until the regulation is filed and made public.

In June 2016, OPG received a Shareholder Declaration and a Shareholder Resolution that requires the Company to sell its former Lakeview GS site located in Mississauga, Ontario. The Lakeview GS site assets were fully depreciated prior to June 2017. OPG entered into a purchase and sale agreement with a purchaser with the sale scheduled to close in March 2018. An estimated after-tax gain on sale of approximately $200 million will be recognized in net income upon completion of the transaction in the first quarter of 2018. **[MONITOR]** Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. In accordance with the Shareholder Resolution, approximately one-third of the site is to be transferred to the City of Mississauga, by the purchaser, for parkland, institutional, and cultural uses. **[MONITOR]**

18. NET CHANGES IN NON-CASH WORKING CAPITAL BALANCES

(millions of dollars)	December 31 2017	2016
Receivables from related parties	**60**	116
Prepaid expenses	**(14)**	(6)
Other current assets [1]	**(28)**	(32)
Fuel inventory	**1**	34
Materials and supplies	**(3)**	(4)
Income taxes payable	**2**	57
Accounts payable and accrued charges	**36**	15
	54	180

[1] Represents other accounts receivable.

19. RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One, the IESO and the OEFC. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly-owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions for the years ended December 31 are summarized below:

(millions of dollars)	2017 Revenue	2017 Expense	2016 Revenue	2016 Expense
Hydro One				
Electricity sales	**8**	**-**	6	-
Services	**1**	**10**	1	5
Dividends	**7**	**-**	6	-
Province of Ontario				
Change in Decommissioning Segregated Fund amount due to Province [1]	**-**	**456**	-	192
Change in Used Fuel Segregated Fund amount due to Province [1]	**-**	**591**	-	235
Hydroelectric gross revenue charge	**-**	**110**	-	120
ONFA guarantee fee	**-**	**8**	-	8
Other	**-**	**2**	-	-
OEFC				
Hydroelectric gross revenue charge	**-**	**216**	-	203
Interest expense on long-term notes	**-**	**158**	-	169
Income taxes, net of investment tax credits	**-**	**246**	-	104
IESO				
Electricity related revenue	**4,802**	**-**	5,082	-
Fair Hydro Trust	**4**	**3**	-	-
	4,822	**1,800**	5,095	1,036

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at December 31, 2017 and December 31, 2016, the Nuclear Segregated Funds were reported net of amounts due to the Province of $4,462 million and $3,415 million, respectively.

The receivable, AFS securities, payable and long-term debt balances between OPG and its related parties are summarized below:

(millions of dollars)	**December 31 2017**	**December 31 2016**
Receivables from related parties		
Hydro One	**1**	1
IESO − Electricity related receivables	**354**	421
IESO − Fair Hydro Trust [1]	**7**	-
OEFC	**-**	1
PEC	**4**	4
Province of Ontario	**3**	2
Financing receivables		
IESO − Fair Hydro Trust	**1,179**	-
Available-for-sale securities		
Hydro One shares	**188**	212
Accounts payable and accrued charges		
Hydro One	**1**	-
OEFC	**52**	61
Province of Ontario	**9**	2
IESO − Electricity-related payables	**5**	2
IESO − Fair Hydro Trust	**3**	-
Long-term debt (including current portion)		
Notes payable to OEFC	**3,195**	3,295

[1] Balance consists of unbilled revenue.

OPG holds interest-bearing Province of Ontario bonds in the Nuclear Segregated Funds and the OPG registered pension fund. As at December 31, 2017, the Nuclear Segregated Funds held $1,503 million of interest-bearing Province of Ontario bonds. As at December 31, 2016, the Nuclear Segregated Funds and the registered pension fund held $1,652 million and $284 million of interest-bearing Province of Ontario bonds, respectively. These bonds are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

In December 2017, the Trust purchased its first tranche of Investment Interest from the IESO for an exchange amount of $1.18 billion, which has been classified as a financing receivable on OPG's consolidated balance sheet. The transaction was settled in cash using proceeds from the Trust's issuance of senior and subordinated debt. Pursuant to the general regulation of the Act, the IESO is required to pay and remit carrying costs of the Trust, excluding repayment of principal on any debt obligations, up to July 31, 2021. Commencing May 1, 2021, Specified Consumers will be invoiced by their local distribution company for the Clean Energy Adjustment to pay financing and other costs of the Trust. These funds will be remitted to the Trust through the IESO and will be used to settle all funding and other related expenses of the Trust that underlie the financing receivable.

As at December 31, 2017, OPG's consolidated balance sheet included approximately $7 million of unbilled revenue from the IESO primarily for OPG's general fee for 2017 as Financial Services Manager relating to incurred third-party and certain direct labour costs. In February 2018, OPG submitted to the OEB its proposed general fee for 2017 in the amount of approximately $6 million for review pursuant to the requirements of the general regulation of the Fair Hydro Act. Once approved, the fees will be remitted to the Trust by the IESO and the Trust will pay OPG's fees as Financial Services Manager.

20. INVESTMENTS SUBJECT TO SIGNIFICANT INFLUENCE

Investments subject to significant influence consist of OPG's 50 percent ownership interest in the jointly controlled entities of the PEC gas-fired combined cycle generating station and the Brighton Beach, which are accounted for using the equity method. Details of the balances as at December 31, 2017 and December 31, 2016 are as follows:

(millions of dollars)	**2017**	**2016**
PEC		
Current assets	**20**	18
Long-term assets	**240**	256
Current liabilities	**(10)**	(8)
Long-term liabilities	**(6)**	(5)
Brighton Beach		
Current assets	**5**	5
Long-term assets	**160**	168
Current liabilities	**(17)**	(16)
Long-term liabilities	**(9)**	(7)
Long-term debt	**(74)**	(90)
Investments subject to significant influence	**309**	321

21. RESEARCH AND DEVELOPMENT

For the year ended December 31, 2017, research and development expenses of $106 million (2016 – $95 million) were charged to operations.

22. NON-CONTROLLING INTEREST

PSS Generating Station LP

PSS is a limited partnership between OPG, Coral Rapids Power Corporation (CRP) and PSS Generating Station Inc. (PSS GS Inc.). The principal business of the partnership is the development, construction, ownership, operation and maintenance of the 28 Megawatt (MW) Peter Sutherland Sr. hydroelectric GS on the New Post Creek. OPG and PSS GS Inc. are general partners and CRP is a limited partner in the partnership. CRP is a wholly owned subsidiary of the Taykwa Tagamou Nation.

The Peter Sutherland Sr. GS was placed in-service in March 2017 and, in April 2017, CRP increased its interest in PSS to 33 percent under the partnership agreement, by making contributions of $21 million, reducing OPG's interest to 67 percent. CRP's 33 percent interest in PSS is reported as non-controlling interest. As a result of CRP increasing its interest in the partnership, PSS's AOCL and partner's deficit were proportionately allocated to CRP as a reduction to its non-controlling interest.

Nanticoke Solar LP

In March 2016, Nanticoke Solar LP (NSLP), a partnership between OPG, SunEdison Canadian Construction LP (SECCLP) and a subsidiary of the Six Nations of the Grand River Development Corporation, was selected through IESO's Large Renewal Procurement program to construct a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands. In the first quarter of 2017, OPG acquired all of SECCLP's interests in NSLP, which represented 25 percent of the equity interest in NSLP. Subsequent to the acquisition, OPG owns 90 percent of the equity interest in NSLP, with an approximate value of $2 million. OPG consolidates the results of the NSLP in its consolidated financial statements and reports the equity interest of the other partner as non-controlling interest.

ONTARIO POWER GENERATION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

DECEMBER 31, 2017

[DRAFT]

2017 YEAR-END REPORT

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ONTARIO POWER GENERATION INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) should be read in conjunction with the audited consolidated financial statements and accompanying notes of Ontario Power Generation Inc. (OPG or Company) as at and for the year ended December 31, 2017. OPG's consolidated financial statements are prepared in accordance with United States generally accepted accounting principles (US GAAP) and are presented in Canadian dollars.

As required by *Ontario Regulation 395/11*, as amended, a regulation under the *Financial Administration Act* (Ontario) (FAA), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. In 2014, the Ontario Securities Commission (OSC) approved an exemption which allows OPG to apply US GAAP up to January 1, 2019. The term of the exemption is subject to certain conditions, which may result in the expiry of the exemption prior to January 1, 2019. For details, refer to the section, *Critical Accounting Policies and Estimates* under the heading, *Exemptive Relief for Reporting under US GAAP*. This MD&A is dated March 8, 2018.

FORWARD-LOOKING STATEMENTS

The MD&A contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could", and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

All forward-looking statements involve inherent assumptions, risks, and uncertainties, including those set out in the section, *Risk Management,* and forecasts discussed in the section, *Core Business, Strategy, and Outlook.* All forward-looking statements could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's generating station performance and availability, fuel costs, surplus baseload generation (SBG), cost of fixed asset removal and nuclear waste management, performance and earnings of investment funds, refurbishment of existing facilities, development and construction of new facilities, pension and other post-employment benefit (OPEB) obligations and funds, income taxes, proposed new legislation, the ongoing evolution of Ontario's electricity industry, environmental and other regulatory requirements, health, safety and environmental developments, business continuity events, the weather, financing and liquidity, applications to the Ontario Energy Board (OEB) for regulatory prices, the impact of regulatory decisions by the OEB, Ontario's Fair Hydro Plan (Fair Hydro Plan or the Plan) and forecasts of earnings, cash flows, Funds from Operations (FFO) Adjusted Interest Coverage, Return on Common Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI), Total Generating Cost (TGC) and capital expenditures. Accordingly, undue reliance should not be placed on any forward-looking statement. The forward-looking statements included in this MD&A are made only as of the date of this MD&A. Except as required by applicable securities laws, OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events, or otherwise.

THE COMPANY

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG was established under the *Business Corporations Act* (Ontario) (OBCA) and is wholly owned by the Province of Ontario (Province or Shareholder).

As at December 31, 2017, OPG's electricity generation portfolio had an in-service capacity of 16,210 megawatts (MW). OPG operates two nuclear generating stations, 66 hydroelectric generating stations, three thermal generating stations, and one wind power turbine. In addition, OPG and TransCanada Energy Ltd. co-own the 550 MW Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS). OPG and ATCO Power Canada Ltd. co-own the 560 MW Brighton Beach gas-fired combined cycle GS (Brighton Beach). OPG's 50 percent share of the in-service capacity and generation volume of these co-owned facilities is included in the generation portfolio statistics set out in this report. The income from the co-owned facilities is accounted for using the equity method of accounting, and OPG's share of income is presented as income from investments subject to significant influence in the Contracted Generation Portfolio segment.

OPG also owns two other nuclear generating stations, the Bruce A GS and the Bruce B GS, which are leased on a long-term basis to Bruce Power LP (Bruce Power). Income from these leased stations is included in revenue under the Regulated – Nuclear Generation segment. The leased stations are not included in the generation portfolio statistics set out in this report.

All of OPG's owned and co-owned generating facilities are located in Ontario. OPG does not operate PEC, Brighton Beach, the Bruce A GS and the Bruce B GS.

OPG's Reporting Structure

Effective in the fourth quarter of 2017, following the establishment of the Fair Hydro Trust (the Trust) as the financing entity to implement the Fair Hydro Plan under the *Ontario Fair Hydro Plan Act, 2017* (the Fair Hydro Act or the Act), OPG has modified its reportable business segments to include the Fair Hydro Trust segment. Through its control over the key activities of the Trust and its obligation to absorb losses through ownership of the Trust's subordinated debt, the Company consolidates the financial results of the Trust in accordance with US GAAP. The Fair Hydro Trust segment reports the income related to OPG's role as Financial Services Manager under the Act and holder of subordinated debt issued by the Trust, including the financial results of the Trust. The Fair Hydro Plan and the Fair Hydro Trust are discussed in the section, *Recent Developments* and in the section, *Core Business, Strategy, and Outlook* under the heading, *Business Segments*.

The composition of OPG's reportable business segments is as follows:

- Regulated – Nuclear Generation
- Regulated – Nuclear Waste Management
- Regulated – Hydroelectric
- Contracted Generation Portfolio
- Services, Trading, and Other Non-Generation
- Fair Hydro Trust.

OPG receives regulated prices for electricity generated from most of its hydroelectric facilities and all of the nuclear facilities that it operates (collectively, prescribed facilities or regulated facilities). The regulated facilities comprise 54 hydroelectric generating stations across a number of major river systems in the province, the Pickering Nuclear GS (Pickering GS) and Darlington Nuclear GS (Darlington GS).

The operating results related to these regulated facilities are described under the Regulated – Nuclear Generation, Regulated – Nuclear Waste Management, and Regulated – Hydroelectric segments. For the remainder of OPG's operating generating facilities, the operating results are described under the Contracted Generation Portfolio segment. A description of all OPG's segments is provided under the section, *Business Segments*.

In-Service Generating Capacity

OPG's in-service generating capacity by business segment as of December 31 was as follows:

(MW)	**2017**	**2016**
Regulated – Nuclear Generation [1]	**5,728**	5,728
Regulated – Hydroelectric	**6,426**	6,421
Contracted Generation Portfolio [2]	**4,056**	4,028
Total	**16,210**	16,177

[1] The in-service generating capacity as of December 31, 2017 and December 31, 2016 excludes Unit 2 of the Darlington GS. The unit, which has a generating capacity of 878 MW, was taken offline in mid-October 2016 and is currently undergoing refurbishment.

[2] Includes OPG's share of in-service generating capacity of 275 MW for PEC and 280 MW for Brighton Beach.

The total in-service capacity as at December 31, 2017 increased by 33 MW compared to 2016. The increase was primarily due to the completion of the 28 MW Peter Sutherland Sr. hydroelectric GS, which was placed in-service in the first quarter of 2017, and the upgrade of Unit 10 of the Sir Adam Beck 1 hydroelectric GS, which was completed in June 2017. Further details on the Peter Sutherland Sr. GS project are found in the section, *Core Business, Strategy, and Outlook* under the heading, *Project Excellence*.

REVENUE MECHANISMS FOR REGULATED AND NON-REGULATED GENERATION

Regulated Generation

The OEB sets the prices for electricity generated from OPG's regulated nuclear and regulated hydroelectric facilities. The following table presents the OEB-authorized regulated prices for electricity generated from these facilities during the periods from January 1, 2016 to May 30, 2017, as well as new regulated prices retrospectively effective June 1, 2017 that OPG has calculated and submitted to the OEB, based on the OEB's decision on OPG's 2017-2021 application for new regulated prices issued on December 28, 2017:

($/MWh)	2017		2016
	January 1 to May 31	**June 1 to December 31** [1]	
Regulated – Nuclear Generation			
Base regulated price	**59.29**	**80.65**	59.29
Variance and deferral account rate rider	**-**	**-**	10.84 [2]
	59.29	**80.65**	70.13
Regulated – Hydroelectric			
Base regulated price	**40.72**	**41.67**	40.72
Variance and deferral account rate rider	**-**	**-**	3.19 [2]
	40.72	**41.67**	43.91

[1] Regulated prices for the June 1, 2017 to December 31, 2017 period were calculated and submitted to the OEB by OPG in January 2018 based on the OEB's December 28, 2017 decision on OPG's 2017-2021 application for new regulated prices. The final regulated prices will be determined by the OEB as part of the final payment amounts order process, which is expected to be completed in the first half of 2018. As part of the process, the OEB is expected to authorize separate rate riders to allow for the recovery of the shortfall between the new regulated prices and the previous regulated prices that OPG continues to receive during the period between June 1, 2017 and the implementation date of the new regulated prices pending the issuance of the final payment amounts order. The incremental revenue for the period between June 1, 2017 and December 31, 2017 arising from this retrospective application of new regulated prices was accrued in 2017. **[MONITOR]**

[2] The OEB authorized interim period rate riders for the period from October 1, 2015 to December 31, 2016 to allow for the recovery of the riders effective July 1, 2015 for the period from July 1, 2015 to September 30, 2015. The nuclear interim period rate rider was $2.17 per megawatt hour (MWh) and the regulated hydroelectric interim period rate rider was $0.64/MWh. These interim period rate riders have not been included in the above table. All rate riders in effect during 2016 expired on December 31, 2016.

Based on the OEB's December 2017 decision, the new base regulated prices are determined on an incentive ratemaking methodology for the hydroelectric operations and under a custom incentive regulation framework for the nuclear operations. For the hydroelectric facilities, the new base regulated price is determined using a formula that annually escalates the previous regulated prices, subject to some adjustments, based on inflation less a stretch factor to incent additional innovation and efficiency. For the nuclear facilities, the new regulated price is determined under a rate smoothing approach that defers a portion of the approved nuclear revenue requirement for future collection, with the aim of making more stable changes in OPG's production-weighted regulated prices year over year. The nuclear revenue requirement is based on the OEB-approved forecasts of operating costs as reduced by a stretch factor and a return on rate base. Rate base for OPG represents the average net level of investment in regulated fixed and intangible assets in service and an allowance for working capital. The OEB's December 2017 decision and OPG's new regulated prices are discussed further in the section, *Recent Developments*.

The base regulated prices in effect during 2016 were established by the OEB's November 2014 decision and December 2014 order, effective November 1, 2014, using a forecast cost-of-service methodology based on the OEB-approved revenue requirements for the 2014 to 2015 period, taking into account the OEB-approved forecasts of production and operating costs for the regulated facilities and a return on rate base.

The increase in base regulated prices for the Regulated – Nuclear Generation segment from those last approved in 2014 is impacted by lower production for Darlington GS for the duration of Unit 2's refurbishment. The increase also

reflects OPG's ability to earn a return on higher in-service capital and recover costs to enable Pickering to operate beyond 2020 in line with the Long-Term Energy Plan (LTEP).

Rate riders for OPG are typically established to recover or repay approved balances in OEB-authorized regulatory variance and deferral accounts (regulatory accounts). Variance and deferral accounts typically capture, for subsequent review and approval, differences between actual costs and revenues and the corresponding forecast amounts approved by the OEB in setting regulated prices, or record the impact of items not reflected in the approved regulated prices. The rate riders in effect to the end of 2016 were established by the OEB's October 2015 order on OPG's 2014 application to recover the December 31, 2014 variance and deferral account balances. Revenue received from the recovery of variance and deferral account balances is largely offset by amortization expense related to these balances.

Non-Regulated Generation

Electricity generated from most of OPG's non-regulated assets is subject to Energy Supply Agreements (ESAs) with the Independent Electricity System Operator (IESO).

During 2017, ESAs were in effect for the following thermal generating facilities:

- Lennox GS: Capacity and production provided by the station are subject to an ESA for the period from January 1, 2013 to September 30, 2022
- Atikokan GS: Capacity and production provided by the station are subject to a ten-year ESA expiring in July 2024
- Thunder Bay GS: Capacity and production provided by the station are subject to a five-year ESA expiring in January 2020.

In addition, long-term hydroelectric ESAs are in place for the following facilities, with expiry dates ranging from 2059 to 2067:

- Lac Seul and Ear Falls generating stations
- Healey Falls GS
- Sandy Falls, Wawaitin, Lower Sturgeon, and Hound Chute generating stations
- Little Long, Harmon, Smoky Falls, and Kipling generating stations (collectively the Lower Mattagami River generating stations)
- Peter Sutherland Sr. GS, which was placed in-service in March 2017.

HIGHLIGHTS

Overview of Results

This section provides an overview of OPG's operating results for the years ended December 31, 2017 and December 31, 2016.

(millions of dollars – except where noted)	**2017**	**2016**
Revenue	**5,158**	5,653
Fuel expense	**689**	727
Gross margin	**4,469**	4,926
Operations, maintenance and administration	**2,824**	2,747
Depreciation and amortization	**679**	1,257
Accretion on fixed asset removal and nuclear waste management liabilities	**960**	929
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(801)**	(746)
Earnings from Fair Hydro Trust	**(1)**	-
Income from investments subject to significant influence	**(38)**	(37)
Property taxes	**40**	46
Restructuring	**-**	6
	3,663	4,202
Income before other gains, interest, and income taxes	**806**	724
Other gains	**379**	17
Income before interest and income taxes	**1,185**	741
Net interest expense	**95**	120
Income before income taxes	**1,090**	621
Income tax expense	**209**	168
Net income	**881**	453
Net income attributable to the Shareholder	**860**	436
Net income attributable to non-controlling interest [1]	**21**	17
Electricity production (TWh) [2]	**74.1**	78.2
Cash flow		
Cash flow provided by operating activities	**944**	1,817

[1] Relates to the 25 percent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in the Lower Mattagami Limited Partnership, the 33 percent interest of Coral Rapids Power Corporation (CRP), a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership (PSS), and the 10 percent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP. CRP increased its partnership interest to 33 percent in April 2017.

[2] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach and excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS was excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

Net income attributable to the Shareholder was $860 million for 2017, representing an increase of $424 million compared to 2016. Income before interest and income taxes was $1,185 million for 2017, representing an increase of $444 million compared to 2016. The following summarizes the significant factors which contributed to the variance:

Significant factors that increased income before interest and income taxes:

- Higher revenue from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments of approximately $480 million recorded in the fourth quarter of 2017 to reflect the OEB's decision on OPG's application for new regulated rates issued in December 2017 with a retrospective effective date of June 1,

2017. This revenue increase for the June 1, 2017 to December 31, 2017 period was recorded as an increase in regulatory assets, based on new regulated prices for that period proposed in OPG's January 2018 submission to the OEB based on the findings in the December 2017 decision, net of a regulatory liability recognized in relation to OPG's nuclear rate smoothing proposal included in that submission. The new regulated prices, the future collection period for the retrospective revenue increase, and the rate smoothing proposal are pending the OEB's approval through the payment amounts order process, which typically follows the OEB's issuance of a decision on a major rates application. The OEB's approval of the final payment amounts order, including determinations on the new regulated prices and rate smoothing, are not expected to have a material impact on the total revenue recorded for the June 1, 2017 to December 31, 2017 period. The OEB is expected to issue the final payment amounts order in the first half of 2018. **[MONITOR]**

- Higher earnings of $377 million from the Services, Trading, and Other Non-Generation segment, primarily as a result of the gain on sale of OPG's head office premises and associated parking facility, a non-core asset of the business. A gain on sale of $283 million, which is net of tax effects of $95 million, was recognized in net income upon completion of the transaction in the second quarter of 2017. The sale was undertaken pursuant to a Shareholder Declaration and a Shareholder Resolution. Further details can be found under the heading, *Recent Developments – Shareholder Declarations and Shareholder Resolutions to Sell Certain Non-Core Real Estate Properties*.
- Higher earnings of $24 million from the Regulated – Nuclear Waste Management segment, primarily due to higher earnings from the nuclear fixed asset removal and nuclear waste management funds (Nuclear Segregated Funds), partially offset by an increase in accretion expense on the nuclear fixed asset removal and nuclear waste management liabilities (Nuclear Liabilities).

Significant factors that reduced income before interest and income taxes:

- Lower revenue of approximately $285 million, partially offset by a decrease in fuel expense of $31 million, reflecting lower electricity generation of 4.9 terawatt hours (TWh) from the Regulated – Nuclear Generation segment. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS since October 2016, partially offset by an increase in generation from the Pickering GS. The increase in generation from the Pickering GS was primarily due to outage cycle optimization, favourable unit conditions and execution of planned outage work resulting in fewer unplanned and planned outage days at the station.
- Higher operations, maintenance and administration (OM&A) expenses of $77 million, mainly in the Regulated – Nuclear Generation segment, reflecting planned expenditures related to the major maintenance activities occurring at the nuclear stations.
- Higher depreciation and amortization expense of $22 million in the Regulated – Nuclear Generation segment, excluding amortization expense related to balances in regulatory accounts, primarily due to new assets in service.
- A gain of $22 million recorded in the first quarter of 2016 to reflect the OEB's decision on OPG's motion asking the OEB to review and vary parts of its November 2014 decision on OPG's regulated prices.

The expiry of rate riders for the recovery of OEB-approved balances in regulatory accounts on December 31, 2016 contributed to the decrease in revenue in 2017, compared to 2016, but was largely offset by a decrease in the amortization expense related to regulatory account balances.

Net interest expense decreased by $25 million in 2017, compared to 2016, primarily due to a higher amount of interest costs capitalized for the Darlington Refurbishment project.

Income tax expense increased by $41 million in 2017, compared to 2016, primarily due to higher income before income taxes, partially offset by a higher amount of income tax expense deferred in regulatory assets in 2017.

Segment Results

The following table summarizes OPG's income before interest and income taxes by business segment. Significant factors which contributed to the higher income during 2017, compared to 2016, are discussed above. A detailed discussion of OPG's performance by reportable segment is included in the section, *Discussion of Operating Results by Business Segment*.

(millions of dollars)	**2017**	**2016**
Income (loss) before interest and income taxes		
Regulated – Nuclear Generation	**57**	4
Regulated – Hydroelectric	**614**	642
Contracted Generation Portfolio	**300**	282
Total electricity generation business segments	**971**	928
Regulated – Nuclear Waste Management	**(150)**	(174)
Services, Trading, and Other Non-Generation	**364**	(13)
Fair Hydro Trust	**-**	-
	1,185	741

Electricity Generation

Electricity generation for 2017 and 2016 was as follows:

(TWh)	**2017**	**2016**
Regulated – Nuclear Generation	**40.7**	45.6
Regulated – Hydroelectric	**30.7**	29.5
Contracted Generation Portfolio [1]	**2.7**	3.1
Total OPG electricity generation	**74.1**	78.2
Total electricity generation by other generators in Ontario [2]	**70.5**	72.7

[1] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

[2] Non-OPG generation is calculated as the Ontario electricity demand plus net exports, as published by the IESO, minus OPG electricity generation.

Total OPG electricity generation decreased by 4.1 TWh in 2017, mainly due to lower electricity generation of 4.9 TWh from the Regulated – Nuclear Generation segment. As expected, this was primarily the result of the removal from service of Unit 2 at the Darlington GS for the duration of the unit's refurbishment, which began in October 2016. This decrease in electricity generation was partially offset by an increase in generation from the Pickering GS, primarily due to outage cycle optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of outage days at the station, as well as higher electricity generation from the Regulated – Hydroelectric segment.

The higher electricity generation from the Regulated – Hydroelectric segment in 2017 was due to higher water flows primarily on the eastern Ontario river systems, net of forgone electricity generation as a result of SBG conditions, discussed below.

The lower electricity generation from the Contracted Generation Portfolio segment was primarily due to higher SBG conditions.

OPG's operating results are affected by changes in grid-supplied electricity demand resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. Ontario's electricity demand as reported

by the IESO was 132.1 TWh in 2017 and 137.0 TWh and 2016, respectively, which excludes electricity exports out of the province.

Power that is surplus to the Ontario market is managed by the IESO, mainly through generation reductions at hydroelectric and nuclear stations and other grid-connected renewable resources. Reducing hydroelectric production is a measure used by the IESO to manage SBG conditions. Baseload generation supply surplus in Ontario was more prevalent in 2017 than in 2016, mainly due to higher water flows and reduced electricity demand in the province during 2017. During 2017 and 2016, OPG lost 5.9 TWh and 4.7 TWh of hydroelectric generation due to SBG conditions, respectively. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions in 2017 and 2016 was offset by the impact of a regulatory variance account authorized by the OEB. OPG did not forgo any electricity production at its nuclear stations due to SBG conditions.

Average Sales Prices

The majority of OPG's generation is from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments. The regulated prices authorized by the OEB for electricity generated from OPG's nuclear and regulated hydroelectric generating stations are discussed in the section, *Revenue Mechanisms for Regulated and Non-Regulated Generation*.

The average sales price for the Regulated – Nuclear Generation segment during 2017 was 7.1 cents per kilowatt hour (¢/kWh), compared to 6.9 ¢/kWh during 2016. The increase in this average sales price was primarily due to an increase in revenue for the period June 1, 2017 to December 31, 2017 recorded in the fourth quarter of 2017 to reflect the OEB's December 2017 decision on OPG's application for new regulated prices, with an effective date of June 1, 2017. The increase was partially offset by the expiry of an OEB-authorized nuclear rate rider of $10.84 per MWh, on December 31, 2016, for the recovery of variance and deferral account balances. The average sales price for the Regulated – Hydroelectric segment during 2017 was 4.2 ¢/kWh, compared to 4.4 ¢/kWh during 2016. The decrease in this average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized regulated hydroelectric rate rider of $3.19/MWh for the recovery of variance and deferral account balances, partially offset by the impact of an increase in revenue for the period June 1, 2017 to December 31, 2017 recorded in the fourth quarter of 2017 to reflect the OEB's December 2017 decision. The rate riders that expired on December 31, 2016 were established to recover approved balances recorded in the variance and deferral accounts in prior years. As such, the year-over-year changes in revenue from the rate riders were largely offset by changes in amortization expense related to these balances.

Cash Flow from Operations

Cash flow provided by operating activities for 2017 was $944 million, compared to $1,817 million for 2016. The decrease in cash flow provided by operating activities was expected and primarily due to lower generation revenue receipts reflecting lower generation from the Regulated – Nuclear Generation segment as a result of the ongoing refurbishment of Unit 2 at the Darlington GS and the expiry, on December 31, 2016, of the OEB-authorized rate riders for nuclear and regulated hydroelectric generation. The decrease in cash flow was also due to higher income tax instalments during 2017, compared to 2016.

The decrease in cash flow provided by operating activities was partly offset by lower contributions to the Used Fuel Segregated Fund in 2017. Both the Used Fuel Segregated Fund and the Decommissioning Segregated Fund were determined to be fully funded based on an updated estimate of OPG's nuclear waste management and nuclear facilities decommissioning obligations pursuant to an Ontario Nuclear Funds Agreement (ONFA) reference plan approved by the Province, effective January 1, 2017. Pursuant to the ONFA, the reference plan is required to be updated at least once every five years. Contributions to either or both of the Nuclear Segregated Funds may be required in the future should the funds be in an underfunded position at the time of the next ONFA reference plan update. The decrease in cash flow compared to the prior year also was partially offset by the payment of a supplemental rent rebate to Bruce Power in the first quarter of 2016 in relation to a period in 2015. The lease

agreement for the Bruce nuclear generating stations was amended in late 2015 to eliminate this rebate provision going forward.

Funds from Operations Adjusted Interest Coverage

FFO Adjusted Interest Coverage is an indicator of OPG's ability to meet interest obligations from operating cash flow. The indicator is measured over a 12-month period. The FFO Adjusted Interest Coverage was 3.3 times for 2017 compared to 5.1 times for 2016. FFO Adjusted Interest Coverage in 2017 reflected a year-over-year decrease in FFO before interest due to lower cash flow provided by operating activities and changes to non-cash working capital balances, offset by the impact of a lower adjusted interest expense due to a decrease in the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets.

The decrease in the excess of interest on pension and OPEB benefit obligations over expected return on pension plan assets in 2017 was primarily due to the change in the method used to estimate the interest cost and service cost component of pension and OPEB costs prospectively adopted as of January 1, 2017. The change in the method is discussed in the section, *Critical Accounting Policies and Estimates* under the heading, *Pension and Other Post-Employment Benefits*.

Return on Common Equity Excluding Accumulated Other Comprehensive Income

ROE Excluding AOCI is an indicator of OPG's performance consistent with the Company's strategy to provide value to the Shareholder. ROE Excluding AOCI is measured over a 12-month period. ROE Excluding AOCI for 2017 was 7.5 percent, compared to 4.2 percent for 2016. ROE Excluding AOCI increased for 2017, compared to 2016, primarily due to higher net income attributable to the Shareholder as a result of the gain on the sale of OPG's head office premises and associated parking facility recorded during the second quarter of 2017 and an increase in revenue for the period June 1, 2017 to December 31, 2017 recorded in the fourth quarter of 2017 to reflect the OEB's December 2017 decision on OPG's application for new regulated prices, with an effective date of June 1, 2017. The increase in net income attributable to the Shareholder was partially offset by the impact of lower nuclear electricity generation reflecting the Unit 2 refurbishment outage at the Darlington GS.

Enterprise Total Generating Cost per Megawatt-Hour

The Enterprise TGC per megawatt-hour (MWh) was $50.66 for the year ended December 31, 2017, compared to $48.45 for the same period in 2016. The increase in Enterprise TGC per MWh was expected and primarily due to lower nuclear electricity generation as a result of the Unit 2 refurbishment outage at the Darlington GS and higher sustaining capital expenditures, partially offset by higher SBG-adjusted hydroelectric electricity generation reflecting higher water flows.

If Unit 2 at the Darlington GS was not currently undergoing refurbishment and had continued to operate in a manner consistent with the performance of the remaining units at the station, adjusting for generation constraints on these units related to the transition of the station toward refurbishment, the Enterprise TGC would have been approximately $4 to $5 per MWh lower for the year ended December 31, 2017. This sensitivity was calculated using the estimated incremental electricity generation and associated fuel cost that are expected to have had resulted in the absence of the refurbishment.

Nuclear Total Generating Cost per Megawatt-Hour

The Nuclear TGC per MWh was $70.95 for the year ended December 31, 2017, compared to $62.30 for the same period in 2016. The increase in Nuclear TGC per MWh was expected and primarily due to the decrease in nuclear electricity generation primarily as a result of the Unit 2 refurbishment outage at the Darlington GS and higher sustaining capital expenditures.

Hydroelectric Total Generating Cost per Megawatt-Hour

The Hydroelectric TGC per MWh was $23.91 for the year ended December 31, 2017, compared to $25.49 for the same period in 2016. The improvement in the Hydroelectric TGC per MWh was primarily due to higher SBG-adjusted hydroelectricity generation reflecting higher water flows.

ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are not measurements in accordance with US GAAP and should not be considered alternative measures to net income, cash flow provided by operating activities, or any other performance measure under US GAAP. OPG believes that these non-GAAP financial measures are effective indicators of its performance and are consistent with the Company's strategic imperatives and related objectives. The definition and calculation of ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are found in the section, *Supplementary Non-GAAP Financial Measures*.

Recent Developments

OEB's Decision on OPG's Application for New Regulated Prices

The OEB's decision on OPG's May 2016 five-year application for new regulated prices for its nuclear and regulated hydroelectric generation was issued on December 28, 2017, following a public hearing process. The OEB set an effective date for OPG's new regulated prices of June 1, 2017. OPG had requested an effective date of January 1, 2017. The decision reflected the terms of an OEB-approved partial settlement agreement reached by OPG and intervenors on a limited set of issues in the first quarter of 2017 (Settlement Agreement). For the first time since OPG's prescribed facilities became subject to rate regulation, the new prices have been determined on an incentive ratemaking methodology for the hydroelectric operations and a custom incentive regulation framework for the nuclear operations.

For the hydroelectric facilities, effective June 1, 2017, the base regulated prices in effect prior to June 1, 2017, with some adjustments, will be escalated for each of years 2017 to 2021 using a formula equal to an industry-specific weighted inflation factor based on indices published annually by the OEB for use in incentive regulation formulas, less a stretch factor adjustment. The OEB accepted OPG's proposal to set the annual stretch factor adjustment at 0.3 percent. Based on the approved formula, the 2017 increase in the base regulated price for the regulated hydroelectric facilities is 1.4 percent as of June 1, 2017 and the 2018 increase is 0.9 percent as of January 1, 2018. For the 2019-2021 period, the base regulated price for the regulated hydroelectric facilities will be determined annually before the beginning of each year using the approved formula and inflation indices published by the OEB.

For the nuclear operations, a revenue requirement is determined for each of the years 2017 to 2021 based on the OEB-allowed level of OPG's forecast operating costs, reduced by a stretch factor amount, as well as a return on rate base determined using OEB's generic prescribed rate of return and an OPG-specific deemed capital structure. OPG has calculated that the findings of the OEB's December 2017 decision with respect to the forecast operating costs, rate base and deemed capital structure for the nuclear generating facilities will result in nuclear revenue requirements totalling $15.9 billion over the five years.

The OEB's findings with respect to the nuclear revenue requirement include approval for inclusion in rate base of in-service amounts related to the Darlington Refurbishment of $5.5 billion by 2021, including $4.8 billion forecast in the first quarter of 2020 upon return to service of Unit 2, $0.4 billion forecast for pre-requisite projects excluding the Heavy Water Storage and Drum Handling Facility (HWSF) over the 2016-2021 period and $0.3 billion for pre-requisite projects placed in service prior to 2016. The OEB is expected to review the HWSF project as part of a future application. In the decision, the OEB concluded that it is appropriate to evaluate OPG's performance on the Darlington Refurbishment project at an overall level rather by individual cost component, with recovery of any increases over the approved in-service amounts subject to a future prudence review. The revenue requirement impact of differences between the approved in-service additions and the actual in-service additions will be recorded in

the Capacity Refurbishment Variance Account authorized by the OEB pursuant to *Ontario Regulation 53/05*. The $4.8 billion forecast in-service amount upon return to service of Unit 2 includes expenditures incurred during the definition and planning phase of the project.

The OEB also approved OPG's requested forecast costs of approximately $292 million for activities to enable Pickering operations beyond 2020 and agreed to inclusion of operating cost and generation impacts associated with continued operation of Pickering in 2021 in nuclear regulated prices. The differences between approved forecast enabling costs for continued Pickering operations and the actual amounts will be recorded in the Capacity Refurbishment Variance Account for future review and disposition by the OEB.

Excluding amounts that otherwise would have been recorded in OEB-authorized regulatory accounts for repayment to, or recovery from, customers in the future, the OEB's decision reduced OPG's proposed five-year nuclear revenue requirement by $0.6 billion. The main adjustments made by the OEB included a reduction of $100 million per year to requested OM&A costs, a reduction of 10 percent per year to forecast non-Darlington refurbishment capital in-service additions entering rate base over the 2017-2021 period, an increase and expansion of the scope of the stretch factor for nuclear costs that further reduced the revenue requirement, and a rejection of OPG's request to increase the equity component of the existing deemed capital structure of 45 percent equity and 55 percent debt. The OEB increased and expanded the annual stretch factor to 0.6 percent to most of OPG's OM&A expenses incurred directly for, or allocated to, the nuclear facilities, as well as to non-Darlington refurbishment capital in-service additions. The stretch factor is applied starting in 2018 and compounds in each year to 2021.

In accordance with *Ontario Regulation 53/05*, the nuclear revenue requirement continues to be adjusted by the amount of OPG's revenues, net of costs, from leasing the Bruce nuclear generating stations to Bruce Power. As directed by the OEB, OPG's revenues and costs related to the Bruce nuclear generating stations continue to be determined in accordance with US GAAP for the purposes of establishing the nuclear revenue requirement and are subject to the Bruce Lease Net Revenues Variance Account in accordance with *Ontario Regulation 53/05*. This includes costs related to the portion of the Nuclear Liabilities associated with the Bruce nuclear generating stations. The OEB's decision maintained the previously approved cost recovery methodology for the costs of the Nuclear Liabilities for the prescribed facilities and for the Bruce facilities, directing OPG to file a future study examining such methodologies jurisdictionally and for OPG's assets specifically. The decision fully incorporated the impacts of the updated estimate of OPG's obligations for nuclear waste management and nuclear facilities decommissioning as at December 31, 2016, including through a new ONFA reference plan effective January 1, 2017 and the change in the Nuclear Liabilities recorded on December 31, 2016.

As proposed by OPG, the OEB set recovery of pension and OPEB costs in the nuclear revenue requirement on the basis of OPG's cash payments for pension and OPEB plans, with differences between pension and OPEB accrual costs and cash payments continuing to be recorded in the Pension & OPEB Cash to Accrual Differential Deferral Account. The regulatory treatment of pension and OPEB costs is discussed further under the heading, *OEB's Report on Regulatory Treatment of Pension and OPEB Costs*.

The OEB accepted all variance and deferral account balances proposed for recovery that were not already accepted as part of the Settlement Agreement, resulting in approval of recovery of $305 million recorded in variance and deferral variance accounts as at December 31, 2015, without adjustments. The Settlement Agreement provided for the continuation of all applicable existing variance and deferral accounts. In addition to the Rate Smoothing Deferral Account discussed below, the OEB established, as of the effective date of the new regulated prices, new variance and deferral accounts to record costs related to implementing the Canadian Nuclear Safety Commission's (CNSC) Fitness for Duty program and to record differences between forecast and actual amount of Scientific Research & Experimental Development investment tax credits attributable to the nuclear facilities.

Consistent with the requirements of *Ontario Regulation 53/05*, OPG's overall production-weighted regulated prices will be smoothed, with a resulting portion of the approved annual nuclear revenue requirements for the 2017-2021 period deferred in the Rate Smoothing Deferral Account for future collection. The non-deferred portion of each year's

nuclear revenue requirement is divided by the OEB-approved forecast of OPG's nuclear electricity generation for the corresponding year to determine the base nuclear regulated price. The OEB approved the nuclear electricity generation forecast as requested by OPG.

As amended in March 2017, *Ontario Regulation 53/05* requires rate smoothing to be applied in a manner that makes changes in OPG's weighted-average nuclear and hydroelectric regulated prices more stable year over year. Previously, the regulation required that rate smoothing be applied with a view of making more stable year-over-year changes in OPG's nuclear regulated prices only. Per the regulation, the deferral account records interest at a long-term debt rate reflecting OPG's cost of long-term borrowing approved by the OEB, compounded annually. The regulation requires the OEB to authorize recovery of the balance in the account on a straight line basis over a period not to exceed ten years following the end of the Darlington Refurbishment project. OPG recognizes positive amounts deferred under rate smoothing as an increase in net regulatory assets and an increase in revenue in the period to which the underlying approved revenue requirement relates. Negative amounts determined under rate smoothing are correspondingly recorded as a decrease in net regulatory assets and a decrease to revenue.

On January 17, 2018, OPG submitted a draft payment amounts order to the OEB that proposed nuclear base regulated prices for each year of the 2017-2021 period, including a rate smoothing proposal, based on the December 2017 decision's findings. The rate smoothing proposal takes into account the near-term and future impacts on customers, while seeking to ensure that resulting nuclear regulated prices allow for sufficient cash flow to maintain the Company's investment grade credit rating and support availability of cost effective funding, while taking into account both near-term and future impacts on customers. Based on the OEB's direction, the draft payment amounts order also included proposed periods for recovery, through interim period shortfall rate riders, of the retrospective revenue shortfall for the period between June 1, 2017 and the implementation date of the new regulated prices based on proposed new regulated prices that would have been in effect during that period. The draft payment amounts also included proposed recovery periods, through variance and deferral account rate riders, for regulatory account balances approved for recovery in this application. **[MONITOR]**

To reflect the OEB's decision, in the fourth quarter of 2017, OPG recorded incremental revenue of approximately $480 million for the period June 1, 2017 to December 31, 2017 based on the draft payment amounts order. The revenue was recorded as an increase in regulatory assets for the June 1, 2017 to December 31, 2017 revenue shortfall based on proposed new regulated prices for nuclear facilities and regulated hydroelectric facilities, net of a regulatory liability recognized in relation to OPG's rate smoothing proposal. The OEB's approval of the final payment amounts order, including the allocation of the approved revenue requirement between nuclear regulated prices and rate smoothing deferrals, is not expected to have a material impact on the net revenue increase recorded in the fourth quarter of 2017. The OEB is expected to issue the final payment amounts order and implement new regulated prices in the first half of 2018. **[MONITOR]**

Consistent with the effective date of the OEB's December 2017 decision, for the period from January 1, 2017 to May 31, 2017, OPG continued to record additions to the existing variance and deferral accounts for the nuclear and regulated hydroelectric facilities pursuant to the OEB's previous decisions and orders. These additions reflected differences between actual and forecast amounts embedded in the regulated prices in effect prior to the June 1, 2017 effective date.

In January 2018, OPG filed a motion asking the OEB to review and vary the effective date of the new regulated prices to January 1, 2017. The motion did not impact OPG's financial results for the year ended December 31, 2017.

Ontario's 2017 Long-Term Energy Plan

On October 26, 2017, Ontario's Ministry of Energy issued the 2017 LTEP that outlines the Province's plans for the future development of Ontario's electricity system. The 2017 LTEP focuses on the affordability, reliability and flexibility of a clean energy supply in the province. The 2017 LTEP replaces the previous LTEP issued in 2013.

As it relates to the supply of electricity, the 2017 LTEP recognizes the refurbishment of Ontario's nuclear generating stations as the most cost-effective option for producing emission-free baseload generation to meet Ontario's needs and reaffirms the Province's support for the refurbishment of the four units at the Darlington GS and the six units at the Bruce generating stations, subject to the principles established in the 2013 LTEP. The 2017 LTEP also recognizes the value to customers of continuing to operate the Pickering GS until 2024, as planned. With respect to hydroelectric electricity generation, the 2017 LTEP highlights the opportunity to continue to invest in optimizing existing hydroelectric facilities, noting that pumped hydroelectric storage could play an important role in the reliability of the electricity system.

Additionally, the 2017 LTEP discusses the potential impact of a number of innovative technologies on the future of the electricity system. Among others, these include the increased electrification of the transportation sector, the emergence of energy storage, and the opportunity for Ontario to foster nuclear innovation technologies. OPG continues to assess how best to capitalize on potential business opportunities in these and other areas. The 2017 LTEP also recognizes the importance of Indigenous peoples' continuing role in shaping Ontario's energy planning, projects and policies.

Darlington Refurbishment

In October 2016, OPG commenced the refurbishment of the first Darlington GS unit, Unit 2, as part of the Darlington Refurbishment project. The de-fuelling of the reactor and islanding of Unit 2, the physical separation of the unit under refurbishment from the three operating units, were completed in the first half of 2017.

The disassembly of reactor components commenced in the third quarter of 2017, with the removal of feeder tubes completed in September 2017. The removal of fuel channel assemblies commenced in October 2017. As part of the fuel channel assemblies, the removal of pressure tubes is in progress and will be followed by the removal of calandria tubes. The second major segment and the removal of all reactor components is expected to be completed by mid-2018.

All of the pre-requisite projects, including construction of facilities, infrastructure upgrades and installation of safety enhancements, with the exception of the HWSF, have been completed and placed in service. The completion of the HWSF has been delayed due to challenges with construction, with construction activities suspended for a portion of 2017. Construction to complete the facility recommenced in the fourth quarter of 2017, including work to preserve and protect the facility during winter. The HWSF is expected to be completed by the second quarter of 2019 and is not on the critical path for the Darlington Refurbishment project, which continues to track on schedule. The increase in the cost estimate for the HWSF will be accommodated within the overall Darlington Refurbishment budget of $12.8 billion. Taking into account the execution performance of the Unit 2 refurbishment, the overall Darlington Refurbishment project continues to track on budget.

On November 21, 2017, the Financial Accountability Office of Ontario issued a report, "*An Assessment of the Financial Risks of the Nuclear Refurbishment Plan*". The report assesses the impact of OPG and Bruce Power's nuclear refurbishments on customers and the Province based on mechanisms in place for the recovery of the costs to refurbish and subsequently operate the nuclear stations. The report concludes that refurbishment of the four units at the Darlington GS and the six units at the Bruce nuclear generating stations provides the most cost effective, low emission generation source available to meet Ontario's baseload electricity requirements.

The Darlington Refurbishment project is discussed further in the section, *Core Business, Strategy, and Outlook* under the heading, *Project Excellence*.

Canadian Nuclear Safety Commission Safety Rating for the Darlington GS and the Pickering GS

The CNSC publishes an annual report on the safety performance of Canada's nuclear power plants. The report assesses how well plant operators are meeting regulatory requirements and program expectations in the areas of operational performance, safety analysis, radiation protection, waste management and conventional health and

safety. On September 8, 2017, the CNSC issued an executive summary of its 2016 annual report, giving both the Darlington GS and the Pickering GS the highest possible safety rating of "Fully Satisfactory". The Darlington GS achieved this rating for the eighth consecutive year, while the Pickering GS achieved this rating for the second consecutive year.

Ontario's Fair Hydro Plan

On March 2, 2017, the Province announced the Fair Hydro Plan aimed at reducing electricity bills for eligible residential, farm, small businesses ~~and other eligible~~ consumers (Specified Consumers) in the province by refinancing a portion of the Global Adjustment costs over a longer period of time. The Global Adjustment includes the difference between Ontario's electricity market clearing price used to dispatch generation and the prices paid to contracted and regulated generators in the province, and the cost of conservation and demand management programs. On June 1, 2017, the Fair Hydro Act received Royal Assent and the associated general regulation came into force in June 2017. The Act established a framework under which the costs and benefits associated with the Government of Ontario's clean energy initiatives are to be allocated between present and future consumers of electricity under the Fair Hydro Plan. The general regulation provides details on the structural, operational and financial elements required to implement the Fair Hydro Plan.

Pursuant to the Act, effective May 1, 2017, the IESO began to defer a portion of the Global Adjustment costs. The Act allows the IESO to transfer a portion of the deferred balance to a financing entity that would fund the deferral in exchange for an irrevocable right to recover the balance and associated financing and other costs from Specified Consumers in the future (Investment Interest). The legislation appointed OPG as the Financial Services Manager under the Act and conveyed upon the Financial Services Manager statutory obligations, including the creation of one or more financing entities that may acquire Investment Interests from the IESO.

In November 2017, OPG's Board of Directors provided its final approval regarding OPG's involvement with the Trust on commercial terms following the fulfilment of all conditions it established in May 2017. Accordingly, the Fair Hydro Trust was established as the financing entity contemplated by the Act in December 2017. The majority unitholder and beneficiary of the Trust is a wholly-owned subsidiary of OPG. The Trust is structured to be bankruptcy remote and ring fenced from OPG in order to protect the Company's assets and operations.

In order for the Trust to finance the Investment Interest acquired from the IESO, it will incur senior debt from capital markets and subordinated debt from OPG. The Trust's investment will attract financing amounts and other related fees, which, under the general regulation, will be payable by the IESO as carrying costs until July 2021 and by Specified Consumers through the Clean Energy Adjustment to be invoiced by local distribution companies commencing in May 2021, with the three-month lag in 2021 intended to cover the billing and collection lag from the introduction of the Clean Energy Adjustment. The carrying costs include all financing and third-party costs other than payment of principal on debt.

Concurrent with every issuance of the Trust's senior notes, it is expected that OPG will purchase subordinated debt of the Trust in an aggregate amount not to exceed 49 percent of the Trust's total outstanding debt, with 44 percent of the funding to be provided by the Province through equity injections and five percent to be provided by OPG. The subordination level may vary over time, but must at least equal to, or be greater than 35 percent of all outstanding debt. Through OPG's control over the key activities of the Trust and its obligation to absorb losses through ownership of the Trust's subordinated debt, the Company consolidates the financial results of the Trust in accordance with US GAAP.

On December 21, 2017, the Trust purchased its first tranche of Investment Interest from the IESO in the amount of approximately $1.18 billion. Fifty-one percent of the funding requirement or $601 million was financed by the Trust through a revolving warehouse facility ranked as senior notes, and the remaining 49 percent was funded through the issuance of short-term subordinated debt to OPG. The Investment Interest has been classified as a financing receivable on OPG's consolidated balance sheet.

OPG's subordinated debt investment in the Trust was funded through the following sources:

- The Province provided 44 percent of the total funding requirement or $519 million, through an equity injection in OPG in exchange for approximately 12.2 million non-voting Class A common shares at a price of $42.46 per share. The Company's Articles of Amalgamation were amended effective December 1, 2017 to allow for the creation and issuance of Class A shares. Refer to Note 14 of OPG's 2017 audited consolidated financial statements for further details; and
- OPG provided five percent of the total funding requirement or approximately $60 million.

In February 2018, the Trust issued $500 million of senior notes payable with a coupon interest rate of 3.36 percent and an effective interest rate of 3.42 percent, payable semi-annually until maturity on May 15, 2033. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility issued in December 2017. By the end of the first quarter of 2018, the Trust is expected to acquire another tranche of Investment Interest from the IESO, which it expects to fund using its revolving warehouse facility.

Refer to the section, *Liquidity and Capital Resources* under the heading, *Financing Activities* for further details on the Trust's financing arrangements and OPG's public debt offering.

OEB's Report on Regulatory Treatment of Pension and OPEB Costs

On September 14, 2017, the OEB issued its final report on the guiding principles and policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the Ontario electricity and natural gas sectors. The report establishes the accrual basis of accounting as the method of determining pension and OPEB amounts for rate-setting purposes, unless the OEB finds that this method does not result in just and reasonable rates in the circumstances of a particular utility. The report also provides for the establishment of a generic variance account to record asymmetric carrying charges in favour of ratepayers on the differences between the accrual costs recovered and cash payments made by a utility in respect of pension and OPEB plans. Carrying charges on this differential are to be assessed at the OEB's prescribed interest rate, on a prospective basis from the effective date of the new variance account. For OPG, this differential will include amounts going back to November 1, 2014, with the charges calculated on the portion of the differential that has been recovered through regulated prices. None of this differential has been recovered to date. The prescribed interest rate is set quarterly by the OEB based on the quarterly return of a mid-term corporate bond index yield.

The OEB's September 2017 report and the OEB's December 2017 decision on OPG's application for new regulated prices require OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the Pension & OPEB Cash to Accrual Differential Deferral Account in effect since November 1, 2014, until such time as the OEB approves resumption of the accrual basis of recovery for OPG. The future recovery of amounts recorded in the account will be subject to this approval. The OEB's report did not impact OPG's financial results for the year ended December 31, 2017.

The Company recognizes the amount set aside in the Pension & OPEB Cash Versus Accrual Differential Deferral Account as a regulatory asset. As at December 31, 2017, the regulatory asset had a balance of $614 million. Consistent with the expectations set out in the OEB's December 2017 decision, in 2018, OPG plans to file an application with the OEB requesting disposition of the Pension & OPEB Cash Versus Accrual Differential Deferral Account balance as well as balances accumulated since December 31, 2015 in other regulatory accounts.

Shareholder Declarations and Shareholder Resolutions to Sell Certain Non-Core Real Estate Properties

In December 2015, OPG received a Shareholder Declaration and a Shareholder Resolution requiring the Company to sell its head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street in Toronto, Ontario. The sale was completed in April 2017, with a gain on sale of $283 million, which is net of tax effects of $95 million, recognized in net income in the second quarter of 2017. The pre-tax gain on sale was recorded

as an item of Other gains in the consolidated statement of income in the Services, Trading and Other Non-Generation segment. Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. The amount of designated proceeds transferred into the Consolidated Revenue Fund are expected to approximate ~~will be equal to~~ the after-tax gain on sale. **[MONITOR]** The transfer is expected to take place ~~as early as~~ in the first quarter of 2018, through a special dividend authorized by OPG's Board of Directors in March 2018. **[MONITOR]**

Commented [DS1]: The amount of designated proceeds will be determined by regulation and therefore uncertain until the regulation is filed and made public.

In June 2016, OPG received a Shareholder Declaration and a Shareholder Resolution that requires the Company to sell its former Lakeview GS site located in Mississauga, Ontario. OPG has entered into a purchase and sale agreement with a purchaser with the sale scheduled to close in March 2018. An estimated after-tax gain on sale of approximately $200 million is expected to be recognized in net income upon completion of the transaction in the first quarter of 2018. **[MONITOR]** Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. OPG anticipates the amount of designated proceeds transferred into the Consolidated Revenue Fund to approximate the after-tax gain on the sale. In accordance with the Shareholder Resolution, approximately one-third of the site is to be transferred to the City of Mississauga, by the purchaser, for parkland, institutional, and cultural uses.

CORE BUSINESS, STRATEGY, AND OUTLOOK

OPG's mission is to provide low cost power in a safe, clean, reliable and sustainable manner for the benefit of its customers and its Shareholder. OPG also seeks to pursue, on a commercial basis, generation development projects and other business expansion opportunities to the benefit of the Shareholder.

OPG's four key strategic imperatives are as follows:

- Operational Excellence
- Project Excellence
- Financial Strength
- Social Licence.

Operational Excellence

Operational excellence at OPG is accomplished by the safe and environmentally responsible generation of reliable and cost-effective electricity from the Company's generating assets through a highly trained and engaged workforce.

Workplace Safety and Public Safety

Workplace safety and public safety are fundamental core values at OPG. OPG is committed to operating all of its facilities in a safe, secure, and reliable manner that minimizes risks to a reasonably achievable level. Safety is an overriding priority in all activities performed at OPG's generating and other facilities, and all employees and contractors are expected to conduct themselves in manner that ensures workplace safety and public safety in line with the Company's safety culture.

In the area of workplace safety, OPG is committed to achieving excellent performance through continuous improvement and a strong safety culture, with the ultimate goal of zero injuries. OPG utilizes an integrated health and safety management system and a set of operational risk control procedures to ensure continued monitoring of health and safety performance and to support continuous learning and improvement in this area. Over the past five years, OPG has repeatedly stood in the top quartile of its comparator Canadian electrical utilities in various safety performance metrics.

Workplace safety performance is measured using two primary indicators at OPG, All Injury Rate (AIR) and Accident Severity Rate (ASR). OPG's AIR and ASR results for employee workplace safety were as follows for the year ended December 31:

	2017	2016
AIR *(injuries per 200,000 hours worked)*	**0.48**	0.56
ASR *(days lost per 200,000 hours)*	**3.57**	2.59

In 2017, OPG's AIR improved from 2016 and was the third-best performance year in the Company's history. For those employee injuries that caused lost time from work, the total time lost from work in 2017 was greater than the previous year. OPG's analysis of the underlying safety events indicated that major contributors to the injuries and near misses included inadequate situational awareness and attention to detail, and suboptimal risk-based decisions, rather than missing or inadequate standards or programs. OPG continues to implement a number of initiatives to target the injury trends based on the analysis of the safety events, with a focus on the use of human performance tools including increased field supervisory oversight, situational awareness, communication, and procedural use and adherence.

In order to strengthen its safety performance, OPG continues to progress an organization-wide "iCare Enough to Act" initiative launched in 2016 and aimed at renewing employees' commitment to their own and each other's safety and well-being. Approaches to supervisory oversight, communication and safe work planning are being modified and updated to further strengthen safety as a foundational element of the Company's values-based culture.

Contractors are required to conduct work safely at OPG sites. In support of this requirement, OPG utilizes an independent contractor pre-qualification process, provides on-site safety support for many of its major projects, and works with contract partners to improve their health and safety programs to meet OPG's requirements. In the past nine years, OPG has consistently shown a Construction Contractor AIR that is markedly better than the Infrastructure Health and Safety Association Contractor AIR, a metric of construction contractor safety performance across Ontario. OPG has maintained this performance while engaging in the refurbishment of the Darlington GS, one of the largest infrastructure projects in Canada. The hours worked by contractors in 2017 were the largest in OPG's history, largely attributable to this project.

OPG continues to maintain a strong focus on the nuclear safety program and to invest in nuclear safety systems. To ensure continued public safety, radiation exposure to members of the public resulting from the operation of OPG's nuclear generating stations is estimated on an annual basis for individuals living or working near the stations. The annual dose to the public resulting from operations of each nuclear facility is expressed in microsieverts (µSv), which is an international unit of radiation dose measurement. For 2016, the annual public doses resulting from the Darlington GS operations and the Pickering GS operations were 0.6 µSv and 1.5 µSv, respectively, which is less than 0.1 and 0.2 percent of the annual legal limit of 1,000 µSv, respectively. While the public doses from OPG's nuclear operations for the 2017 operating year will not be finalized until the second quarter of 2018, they are not expected to differ significantly from the 2016 levels.

In June 2016 and August 2016, the CNSC released sampling results from its independent environmental monitoring program, which confirmed that the public and the environment around OPG's nuclear generating stations continued to be safe. In September 2017, the CNSC issued an executive summary of its 2016 annual report on the safety performance of Canada's nuclear power plants, which gave both the Pickering GS and the Darlington GS the highest possible safety rating of "Fully Satisfactory". For further details, refer to the CNSC safety rating discussion in the section, *Highlights* under the heading, *Recent Developments*.

OPG remains committed to high standards of public safety on waterways around hydroelectric generating stations and dams, and continues to make investments in waterway and dam safety upgrades. The Company's practices in this area are routinely reviewed by an independent panel comprised of internationally recognized experts, who have

concluded that OPG's Dam Safety Program is industry leading in a number of areas. During 2017, OPG continued its water safety campaign with a series of public service announcements illustrating the danger of water near hydroelectric dams and hydroelectric generating stations.

Electricity Generation Production and Reliability

Key strategic initiatives in support of operational excellence, specific to each of OPG's core generating operations, are discussed below. Generation and reliability performance for 2017 is discussed by operating segment in the section, *Discussion of Operating Results by Business Segment*.

Nuclear Operations

OPG is pursuing a number of strategic initiatives aimed at the continued safe and reliable operation of the Pickering GS and targeting top performance at the Darlington GS.

OPG's objective is to maximize the safe and reliable operating life of the Pickering units. As announced in 2016 and approved by the Province, OPG is continuing to execute on a plan to extend safe and reliable operation of the Pickering GS to 2024. In addition to providing Ontario with a clean, reliable source of baseload electricity during nuclear unit refurbishments at the Darlington GS and the Bruce nuclear generating stations, extending operations at the Pickering GS will provide continued employment for up to 4,000 full-time employees at OPG and help to reduce approximately 17 million tonnes of carbon dioxide emissions, which is equivalent to removing approximately 3.4 million cars from Ontario's roads.

As part of the plan to extend Pickering operations, OPG has been continuing to undertake the required technical work to confirm that the station's pressure tubes, a key life-limiting component of the station, will remain fit for service for operation to 2024. In the fourth quarter of 2017, OPG has confirmed that technical assessments completed to date provide sufficient confidence in the programs and provisions in place to assure fitness-for-service of fuel channel components in line with the planned extended operations period. This evaluation is consistent with the safety case reflected in OPG's operating licence renewal application for the Pickering GS submitted to the CNSC in 2017, discussed below. Taking these factors into account, OPG revised the accounting end-of-life assumptions for the Pickering GS from December 31, 2020 for all units to December 31, 2022 for Units 1 and 4 and December 31, 2024 for Units 5 to 8, effective December 31, 2017.

The change in the Pickering GS accounting end-of-life assumptions did not impact OPG's net income in 2017. The change is expected to decrease depreciation expense by $77 million in 2018, including the associated impact on the nuclear asset retirement obligation (ARO) recorded as of December 31, 2017 but before the impact of regulatory accounts. Regulatory accounts, including a new deferral account proposed by OPG in a December 2017 application to the OEB, are expected to largely offset the decrease in depreciation expense. The change in the nuclear ARO recorded in the fourth quarter of 2017 is discussed in the section, *Critical Accounting Policies and Estimates* under the heading, *Asset Retirement Obligation*. On December 29, 2017, OPG applied for an accounting order to establish a variance account to record, from January 1, 2018 until the effective date of the OEB's next payment amounts order, the revenue requirement impact of changes to nuclear liabilities and depreciation and amortization expense resulting from changes to station end-of-life dates for OPG's Pickering prescribed nuclear facilities that will be effective December 31, 2017. Pending the OEB's review of the application, an interim order was issued January 31, 2018 establishing the proposed variance account effective January 1, 2018. The OEB's final decision for the account is expected later in 2018.

OPG's current five-year operating licence for the Pickering GS was approved by the CNSC in 2013 and expires on August 31, 2018. This current licence was issued assuming that the station would shut down in 2020. On June 28, 2017, OPG confirmed to the CNSC that it intends to cease commercial operation of all Pickering units on December 31, 2024. On August 28, 2017, OPG submitted a ten-year licence renewal application to the CNSC. The requested licence term spans the planned extended commercial operations period, through to the planned period of de-fuelling,

de-watering and beginning to place the station in a safe storage state in 2028. In support of the licence renewal, OPG undertook a Periodic Safety Review (PSR), a comprehensive assessment of the station's design and operation to confirm that there is a high level of safety throughout the operating life and to determine what reasonable and practical enhancements can be made to further improve safety. The PSR also includes a component condition assessment of the station to identify the work required to support the station's continued operation. The PSR has confirmed that extending operations of the Pickering units will continue to pose minimal risk to the health, safety and security of workers, the public and the environment. The final major component of the PSR was submitted to the CNSC in November 2017. The CNSC's review of the PSR submission and licence application is in progress. Based on the evidence and documentation submitted to the CNSC, OPG is confident in obtaining a licence renewal that would support its extended operations plan for Pickering GS.

OPG's nuclear operations are regularly benchmarked against top performing nuclear facilities around the world. This allows OPG to identify, develop and implement initiatives to further improve performance. In September 2016, OPG hosted a team of experts from the International Atomic Energy Agency (IAEA) at the Pickering GS to conduct a standard Operational Safety Review Team mission. The team conducted an in-depth review of performance and adherence to international safety standards. In the second quarter of 2017, the IAEA's Operational Safety Review Team released the final report and confirmed that the Pickering GS demonstrates strong commitment to safety. In December 2017, OPG hosted a World Association of Nuclear Operators (WANO) peer evaluation for the Pickering GS, which focused on the safe and reliable operation of the station while evaluating the plant material condition, functional and cross-functional areas of the organization. Pickering showed significant improvement since its last review and has sustained its strong rating in 2018, resulting in its best ever WANO peer review.

OPG remains focused on improving reliability and increasing electricity generation output from its nuclear fleet. This includes improving equipment reliability, optimizing outages, implementing integrated asset management planning and enhancing maintenance programs. Improved equipment reliability generally results in fewer generation interruptions. Nuclear inspection and testing programs are largely driven by maintenance and regulatory requirements, and are designed to ensure that equipment is performing safely and reliably. Execution of this and other outage work continues to be a high priority. As part of its commitment to operational excellence, OPG continues to focus on improving the planning, execution, monitoring, and reporting of outage work.

OPG continues to make investments in the performance of the Pickering GS, with a focus on improving plant reliability and maximizing the value of the asset over its remaining life through implementing equipment modifications and fuel handling reliability improvements, reducing equipment maintenance backlogs, and completing critical and high priority work. OPG also continues to make investments in the Darlington GS necessary to sustain safe and reliable operations for the next three decades and aimed at positioning the station for industry-leading operating and cost performance in the longer term. This includes investments in life cycle and aging management projects, facility upgrades as well as work in support of regulatory commitments.

Delivering solutions that provide the best combination of safety, cost and effectiveness, as well as establishing challenging financial targets based on comprehensive benchmarking and taking into account the operating environment of the nuclear stations, continues to be a vital part of OPG's strategy to improve performance of the nuclear business unit. Financial and staffing targets continue to be reviewed and adjusted where necessary to reduce operating costs, while ensuring safety and reliability are not compromised.

In 2016, OPG submitted applications with the CNSC seeking a ten-year licence renewal for the Western Waste Management Facility (WWMF), located at the Bruce generating stations' site, to May 31, 2027, and a ten-year licence renewal for the Pickering Waste Management Facility (PWMF) to August 31, 2028. The licence renewal applications were presented to the CNSC at public hearings in April 2017. On May 30, 2017, the CNSC announced that the WWMF licence was renewed for a ten-year period and will be valid until May 31, 2027. On February 7, 2018, the CNSC announced that the PWMF licence was renewed for a ten-year period and will be valid until August 31, 2028.

In 2017, the CNSC approved regulatory document *REGDOC 2.2.4 – Fitness for Duty – Managing Alcohol and Drug Use* for use at Canadian nuclear power plants. This document sets out requirements for managing fitness for duty of workers in relation to alcohol and drug use at high-security sites, including for-cause alcohol and drug testing for workers in positions identified as safety-sensitive or safety-critical and random alcohol and drug testing for workers holding safety-critical positions. OPG intends to enhance its existing Fitness for Duty program to comply with these new requirements. OPG is working with its partners in the Canadian nuclear industry to develop a program suitable for Canada and its workers.

Hydroelectric Operations

The objectives of OPG's hydroelectric operations include operating and maintaining the generating facilities in a safe, efficient and cost-effective manner, while increasing the output from the facilities and pursuing opportunities to increase capacity. OPG aims to increase the facilities' output by improving operational flexibility, enhancing reliability, optimizing outage planning and, subject to water conditions, increasing availability to meet electricity system demand. OPG continues to evaluate and implement plans to increase capacity, maintain and improve operational performance, and extend the operating life of its hydroelectric generating assets.

OPG's hydroelectric operations are regularly benchmarked against peer utilities in North America. Based on 2016 data, 19 of the OPG's 25 large regulated hydroelectric facilities benchmarked in the top two quartiles for unit energy costs. This group of 19 facilities represents 94 percent of the energy delivered from the regulated hydroelectric fleet. Similarly, 18 of 25 large regulated hydroelectric facilities benchmarked in the top two quartiles for availability based on 2016 data. OPG continues to pursue innovation and technology-based improvements in its asset management and equipment maintenance strategies in order to increase reliability and further reduce costs of the hydroelectric fleet.

As part of OPG's ongoing strategy to reduce costs and increase operational efficiency, the operations of the Company's hydroelectric and thermal assets were previously combined into one organization, with five regional operations groups. In 2017, OPG reduced the number of regional operations groups to four, by integrating the Central Operations work centres into three of the other existing regional operations groups. In addition, during the third quarter of 2017, OPG opened an amalgamated control room located at the Saunders hydroelectric GS, combining the Chenaux and Saunders control rooms. The amalgamated control room will control all operational activities at the ten hydroelectric stations along the Madawaska, Ottawa and St. Lawrence rivers.

OPG's plans for its existing hydroelectric generating stations are accomplished through multi-year capital investment and other programs, including replacements and upgrades of turbine runners, and refurbishment or replacement of existing generators, transformers, and controls. The aim of OPG's runner replacement and upgrade program is to increase hydroelectric station capacity by leveraging efficiency enhancements in runner design. Where economical and practical, OPG also pursues opportunities to refurbish, expand or redevelop its existing hydroelectric stations. Over the next four years, OPG plans to increase the total capacity of its hydroelectric generating fleet by approximately 150 MW, which, in addition to the runner replacement and upgrade program, includes the Ranney Falls GS and Sir Adam Beck frequency conversion projects. OPG is also planning to repair, rehabilitate, or replace a number of aging civil hydroelectric structures.

As part of its commitment to operational excellence, OPG continues to make investments in its existing hydroelectric generating fleet. During 2017, OPG continued to execute a number of projects, including:

- Completion of the overhaul and upgrade of Unit 10 of the Sir Adam Beck 1 GS, which increased the station's capacity by 6 MW
- Continued work on the overhaul and rehabilitation of Unit 1 of the Sir Adam Beck Pump GS to ensure reliable unit operation for approximately the next 20 years
- Completion of the replacement of the Shebandowan Lake Control Dam at the Kakabeka Falls GS, which will maintain structural integrity and enhance dam safety for another 100 years

- Continued work on the overhaul and upgrade of Unit 1 of the Harmon GS with completion of the turbine upgrade, generator rehabilitation and upgrade of protection and control systems
- Continued work on the overhaul and upgrade of Unit 2 of the DeCew Falls GS, with turbine and generator rehabilitation and upgrade of protection and control systems completed during the year, and, in the fourth quarter of 2017, commencement of the overhaul and upgrade of Unit 2 of the Little Long GS
- Continued work on the overhaul and rehabilitation of Unit 2 of the Lower Notch GS, with generator rehabilitation completed during the year, and in the fourth quarter of 2017, commencement of the overhaul and rehabilitation of Unit 6 of the Sir Adam Beck Pump GS
- Commencement of definition phase work for the Water Conveyance System project to rehabilitate the Sir Adam Beck 1 GS canal and associated structures, ensuring their continued safe and reliable operations for approximately the next 50 years.

In 2018, OPG plans to commence execution of several major sustaining projects across the hydroelectric fleet, including the overhaul and upgrade of Unit 5 of the Sir Adam Beck 1 GS, the rehabilitation of Caribou Falls Block Dam No.2, and automatic sluicegates system replacement at the Whitedog Falls GS. Definition phase activities on several other major projects are also expected to commence in 2018, including frequency conversion of Units 1 and 2 of the Sir Adam Beck 1 GS and the overhaul and upgrade of the R.H. Saunders GS units.

Thermal Operations

OPG's thermal operations consist of biomass-fuelled generating units at each of Atikokan GS and Thunder Bay GS, and the oil/gas dual-fuelled Lennox GS.

These stations, which operate as peaking facilities under their respective energy supply requirements, provide Ontario's electricity system with the flexibility to meet changing daily system demand and capacity requirements and enable the system to accommodate the expansion of Ontario's renewable generation portfolio. The continued operation of these stations will continue to provide Ontario with over 2,000 MW of peaking generation capacity. The stations operate under their respective ESAs.

OPG's biomass-fuelled generating units are among the world's leading in their innovation. The Atikokan GS is the largest generating station in North America fuelled by 100 percent biomass, while the Thunder Bay GS unit uses advanced biomass that is thermally treated to allow it to be stored outdoors and withstand exposure to the weather.

Former thermal stations that are no longer available to generate electricity are included in the Services, Trading, and Other Non-Generation segment once they are removed from service. This includes the Lambton GS and Nanticoke GS sites, which ceased operations in 2013. Over 2015 and 2016, OPG announced that these stations would be decommissioned safely, securely and in an environmentally responsible manner. The costs of the decommissioning are charged to a previously established decommissioning provision.

During 2017, OPG substantially completed the demolition of the Nanticoke coal yard equipment and structures and issued a contract for the demolition of the Nanticoke powerhouse and associated structures. In the fourth quarter of 2017, the demolition contractor had been mobilized to prepare for the removal of the powerhouse and associated structures and initiated the preparatory work for the demolition of the stacks. The demolition of the stacks took place in February 2018. **[MONITOR]** A competitive bidding process for the demolition of the Lambton GS is in progress, with a contract for the removal of the powerhouse and associated structures expected to be issued during 2018. The decommissioning plan for the Nanticoke GS accommodates the construction and operation of the Nanticoke solar facility.

An update of the asset retirement obligations related to the Nanticoke and Lambton sites has been completed. For a discussion of the revaluation of this liability for non-nuclear fixed asset removal as at December 31, 2017, refer to the section, *Critical Accounting Policies and Estimates* under the heading, *Asset Retirement Obligations*.

Environmental Performance

OPG's Environmental Policy states that "OPG shall meet compliance obligations, including any environmental commitments that it makes, with the objective of exceeding these compliance obligations where it makes business sense". This policy commits OPG to:

- maintain an ISO 14001-registered environmental management system (EMS)
- work to prevent or mitigate adverse impacts on the environment with a long-term objective of continual improvement
- strive to be a leader in climate change mitigation
- manage sites in a manner that strives to maintain, or enhance where it makes business sense, significant natural areas and associated species of concern.

In 2017, OPG maintained the ISO 14001 registration of its company-wide EMS. Within the EMS, OPG has planning, operational control, and monitoring programs to manage the Company's positive and negative impacts on the environment. Significant environmental aspects of OPG's operations include: spills, chemical and thermal emissions to water, water flow and level changes, radiological emissions, low and intermediate level radioactive waste (L&ILW), enhancement and disruption of wildlife habitat, displacement of fossil fuels, and fish impingement and entrainment. Further details regarding OPG's environmental risks can be found in the section, *Risk Management* under the heading, *Environmental Risk*.

Environmental performance targets are set as part of the annual business planning process. These targets are based on past performance and external benchmarking to promote continual improvement. OPG met or outperformed its 2017 targets for spills, environmental infractions, carbon-14 emissions to air, and L&ILW. Targets for tritium emissions to air and water were not achieved due to equipment performance issues; however, emissions remained less than one percent of the regulatory limit. There were no significant environmental events during 2017.

In 2016, the Government of Ontario passed the *Climate Change Mitigation and Low-Carbon Economy Act, 2016* and the associated *Cap and Trade Program Regulation*. The legislation provides the foundation for regulating greenhouse gas (GHG) emissions in Ontario and establishes a cap and trade program, with the first compliance period being from January 1, 2017 to December 31, 2020.

The cap and trade program is a market mechanism intended to give Ontarians an incentive to reduce GHG emissions by putting a price on carbon. OPG has an internal program to meet its GHG emissions compliance obligations. With OPG's low GHG emitting fleet, these obligations are not expected to have a material financial impact on the Company.

OPG monitors actions being taken by the Government of Ontario and the Government of Canada to reduce GHG emission levels and transition to a low-carbon economy. In support of efforts to mitigate climate change, the Company continues to evaluate and implement plans to increase the generation capacity of its hydroelectric generating fleet, where economical, invest in other low-carbon technologies, and take a leadership role in the electrification of Ontario's transportation sector.

OPG has developed biodiversity management plans that identify priority natural areas, conservation goals, threats, and proposed actions to sustain biodiversity at its properties. To maximize benefits and manage impacts, initiatives include biodiversity monitoring, site naturalization, habitat creation, and control of invasive species.

OPG works with community partners to support regional ecosystems and biodiversity across Ontario. In 2017, OPG continued efforts to protect and restore habitat, promote biodiversity education and awareness, and help the recovery of species at risk. In November 2017, OPG's biodiversity program was recognized by the Canadian Electricity Association with the 2017 Sustainable Electricity award for Commitment to Continuous Performance Improvement.

OPG communicates its environmental performance internally to employees and to external stakeholders, including the Ontario Ministry of the Environment and Climate Change (MOECC), Environment and Climate Change Canada, the CNSC, and local communities. Details of OPG's environmental performance and initiatives to fulfill the Company's Environmental Policy can be found in OPG's 2016 Sustainability Report, available on the Company's website at www.opg.com.

Improving Efficiency and Reducing Costs

As part of its commitment to operational excellence, OPG remains strongly focused on reducing costs by pursuing sustainable efficiency and productivity improvements across operating business units and support functions, while ensuring that there is no adverse impact on the safety, reliability and environmental sustainability of the Company's operations. Building on significant efficiency achieved since 2011 under a more scalable, centre-led organizational model, this includes streamlining of processes, simplifying governance, upgrading technology, optimizing service delivery models, and continuing to leverage attrition to achieve human resource targets aligned with business requirements. Strategies to improve cost performance and organizational capability are being implemented at the enterprise and business unit level. These strategies are supported by continuing to embed an outcomes-driven culture that reinforces cost effectiveness, efficiency and organizational agility as part of business decision-making.

OPG is proceeding with an enterprise-wide process to evaluate the impact of the eventual shutdown of the Pickering GS on the Company's operating cost structure. This multi-year initiative, known as OPG25, involves identifying and implementing a coordinated set of plans and targets to ensure the optimization of the Company's longer-term operating model, business strategies and organizational design between now and the planned end of Pickering commercial operations. The overall aim of the initiative is to ensure ongoing cost effectiveness of the Company's operations after the eventual shutdown of the Pickering GS and to mitigate the cost impacts associated with the shutdown. Through this work and a continued focus on productivity enhancements, OPG expects to deliver increased value to customers and achieve improvement in outcomes of future applications for regulated prices under the OEB's incentive regulation framework.

In 2017, OPG also launched a strategy to accelerate the pace of digital transformation across the enterprise. The strategy is focused on making investments to modernize information technology infrastructure, enhance mobility, connectivity and field and office productivity, and improve equipment reliability and station performance through data management and data analysis. The strategy will increase operational efficiency, reduce operating costs and help to enable optimization initiatives in support of OPG25.

People and Culture

A well trained and engaged workforce is fundamental to the achievement of OPG's strategic imperatives. To succeed in a demanding business environment, OPG is focused on building a diverse, healthy, engaged workforce and fostering a culture of collaboration, accountability and innovation. OPG also continues to communicate and implement the values and behaviours expected from its employees in order to maintain a strong focus on safety, performance excellence, continuous improvement, and corporate citizenship.

The Company continues to focus on improving the capability of its workforce through leadership development, knowledge management, diversity and inclusion programs, and hiring in critical areas. Ability to secure the right talent mix in order to effectively meet the Company's immediate and longer term business needs on a timely basis is supported through workforce planning, resourcing and on-boarding strategies, both to acquire external talent into the organization and to develop existing employees. The goal of workforce planning and resourcing strategies is to ensure that the Company has a diverse workforce with the right skill set and capability for the safe and effective operation of the generating facilities and successful delivery of major projects, including the Darlington Refurbishment. These strategies take into account changes in anticipated staffing requirements leading up and subsequent to the end of planned commercial operations of the Pickering GS and the period to de-fuel, de-water and

place the station in a safe state condition after shutdown. The end of commercial operations at the Pickering GS is expected to lead to a significant reduction in OPG's workforce.

As part of the strategy to develop and engage employees and to build leadership talent in support of the Company's long-term success, OPG has an active succession planning program with a focus on accelerating development. This includes a company-wide high-potential leadership development program for qualified internal candidates. This 14-month cross-functional, competitive-entry program is designed to identify and develop candidates for future leadership positions while they are relatively early in their careers. OPG also has a talent management monitoring process to proactively assess staffing risks, challenges and opportunities.

Electricity generation involves complex technologies that require highly skilled and trained workers. Many positions at OPG have significant educational prerequisites and rigorous requirements for continuous training and periodic requalification. In addition to maintaining its internal training infrastructure, OPG relies on partnerships with government agencies, other electrical industry partners and educational institutions to meet the required level of qualification. Training delivery models are evaluated for effectiveness and efficiency.

Effective January 1, 2017, OPG implemented an Executive Compensation Program that is compliant with *Ontario Regulation 304/16: Executive Compensation Framework*, introduced in September 2016. While the Province released two subsequent amendments, *Ontario Regulation 187/17* and *Ontario Regulation 400/17* in June 2017 and November 2017, respectively, OPG's Executive Compensation Program continues to be subject to the original regulation's requirements. The regulation sets out how all employers designated under the *Broader Public Sector Executive Compensation Act, 2014*, including OPG, must establish and post compensation programs for executives. The program must include the compensation philosophy, salary and performance-related pay caps, comparative analysis details, and a description of other elements of compensation. OPG's Executive Compensation Program, which applies to employees at the Vice President level and higher, is designed to provide compensation that is at the 50th percentile of the market and focused on at-risk, performance based pay. The program will better enable OPG to attract, align and retain the executive talent critical to delivering Shareholder and customer value, while ensuring continued safe and reliable operations.

Project Excellence

OPG is pursuing a number of generation development and other major projects in support of Ontario's electricity planning initiatives. OPG also continues to plan and execute maintenance and capital improvement projects related to its existing assets. OPG strives for excellence in the planning and delivery of all projects across the Company.

OPG's vision for project excellence is to be an industry leader in project management capability and performance. As part of its commitment to project excellence, OPG continues to enhance and streamline its approach to project planning and execution, with the goal of delivering all projects safely, on time, on budget, and with high quality. Achieving project excellence at OPG involves, among other things, implementing a common, scalable project delivery model across all business units, establishing qualified project management teams, optimizing contracting strategies, engaging qualified and experienced vendors, and effectively monitoring and controlling performance.

The status updates for OPG's major projects as of December 31, 2017 are outlined below.

Project	Capital expenditures		Approved budget	Expected in-service date	Current status
(millions of dollars)	Year-to-date	Life-to-date			
Darlington Refurbishment	1,249	4,434	12,800 [1]	First unit - 2020 Last unit - 2026	All Unit 2 feeder tubes were removed safety in the fourth quarter of 2017 and the removal of fuel channel assemblies is in progress. Construction activities on the HWSF have recommenced in the fourth quarter. Planning and procurement activities for the refurbishment of Unit 3 are continuing. The overall project is tracking on schedule and on budget.
Peter Sutherland Sr. Hydroelectric GS	41	277	300	2017	The station was placed in-service on March 31, 2017, ahead of the originally planned schedule, and is expected to close below the approved budget. Project close-out activities are in progress.
Sir Adam Beck Pump GS Reservoir Refurbishment	3	49	58	2017	The refurbishment was completed and the reservoir was returned to service in February 2017, ahead of the originally planned in-service date and below the approved budget.
Ranney Falls Hydroelectric GS	25	28	77	2019	Excavation has been completed and construction is continuing in the expanded forebay, powerhouse and spillway area. Concrete placement of the new powerhouse and the spillway integrated structure is in progress. The project is tracking on schedule and on budget.
Nanticoke Solar Facility	2	3	107	2019	Significant contracts for equipment and engineering construction services have been executed, with construction planned to commence in the first quarter of 2018. **[MONITOR]**
Deep Geologic Repository (DGR) for L&ILW	9 [2]	204 [2]			On August 21, 2017, the federal Minister of Environment and Climate Change requested further information related to the project's environmental assessment (EA). OPG is working on a response to this information request.

[1] The total project budget of $12.8 billion is for the refurbishment of all four units at the Darlington GS.
[2] Expenditures are charged against the Nuclear Liabilities.

Darlington Refurbishment

The Darlington generating units are approaching their originally designed end-of-life. Refurbishment of the four generating units is expected to extend the operating life of the station by approximately 30 years. The approved budget for the four-unit refurbishment is $12.8 billion, which includes the costs of the pre-requisite projects in support of the execution phase of the refurbishment. The first refurbished unit is scheduled to be returned to service in the first quarter of 2020 and the last unit is scheduled to be completed by 2026. The project continues to track on schedule.

The Darlington Refurbishment project is a multi-phase program comprising the following five major sub-projects:

- **Retube and Feeder Replacement**, which includes the removal and replacement of fuel channel assemblies and feeder tubes in each reactor
- **Turbines and Generators**, which consists of inspections and repairs of turbine generator sets and the replacement of analog control systems with digital control systems
- **De-fuelling and Fuel Handling**, which involves the de-fuelling of the reactors and the refurbishment of the fuel handling equipment
- **Steam Generators**, which includes mechanical cleaning, water lancing, and inspection and maintenance work on the generators
- **Balance of Plant**, which consists of work on smaller projects to replace or repair certain other station components.

In 2016, the Darlington Refurbishment project transitioned from the planning phase to the execution phase, as OPG commenced the refurbishment of the first unit, Unit 2, in October 2016 as planned. The unit was taken offline on October 15, 2016. De-fuelling of the reactor was completed in January 2017, with a total of 480 fuel channels de-fuelled. Islanding of Unit 2, the physical separation of the unit under refurbishment from the three operating units, was completed in April 2017, signifying the completion of the first major segment of the project.

The second major segment includes preparatory work to support the removal of feeder tubes and fuel channel assemblies, followed by the removal of reactor components. The preparatory work was completed in the second quarter of 2017. The Re-tube Tooling Platform for hosting the tooling for the removal, inspection and installation activities, and the setup of specialized tooling and equipment needed for the removal and replacement of the reactor components were completed in the third quarter of 2017. The disassembly of reactor components commenced in August 2017, with the removal of all 960 feeder tubes completed safely in September 2017. The removal of fuel channel assemblies commenced in October 2017. As part of the fuel channel assemblies, the removal of pressure tubes is in progress and will be followed by the removal of calandria tubes. The second major segment and the removal of all reactor components is expected to be completed by mid-2018. Key projects in the second major segment finished in 2018 include the completion of the primary side steam generator layup and installation of steam generator access ports to support future inspections. Other key project activities being executed during the second segment include the continuation of the major turbine generator overhaul, which will be completed in the second quarter of 2018, and continued execution of the major electrical scope. OPG is also continuing to execute work to support the requirements set out in the CNSC-approved Integrated Implementation Plan for the station.

Most of the pre-requisite projects, including construction of facilities, infrastructure upgrades and installation of safety enhancements, have been completed and placed in-service. The Re-tube Waste Processing Building was completed in November 2017. Completion of the HWSF has been delayed due to challenges with construction. OPG suspended the project in the second quarter of 2017 to evaluate the best approach to optimize cost and schedule and complete the project. Construction to complete the facility recommenced in the fourth quarter of 2017. The HWSF is expected to be completed by the second quarter of 2019 and is not on the critical path for the Darlington Refurbishment project, which continues to track on schedule. The increase in the cost estimate for the HWSF will be accommodated within the overall Darlington Refurbishment budget of $12.8 billion. Taking into account the execution performance of the Unit 2 refurbishment, the overall Darlington Refurbishment project continues to track on budget.

In addition to the execution of refurbishment activities on Unit 2, OPG is continuing planning activities for the refurbishment of the second unit, Unit 3, and is entering into associated commitments to procure major components that require long lead times. As of December 31, 2017, $93 million has been invested in planning activities related to the refurbishment of the second unit, Unit 3. These planning activities are being undertaken in accordance with the refurbishment project schedule. In February 2018, the Province confirmed its commitment to proceed with Darlington's Unit 3 refurbishment in 2020. **[MONITOR]**

Peter Sutherland Sr. Hydroelectric GS

In March 2017, the project to construct the 28 MW two-unit Peter Sutherland Sr. hydroelectric GS successfully completed final testing and commissioning of the turbine and generator units, and both units were declared substantially complete. On March 31, 2017, the project received a permit from the MOECC to take water for operations to allow the station to operate commercially. This in-service date was well ahead of the originally planned schedule of the first half of 2018. The project's schedule was accelerated to take advantage of favourable weather conditions. The project is expected to close below the approved budget of $300 million. Project close-out activities are in progress. OPG began to receive contracted revenue for the project following the IESO's confirmation of the station's commercial operations as of March 31, 2017, under a hydroelectric ESA.

Under the partnership agreement, as the unit is placed in-service, the CRP, a corporation wholly owned by the Taykwa Tagamou Nation, may acquire up to a 33 percent partnership interest through its investment in PSS. In April 2017, the CRP acquired a 33 percent interest in PSS.

Sir Adam Beck Pump GS Reservoir Refurbishment

The Sir Adam Beck Pump GS refurbishment construction began in April 2016 and the 300-hectare reservoir was returned to service in February 2017 upon completion of the reservoir commissioning program. The Sir Adam Beck Pump GS facility allows OPG to pump and store water diverted from the Sir Adam Beck generating complex during periods of low electricity demand, to be used to generate up to 600 MW of electricity during subsequent periods of high electricity demand. The work on the project included installation of a new partial liner and construction of a grout curtain in the bedrock foundation of the reservoir dyke. The refurbishment is expected to add approximately 50 more years to the reservoir's life. The project was completed ahead of the originally planned in-service date of April 2017 and below the approved budget of $58 million. The Sir Adam Beck Pump GS is reported in the Regulated – Hydroelectric segment.

Ranney Falls Hydroelectric GS

In 2017, OPG began construction work on a 10 MW single-unit powerhouse on the existing Ranney Falls GS site, as part of the Regulated – Hydroelectric segment. The new unit will replace an existing unit that reached its end of life in 2014. The existing forebay structure has been demolished and the new concrete structure has been completed. Excavation has been completed and construction continues in the expanded forebay, powerhouse and spillway area. The new forebay concrete wall has been completed, and concrete placement of the new powerhouse and the spillway integrated structure is in progress. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget.

Nanticoke Solar Facility

The construction of a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands under a Large Renewable Procurement contract with the IESO, through Nanticoke Solar LP, a partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation, is planned to commence in the first quarter of 2018. During 2017, the partnership continued work to obtain approvals and permits required to enable the commencement of construction. Significant contracts for equipment and engineering construction services were executed in the first quarter of 2018. The facility is expected to be completed in the first quarter of 2019, with a budget of $107 million. **[MONITOR]**

Deep Geologic Repository for Low and Intermediate Level Waste

OPG has proposed a deep geologic repository as the preferred solution for the safe long-term management of the L&ILW produced from the continued operation of OPG-owned nuclear generating stations. Agreement has been reached with local municipalities for OPG to develop the L&ILW DGR on lands adjacent to the WWMF in Kincardine, Ontario. The environmental effects of the proposed L&ILW DGR were examined by the CNSC and Canadian Environmental Assessment Agency (CEAA)-appointed Joint Review Panel (JRP) to meet the requirements of the *Canadian Environmental Assessment Act*. The JRP submitted its report on the EA to the federal Minister of Environment in May 2015, concluding that, given mitigation, there is unlikely to be significant environmental impact from the project and recommending that the Minister approve the EA. In December 2016, at the request of the federal Minister of Environment and Climate Change, OPG submitted additional information on certain aspects of the EA, including information related to alternate locations for the project. Following its review of OPG's submission and a period of public comment, the CEAA requested further information that OPG subsequently provided in May 2017. In June 2017, the CEAA notified OPG that it had sufficient and adequate information to proceed with the next step of the environmental assessment process and advised that a draft report and updated terms and conditions would be prepared for public review.

On August 21, 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of potential cumulative effects of the project on the Saugeen Ojibway Nation's (SON) physical and cultural heritage, including a description of the potential effects of the project on the Nation's spiritual and cultural connection to the land, taking into account the results of the SON Community Process. OPG is working closely with the SON to formulate a response to the information request.

The L&ILW DGR at the WWMF site remains OPG's preferred solution for the safe long-term management of the L&ILW. The in-service date of the L&ILW DGR is expected to be approximately six to seven years from the start of construction.

Financial Strength

As a commercial enterprise, OPG's financial priority is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future expansion. Inherent in this priority are four objectives:

- Increasing revenue, reducing costs and achieving appropriate return
- Ensuring availability of cost effective funding for operational needs, generation development projects and other business opportunities, and long-term obligations
- Pursuing opportunities to expand the existing core business and capitalize on new growth paths
- Managing risks, which is discussed in the section, *Risk Management*.

Increasing Revenue, Reducing Costs and Achieving Appropriate Return

In line with its commercial mandate, OPG is focused on increasing revenue and net income and achieving an appropriate rate of return on the Shareholder's investment, while taking into account the impact on Ontario electricity customers by seeking further efficiencies in the Company's cost structure.

For the regulated operations, achievement of the above objectives is largely dependent on outcomes of rate applications to the OEB and growth of the asset base earning a return as part of the regulated prices.

With respect to rate application outcomes, OPG has been focused on demonstrating in its rate applications that the costs required to operate and invest in the assets are reasonable and being prudently incurred, and should be fully recovered, and that the Shareholder's investment in these assets should earn an appropriate rate of return. While the OEB's decision on OPG's 2017-2021 application for new regulated prices reduced OPG's forecasted costs used to set new regulated prices, the decision will result in a substantial increase in revenue and net income compared to

existing regulated prices. The existing base regulated prices were set in 2014 to allow the Company to recover its approved nuclear costs over a higher nuclear production volume, based on the 2014 and 2015 outage profile that did not include a Darlington refurbishment outage.

The OEB's decision to reduce recovery of OPG's forecasted cost levels, including through the use of stretch factors under an incentive rate-making model, will negatively impact OPG's ability to earn an appropriate return on the Shareholder's investment in the regulated assets. To improve the financial strength of the regulated operations, OPG will continue to focus on optimizing operational performance and outage plans across the generating fleet and on pursuing further efficiency improvements in the Company's cost structure and operating model. OPG's cost and productivity improvement strategies are discussed further in the section, *Core Business, Strategy and Outlook* under the heading, *Operational Excellence – Improving Efficiency and Reducing Costs*.

OPG continues to invest in the regulated asset base, with the Darlington Refurbishment project being the single largest such capital investment. In its decision on OPG's 2017-2021 application for new regulated prices, the OEB has allowed inclusion of a total of $5.5 billion in Darlington Refurbishment in-service capital additions by 2021, including pre-requisite projects other than HWSF and including in-service amounts upon planned return to service of Unit 2 in the first quarter of 2020. Once in-service, these assets will attract a return on equity of approximately 8.8 percent during the 2017-2021 period set by the OEB, based on a deemed capital structure of 45 percent equity and 51 percent debt. The average OEB-approved cost of deemed debt for the 2017-2021 period is approximately 4.6 percent. OPG also continues to pursue an extensive capital program across its regulated hydroelectric operations that includes expansion, redevelopment and life extension of the generating facilities, where economic. These renewable assets have long service lives and, with either maintenance efforts or rebuilding, will continue to supply electricity for the foreseeable future. The OEB's decision on OPG's application for new regulated prices is discussed further in the section, *Highlights* under the heading, *Recent Developments*.

For generation assets that do not form part of the assets regulated by the OEB, OPG's strategy has been to secure appropriate long-term revenue arrangements. In line with this strategy, virtually all of OPG's non-regulated operating facilities and assets under construction are subject to long-term ESAs or other long-term contracts with the IESO. This includes the Peter Sutherland Sr. GS, which was placed in service and began receiving contracted revenue under a hydroelectric ESA as of March 31, 2017. The Peter Sutherland Sr. GS ESA expires in 2067.

OPG's capital structure currently reflects lower levels of debt than the deemed capital structure reflected in the Company's existing regulated prices and maintained by the OEB's December 2017 decision on new regulated prices. OPG continues to evaluate strategies to enhance Shareholder returns by optimizing the Company's capital structure through better alignment with the deemed capital structure, taking into account the overall financial strength of the Company and the potential impact on the Company's investment grade credit rating.

Ensuring Availability of Cost Effective Funding

OPG actively monitors its funding requirements and forecasts availability of funds to ensure that it can meet the Company's operational needs, project commitments and long-term obligations. OPG utilizes multiple sources of funds, including funds generated from operations, commercial paper, securitization of assets, letters of credit, credit facilities, long-term corporate debt (sourced from both the OEFC and public debt offerings), credit facilities with the OEFC, private placement project financing, and equity issuance. The Company's financing strategy leverages the strength of its balance sheet to obtain cost effective long-term corporate debt. OPG also accesses the capital markets for private placement project financing, secured by the assets of the project, where the characteristics of the project support such financing. Maintaining an investment grade credit rating is critical to OPG's ability to access cost effective financing.

In April 2017, DBRS Limited (DBRS) re-affirmed the long-term credit rating on OPG's debt at 'A (low)' and OPG's commercial paper rating at 'R-1 (low)'. All ratings from DBRS have a stable outlook. In July 2017, S&P Global

Ratings (S&P) re-affirmed OPG's long-term credit rating at 'BBB+' with a stable outlook. S&P's commercial paper rating for OPG is 'A-1 (low)'.

OPG intends to continue to access the capital markets, where appropriate, to obtain cost effective financing for future generation development projects. The Company continues to evaluate arrangements that would appropriately support its financing needs, its capital expenditure programs, its financing of OPG's subordinated debt investment in the Trust, and the Trust's acquisition of Investment Interest from the IESO. OPG's liquidity and capital resources are discussed in the section, Liquidity and Capital Resources.

Building Our Business

Through pursuit of commercial-based opportunities to expand its business, OPG strives to be a leader in the North American transition toward a low carbon future while maintaining and expanding the Company's scale and energy industry leadership. This strategy considers the Company's financial position and anticipated future changes in the generating fleet, including the eventual end of Pickering commercial operations. The strategy is also informed by industry, technological, environmental, social, and economic external factors. Opportunities are evaluated using financial and risk-based analyses as well as strategic considerations.

Currently, OPG's strategy primarily focuses on the renewal and expansion of the Company's portfolio of generating assets in Ontario, including the redevelopment and expansion of existing sites and potential new developments. The strategy leverages OPG's operating and project development expertise as well as the Company's existing diverse physical asset base. Acquisition opportunities are considered as they arise, taking into account operating synergies, strategic benefits, financial returns and risk profile. OPG's current major generation development projects and asset life extension initiatives are discussed in the section, *Core Business, Strategy, and Outlook* under the headings, *Operational Excellence* and *Project Excellence*.

OPG also actively seeks to expand beyond its core generation business through investments in innovation and emergent low-carbon technologies, including selective solar generation, nuclear innovation, energy storage, distributed generation, electric vehicle infrastructure and other development. Additionally, OPG continues to consider potential paths to extend its business through broader electricity sector opportunities, within and outside Ontario. Business expansions opportunities may be pursued in partnership with other commercial entities where appropriate synergies exist and are aligned with OPG's business objectives.

Social Licence

As the largest electricity generator in Ontario with diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust. OPG is committed to maintaining high standards of public safety and corporate citizenship, including environmental stewardship, transparency, community engagement, and Indigenous relations. OPG works to maintain public trust with stakeholders by engaging site communities, sharing information, and being transparent about performance. In addition, OPG's operations are subject to extensive regulatory oversight, with public participation, by the CNSC, the OEB, and other bodies. OPG's commitment to safety is discussed in the section, *Core Business, Strategy, and Outlook* under the heading, *Workplace and Public Safety*.

OPG is focused on building long-term, mutually beneficial working relationships with Indigenous communities, businesses and organizations across Ontario, and continues to support procurement, employment and educational opportunities with its Indigenous community partners. The Company seeks to establish these relationships based on a foundation of respect for the languages, customs, and political, social and cultural organizations of the Indigenous communities.

OPG's commitment in this area includes pursuing generation-related development partnerships on the basis of long-term commercial arrangements, such as the construction of the Peter Sutherland Sr. GS in partnership with Taykwa Tagamou Nation and the development of the Nanticoke solar facility in partnership with the Six Nations of the Grand

River. During 2017, OPG also continued to engage with Indigenous communities regarding the Company's nuclear waste management operations, through regularly scheduled meetings and ongoing dialogue in connection with OPG's proposed L&ILW DGR, the re-licensing of the PWMF and the WWMF, and the Pickering GS re-licensing. Engagement was also conducted with First Nations in southwestern Ontario regarding the demolition of the Lambton and Nanticoke generating stations and with the Mississaugas of New Credit regarding the Shareholder-directed sale of the former Lakeview GS site.

OPG is also committed to improving Indigenous access to procurement and employment opportunities, including increasing the profile of the nuclear generation industry in Indigenous communities. In 2017, OPG launched an Indigenous Business Engagement (IBE) Initiative. The purpose of this initiative is to increase access to procurement opportunities for Indigenous businesses interested in supplying materials and services to OPG. The IBE Initiative is based on a strategy that will identify opportunities in contracts, scopes of work and business plans for potential Indigenous business engagement; include criteria related to suppliers' ability to engage or partner with Indigenous people or businesses in assessing procurement proposals; and invest in relationships with Indigenous communities by increasing outreach efforts to enhance understanding of how to do business with OPG. OPG has been engaging with Indigenous businesses and communities as well as its suppliers to promote the IBE Initiative, including the Mohawk Council of Akwesasne as well as the Williams Treaties First Nations, located proximate to the Pickering and Darlington nuclear generating stations.

OPG has been actively developing recruitment plans targeting Indigenous peoples. As part of this initiative, during the fourth quarter of 2017, OPG participated in several Indigenous-specific career fairs, hosted a Day in the Trades event for Indigenous students and job seekers as part of an open house at the Darlington Energy Centre, and approved plans aimed at increasing the number of Indigenous apprentices as part of the nuclear operations' recruitment program.

OPG also contributes to the well-being of its host communities through the Company's Corporate Citizenship Program (CCP), which supports charitable and non-profit grassroots initiatives in the areas of environment, education, and community involvement, including support for Indigenous initiatives. In 2017, OPG's CCP provided support to over 800 initiatives, of which 84 were Indigenous.

OPG has a strategy to help position the Company as a leader in transportation electrification in the province. The strategy aims to leverage the Company's clean, reliable and cost-effective electricity to power transportation, capitalize on future commercial growth opportunities, and enhance the Company's social licence. OPG is pursuing initiatives to increase the use of electric vehicles within its operations, and is assessing vehicle grid integration and hydrogen applications for the transportation sector. Ontario's climate change plan aims for electric and hydrogen passenger vehicles to represent five percent of new vehicle sales in the province by 2020.

As part of its commitment to help de-carbonize Ontario's transportation sector, OPG is a founding sponsor of Plug'n Drive, a non-profit organization working to accelerate the adoption of electric vehicles and to maximize their environmental and economic benefits. In May 2017, Plug'n Drive announced the opening of the world's first experiential learning facility dedicated to electric vehicle education and awareness, with OPG sponsoring the Centre's training facility.

Further details regarding OPG's commitment to sustainable development, including information regarding the Company's environmental and social performance and initiatives, are provided in OPG's 2016 Sustainability Report available on the Company's website at www.opg.com.

Outlook

The financial performance of OPG's regulated operations is driven, in large part, by the outcome of applications for regulated prices to the OEB. Subject to the OEB's issuance of the final payment amounts order expected in the first half of 2018, the OEB's December 2017 decision on OPG's application for new regulated prices provides substantial

price certainty for the regulated business for the 2017 to 2021 period. During this period, OPG will continue to focus on optimizing operational performance and outage plans across the generating fleet and on pursuing further efficiency improvements in the Company's cost structure and operating model.

The OEB's decision established June 1, 2017 as the effective date of the new regulated prices, which negatively affected OPG's net income and ROE Excluding AOCI in 2017 relative to OPG's requested effective date of January 1, 2017. The full-year effect of new regulated prices in 2018 is expected to contribute to an improvement in net income and ROE Excluding AOCI over the 2017 results.

Subject to the OEB's final determination on nuclear rate smoothing as part of the payment amounts order process, OPG expects an improvement in cash flow from operating activities in 2018, compared to 2017. This will reflect OPG beginning to receive revenue from the IESO based on new regulated prices following the OEB's implementation of these prices, expected in the first half of 2018. Additionally, the Fair Hydro Trust segment will begin to contribute positive cash flow from operating activities in 2018. OPG expects to continue to have the necessary financial capacity and sufficient access to cost effective financing sources to continue to fund its capital requirements and other disbursements, including the financing of the Fair Hydro Trust.

Several OEB-authorized regulatory variance and deferral accounts currently in place contribute to reducing the relative variability of the Company's net income and ROE Excluding AOCI. Among others, the regulatory accounts include those related to the revenue impact of variability in water flows and forgone production due to SBG conditions at the regulated hydroelectric stations. As there are no variance or deferral accounts in place related to the impact of generation performance of the nuclear stations on revenue from base regulated prices, the Regulated – Hydroelectric segment generally is expected to produce overall more predictable earnings. OPG continues to operate and maintain its nuclear facilities with a view to optimize their performance and availability, while focusing on improving the overall reliability and predictability of the fleet.

Electricity generated from most of OPG's non-regulated assets is subject to ESAs or other long-term contracts with the IESO. Based on these agreements, OPG expects the Contracted Generation Portfolio segment to continue to contribute a generally stable level of earnings and cash flow from operating activities going forward.

Lower nuclear generation due to the Darlington Refurbishment outages will continue, as planned, to negatively impact the Enterprise TGC and Nuclear TGC metrics for the duration of the refurbishment project. Lower hydroelectric generation due to outages related to various refurbishment and operational projects may negatively impact Enterprise TGC and Hydroelectric TGC for the duration of these projects. Variability in sustaining capital investment expenditures and nuclear outage profile may also impact TGC metrics in future periods.

OPG's total forecast capital expenditures for the 2018 year are approximately $2.1 billion. **[CONFIRM]** This includes amounts for the Darlington Refurbishment project, hydroelectric and other development projects including the Ranney Falls GS redevelopment and construction of the Nanticoke solar facility, and sustaining capital investments across the generating fleet. OPG's major projects are discussed in the section, *Project Excellence*.

In addition to the operating and financial performance of the electricity generation business, OPG's results are affected by the earnings on the Nuclear Segregated Funds, which are reported in the Regulated – Nuclear Waste Management segment. While the Nuclear Segregated Funds are managed to achieve, in the long term, the target rate of return based on the discount rate specified in the ONFA, the rates of return earned in a given period can be subject to various external factors including financial market conditions and, for the portion of the Used Fuel Segregated Fund guaranteed by the Province under the ONFA, changes in the Ontario consumer price index (CPI). In the near term, these factors can be volatile and cause fluctuations in the Company's income. This volatility is partially mitigated by the impact of the OEB-authorized Bruce Lease Net Revenues Variance Account and the funded status of the two segregated funds, discussed below.

As OPG does not have the right to withdraw surplus amounts from the Nuclear Segregated Funds, OPG limits the amount of Nuclear Segregated Funds assets reported on the balance sheet to the present value of the underlying life cycle funding liabilities per the most recently approved ONFA Reference Plan. This reduces the volatility of earnings on the Nuclear Segregated Funds reflected in net income when the funds are in a fully funded or overfunded position. As at December 31, 2017, the Decommissioning Segregated Fund was overfunded by approximately 27 percent, and the Used Fuel Segregated Fund was marginally overfunded, by less than one percent, based on the 2017 ONFA Reference Plan. Variability in asset performance due to volatility inherent in financial markets and changes in Ontario CPI, or changes in funding liability estimates, may result in either or both funds becoming underfunded in the future.

OPG's results are also affected by the earnings from the Fair Hydro Trust segment. Management expects an increase in 2018 earnings from the segment, primarily related to interest income from OPG's investment in subordinated debt of the Trust. OPG's involvement with the Fair Hydro Plan over time is expected to put downward pressure on ROE Excluding AOCI as a result of increases in shareholder's equity through future issuances of Class A common shares to partially fund OPG's subordinated debt investment in the Trust.

KEY OPERATING AND FINANCIAL PERFORMANCE INDICATORS

OPG evaluates the performance of its generating stations using a number of key indicators. Key operating performance indicators aligned with corporate strategic imperatives are measures of production reliability, cost effectiveness, environmental performance, and safety performance. Certain of the measures used vary depending on the generating technology.

Enterprise TGC, Nuclear TGC, Hydroelectric TGC, ROE Excluding AOCI, and FFO Adjusted Interest Coverage ratio discussed below are not measurements in accordance with US GAAP. They should not be considered as alternative measures to net income or any other measure of performance under US GAAP. However, OPG believes that these non-GAAP financial measures are effective indicators of its performance and are consistent with the Company's strategic imperatives and related objectives. The definition and calculation of Enterprise TGC per MWh, Nuclear TGC per MWh, Hydroelectric TGC per MWh, ROE Excluding AOCI, and FFO Adjusted Interest Coverage are found in the section, *Supplementary Non-GAAP Financial Measures*.

Enterprise Total Generating Cost per Megawatt-Hour

Enterprise TGC per MWh is used to measure OPG's overall organizational cost performance. Enterprise TGC per MWh is defined as OM&A expenses (excluding the Darlington Refurbishment project and other generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to OPG's electricity generation business), fuel expense for OPG-operated stations including hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures (excluding the Darlington Refurbishment project and other generation development projects) incurred during the period, divided by total electricity generation from OPG-operated generating stations plus electricity generation forgone due to SBG conditions during the period.

Nuclear Total Generating Cost per Megawatt-Hour

Nuclear TGC per MWh is used to measure the cost performance of OPG's nuclear generating assets. Nuclear TGC per MWh is defined as OM&A expenses of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to OPG's nuclear electricity generation business), nuclear fuel expense for OPG-operated stations (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs) incurred during the period, divided by nuclear electricity generation for the period.

Hydroelectric Total Generating Cost per Megawatt-Hour

Hydroelectric TGC per MWh is used to measure the cost performance of OPG's hydroelectric generating assets. Hydroelectric TGC per MWh is defined as OM&A expenses of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segments (excluding generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the hydroelectric electricity generation business), hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding expenditures related to the Peter Sutherland Sr. GS, Ranney Falls GS, and other hydroelectric generation development projects) incurred during the period, divided by total hydroelectric electricity generation plus hydroelectric electricity generation forgone due to SBG conditions during the period. OPG reports hydroelectric gross revenue charge and water rental payments as fuel expense.

Nuclear Unit Capability Factor

OPG's nuclear stations are baseload facilities that are not designed for fluctuating production levels to meet peaking demand. The nuclear Unit Capability Factor is a key measure of nuclear station performance. It measures the amount of energy that the unit(s) generated over a period of time, adjusted for externally imposed constraints such as transmission or demand limitations, as a percentage of the amount of energy that would have been produced over the same period had the unit(s) produced maximum generation. Capability factors are primarily affected by planned and unplanned outages. By industry definition, capability factors exclude production losses beyond plant management's control, such as grid-related unavailability. The nuclear Unit Capability Factor also excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS is excluded from the measure effective October 15, 2016, when the unit was taken offline as part of the Darlington Refurbishment project.

Hydroelectric Availability

OPG's hydroelectric stations operate as baseload, intermediate, or peaking stations. Hydroelectric Availability represents the percentage of time the generating unit is capable of providing service, whether or not it is actually generating electricity, compared to the total time for the respective period.

Thermal Equivalent Forced Outage Rate

Equivalent Forced Outage Rate (EFOR) is an index of the reliability of a generating unit at OPG's thermal stations. It is measured by the ratio of time a generating unit is forced out of service by unplanned events, including any forced deratings, compared to the amount of time the generating unit was available to operate.

Return on Common Equity Excluding Accumulated Other Comprehensive Income

ROE Excluding AOCI is an indicator of OPG's performance consistent with its objective to deliver value to the Shareholder. ROE Excluding AOCI is defined as net income attributable to the Shareholder for the period divided by average equity attributable to the Shareholder excluding AOCI for that period, and is measured over a period of 12 months.

Funds from Operations Adjusted Interest Coverage

The FFO Adjusted Interest Coverage ratio is an indicator of OPG's ability to meet interest obligations from operating cash flow and is consistent with the Company's objective of ensuring availability of cost effective funding. The FFO Adjusted Interest Coverage ratio is defined as FFO before interest divided by adjusted interest expense, and is measured over a period of 12 months.

Other Key Indicators

In addition to production reliability, cost effectiveness, and financial performance indicators, OPG has identified certain environmental and safety performance measures. These measures are discussed in the section, *Core Business, Strategy, and Outlook*.

BUSINESS SEGMENTS

Effective in the fourth quarter of 2017, OPG has the following six reportable business segments:

- Regulated – Nuclear Generation
- Regulated – Nuclear Waste Management
- Regulated – Hydroelectric
- Contracted Generation Portfolio
- Services, Trading, and Other Non-Generation
- Fair Hydro Trust.

Regulated – Nuclear Generation Segment

The Regulated – Nuclear Generation business segment operates in Ontario, generating and selling electricity from the Pickering GS and the Darlington GS, both owned and operated by OPG. The business segment also includes revenue under the terms of a long-term lease arrangement and related agreements with Bruce Power related to the Bruce nuclear generating stations. This revenue includes lease revenue, fees for nuclear waste management, and revenue from heavy water sales and detritiation services. The segment also earns revenue from isotope sales and ancillary services supplied by OPG from the nuclear stations it operates. Ancillary revenues are earned through voltage control and reactive support. Revenues under the agreements with Bruce Power, including a portion of heavy water sales, and from existing isotope sales contracts and ancillary services are included by the OEB in the determination of the regulated prices for production from OPG's nuclear facilities, which has the effect of reducing these prices.

Regulated – Nuclear Waste Management Segment

OPG's Regulated – Nuclear Waste Management segment reports the results of the Company's operations associated with the management of nuclear used fuel and L&ILW, the decommissioning of OPG's nuclear generating stations including the stations on lease to Bruce Power and other facilities, the management of the Nuclear Segregated Funds, and related activities including the inspection and maintenance of the waste storage facilities. Accordingly, accretion expense, which is the increase in the Nuclear Liabilities carried on the consolidated balance sheets in present value terms due to the passage of time, and earnings from the Nuclear Segregated Funds are reported under this segment.

As the nuclear generating stations operate over time, OPG incurs incremental costs related to used nuclear fuel and L&ILW, which increase the Nuclear Liabilities. OPG charges these incremental costs to current operations in the Regulated – Nuclear Generation segment to reflect the cost of producing energy from the Pickering and Darlington nuclear generating stations and earning revenue under the Bruce Power lease arrangement and related agreements. Since the incremental costs increase the Nuclear Liabilities reported in the Regulated – Nuclear Waste Management segment, OPG records an inter-segment charge between the Regulated – Nuclear Generation and the Regulated – Nuclear Waste Management segments. The impact of the inter-segment charge is eliminated in the consolidated statements of income and balance sheets.

The Regulated – Nuclear Waste Management segment is considered rate regulated because OPG's costs associated with the Nuclear Liabilities are included in the OEB's determination of regulated prices for production from the Pickering and Darlington nuclear generating stations.

Regulated – Hydroelectric Segment

OPG's Regulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from most of the Company's hydroelectric generating stations. The business segment comprises the results of 54 hydroelectric generation stations across a number of major river systems in the province.

In addition, the business segment includes ancillary and other revenues from OPG's regulated hydroelectric stations. Ancillary revenues are earned through offering available generating capacity as operating reserve and through the supply of other ancillary services including voltage control and reactive support, certified black start facilities, regulation service, and other services. These ancillary revenues and other revenues are included by the OEB in the determination of the regulated prices for production from OPG's prescribed hydroelectric facilities, which has the effect of reducing these prices.

Contracted Generation Portfolio Segment

The Contracted Generation Portfolio business segment operates in Ontario, generating and selling electricity from the Company's generating stations that are not prescribed for rate regulation. The segment primarily includes generating facilities that are under an ESA with the IESO or other long-term contracts.

The Contracted Generation Portfolio segment also includes OPG's share of equity income from its 50 percent ownership interests in the PEC and Brighton Beach stations. Brighton Beach operates under an energy conversion agreement between Brighton Beach and Shell Energy North America (Canada) Inc., and the PEC station is operated under the terms of an Accelerated Clean Energy Supply contract with the IESO. OPG's share of the in-service generating capacity and generation volume from its interests in the PEC and Brighton Beach stations are reported in this segment.

The business segment also includes ancillary revenues and other revenues from the stations included in the segment, which are earned through offering available generating capacity as operating reserve, and the supply of other ancillary services including voltage control and reactive support, certified black start facilities, regulation service, and other services.

Services, Trading, and Other Non-Generation Segment

The Services, Trading, and Other Non-Generation segment is a non-generation segment that is not subject to rate regulation. It includes the revenue and expenses related to OPG's trading and other non-hedging activities. As part of trading activities, OPG transacts with counterparties in Ontario and neighbouring energy markets in predominantly short-term trading activities of typically one year or less in duration. These activities relate to electricity that is purchased and sold at the Ontario border, financial energy trades, financial risk management energy product revenues, and sales of energy-related products. In addition, OPG has a wholly owned trading subsidiary that transacts solely in the United States (US) market. The results of this subsidiary are reported in this segment. All contracts that are not designated as hedges are recorded as assets or liabilities at fair value on the consolidated balance sheets, with changes in fair value recorded in the revenue of this segment.

In addition, the segment includes revenue from real estate rentals and non-regulated services, gains or losses on disposition of non-regulated real estate assets, costs associated with non-regulated business development activities, and costs related to the Lambton GS and Nanticoke GS sites.

Fair Hydro Trust Segment

The Fair Hydro Trust segment is a non-generation segment that is not subject to rate regulation. It includes OPG's earnings from the Fair Hydro Trust, which includes the financial results of the Trust, as well as income related to OPG's role as Financial Services Manager of the Fair Hydro Trust and holder of subordinated debt issued by the Trust. Earnings include interest income from OPG's investment in subordinated debt of the Trust of up to 49 percent of the Trust's total outstanding debt, recovery of third-party costs and fees for financial management and ongoing administration services, partially offset by interest costs on debt issued by OPG to fund five percent of the subordinated investment in the Trust, incurred third-party costs, and other incurred costs related to the management and administration of the Trust.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

Regulated – Nuclear Generation Segment

(millions of dollars)	**2017**	**2016**
Revenue	**3,095**	3,481
Fuel expense	**284**	315
Gross margin	**2,811**	3,166
Operations, maintenance and administration	**2,293**	2,210
Depreciation and amortization	**431**	925
Property taxes	**26**	26
Income before other losses, interest, and income taxes	**61**	5
Other gains	**4**	1
Income before interest and income taxes	**57**	4

Income before interest and income taxes from the segment increased by $53 million in 2017, compared to 2016. Segment earnings were favourably affected by the OEB's decision on OPG's application for new regulated prices issued in December 2017 with a retrospective effective date of June 1, 2017. The revenue increase of approximately $465 million in relation to the June 1, 2017 to December 31, 2017 period resulting from the OEB's decision was recorded as an increase in net regulatory assets in the fourth quarter of 2017. This revenue increase was based on new regulated prices for that period proposed in OPG's January 2018 submission to the OEB based on the findings in the decision and is net of a regulatory liability recognized in relation to OPG's nuclear rate smoothing proposal in that submission.

Segment earnings were unfavourably affected by a reduction in electricity generation of 4.9 TWh in 2017, compared to 2016. This reduced revenue by approximately $285 million, partially offset by a decrease in fuel expense. The lower electricity generation was primarily due to the ongoing Unit 2 refurbishment outage at the Darlington GS that began in October 2016, partially offset by the higher electricity generation from the Pickering GS. The income impact of OEB-approved regulatory accounts also contributed to the decrease in income for the year.

The increase in OM&A expenses of $83 million in 2017, compared to 2016, reflected planned expenditures related to the major maintenance activities and higher project expenditures occurring at the nuclear stations. Depreciation and amortization expenses, excluding amortization expense related to regulatory account balances, increased by $22 million primarily due to new assets in service in 2017.

The expiry of a nuclear rate rider for the recovery of OEB-approved balances in regulatory accounts on December 31, 2016 contributed to the decrease in segment revenue in 2017, compared to 2016, but was largely offset by a decrease in amortization expense related to these balances.

The Unit Capability Factors for the Darlington GS and Pickering GS for 2017 and 2016 were as follows:

	2017	2016
Unit Capability Factor *(%)* [1]		
Darlington GS	**85.2**	89.5
Pickering GS	**80.0**	75.2

[1] The nuclear Unit Capability Factor excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS was excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

The lower Unit Capability Factor at the Darlington GS in 2017, compared to 2016, reflected the higher number of planned outage days in 2017, largely driven by constraints related to the transition of the station's operating units toward refurbishment.

The increase in the Unit Capability Factor at the Pickering GS in 2017, compared to 2016, was primarily due to outage cycle optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station compared to 2016.

The definition of the nuclear Unit Capability Factor is found in the section, *Key Operating and Financial Performance Indicators.*

Regulated – Nuclear Waste Management Segment

(millions of dollars)	2017	2016
Revenue	**121**	138
Operations, maintenance and administration	**129**	146
Accretion on nuclear fixed asset removal and nuclear waste management liabilities	**943**	912
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(801)**	(746)
Loss before interest and income taxes	**(150)**	(174)

Earnings from the segment improved by $24 million in 2017 compared to 2016. The improvement was primarily due to higher earnings from the Nuclear Segregated Funds, partially offset by an increase in accretion expense on the Nuclear Liabilities. Accretion expense represents a financing cost due to the increase in the present value of the underlying liabilities with the passage of time.

The year-over-year increase in the earnings from the funds was primarily due to a reduction in the earnings recorded in the fourth quarter of 2016 to reflect an accounting adjustment to limit Nuclear Segregated Funds assets reported on the consolidated balance sheet to the underlying funding liabilities based on an updated ONFA reference plan approved by the Province. The updated ONFA reference plan resulted in a reduction in the funding liabilities. As both the Decommissioning Segregated Fund and the Used Fuel Fund have been in an overfunded position since the beginning of 2017, the earnings on the funds recognized in net income during the year reflected the growth rate in the present value of the funding liabilities and were not impacted by market returns and the rate of return guaranteed by the Province for the portion of the Used Fuel Segregated Fund. Further details on the accounting for the Nuclear Segregated Funds can be found in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

The year-over-year increase in accretion on nuclear fixed removal and nuclear waste management liabilities in 2017, compared to 2016, was primarily due to the impact on accretion expense related to the increase in asset retirement obligation associated with the life extension of the Bruce nuclear assets from the agreement executed between Bruce Power and the Province in late 2015. This increase was offset in 2016 due to the Bruce Lease Net Revenues Variance Account but is reflected in accretion with the resetting of base rates in 2017. This increase was partially

offset by the impact of the decrease in Nuclear Liabilities to reflect an updated estimate as part of the ONFA reference plan update process.

As of December 31, 2016, OPG recorded a decrease of approximately $1,570 million to the Nuclear Liabilities and associated asset retirement costs capitalized as part of the carrying value of the nuclear generating stations to reflect an updated estimate of OPG's obligations for nuclear waste management and nuclear facilities decommissioning determined as part of the ONFA reference plan update process. The resulting year-over-year decreases in accretion expense recorded in the Regulated – Nuclear Waste Management segment and depreciation and fuel expenses recorded in the Regulated – Nuclear Generation segment were offset by the impact of the OEB-authorized Bruce Lease Net Revenues Variance Account and Nuclear Liability Deferral Account recorded in the corresponding segments for the period up to May 31, 2017, and by the retrospective revenue impact of the OEB's decision for the period from June 1, 2017 to December 31, 2017 recorded in the Regulated – Nuclear Generation segment.

Regulated – Hydroelectric Segment

(millions of dollars)	**2017**	**2016**
Revenue [1]	**1,436**	1,527
Fuel expense	**351**	353
Gross margin	**1,085**	1,174
Operations, maintenance and administration	**330**	325
Depreciation and amortization	**139**	225
Property tax	**1**	1
Income before other gains, interest and income taxes	**615**	623
Other losses (gains)	**1**	(19)
Income before interest and income taxes	**614**	642

[1] During 2017 and 2016, the Regulated – Hydroelectric segment revenue included incentive payments of $12 million and $14 million, respectively, related to the OEB-approved hydroelectric incentive mechanism. The mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers.

The decrease in income before interest and income taxes of $28 million in 2017, compared to 2016, was primarily due to a gain of $22 million recognized during the first quarter of 2016 to reflect the OEB's January 2016 decision reversing a portion of an earlier capital cost disallowance related to the Niagara Tunnel project expenditures, in response to a motion by OPG. The income impact of OEB-approved regulatory accounts and higher OM&A expenses also contributed to the decrease in income for the year. The higher OM&A expenses were primarily related to overhaul work and civil repairs completed during the year.

These factors were partially offset by the recognition of a revenue increase of approximately $15 million in the fourth quarter of 2017 to reflect the OEB's decision on OPG's application for new regulated prices. This incremental revenue was in relation to the June 1, 2017 to December 31, 2017 period based on the June 1, 2017 retrospective effective date of the new regulated prices and was recorded as an increase to regulatory assets.

The decrease in revenue from the segment for the year ended December 31, 2017, compared to the same period in 2016, was largely due to the expiry of an OEB-authorized hydroelectric rate rider on December 31, 2016. As the rate rider allowed for the recovery of approved balances in OEB-authorized regulatory accounts, this decrease in revenue was largely offset by lower amortization expense related to these balances.

The Hydroelectric Availability for the stations included in the Regulated – Hydroelectric segment was as follows:

	2017	2016
Hydroelectric Availability *(%)*	**88.0**	89.0

The Hydroelectric Availability decreased during 2017, compared to 2016, primarily due to a higher number of unplanned outage days at the Northwestern Ontario, Niagara, and Eastern Ontario regions' hydroelectric stations, partially offset by higher availability from the Sir Adam Beck Pump GS due to a higher number of planned outages days in 2016 as a result of the refurbishment of the station's reservoir.

The definition of Hydroelectric Availability is found in the section, *Key Operating and Financial Performance Indicators*.

Contracted Generation Portfolio Segment

(millions of dollars)	2017	2016
Revenue	**579**	573
Fuel expense	**53**	58
Gross margin	**526**	515
Operations, maintenance and administration	**169**	178
Depreciation and amortization	**79**	75
Accretion on fixed asset removal liabilities	**9**	9
Property taxes	**7**	7
Income from investments subject to significant influence	**(38)**	(37)
Income before other losses, interest, and income taxes	**300**	283
Other losses	**-**	1
Income before interest and income taxes	**300**	282

Income before interest and income taxes increased by $18 million during 2017, compared to 2016. The increase in earnings primarily resulted from revenues from the Peter Sutherland Sr. GS that was placed in-service at the end of the first quarter of 2017 and lower OM&A expenses, partially offset by lower revenues from the Lower Mattagami River hydroelectric generating stations and Atikokan GS. The lower OM&A expenses were mainly due to the prospective adoption of the full yield curve approach to the estimation of the service and interest cost components of pension and OPEB costs starting in 2017.

The Hydroelectric Availability and the Thermal EFOR for the Contracted Generation Portfolio segment were as follows:

	2017	2016
Hydroelectric Availability *(%)*	**74.6**	77.3
Thermal EFOR *(%)*	**2.4**	1.6

Lower Hydroelectric Availability during 2017, compared to 2016, was primarily due to an increase in the number of planned outage days at the Lower Mattagami River hydroelectric generating stations.

The higher thermal EFOR in 2017, compared to 2016, was primarily due to a higher number of unplanned outage days at a Lennox GS unit as a result of a transmission outage and a generator-related outage in 2017.

The definitions of Hydroelectric Availability and Thermal EFOR are found in the section, *Key Operating and Financial Performance Indicators*.

Services, Trading, and Other Non-Generation Segment

(millions of dollars)	2017	2016
Revenue	**43**	68
Fuel expense	**1**	1
Gross margin	**42**	67
Operations, maintenance and administration	**18**	22
Depreciation and amortization	**30**	32
Accretion on fixed asset removal liabilities	**8**	8
Property taxes	**6**	12
Restructuring	**-**	6
Loss before other gain, interest, and income taxes	**(20)**	(13)
Other gains	**(384)**	-
Income before interest and income taxes	**364**	(13)

Segment earnings improved by $377 million in 2017 compared to 2016. The increase in earnings mainly reflected the gain on the sale of OPG's head office premises and associated parking facility recorded during the second quarter of 2017 of $283 million, which is net of tax effects of $95 million, partially offset by a decrease in rental revenue due to the sale of the head office premises.

The year-over-year decrease in OM&A expenses in 2017 reflected higher expenses incurred in 2016 prior to the decision taken in the fourth quarter of 2016 to proceed with the decommissioning of the Lambton GS, largely offset by a higher write-off of previously incurred project expenditures in 2017.

During the fourth quarter of 2017, OPG recorded $12 million in Other gains related to the revaluation of the asset retirement obligations for Lambton and Nanticoke generating stations in line with the current decommissioning plans and cost estimates. During each of 2017 and 2016, OPG recorded a charge against earnings to adjust the scrap value estimate for the Lambton GS, as a reduction to Other gains.

Fair Hydro Trust Segment

(millions of dollars)	2017
Operations, maintenance and administration	**1**
Earnings from Fair Hydro Trust	**(1)**
Income before interest and income taxes	**-**

The Fair Hydro Trust was established on December 20, 2017. The Fair Hydro Trust segment includes the revenue and expenses related to OPG's role as Financial Services Manager of the Fair Hydro Trust and holder of subordinated debt issued by the Trust, including the financial results of the Trust. Earnings from Fair Hydro Trust were $1 million in 2017, primarily due to net interest income earned on OPG's subordinated debt investment for the 11-day period following the acquisition of the first tranche of Investment Interest from the IESO on December 21, 2017. The earnings were offset by an allocation of OM&A expenses for labour costs relating to OPG's employees that are not exclusively dedicated to the segment but who provided services to set up the Trust during the year. Pursuant to the general regulation of the Fair Hydro Act, such labour costs are not recoverable as part of OPG's fees for 2017. Refer to the section, *Recent Developments* under the heading, *Ontario's Fair Hydro Plan* and the section, *Business Segments* under the heading, *Fair Hydro Trust Segment* for further details on the Fair Hydro Trust.

LIQUIDITY AND CAPITAL RESOURCES

OPG's primary sources of liquidity and capital are funds generated from operations, bank financing, credit facilities provided by the Ontario Electricity Financial Corporation (OEFC), long-term corporate debt, including public debt offerings and notes payable to the OEFC, private placement project financing, and equity issuance. These sources are used for multiple purposes including: to invest in plants and technologies, to undertake major projects, to fund long-term obligations such as contributions to the pension fund and the Nuclear Segregated Funds, to make payments under the OPEB plans, to fund expenditures on Nuclear Liabilities not eligible for reimbursement from the Nuclear Segregated Funds, and to service and repay long-term debt, to provide general working capital, and to fund a portion of OPG's subordinated debt investment in the Fair Hydro Trust and the Trust's acquisition of Investment Interest from the IESO.

Changes in cash and cash equivalents for 2017 and 2016 were as follows:

(millions of dollars)	**2017**	**2016**
Cash and cash equivalents, beginning of period	**186**	464
Cash flow provided by operating activities	**944**	1,817
Cash flow used in investing activities	**(2,478)**	(1,919)
Cash flow provided by (used in) financing activities	**1,582**	(176)
Net increase (decrease) in cash and cash equivalents	**48**	(278)
Cash and cash equivalents, end of period	**234**	186

For a discussion regarding cash flow provided by operating activities and the FFO Adjusted Interest Coverage ratio, refer to the details in the section, *Highlights* under the heading, *Overview of Results*.

Investing Activities

Electricity generation is a capital-intensive business. It requires continued investment in plants and technologies to maintain and improve operating performance including asset reliability, safety and environmental performance, to increase the generating capacity of existing stations, and to invest in the development of new generating stations, emerging technologies and other business growth opportunities.

Cash flow used in investing activities in 2017 increased by $834 million compared to 2016. The increase in net cash flow used in investing activities was primarily due to the Trust's acquisition of the first tranche of Investment Interest from the IESO in the amount of approximately $1.18 billion in December 2017 and higher expenditures on the Darlington Refurbishment project in 2017.

The increase in net cash flow used in investing activities was partially offset by the receipt of proceeds from the sale of OPG's head office premises and associated parking facility in 2017 and the acquisition of nine million common shares of Hydro One Limited (Hydro One) in 2016. OPG acquired the Hydro One shares for investment purposes, to mitigate the risk of future price volatility related to the Company's future share delivery obligations under the current collective agreements with the Power Workers' Union (PWU) and The Society of Energy Professionals (The Society).

Financing Activities

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. In the second quarter of 2017, OPG renewed and extended the expiry date of both tranches from May 2021 to May 2022. There were no amounts outstanding under the bank credit facility as at December 31, 2017.

There was $100 million of commercial paper outstanding under OPG's commercial paper program as at December 31, 2017.

As at December 31, 2017, OPG also maintained $25 million of short-term, uncommitted overdraft facilities, and a further $468 million of short-term, uncommitted credit facilities which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other general corporate purposes. As at December 31, 2017, a total of $390 million of Letters of Credit had been issued under these facilities. This included $353 million for the supplementary pension plans, $36 million for general corporate purposes, and $1 million related to the operation of the PEC.

The Company has an agreement to sell an undivided co-ownership interest in its current and future accounts receivable to an independent trust, expiring on November 30, 2018. The maximum amount of co-ownership interest that can be sold under this agreement is $150 million. As at December 31, 2017, no borrowings were issued under this agreement and there were Letters of Credit outstanding under this agreement of $150 million, which were issued in support of OPG's supplementary pension plans.

As at December 31, 2017, Lower Mattagami Energy Limited Partnership (LME) maintained a $400 million bank credit facility to support the funding requirements for the Lower Mattagami River project including support for LME's commercial paper program. The facility consists of a $300 million tranche maturing in August 2022 and a $100 million tranche maturing in August 2018. As at December 31, 2017, there was $160 million commercial paper outstanding under LME's commercial paper program. A letter of credit of $55 million was issued in July 2017 and remains outstanding as at December 31, 2017 under the $300 million tranche of LME's credit facility.

In June 2016, OPG entered into a $700 million general corporate credit facility agreement with the OEFC, with an expiry date of December 31, 2017. During 2017, the agreement was amended to increase the credit facility to $2,350 million and to extend its expiry date to December 31, 2018. As at December 31, 2017, there were outstanding long-term borrowings of $800 million under this credit facility.

In February 2017, OPG issued senior notes payable to the OEFC totalling $200 million and maturing in February 2047. The effective interest rate and coupon interest rate of these notes was 4.12 percent. In June 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in June 2047. The effective interest rate and coupon interest rate of these notes was 3.65 percent. In August 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in August 2047. The effective interest rate and coupon interest rate of these notes was 3.86 percent. In September 2017, OPG issued senior notes payable to the OEFC totalling $400 million and maturing in September 2047. The effective interest rate and coupon interest rate of these notes was 4.07 percent.

In October 2017, OPG issued $500 million of senior notes payable under a Medium Term Note Program. The notes bear a coupon interest rate of 3.32 percent and an effective rate of 3.43 percent, payable semi-annually until maturity on October 4, 2027. The offering was made under OPG's $2 billion short form base shelf prospectus dated September 12, 2017. The net proceeds will be used for general corporate purposes.

In December 2017, the Fair Hydro Trust entered into an $800 million revolving warehouse facility agreement with an expiry date of December 21, 2019. As at December 31, 2017, there were outstanding senior notes of $601 million under this credit facility, which were used to finance 51 percent of the Trust's funding requirement for the acquisition of the first tranche of Investment Interest from the IESO in December 2017.

In February 2018, the Trust issued $500 million of senior notes payable with a coupon interest rate of 3.36 percent and an effective interest rate of 3.42 percent, payable semi-annually until maturity on May 15, 2033. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility issued by the Trust in December 2017. By the end of the first quarter of 2018, the Trust is expected to acquire another tranche of Investment Interest from the IESO, which it expects to fund using its revolving warehouse facility.

As at December 31, 2017, OPG's long-term debt outstanding was $5,735 million, including $398 million due within one year and excluding Fair Hydro Trust's senior debt included in OPG's consolidated balance sheets. The Fair Hydro Trust's senior debt outstanding was $601 million as at December 31, 2017.

Contractual Obligations

OPG's contractual obligations as at December 31, 2017, are as follows:

(millions of dollars)	2018	2019	2020	2021	2022	Thereafter	Total
Fuel supply agreements	158	125	115	88	67	67	620
Contributions to the OPG registered pension plan [1]	215	219	-	-	-	-	434
OPG long-term debt repayment	398	368	663	413	172	3,721	5,735
Interest on OPG long-term debt	244	226	204	175	161	3,006	4,016
Fair Hydro Trust senior debt repayment [2]	-	601	-	-	-	-	601
Interest on Fair Hydro Trust senior debt	15	15	-	-	-	-	30
Commitments related to Darlington Refurbishment project [3]	473	-	-	-	-	-	473
Commitments related to Ranney Falls GS project	29	5	-	-	-	-	34
Operating licences	40	41	24	28	28	87	248
Operating lease obligations	28	24	24	22	22	79	199
Unconditional purchase obligations	59	58	56	5	-	-	178
Accounts payable and accrued charges	957	8	-	-	-	16	981
Other	57	30	2	1	1	64	155
Total	2,673	1,720	1,088	732	451	7,040	13,704

[1] The pension contributions include ongoing funding requirements and additional funding requirements towards the deficit, in accordance with the actuarial valuation of the OPG registered pension plan as at January 1, 2017. The next actuarial valuation of the OPG registered pension plan must have an effective date no later than January 1, 2020. The pension contributions are affected by various factors including market performance, changes in actuarial assumptions, plan experience, changes in the pension regulatory environment, and the timing of funding valuations. Funding requirements after 2019 are excluded due to significant variability in the assumptions required to project the timing of future cash flows. The amount of OPG's additional, voluntary contribution, if any, is revisited from time to time.

[2] The notes were issued by the Fair Hydro Trust under an $800 million two-year revolving warehouse facility in December 2017. In February 2018, the Trust issued $500 million of senior notes payable to repay the majority of the outstanding balance of the revolving warehouse facility.

[3] Represents estimated currently committed costs to close the project, including accruals for completed work, demobilization of project staff and cancellation of existing contracts and material orders.

Other Commitments

Collective Agreements

As of December 31, 2017, OPG had approximately 9,200 regular employees. Most of OPG's regular employees are represented by two unions:

- The PWU – This union represents approximately 4,850 OPG employees or approximately 53 percent of OPG's regular workforce as at December 31, 2017. Union membership includes operators, technicians, skilled trades, clerical, and security personnel. The current collective agreement between OPG and the PWU has a three-year term, expiring on March 31, 2018. Negotiations for a new labour agreement with the PWU are underway. **[MONITOR]**
- The Society – This union represents approximately 3,250 OPG employees or approximately 35 percent of OPG's regular workforce as at December 31, 2017. Union membership includes supervisors, professional engineers, scientists, and other professionals. The current collective agreement between OPG and The Society has a three-year term, expiring on December 31, 2018.

In addition to the regular workforce, construction work is performed through 19 craft unions with established bargaining rights at OPG facilities. These bargaining rights are established either through the Electrical Power Systems Construction Association (EPSCA) or directly with OPG. Collective agreements between the Company and its construction unions are negotiated either directly or through EPSCA. All of these collective agreements currently have multi-year terms, expiring on April 30, 2020.

BALANCE SHEET HIGHLIGHTS

The following section provides other highlights of OPG's audited consolidated financial position using selected balance sheet data as at December 31:

(millions of dollars)	**2017**	**2016**
Property, plant and equipment – net	**21,322**	19,998
The increase was primarily due to capital expenditures on the Darlington Refurbishment project, partially offset by depreciation expense.		
Nuclear fixed asset removal and nuclear waste management funds *(current and non-current portions)*	**16,724**	15,984
The increase was primarily due to earnings on the Nuclear Segregated Funds, partially offset by reimbursement of eligible expenditures on nuclear fixed asset removal and nuclear waste management activities.		
Regulatory assets and liabilities – net *(current and non-current portions)*	**6,637**	5,545
The increase was primarily due to the addition of the Interim period revenue shortfall account, increases in the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB AOCI regulatory asset. In addition, there was no amortization recorded in 2017 consistent with OPG's proposal in the Draft Payment Amounts Order filed with the OEB in January 2018.		
Long-term debt *(current and non-current portions)*	**6,319**	5,520
The increase was primarily due to the issuance of senior notes payable by the Trust to finance the acquisition of an Investment Interest in the shortfall from the rate reductions mandated by the Fair Hydro Act of $601 million, issuance of senior notes payable totaling $804 million during 2017 primarily with the OEFC, and issuance of senior notes totaling $500 million under the Medium Term Note Program. The balance is offset by the debt repayment of $1 billion in 2017.		
Fixed asset removal and nuclear waste management liabilities	**20,421**	19,484
The increase was primarily a result of accretion expense representing the increase in the present value liabilities due to the passage of time, and an increase in the estimate for the nuclear ARO of $188 million recorded in 2017, which is discussed in *Critical Accounting Policies and Estimates* under the heading, Asset Retirement *Obligation*. The increase was partially offset by expenditures on nuclear fixed asset removal and waste management activities.		
Pension liabilities	**3,423**	3,012
The increase was primarily due to the re-measurement of the liabilities at the end of 2017 reflecting lower discount rates, partially offset by the excess of actual returns on pension plan assets over interest costs on the liabilities during 2017, as discussed in the section, *Critical Accounting Policies and Estimates* under the *heading, Pension and Other Post-Employment Benefits.*		
Other post-employment benefit liabilities	**3,092**	2,897
The increase was primarily due to the remeasurement of the liabilities at the end of 2017 reflecting lower discount rates, partially offset by the updated lower per capital health care claims costs assumption as part of the 2017 actuarial valuation.		

Off-Balance Sheet Arrangements

In the normal course of operations, OPG engages in a variety of transactions that, under US GAAP, are either not recorded in the Company's interim consolidated financial statements or are recorded in the Company's interim consolidated financial statements using amounts that differ from the full contract amounts. Principal off-balance sheet activities for OPG include guarantees and long-term contracts.

Guarantees

As part of normal business, OPG and certain of its subsidiaries and joint ventures enter into various agreements to provide financial or performance assurance to third parties. Such agreements include guarantees, standby Letters of Credit and surety bonds. For more details on guarantees issued by the company, refer to Note 15 of OPG's audited consolidated financial statements.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

OPG's significant accounting policies, including the impact of major recent accounting pronouncements, are outlined in Note 3 of the audited consolidated financial statements. Certain of these policies are recognized as critical accounting policies by virtue of the subjective and complex judgments and estimates required around matters that are inherently uncertain and could result in materially different amounts being reported under different conditions or assumptions. The critical accounting policies and estimates that affect OPG's US GAAP consolidated financial statements are highlighted below.

Exemptive Relief for Reporting under US GAAP

As required by *Ontario Regulation 395/11,* as amended, under the FAA, OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. Since January 1, 2012, OPG also has received exemptive relief from the OSC from the requirements of section 3.2 of National Instrument 52-107 *Acceptable Accounting Policies and Auditing Standards* (NI 52-107). The exemption allows OPG to file consolidated financial statements with the OSC based on US GAAP, rather than International Financial Reporting Standards (IFRS), without becoming a U.S. Securities and Exchange Commission registrant.

The current OSC exemption, received in 2014, will terminate on the earliest of the following:

- January 1, 2019
- The financial year that commences after OPG ceases to have activities subject to rate regulation
- The effective date prescribed by the International Accounting Standards Board (IASB) for the mandatory application of a standard within IFRS specific to entities with rate-regulated activities.

As a result of OPG's 2011 decision to adopt US GAAP, as required by the FAA regulation, OPG's earlier plan to convert to IFRS, effective January 1, 2012, was discontinued. OPG had substantively completed its IFRS conversion project, which included separate diagnostic, development, and implementation phases, when it suspended the project. If a future transition to IFRS for the purposes of OPG's consolidated financial statements is required, conversion work can be effectively restarted with sufficient lead time to evaluate and conclude on changes that occurred subsequent to the decision to suspend the project. OPG continues to monitor the IASB's current standard-setting project related to entities with rate-regulated activities and is evaluating alternatives with respect to the Company's future financial reporting.

Rate Regulated Accounting

The *Ontario Energy Board Act, 1998* and *Ontario Regulation 53/05* provide that OPG receives regulated prices for electricity generated from 54 hydroelectric generating stations and the Pickering and Darlington nuclear generating stations. OPG's regulated prices for these facilities are determined by the OEB.

The OEB is a self-funding Crown corporation. Its mandate and authority come from the *Ontario Energy Board Act, 1998*, the *Electricity Act, 1998*, and a number of other provincial statutes. The OEB is an independent, quasi-judicial tribunal that reports to the Legislature of the Province through the Ontario Ministry of Energy. It regulates market participants in Ontario's natural gas and electricity industries. The OEB carries out its regulatory functions through public hearings and other more informal processes such as consultations.

US GAAP recognizes that rate regulation can create economic benefits and obligations that are required by the regulator to be obtained from, or settled with, the customers. When the Company assesses that there is sufficient assurance that incurred costs in respect of the regulated facilities will be recovered in the future, those costs are deferred and reported as a regulatory asset. When the Company is required to refund amounts to customers in the future in respect of the regulated facilities, including amounts related to costs that have not been incurred and for which the OEB has provided recovery through regulated prices, the Company records a regulatory liability.

Certain of the regulatory assets and liabilities recognized by the Company relate to variance and deferral accounts authorized by the OEB, including those authorized pursuant to *Ontario Regulation 53/05.* The measurement of these regulatory assets and liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of *Ontario Regulation 53/05* and the OEB's decisions. The estimates and assumptions made in the interpretation of the regulation and the OEB's decisions are reviewed as part of the OEB's regulatory process.

Regulatory assets and liabilities for variance and deferral account balances approved by the OEB for inclusion in regulated prices are amortized based on approved recovery or repayment periods.

In addition to regulatory assets and liabilities for variance and deferral accounts, OPG recognizes regulatory assets and liabilities for unamortized amounts recorded in AOCI in respect of pension and OPEB obligations, and deferred income taxes, in order to reflect the expected recovery or repayment of these amounts through future regulated prices charged to customers. There are measurement uncertainties related to these balances due to the assumptions made in the determination of pension and OPEB obligations and deferred income taxes that are attributed to rate regulated business segments.

The regulatory asset for unamortized pension and OPEB amounts recorded in AOCI has reflected the OEB's use, since April 1, 2008, of the accrual basis of accounting for including pension and OPEB amounts in approved regulated prices for OPG. This is also the manner in which these costs are recognized in OPG's consolidated financial statements. Therefore, unamortized amounts in respect of OPG's pension and OPEB plans recognized in AOCI generally would not be reflected in regulated prices until they have been reclassified from AOCI and recognized as amortization components of the benefit costs for these plans.

Since November 1, 2014, the OEB has limited amounts for pension and OPEB costs included in the approved revenue requirements and regulated prices to the regulated business portion of the Company's cash expenditures for its pension and OPEB plans. The difference between actual pension and OPEB costs determined using the accrual method applied in OPG's audited consolidated financial statements and OPG's corresponding actual cash expenditures for these plans is captured in OEB-authorized Pension & OPEB Cash Versus Accrual Differential Deferral Account for future consideration. In 2017, the OEB issued a report outlining the guiding principles and policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the Ontario electricity and natural gas sectors. The report establishes the accrual basis of accounting as the method of determining pension and OPEB amounts for rate-setting purposes, unless the OEB finds that this method does not result in just and reasonable rates in the circumstances of a particular utility. The OEB's report and the OEB's December 2017 decision on OPG's

application for new regulated prices require OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the existing deferral account, until such time as the OEB approves resumption of the accrual basis of recovery for OPG. The future recovery of amounts recorded in the account will be subject to this approval. Further details on the OEB's 2017 report can be found in the section, *Highlights* under the heading, *Recent Developments – OEB's Decision on OPG's Application for New Regulated Prices*.

It remains the Company's position that, taken collectively, OEB's decisions on OPG's applications for regulated prices and the OEB's 2017 report in this area do not constitute a change in the basis of OPG's rate recovery of pension and OPEB costs. The Company continues to believe that there is sufficient likelihood that unamortized pension and OPEB amounts that have not yet been reclassified from AOCI will be included in future regulated prices, or in an OEB-authorized regulatory account for future recovery, as they are recognized in benefit costs. Similarly, the Company continues to believe that there is sufficient likelihood that amounts recorded in the Pension & OPEB Cash Versus Accrual Differential Deferral Account will be recovered, and consistent with the expectations set out in the OEB's December 2017 decision, plans to file an application with the OEB in 2018 requesting recovery of the account balance. Therefore, the Company continues to recognize regulatory assets for the above amounts.

See Notes 3, 5, 8, 9, and 11 of OPG's 2017 audited consolidated financial statements for additional disclosures related to the OEB's decisions, regulatory assets and liabilities, and rate regulated accounting.

Useful Lives of Long-Lived Assets

OPG reviews estimated station useful lives for its generating assets on a regular basis.

Nuclear Generating Stations

For the nuclear stations, this process involves reviewing major life limiting components (such as pressure tubes, feeders and steam generators) to determine an appropriate end-of-life date for the station. Useful lives are set such that, with normal and customary maintenance activities, stations are expected to be operational until such time as their life-limiting component's threshold is expected to be reached.

Hydroelectric and Thermal Generating Stations

Although there is a link between the age of a facility and the capital investment required to maintain that facility, age does not establish an upper limit on the expected useful life of hydroelectric facilities and dams. Regular maintenance and the replacement of specific components typically allow hydroelectric stations to operate for very long periods. For hydroelectric generating stations, an upper age limit of 100 years have been set.

Thermal generating stations reported in the Contracted – Generation Portfolio business segment primarily have useful lives that are in line with the term of the Energy Supply Agreements with the IESO.

Financing Receivables

Financing receivables consist of the current and irrevocable right of the Fair Hydro Trust to collect payments from Specified Consumers in the future in accordance with the Fair Hydro Act and associated general regulation. These amounts are measured at the transaction price entered into with the IESO on market terms upon acquisition and subsequently measured on an amortized cost basis. The basis of amortization follows the effective interest method.

Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

In accordance with the ONFA, OPG sets aside and invests funds that are held in segregated custodian and trustee accounts specifically for discharging its obligation for nuclear facilities decommissioning and long-term nuclear waste management. The Decommissioning Segregated Fund was established to fund the future costs of nuclear fixed asset removal and long-term L&ILW management, and certain costs of used fuel storage incurred after the stations are shut down. The Used Fuel Segregated Fund was established to fund the future costs of long-term nuclear used

fuel management and certain costs of used fuel storage incurred after the stations are shut down. Costs for L&ILW management and used fuel storage incurred during station operation are not funded by the Nuclear Segregated Funds. They are funded through the Company's operating cash flow or other sources of liquidity.

Based on the current approved ONFA reference plan, starting in 2017, OPG is not currently required to make overall contributions to the Used Fuel Segregated Fund or the Decommissioning Segregated Fund. Prior to 2017, OPG made contributions to the Used Fuel Segregated Fund quarterly, including a one-time special payment in earlier years, as required by the ONFA. These contributions reflected ONFA requirements to fund the majority of the underlying used fuel liability by the end of the initial estimated useful lives of the nuclear stations assumed in the ONFA, resulting in significantly higher contributions to the Used Fuel Segregated Fund in the earlier years of OPG's existence. OPG has not been required to make contributions to the Decommissioning Segregated Fund, which was fully funded at its inception through the initial contribution made by the Province and, taking into account asset performance and changes in underlying funding obligations over time, at the time of every subsequent approved ONFA reference plan. Contributions to either or both funds may be required in the future should the funds be in an underfunded position when a new reference plan is prepared. Such may be the case as a result of variability in asset performance due to volatility inherent in financial markets and, for the portion of the Used Fuel Segregated Fund guaranteed by the Province, changes in the Ontario CPI. Future contribution levels also are dependent on changes in baseline cost estimates and underpinning assumptions used to establish the funding obligations in subsequent ONFA reference plans.

Decommissioning Segregated Fund

Upon termination of the ONFA, the Province has the sole right to any excess funds in the Decommissioning Segregated Fund. Accordingly, when the Decommissioning Segregated Fund is overfunded, OPG limits the fund earnings it recognizes in the consolidated financial statements by recording an amount due to the Province, such that the fund asset recognized on the consolidated balance sheet is equal to the cost estimate of the liability based on the most recently approved ONFA reference plan. Additionally, OPG recognizes the portion of the surplus that it may direct to the Used Fuel Segregated Fund, which is possible when the surplus is such that the underlying liabilities, as defined by the most recently approved ONFA reference plan, are at least 120 percent funded. In those circumstances, OPG may direct, at the time a new or amended reference plan is approved, up to 50 percent of the surplus over 120 percent to the Used Fuel Segregated Fund, with the OEFC entitled to a distribution of an equal amount. Therefore, when the Decommissioning Segregated Fund is at least 120 percent funded, OPG recognizes 50 percent of the excess greater than 120 percent in income, up to the amount by which the Used Fuel Segregated Fund is underfunded.

The amount due to the Province in respect of the Decommissioning Segregated Fund could be reduced in subsequent periods in the event that the fund earns less than is target rate of return, a new ONFA reference plan is approved with a higher underlying liability, or the amount of the underfunding in the Used Fuel Segregated Fund increases.

When the Decommissioning Segregated Fund is underfunded, the earnings on the fund reflect actual fund returns based on the market value of the assets.

Used Fuel Segregated Fund

Under the ONFA, the Province guarantees OPG's annual return in the Used Fuel Segregated Fund at 3.25 percent plus the change in the Ontario CPI, as defined in the ONFA, for funding related to the first 2.23 million used fuel bundles ("committed return"). OPG recognizes the committed return on the Used Fuel Segregated Fund as earnings on the Nuclear Segregated Funds. The difference between the committed return and the actual market return determined based on the fair value of the fund's assets related to the first 2.23 million used fuel bundles is recorded as due to or due from the Province. This amount represents the amount OPG would pay to, or receive from, the Province if the committed return were to be settled as of the consolidated balance sheet date. Upon approval of a

new or amended ONFA reference plan, the Province is obligated to make an additional contribution to the Used Fuel Segregated Fund in relation to the first 2.23 million used fuel bundles if the fund's assets earned a rate of return that is less than the guaranteed rate of return. If the return on the fund's assets exceeds the Province's guaranteed rate of return, the Province is entitled to withdraw any portion of the excess related to the 2.23 million used fuel bundles, upon approval of a new or amended ONFA reference plan. The 2.23 million threshold represents the estimated total life cycle fuel bundles based on the initial estimated useful lives of the nuclear stations assumed in the ONFA.

As prescribed under the ONFA, OPG's contributions attributed to the used fuel bundles in excess of 2.23 million are not subject to the rate of return guaranteed by the Province, and earn a return based on changes in the market value of the assets of the Used Fuel Segregated Fund.

If there is a surplus in the Used Fuel Segregated Fund such that the funding liabilities, as defined by the most recently approved ONFA Reference Plan, are at least 110 percent funded, the Province has the right, at any time, to access the excess amount greater than 110 percent. Upon termination of the ONFA, the Province is entitled to any surplus in the fund. Accordingly, when the Used Fuel Segregated Fund is overfunded, OPG limits the fund earnings it recognizes in the consolidated financial statements by recording an amount due to the Province, such that the balance of the fund is equal to the cost estimate of the liability based on the most recently approved ONFA reference plan. In accordance with the ONFA, neither OPG nor the Province have a right to direct any amounts from the Used Fuel Segregated Fund to the Decommissioning Segregated Fund.

Provincial Guarantee

In accordance with the *Nuclear Safety and Control Act* (Canada), the CNSC requires OPG to have sufficient funds available to discharge its existing nuclear waste management and nuclear decommissioning obligations. The CNSC process requires the CNSC financial guarantee requirement to be updated once every five years and for OPG to provide an annual report to the CNSC on the assumptions, asset values, and resulting financial guarantee requirements. The CNSC financial guarantee requirement calculation takes into account nuclear waste expected to be generated to the end of each year.

In November 2017, the CNSC accepted OPG's proposed 2018-2022 CNSC financial guarantee requirement to be satisfied by the forecast fair market value of the Nuclear Segregated Funds without the requirement of a Provincial Guarantee for the 2018-2022 period. As required by the terms of the ONFA, the Province is committed to provide a Provincial Guarantee to the CNSC, on behalf of OPG, should there be a shortfall between the CNSC financial guarantee requirement and the fair market value of the Nuclear Segregated Funds in the 2018-2022 period, as it has done in the past. OPG pays the Province an annual guarantee fee equal to 0.5 percent of the outstanding amount, if any, of the Provincial Guarantee.

The value of the Provincial Guarantee in effect through to the end of 2017 was $1,551 million. Based on this guarantee amount, OPG paid a guarantee fee of $8 million to the Province for each of 2016 and 2017.

Pension and Other Post-Employment Benefits

The determination of OPG's pension and OPEB costs and obligations is based on accounting policies and assumptions, as discussed below.

Accounting Policy

OPG's post-employment benefit programs consist of a contributory defined benefit registered pension plan, a defined benefit supplementary pension plan, and other post retirement benefits (OPRB) including group life insurance and health care benefits, and long-term disability (LTD) benefits. Post-employment benefit programs also are provided by the Nuclear Waste Management Organization (NWMO), which is consolidated into OPG's financial results. Unless otherwise noted, information on the Company's post-employment benefit programs is presented on a consolidated basis.

OPG accrues its obligations under pension and OPEB plans in accordance with US GAAP. The obligations for pension and OPRB are determined using the projected benefit method pro-rated on service. The obligation for LTD benefits is determined using the projected benefit method on a terminal basis. Pension and OPEB obligations are impacted by factors including interest rates, adjustments arising from plan amendments, demographic assumptions, experience gains or losses, salary levels, inflation, and health care cost escalation assumptions. Pension and OPEB costs and obligations are determined annually by independent actuaries using management's best estimate assumptions.

Pension fund assets include equity securities, corporate and government debt securities, pooled funds, real estate, infrastructure and other investments. These assets are managed by professional investment managers. The pension fund does not invest in equity or debt securities issued by OPG. Pension fund assets are valued using market-related values for purposes of determining the amortization of actuarial gains or losses and the expected return on plan assets. The market-related value recognizes gains and losses on equity assets relative to a six percent assumed real return over a five-year period.

Pension and OPEB costs include current service costs, interest costs on the obligations, the expected return on pension plan assets, adjustments for plan amendments and adjustments for actuarial gains or losses, which result from changes in assumptions and experience gains and losses. Past service costs or credits arising from pension and OPRB plan amendments are amortized on a straight-line basis over the expected average remaining service life to full eligibility of the employees covered by the corresponding plan. Past service costs or credits arising from amendments to LTD benefits are immediately recognized as OPEB costs in the period incurred. Due to the long-term nature of pension and OPRB liabilities, the excess of the net cumulative unamortized gain or loss, over 10 percent of the greater of the benefit obligation and the market-related value of the plan assets (the corridor) for each plan is amortized over the expected average remaining service life of the employees covered by the plan, which represents the period during which the associated economic benefits are expected to be realized by the Company. Actuarial gains or losses for LTD benefits are immediately recognized as OPEB costs in the period incurred.

OPG recognizes the funded status of its defined benefit plans on the consolidated balance sheets. The funded status is measured as the difference between the fair value of plan assets and the benefit obligation, on a plan-by-plan basis.

Actuarial gains or losses and past service costs or credits arising during the year that are not recognized immediately as components of benefit costs are recognized as increases or decreases in other comprehensive income (OCI), net of income taxes. These unamortized amounts in AOCI are subsequently reclassified and recognized as amortization components of pension and OPRB costs as described above.

As at December 31, 2017, the unamortized net actuarial loss and unamortized past service costs for the pension and OPEB plans totalled $4,148 million (2016 – $3,668 million). Details of the unamortized net actuarial loss and unamortized past service costs as at December 31, 2017 and 2016 are as follows:

(millions of dollars)	Registered Pension Plans 2017	2016	Supplementary Pension Plans 2017	2016	Other Post-Employment Benefits 2017	2016
Net actuarial gain not yet subject to amortization due to use of market-related values	**(418)**	(570)	**-**	-	**-**	-
Net actuarial loss not subject to amortization due to use of the corridor	**1,735**	1,619	**36**	34	**299**	267
Net actuarial loss subject to amortization	**2,333**	2,238	**80**	72	**79**	3
Unamortized net actuarial loss	**3,650**	3,287	**116**	106	**378**	270
Unamortized past service costs	**-**	-	**-**	-	**4**	5

OPG records an offsetting regulatory asset or liability for the portion of the adjustments to AOCI that is attributable to the regulated operations in order to reflect the expected recovery or refund of these amounts through future regulated prices charged to customers. For the recoverable or refundable portion attributable to regulated operations, OPG records a corresponding change in this regulatory asset or liability for the amount of the increases or decreases in OCI and for the reclassification of AOCI amounts into benefit costs during the period.

When the recognition of the transfer of employees and employee-related benefits gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement. A curtailment is the loss by employees of the right to earn future benefits under the plan. A settlement is the discharge of a plan's liability.

Accounting Assumptions

Assumptions are significant inputs to actuarial models that measure pension and OPEB obligations and related effects on operations. Discount rate, inflation rate and changes in salary levels are three critical assumptions in the determination of benefit costs and obligations. In addition, the expected long-term rate of return on plan assets is a critical assumption in the determination of registered pension plan cost, and the health care cost trend rate is a critical assumption in the determination of OPEB cost and obligations. These assumptions, as well as other assumptions involving demographic factors such as retirement age, mortality, and employee turnover, are evaluated periodically by management in consultation with independent actuaries. During the evaluation process, the assumptions are updated to reflect past experience and expectations for the future. Actual results in any given year will often differ from actuarial assumptions because of economic and other factors giving rise to actuarial gains and losses.

The discount rates, which are representative of the AA corporate bond yields, are used to calculate the present value of the expected future cash flows on the measurement date in order to determine the projected benefit obligations for the Company's employee benefit plans. A lower discount rate increases the benefit obligations. The weighted-average discount rate used to determine the projected pension and OPEB benefit obligations as at December 31, 2017 was 3.6 percent. This represents a decrease compared to the 3.9 percent discount rate that was used to determine the obligations as at December 31, 2016.

In 2016 and prior years, benefit costs were calculated using the same single weighted-average discount rates as reflected in the calculation of the benefit obligations. Effective January 1, 2017, OPG adopted a full yield curve approach to the estimation of the service and interest cost components of pension and OPEB costs, by applying the specific spot rates along the yield curve used in the determination of the projected benefit obligations to the relevant projected cash flows. The change improves the correlation between projected benefit cash flows and the corresponding yield curve spot rates, and provides a more precise measurement of service and interest costs. This change in the method was accounted for prospectively, as a change in estimate. The resulting reduction in pension and OPEB costs is estimated at approximately $135 million for the twelve months ended December 31, 2017. Approximately 90 percent of this reduction in pension and OPEB costs was attributed to the Company's regulated

business segments and therefore was offset by the impact of OEB-authorized regulatory accounts. The change does not affect the measurement of the total benefit obligation as the change in the current service and interest cost components from the previous method is offset by a corresponding change in the actuarial gain or loss recorded in AOCI.

The expected rate of return on plan assets is determined based on the pension fund's asset allocation and the expected return considering long-term risks and returns associated with each asset class within the plan portfolio. A lower expected rate of return on plan assets increases pension cost.

A new actuarial valuation of the OPG registered pension plan was filed with the Financial Services Commission of Ontario in September 2017 with an effective date of January 1, 2017. The annual funding requirements in accordance with the new actuarial valuation are outlined in the section, *Liquidity and Capital Resources* under the heading, *Contractual and Commercial Commitments*. OPG conducted a comprehensive actuarial valuation for accounting purposes of its pension and OPEB plans in 2017, using demographic data as at January 1, 2017 consistent with the new funding valuation and using assumptions as at December 31, 2017. As part of the valuation, the plans' demographic and other assumptions were reviewed and revised, as necessary, by independent actuaries.

The deficit for the registered pension plan, for accounting purposes, increased from $2,693 million as at December 31, 2016 to $3,081 million as at December 31, 2017. This increase was largely due to a re-measurement of the liabilities at the end of 2017 reflecting lower discount rates, partially offset by the excess of actual returns on the pension plan assets over interest costs on the liabilities during the year.

The projected benefit obligations for OPEB increased from $2,992 million as at December 31, 2016 to $3,190 million as at December 31, 2017. This increase was largely due to a re-measurement of the liabilities at the end of 2017 reflecting a decrease in the discount rates, partially offset by the updated, lower per capita health care claims costs assumption as part of the 2017 actuarial valuation.

A change in the following assumptions, holding all other assumptions constant, would increase (decrease) pension and OPEB costs for the year ended December 31, 2017 as follows:

(millions of dollars)	**Registered Pension Plans [1]**	**Supplementary Pension Plans [1]**	**Other Post-Employment Benefits [1]**
Expected long-term rate of return			
0.25% increase	(32)	n/a	n/a
0.25% decrease	32	n/a	n/a
Discount rate			
0.25% increase	(56)	(1)	(2)
0.25% decrease	59	1	13
Inflation			
0.25% increase	98	1	-
0.25% decrease	(91)	(1)	-
Salary increases			
0.25% increase	22	3	-
0.25% decrease	(20)	(2)	-
Health care cost trend rate			
1% increase	n/a	n/a	77
1% decrease	n/a	n/a	(29)

n/a – change in assumption not applicable.

[1] Excludes the impact of regulatory accounts.

Asset Retirement Obligation

OPG recognizes ARO for fixed asset removal and nuclear waste management liabilities, discounted for the time value of money. OPG estimates both the amount and timing of future cash expenditures based on the plans for fixed asset removal and nuclear waste management. The ARO is comprised of expected costs to be incurred up to and beyond termination of operations and the closure of nuclear and thermal generating plant facilities and other facilities. Costs are expected to be incurred for activities such as preparation for safe storage and safe storage of nuclear stations, dismantlement, demolition and disposal of facilities and equipment, remediation and restoration of sites, and the ongoing and long-term management of nuclear used fuel bundles and L&ILW material. The liabilities associated with the decommissioning of the nuclear generating stations and the long-term management of used nuclear fuel comprise the most significant amounts of the total obligation.

The nuclear decommissioning liability includes the estimated costs of closing the nuclear stations after the end of their service lives, which includes preparation and placement of the stations into a safe state condition followed by an assumed 30-year safe store period prior to station dismantlement and site restoration. Activities associated with the placement of stations into a safe state condition include de-fuelling and de-watering of the nuclear reactors. OPG is responsible for the nuclear waste management and nuclear decommissioning obligations associated with the Bruce nuclear generating stations and includes the associated costs in its ARO. Pursuant to the lease agreement, Bruce Power must return the two Bruce stations to OPG together, in a de-fuelled and de-watered state. As such, these de-watering and de-fuelling costs are not part of OPG's ARO.

The life cycle costs of L&ILW management include the costs of processing and storage of such radioactive wastes during and following the operation of the nuclear stations, as well as the costs of the ultimate long-term management of these wastes. The current assumptions used to establish the obligation for these costs include an L&ILW DGR facility to be constructed and operated by OPG, as discussed in the section, *Core Business, Strategy, and Outlook* under the heading, *Project Excellence*. To estimate the liability for nuclear used fuel management, OPG has adopted an approach consistent with the Adaptive Phased Management concept approved by the Government of Canada, which assumes a deep geologic repository for the long-term management of Canada's nuclear used fuel waste. The NWMO is responsible for the design and implementation of Canada's plan for the long-term management of used nuclear fuel.

The following costs are recognized as a liability on OPG's consolidated balance sheets:

- the present value of the costs of decommissioning the nuclear and thermal production facilities and other facilities after the end of their useful lives
- the present value of the fixed cost portion of nuclear waste management programs that are required based on the total volume of waste expected to be generated over the assumed lives of the stations
- the present value of the variable cost portion of nuclear waste management programs taking into account waste volumes generated to date.

The significant assumptions underlying operational and technical factors used in the calculation of the accrued liabilities are subject to periodic review. Changes to these assumptions, including changes to assumptions on the timing of the programs including construction of assumed waste disposal facilities, station end-of-life dates, waste disposal methods, financial indicators, decommissioning strategy, and the technology employed may result in significant changes to the value of the accrued liabilities. With programs of such long-term duration and the evolving technology to handle nuclear waste, there is a significant degree of inherent uncertainty surrounding the measurement of the costs for these programs. These costs may increase or decrease over time.

The estimates for the Nuclear Liabilities are reviewed on an ongoing basis as part of the overall nuclear waste management program. A comprehensive reassessment of all underlying assumptions and baseline cost estimates is performed periodically, at least once every five years, in line with the required ONFA reference plan update process. Changes in the Nuclear Liabilities resulting from changes in assumptions or estimates that impact the amount or

timing of the estimated undiscounted future cash flows are recorded as an adjustment to the liabilities. Upward revisions in the Nuclear Liabilities represent the present value of a net increase in future undiscounted cash flows determined using a current credit-adjusted risk-free rate. Downward revisions in the Nuclear Liabilities represent the present value of a net decrease in future undiscounted cash flows determined using the weighted average discount rate reflected in the existing liability. Resulting changes in the related asset retirement costs are capitalized as part of the carrying amount of nuclear fixed assets in service.

As of December 31, 2017, OPG recorded an increase of $188 million in the Nuclear Liabilities and associated asset retirement costs capitalized as part of carrying value of property, plant and equipment (PP&E) reflecting the change in the Pickering GS accounting end-of-life assumptions from December 31, 2020 for all operating units to December 31, 2022 for Units 1 and 4 and December 31, 2024 for Units 5 to 8. The increase in the liabilities is primarily due to higher fixed costs associated with the Used Fuel Disposal and L&ILW Storage programs, discounted using the current credit-adjusted risk-free rate of 2.94 percent. The adjustment did not impact net income for 2017. The adjustment is not expected to have a material impact on net income in 2018 as the associated impact on expenses is expected to be largely offset by OEB-authorized regulatory accounts. The change in accounting end-of-life assumptions for the Pickering GS are discussed in further detail in the section, *Core Business, Strategy, and Outlook* under the heading, *Operational Excellence – Electricity Generation Production and Reliability*.

For the purposes of calculating OPG's Nuclear Liabilities, as at December 31, 2017, consistent with the current accounting end-of-life assumptions, nuclear station decommissioning activities are projected to occur over approximately the next 80 years.

The liability for nuclear fixed asset removal and nuclear waste management on a present value basis as at December 31, 2017 was $20,077 million (2016 – $19,103 million). As at December 31, 2017, the undiscounted cash flows of expenditures for OPG's Nuclear Liabilities in 2017 dollars are as follows:

(millions of dollars)	**2018**	**2019**	**2020**	**2021**	**2022**	**Thereafter**	**Total**
Expenditures for nuclear fixed asset removal and nuclear waste management [1]	323	326	323	311	598	40,513	42,394

[1] The majority of the expenditures are expected to be reimbursed by the Nuclear Segregated Funds established by the ONFA. Any contributions required under the ONFA are not included in these undiscounted cash flows. Accounting for the Nuclear Segregated Funds is discussed in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

The liability for non-nuclear fixed asset removal was $344 million as at December 31, 2017 (2016 – $381 million). This liability primarily represents the present value of estimated costs of decommissioning OPG's thermal generating stations at the end of their service lives. OPG has updated the asset retirement obligations for the thermal generating stations as of December 31, 2017, based on a review of required decommissioning, clean-up and restoration activities, underlying economic assumptions and anticipated timing of these activities in line with current accounting end-of-life assumptions for the operating sites. For the shutdown Nanticoke and Lambton generating stations, the update reflects the estimated cost of executing current decommissioning plans. For the currently operating sites, OPG recognized a decrease of $18 million in the non-nuclear fixed asset removal liabilities and associated asset retirement costs capitalized as part of the carrying value of PP&E as at December 31, 2017. For the Nanticoke and Lambton sites, a reduction in the non-nuclear fixed asset removal liabilities and a gain of approximately $12 million was recorded in net income in the fourth quarter of 2017, in the, Services, Trading, and Other Non-Generation segment.

For the purpose of measuring the non-nuclear fixed asset removal liability, asset removal activities are assumed to take place approximately over the next one to 12 years. The amount of undiscounted estimated future cash flows associated with the thermal liabilities is approximately $400 million.

OPG has no legal obligation associated with the decommissioning of its hydroelectric generating facilities and the costs cannot be reasonably estimated because of the long service life of these assets. With either maintenance efforts or rebuilding, the water control structures are assumed to be used for the foreseeable future. Accordingly, OPG has not recognized a liability for the decommissioning of its hydroelectric generating facilities.

Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly arm's-length transaction between market participants at the measurement date. Fair value measurements are required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model.

The fair value of financial assets and liabilities for which quoted prices in an active market are available, including exchange traded derivatives and other financial instruments, are determined directly from those quoted market prices.

For financial instruments for which quoted market prices are not directly available, fair values are estimated using forward price curves developed from observable market prices or rates. The estimation of fair value may include the use of valuation techniques or models, based wherever possible on assumptions supported by observable market prices or rates prevailing at the consolidated balance sheet dates. This is the case for over-the-counter derivatives and securities, which include energy commodity derivatives, foreign exchange derivatives, interest rate swap derivatives, and fund investments. Pooled fund investments are valued at the unit values supplied by the pooled fund administrators. The unit values represent the underlying net assets at fair values, determined using closing market prices. Valuation models use general assumptions and market data and therefore do not reflect the specific risks and other factors that may affect a particular instrument's fair value. The methodologies used for calculating the fair value adjustments are reviewed on an ongoing basis to ensure that they remain appropriate. If the valuation technique or model is not based on observable market data, specific valuation techniques are used, primarily based on recent comparable transactions, comparable benchmark information, bid/ask spread of similar transactions, and other relevant factors.

For the financing receivables related to the Investment Interest acquired from the IESO, fair value is estimated to equal the fair value of the underlying debt due to the direct relationship of the asset, and the debt instruments that financed the acquisition.

OPG's use of financial instruments exposes the Company to certain risks, including credit risk, foreign currency risk and interest rate risk. A discussion of how OPG manages these and other risks is found under the section, *Risk Management*.

Recent Accounting Pronouncements Not Yet Adopted

The recent US GAAP accounting pronouncements related to revenue recognition, leases, and financial instruments are described below. Other recent accounting pronouncements applicable to OPG are outlined in Note 3 of the audited consolidated financial statements.

Revenue from Contracts with Customers

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09, *Revenue from Contracts with Customers* (Topic 606), which supersedes nearly all existing revenue recognition guidance, including industry-specific guidance, under US GAAP. The core principle of Topic 606 is to recognize revenues when promised goods or services are transferred to customers in an amount that reflects the consideration to which an entity expects to be entitled for those goods or services. Either a full retrospective

application or a modified retrospective application is required for annual periods beginning on or after January 1, 2018, including interim periods within that year. Early adoption is permitted.

OPG has assessed the impact of the standard on accounting for the Company's revenue streams and consolidated financial statements. OPG's major revenue streams include regulated generation revenue from base regulated prices and rate riders established by the OEB, as well as revenue from generation assets under long-term contractual arrangements with the IESO. OPG has completed its analyses of the impact of Topic 606 on all of its revenue streams, and has not identified any material differences in the timing or amount of revenue recognition for these streams.

The Company will apply the new revenue standard in its 2018 first quarter interim financial statements and is in the process of evaluating the additional disclosures required under the new standard.

Lease Accounting

In February 2016, the FASB issued ASU No. 2016-02, *Leases* (Topic 842). The update includes comprehensive changes to existing guidance for lease accounting, particularly for lessees, and aims to increase transparency and comparability among organizations by requiring the recognition of lease assets and lease liabilities on the balance sheet. The standard is effective for annual periods beginning after December 15, 2018, including interim periods within that year.

Under the current guidance, entities are required to use a modified retrospective approach for leases that exist, or are entered into, after the beginning of the earliest comparative period presented in the financial statements of the period of adoption. Under this method, Topic 842 would effectively be implemented by recognizing any adjustments stemming from the transition, as of beginning of the earliest comparative period presented in the entities' financial statements. Full retrospective application is prohibited. In January 2018, the FASB issued a proposed ASU wherein entities would be able to utilize an additional optional transition method of recording the cumulative impact of adopting the new lease standard to the opening balance in the initial period of adoption; with comparative periods continuing to be presented in accordance with the existing leasing standard, Topic 840 - *Leases*, including disclosures. [**MONITOR**] The Company will continue to monitor the status of this proposed ASU.

The FASB also issued ASU No. 2018-01, *Land Easement Practical Expedient for Transition to Topic 842* in January 2018. The amendments therein allows an entity to choose not to evaluate under Topic 842 land easements that exist or expired before the entity's adoption of the new leasing standard and that were not previously accounted for as leases under Topic 840.

The Company continues to implement and execute a comprehensive project governance framework, which comprises a Steering Committee, Implementation & Stakeholder Committee, Project Management Office, and various working groups in order to evaluate the implement the new standard. The working groups are represented by cross functional finance and non-finance stakeholders who will support the financial and operational implementation of the standard. The Company continues to evaluate the impact of the new leasing standard on its consolidated financial statements.

Recognition and Measurement of Financial Assets and Financial Liabilities

In January 2016, the FASB issued ASU No. 2016-01, *Financial Instruments – Overall: Recognition and Measurement of Financial Assets and Financial Liabilities*. Under the updated guidance, entities will have to measure equity investments at fair value and recognize any changes in fair value in net income. The update will be effective for OPG's 2018 fiscal year, including interim periods. As a result of this update, effective January 1, 2018, the available-for-sale (AFS) classification for equity securities will no longer be available, with any unrealized gains and losses related to such securities recognized in net income instead of OCI. Any unrealized gains and losses for AFS securities reported by OPG in AOCI as of the end of 2017 will be reclassified to retained earnings as of January 1, 2018. OPG's equity shareholdings in Hydro One are currently the Company's only AFS securities. As at December

31, 2017, these shares are valued on the consolidated balance sheet at $188 million, for which a loss of $8 million has been recorded in AOCI. OPG does not expect the new standard to have any other significant impact on its consolidated financial statements.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost

In March 2017, the FASB issued ASU No. 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. Under the new guidance, employers that sponsor defined benefit plans for pensions and/or other postretirement benefits are required to present the service cost component of net periodic benefit cost in the same statement of income line item as other employee compensation costs arising from services rendered during the period. The other components of the net periodic benefit cost are to be presented separately from the line item that includes the service cost and outside of any subtotal of income from operations, if such a subtotal is presented. In addition, the new guidance requires that only the service cost component of net benefit cost be eligible for capitalization.

This guidance is effective for fiscal years beginning after December 15, 2017, including interim periods of those years. The guidance is not expected to have a material impact on OPG's consolidated financial statements, as OPG currently capitalizes only the service cost component of post-retirement benefits costs. Additionally, OPG already includes the service cost component of post-retirement benefit costs with other compensation costs, within the operations, maintenance and administration expenses line item in the consolidated statements of income, and does not show a subtotal of income from operations. As such, the new guidance is not expected to affect the presentation of OPG's consolidated financial statements.

RISK MANAGEMENT

Overview

OPG faces various risks that could significantly impact the achievement of its strategic imperatives. The objective of risk management is to identify, assess and mitigate key risks, and to preserve and increase the value of the Shareholder's investment in the Company.

The Audit and Risk Committee is mandated to fulfill the oversight responsibilities of the Board of Directors for matters relating to the identification and management of the Company's key business risks. OPG's Enterprise Risk Management framework is designed to identify and evaluate risks on the basis of their potential impact on the Company's strategic imperatives and business plan objectives. Formal risk management policies, procedures and systems are in place to identify, assess and mitigate risks to the Company. Senior management also establishes set limits for the market risk, credit risk and energy trading activities of the Company.

The key risks to OPG's strategic imperatives are briefly described below. These are key risks that management believes could materially affect its business, revenues, net income, assets or capital resources. There may be further risks and uncertainties that are not presently known, or that are not currently believed to be material, that may in the future adversely affect the Company's performance or financial condition.

Risks to Achieving Operational Excellence

OPG is exposed to variable output from its existing generating stations that could adversely impact its financial performance. The operational risks of a station are generally a function of its age, human performance, and the technology used.

Asset Conditions and Generation Variability

The uncertainty associated with electricity production by OPG's generating units is primarily driven by the condition of station components and systems, which are subject to the effects of aging and the manner in which the units operate. To safely operate the units to meet electricity system requirements, a unit could be derated resulting in reduced generation. The primary implications of these risks may include additional safety requirements, lower than expected generation and revenues, and higher operating or capital costs. To respond to this risk, OPG continues to:

- monitor performance, implement extensive inspection and maintenance programs;
- identify future work required to sustain and, as appropriate, upgrade a station equipment; and
- undertake projects required to reliably operate within design and operating parameters.

Extension of Commercial Operations at Pickering to 2024

In January 2016, the Province of Ontario announced its approval of OPG's plan to pursue the continued safe and reliable operation of the Pickering GS to 2024. Under OPG's plan, the six operating units at the Pickering GS would operate until 2022, at which point two units would be shut down and the remaining four units would continue to operate until 2024. The current operating licence for the Pickering GS, which expires in August 2018, was issued in 2013 assuming that the station would shut down in 2020. Technical assessments have been completed to determine the ability of the Pickering units to continue to be fit for service to support extended operations. There is high technical confidence in the programs and provisions in place to operate the station to the end of 2024.

Inability to extend operations as planned would result in a reduction of OPG's future generation revenue and cash flows and lead to the advancement of station shutdown and decommissioning expenditures.

Risk factors for extended operations include the discovery of unexpected conditions, equipment failures, the state of critical plant components that are reaching end-of-life and a requirement for significant plant modifications. To mitigate these risks, OPG has implemented actions recommended from the technical assessments as part of the outage work program. OPG has also incorporated those actions into the comprehensive inspection and maintenance program under the Life Cycle Management Plan.

Supply Chain

OPG's ability to operate effectively is in part dependent upon timely access to equipment, materials, and service suppliers. Loss of key equipment, materials and service suppliers, particularly for the nuclear business, could affect OPG's operations and execution of major capital projects. OPG mitigates this risk, to the extent possible, through contract negotiations, contract terms, vendor monitoring, diversification of supplier base and business continuity plans.

Cyber Security

OPG's operations depend in part, on the efficient operation and management of the Company's complex information technology and operational systems in a secure, vigilant and resilient manner that minimizes cyber risks. Cyber security incidents may have an adverse impact on OPG's reputation, energy production, and public and employee safety.

Cyber security incidents have been on the rise for the past few years and this trend is only expected to intensify as global reliance on technology increases. OPG has strategies in place to prepare for, respond to, and recover from cyber security incidents. OPG continuously monitors, assesses, and improves the effectiveness of its strategies and program considering leading industry practices and remains proactive in information and intelligence sharing to learn and adapt to the changing cyber environment. In 2017, the media reported several worldwide cyber-attacks, such as WannaCry and Petya, which impacted multiple sectors including power and utilities. OPG's operational responses to those cyber-attacks were timely and effective resulting in no or low operational impact to OPG.

As a registered Ontario market participant, OPG must comply with reliability standards that apply to the Bulk Electric System elements specified under North American Electric Reliability Corporation and the relevant Bulk Power System facilities as determined by the Northeast Power Coordinating Council. In addition, OPG's nuclear cyber assets are subject to CNSC licensing conditions and regulatory requirements. For other cyber assets not subject to applicable regulatory requirements, OPG has adopted a risk-based approach based on the National Institute of Standards and Technology cyber security framework to manage its cyber security. Policies are in place to manage the Company's cyber risks and programs which are subject to oversight by management and the Board.

Regulatory Compliance

OPG is subject to extensive federal and provincial legislation and regulations by various entities such as the OEB, CNSC and the IESO.

The uncertainty associated with nuclear regulatory compliance is driven by plant aging, changes to technical codes, and challenges raised by the public at regulatory hearings, particularly in the areas of safety, environment and emergency preparedness. Addressing these requirements could add to the cost of operations, including replacement or modification of a station component or additional requirements for waste management. In some instances, these requirements may result in a reduction or elimination of the productive capacity of a station.

The Provincial agency, Office of the Fire Marshal and Emergency Management (OFMEM) is required to periodically update the Provincial Nuclear Emergency Response Plan (PNERP). In 2016, the CNSC advised the OFMEM to consider more severe accidents in the update to the PNERP, which may result in potential changes to the planning basis. Potentially, these changes may include new protective requirements and expansion of the emergency plan requirements for Pickering. In December 2017, the Province approved the updated PNERP Master Plan. The development of a detailed Implementing Plan for the Pickering GS is in progress. To date, there is no significant impact on OPG from the updated PNERP.

In December 2015, the CNSC granted the Darlington GS a ten-year operating licence, valid until November 30, 2025. The new licence spans most of the planned duration of the Darlington Refurbishment project, which provides greater regulatory stability and reduces regulatory risk. As discussed in the section, *Core Business, Strategy and Outlook*, under the heading, *Nuclear Operations*, the plan to extend Pickering operations to 2024 is subject to the CNSC's approval of the Pickering licence renewal application and other regulatory requirements as set out by the CNSC.

Nuclear Waste Management

The handling, storage and disposal of nuclear waste exposes OPG to various risks that it manages in accordance with the applicable regulatory requirements. Additionally, the interim storage of nuclear waste is subject to rigorous oversight and monitoring.

Currently, there are no licenced facilities in Canada for the permanent disposal of used nuclear fuel or L&ILW. The risks to OPG's proposed L&ILW DGR for the safe long-term management of L&ILW are discussed below under the heading, *Risks to Achieving Project Excellence – Deep Geologic Repository for Low and Intermediate Level Waste*.

Human Resources and Organizational Structure

The development of new leaders and retention of staff in critical roles is a key factor to OPG's success. The risk associated with the alignment and availability of skilled and experienced resources continues to exist for OPG in specific areas, including leadership and project management positions. To mitigate this risk, OPG continues to focus on succession planning, leadership development and knowledge management programs to improve the capability of its workforce. OPG expects to meet the human resource needs of the business by developing existing employees and hiring in specific areas, while continuing to leverage attrition through realignment of work and streamlining of processes, where appropriate.

Labour Relations

As of December 31, 2017, approximately 88 percent of OPG's regular labour force was represented by a union. The collective agreements with the PWU and The Society are due for renewal in 2018. There is a risk that OPG may not be able to negotiate terms that allow for compensation levels consistent with its rate orders.

OPG's current collective agreements with the PWU expires on March 31, 2018 and renewal negotiations began in early 2018. In the event of a labour disruption by the PWU, OPG could face financial or reputational implications. OPG has contingency plans in place to minimize the impact. **[MONITOR]**

The collective agreement between OPG and The Society expires on December 31, 2018 and renewal negotiations are expected to begin in mid-2018. The parties do not have the right to strike or lock-out. If the parties are unable to reach an agreement, the terms of the new collective agreement would be decided through interest mediation/arbitration.

Health and Safety

OPG's operations involve inherent occupational safety risks and hazards that could impact the achievement of the Company's health and safety goals. OPG is committed to continuous improvement and achievement of its ultimate goal of zero injuries through a formal enterprise-wide safety management system and by continuing to foster a strong health and safety culture among its employees and contractors. The safety management system serves to focus the Company on proactively managing safety risks and hazard exposures to employees and contractors. OPG also strategically engages with external parties for benchmarking and auditing. This ensures that OPG's management system achieves its intended results and maximizes the opportunity to incorporate program improvements.

Business Continuity and Emergency Management

OPG may be exposed to natural, technological or human-caused hazards including significant events against which it is not fully insured or indemnified; or to parties that fail to meet their indemnification obligations. These hazards have the potential to disrupt operations resulting in decreased generation revenue or additional costs to repair damages and restore operations.

OPG's business continuity program provides a framework to build resilience into critical business processes to ensure continued operation of critical business functions. OPG's emergency management program is designed to ensure that the Company can manage an emergency in a timely and effective manner. OPG's plans and implementation procedures identify immediate response actions to be taken to protect the health and safety of workers and the public, and to limit the impact of the incident on site security, production capability and the environment. The program elements are designed to meet legal and regulatory requirements.

Risks to Achieving Project Excellence

OPG is undertaking several capital intensive projects with significant investments. There may be an adverse effect on the Company if it is unable to: obtain necessary approvals; raise the necessary funds; effectively manage the projects on time and on budget; or fully recover capital costs and earn an appropriate return on investment. These projects may also have a significant impact on OPG's borrowing capacity and credit rating. Some projects may be ultimately reassessed as being uneconomic. The risks associated with OPG's current major projects are described below.

Darlington Refurbishment

There are financial and reputational risk exposures for OPG if actual costs exceed the budget or if OPG does not meet the project schedule. In addition, failure to achieve the objectives of the refurbishment project may result in future forced outages and more complex planned outages, potentially impacting the post-refurbishment performance or useful life of the units. Failure to carry out the refurbishment of the first unit as planned may result in the Province

exercising an off-ramp for the refurbishment of the remaining units. In January 2018, Refurbishment senior management met with the Minister of Energy, Cabinet and Treasury Board to provide an update on the status of the Darlington Refurbishment project and to request a decision to not exercise the Unit 3 off-ramp. The request was based on the performance to date on the Unit 2 project. Additionally, OPG continues to apply lessons learned that have been captured on the execution of Unit 2 into the planning of future units.

There are a number of specific risks that OPG is managing and mitigating in relation to the Darlington Refurbishment project, which include OPG and vendor performance risks, delay or productivity risks, financial risks related to escalation of costs, technical risks such as equipment conditions resulting in additional scope and execution risks. A large portion of the costs for the Darlington Refurbishment project is being paid to contractors and suppliers, including vendors that will engineer, procure and construct components of the project. There is a risk that, as the volume of work increases significantly, vendor capability, capacity and performance shortfalls may impact project objectives and deliverables.

OPG systematically manages the risks associated with the Darlington Refurbishment project through robust risk management practices to achieve project deliverables on time and budget with quality. OPG engaged in an extensive five-year project planning phase to determine the project scope and to rigorously estimate costs. During this phase, OPG also took into account major lessons learned from other nuclear refurbishments and large scale, complex projects. In order to fully define the scope and material requirements for the project, the planning phase included the completion of detailed designs before proceeding with the execution of the unit refurbishments. Further risk mitigation has been implemented through the construction of a full scale model training reactor, which allows for simulations and training for unit refurbishment execution tasks.

OPG's risk management strategy aims to ensure that contractors are held accountable and appropriate incentives and disincentives are in place. There is also an increased risk of contractor initiated safety events, which may impact OPG's reputation. Mitigating actions include:

- Collaborative training and planning with vendors on executing work safely;
- An enhanced human performance program;
- Increased field presence by supervisory staff; and
- Collaboration with Bruce Power to streamline processes and reduce burden on vendors.

OPG is also managing other ongoing risks that could potentially impact the project, including those related to continuity of skilled leaders within OPG and its vendor partners, as well as the availability of technical resources to support the project through execution.

Both management and Board of Directors have engaged Independent, third-party oversight for the execution phase of the project.

Deep Geologic Repository for Low and Intermediate Level Waste

OPG, with the support of Bruce County municipalities, is proposing to construct and operate a deep geologic repository for the safe long-term management of L&ILW. While broad local community support for the proposed L&ILW DGR is stable, OPG continues its engagement with the SON towards securing support for the project.

In August 2017, the federal Minister of Environment and Climate Change wrote to OPG and commended OPG for its collaborative work with the SON and for the practical demonstration of reconciliation practises. In light of that work, the Minster requested OPG to update its analysis of the potential cumulative effects of the DGR project on the physical and cultural heritage of the SON, taking into account the results of the SON Community Process. OPG continues to work with the SON, however the timing and outcome of the SON Community Process and the EA decision by the Minister are uncertain.

Risks to Maintaining Financial Strength

Risks related to rate regulation, financial markets and long-term obligations could significantly impact OPG's financial performance. The Company is also exposed to risks such as weak electricity demand, displacement of generation by competitors and financial risk associated with energy trading.

Rate Regulation

There is an inherent risk that regulated prices established by the OEB may not provide for the recovery of actual costs incurred by OPG's regulated operations or allow the regulated operations to earn an appropriate rate of return. This could occur if, in setting regulated prices, the OEB makes adjustments to forecasts submitted by OPG, if actual production and costs significantly differ from the forecasts approved by the OEB, or if OPG is unable to achieve OEB-approved stretch factors included in regulated prices under incentive ratemaking. Differences between OPG's actual and forecast production and costs could be due to factors such as outages or project execution risks. In providing evidence in support of its applications for regulated prices, OPG aims to clearly demonstrate to the OEB that the costs for the regulated operations are reasonable, prudently incurred and should be fully recovered from customers.

Certain differences between elements of OEB-approved revenue requirements and OPG's actual results are recorded in OEB-approved variance and deferral accounts for future review by the OEB. Additionally, these accounts may be subject to an OEB prudence review. There is uncertainty associated with the outcomes of future proceedings for the recovery or refund of these balances.

Nuclear Rate Smoothing Proposal

Consistent with the requirements of *Ontario Regulation 53/05*, OPG's nuclear rates will be smoothed as a result of OPG deferring a portion of the approved annual nuclear revenue requirements during the period from January 1, 2017 to the end of the Darlington Refurbishment project in a Rate Smoothing Deferral Account.

There is a risk that the magnitude of the deferral ordered by the OEB will result in regulated prices that do not provide sufficient cash flow to the Company for meeting its financial objectives in an optimal manner, including ensuring sufficient liquidity, cost effectively funding the Darlington Refurbishment project and other expenditures and maintaining the Company's investment grade credit rating. Maintaining adequate levels of credit metrics will support OPG's investment grade credit rating. As such, OPG requested the OEB to consider the impact on its credit rating when smoothing the nuclear base rates. **[MONITOR]**

Post-Employment Benefit Obligations Risk

OPG's post-employment benefit obligations include pension, group life insurance, health care benefits, and LTD benefits. OPG's post-employment benefit obligations and costs and pension plan contributions could be materially affected in the future by numerous factors including: changes in discount rates, inflation rates and other actuarial assumptions; future investment returns; experience gains and losses; the funded status of the pension plans; changes in benefits; changes in the regulatory environment including potential changes to the *Pension Benefits Act* (Ontario); changes in OPG's operations and the measurement uncertainty incorporated into the actuarial valuation process.

The OPG registered pension plan, which covers most of OPG's employees and retirees, is a contributory defined benefit plan that is indexed to inflation up to a certain maximum. Contributions to the OPG registered pension plan are determined by actuarial valuations, which are filed with the appropriate regulatory authorities at least every three years. Future actuarial valuations could increase OPG's funding requirements due to market and economic-related conditions. A significant decline in the financial markets could trigger an immediate requirement to update the actuarial valuation based on declines in the funded status. OPG continues to assess the requirements for contributions to the registered pension plan, including the timing of future actuarial valuations. OPG's OPEB

obligations are not funded and the associated employee benefits are paid from cash flows provided by operating activities or other sources of liquidity.

Nuclear Liabilities and Nuclear Segregated Funds

As required by the CNSC, OPG is responsible for the management of used nuclear fuel and L&ILW and the decommissioning of its nuclear stations and waste management facilities. The cost estimates for OPG's nuclear waste management and decommissioning obligations are based on multiple underlying assumptions and estimates that are inherently uncertain and may evolve over time. The assumptions include station end-of-life dates, waste volumes, waste disposal methods, the timing of construction of assumed waste disposal facilities, waste packaging systems, decommissioning strategy and financial indicators. To address the inherent uncertainty, OPG undertakes to perform a comprehensive review of the underlying assumptions and baseline cost estimates at least once every five years, in line with the required ONFA Reference Plan update process.

The most recent comprehensive update of the nuclear waste management and decommissioning obligations was approved by the Province in December 2016 as part the 2017 ONFA Reference Plan. An approved ONFA Reference Plan determines OPG's contributions to the Nuclear Segregated Funds. Based on the 2017 ONFA Reference Plan, no contributions are currently required to the Nuclear Segregated Funds. Additional contributions may be required should the Nuclear Segregated Funds be in an underfunded position in the future.

Nuclear Funds are segregated under ONFA in order to fund the long-term waste management, used fuel management and decommissioning expenditures. These funds are managed to achieve, in the long term, the target rate of return based on the discount rate specified in the ONFA. Investments in the Nuclear Segregated Funds are allocated to certain asset classes including fixed income securities, domestic and international equity securities, pooled funds, infrastructure, agriculture and real estate. The rates of return earned on these segregated funds may vary depending on current and future financial market conditions. The asset mix of the funds is determined jointly by OPG and the Province in accordance with the ONFA.

Under ONFA, OPG bears the market risk related to the portion of the Nuclear Segregated Funds set aside for:

- decommissioning of Pickering and Darlington nuclear generating stations; and
- long-term management of the irradiated used fuel bundles in excess of the first 2.23 million bundles and L&ILW after the respective Pickering GS and Darlington GS shut down.

A significant drawdown in the Nuclear Funds would first reduce the surplus in the respective funds before impacting OPG's net income. As such, the income statement impact of this risk is reduced when the Nuclear Segregated Funds are in a fully funded position.

Liquidity

OPG operates in a capital intensive business. Significant financial resources are required to fund major development and other capital improvement projects, including the Darlington Refurbishment project. In addition, the Company has other significant disbursement requirements including pension contributions, payments towards OPEB and other benefit plans, funding ongoing operations, debt maturities with the OEFC, OPG's investment in the Fair Hydro Plan and investments in new generating capacity and other business development opportunities. OPG must ensure that it has the financial capacity and sufficient access to cost effective financing sources to fund its capital requirements and other disbursements. In support of this objective, OPG utilizes multiple sources and forecasts availability of funds, actively monitors funding requirements and is focused on maintaining its investment grade credit rating. The Company's ability to arrange sufficient and cost-effective debt financing could be adversely affected by a number of factors, including, financial market and general economic conditions, the regulatory environment in Ontario, the Company's results of operations and financial conditions, the ratings assigned to the Company by credit rating agencies and the current timing of debt maturities.

A discussion of corporate liquidity is included in the section, *Liquidity and Capital Resources*.

Commodity Markets

Changes in the market price of fuels used to produce electricity can adversely impact OPG's earnings and cash flow from operations.

To manage the risk of unpredictable increases in the price of fuels, the Company has fuel hedging programs, which include using fixed price and indexed contracts.

The percentages hedged of OPG's fuel requirements are shown in the following table. These amounts are based on yearly forecasts of generation and supply mix and, as such, are subject to change as these forecasts are updated.

	2018	2019	2020
Estimated fuel requirements hedged [1]	72.9%	68.2%	65.3%

[1] Represents the approximate portion of megawatt-hours of expected generation production (and year-end inventory targets) from each type of OPG-operated facility (nuclear, hydroelectric and thermal) for which the Company has entered into contractual arrangements or obligations in order to secure the price of fuel, or which is subject to regulation. In the case of hydroelectric generation, this represents the gross revenue charge and water rental charges. Excess fuel inventories (nuclear and thermal) in a given year are attributed to the next year for the purpose of measuring hedge ratios.

Foreign Exchange

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are primarily denominated in, or tied to US dollars (USD). To manage this risk, OPG employs various financial instruments such as forwards and other derivative contracts, in accordance with approved risk management policies. As at December 31, 2017, OPG had total foreign exchange contracts outstanding with a notional value of USD $5 million.

Trading

OPG's financial performance can be affected by its trading activities. OPG's electricity trading operations are closely monitored, with total exposures measured and reported to senior management on a daily basis. The main metric used to measure the financial risk of trading activity is Value at Risk (VaR). VaR is defined as a probabilistic maximum potential future loss expressed in monetary terms for a portfolio based on normal market conditions over a set period of time. During 2017, the VaR utilization ranged between $0.1 million and $0.4 million, compared to between nil and $1.5 million in 2016.

Credit

The Company's credit risk exposure is a function of its electricity sales, trading and hedging activities, treasury activities including investing and commercial transactions with various suppliers of goods and services. OPG's credit risk exposure relating to electricity sales is considered low as the majority of sales are through the IESO-administered spot market. The IESO oversees the credit worthiness of all market participants. In accordance with the IESO's prudential support requirements, market participants are required to provide collateral to cover funds that they might owe to the market.

The following table summarizes OPG's credit exposure to all counterparties from electricity transactions and trading as at December 31, 2017:

	All Counterparties		Largest Counterparties	
Credit Rating [1]	**Number of Counterparties** [2]	**Potential Exposure** [3] *(millions of dollars)*	**Number of Counterparties**	**Potential Exposure** *(millions of dollars)*
Investment grade	15	18	5	14
IESO [4]	1	360	1	360
Total	16	378	6	374

[1] Credit ratings are based on OPG's own analysis, taking into consideration external rating agency analysis where available, as well as recognizing explicit credit support provided through parental guarantees, Letters of Credit or other forms of security.

[2] OPG's counterparties are defined on the basis of individual master agreements.

[3] Potential exposure is OPG's statistical assessment of maximum exposure over the life of each transaction at a 95 percent confidence interval.

[4] Credit exposure is an estimate of the short-term receivable amount arising from OPG's electricity sales into the IESO market. The credit exposure and associated receivable vary each month based on electricity sales. The monthly receivable from the IESO is typically paid to OPG in the subsequent month as per the IESO payment schedule.

Other major components of OPG's credit risk exposure include those associated with vendors that are contracted to provide services or products. OPG manages its exposure to various suppliers or counterparties by evaluating their financial condition and ensuring that the Company holds appropriate collateral or other forms of security.

Contracted Generation

The Company's generating stations that operate under ESAs with the IESO or other long-term contracts are subject to several obligations, including but not limited to:

- availability targets;
- monthly and annual reporting; and
- must offer obligations, as specified in their respective contracts.

OPG could incur penalties up to and including termination of the respective contract if these facilities fail to meet their contractual obligations. This risk is mitigated through:

- education of staff who work with these facilities;
- continuous communication between staff managing the contracts and staff managing the stations;
- processes that monitor and address contractual obligations and milestones; and
- the implementation of maintenance, capital investment (approved by the IESO when required by the contracts) and other programs.

OPG's owned and co-owned thermal generating stations operate under ESAs with the IESO or other long-term agreements. While OPG expects that its thermal generating stations will continue to provide capacity to the market over the term of the respective agreements, there is a risk that, upon expiry of the current agreements, subsequent contracts for these stations may not be available or may not be financially viable. The Thunder Bay Biomass ESA is the first such contract to reach the end of its term, scheduled for early 2020.

Ontario Electricity Market

OPG's revenue can be impacted by external factors related to the electricity market including: the entrance of new participants into the Ontario market; the competitive actions of market participants; Ontario electricity demand; changes in the regulatory environment; and wholesale electricity prices in the interconnected markets.

The IESO is in the preliminary stages of a Market Renewal Program, which is expected to result in a fundamental redesign of Ontario's electricity markets and may impact OPG depending on the market design that is implemented. To mitigate this risk, OPG is actively participating in Market Renewal stakeholder committees as well as continuing to collaborate with the IESO.

Ownership by the Province

The Province owns all of OPG's issued and outstanding common shares. Accordingly, the Province, as represented by the Ontario Ministry of Energy, has the authority to make appointments to OPG's Board of Directors. OPG could be subject to Shareholder direction, under Section 108 of the OBCA that can directly influence major decisions. These directions could include those related to project development, timing and strategy of applications for regulated prices, acquisitions and asset divestitures, financing and capital structure. As a result, OPG could be required to undertake activities that result in increased expenditures, or that reduce revenues or cash flows relative to the business activities or strategies that would have otherwise been undertaken. In addition, the obligation of OPG's Shareholder to respond to a broad range of matters in its role as the Government of Ontario may compete with OPG's commitment to maximize the return on the Shareholder's investment in the Company. This includes, but is not limited to, the Province's response to mitigate the impact of rising electricity prices on consumers.

Government Legislation and Regulation Change

OPG's core business and strategy may be impacted by changes in federal and provincial legislation and regulations. Matters that are subject to regulation include, among others, rate regulation, electricity generating operations, nuclear waste management and nuclear decommissioning, the Ontario electricity market and taxation. Regulatory bodies may change or enact regulations or rules that could increase OPG's costs, decrease OPG's revenue, or limit the Company's ability to recover appropriate costs or earn a return on the assets.

The next Ontario provincial election is set to take place in June 2018 and electricity rates are a focus of each party's platform. Depending on the outcome of the election, there may be significant legislative changes that could impact OPG.

Since legal requirements are subject to change and to interpretation, OPG is unable to predict the impact of such changes on the Company and its operations. To mitigate legislative risks, OPG continues to monitor and actively engage with the federal and provincial governments in order to determine if future legislation will impact the Company.

Litigation

OPG or its subsidiaries are involved in various legal proceedings covering a range of matters arising out of their business activities. Each of these matters is subject to various uncertainties and some of these matters may be resolved unfavourably. Refer to Note 16 of OPG's 2017 audited consolidated financial statements under the heading, *Litigation* for further details.

Risks to Maintaining Social Licence

OPG is exposed to risks associated with its social licence and public profile due to changes in the opinions of:

- Various stakeholders, including Ontario electricity customers, local communities, government agencies; and
- Indigenous communities.

Maintaining public trust and meeting stakeholders and Indigenous communities' expectations are critical to OPG's success. OPG focuses on building and maintaining its social licence and corporate reputation through safe, reliable, environmentally-responsible operations as well as corporate citizenship initiatives across the province. The inability to maintain safe, reliable operations could negatively impact OPG's reputation and result in a loss of public support.

Ontario Fair Hydro Plan Act

The Fair Hydro Act received Royal Assent and came into force on June 1, 2017. As the Financial Services Manager under the Act, OPG's reputation could potentially be adversely impacted through this involvement and through stakeholder opinions related to this involvement.

Indigenous Communities

The quality of OPG's relationships and the outcome of negotiations with Indigenous communities may impact OPG's project and financial performance, as well as its social licence to operate.

OPG may be subject to claims by Indigenous communities. These claims stem from projects and generation development related to the operations of OPG and historic operations of OPG's predecessor company, Ontario Hydro, which may have impacted the Aboriginal and/or Treaty rights of Indigenous communities.

OPG has an Indigenous Relations Policy, which sets out the Company's commitment to proactively build and maintain positive relationships with Indigenous communities. OPG has been successful in working collaboratively with Indigenous communities to resolve a number of past grievances. However, the outcome of ongoing and any future negotiations depends on a number of factors, including legislation and regulations and precedents created by court rulings, which are subject to change over time. OPG pursues generation-related developments in partnerships with Indigenous communities on the basis of long-term mutually beneficial commercial arrangements.

Environmental Risks

OPG's operations and facilities are subject to environmental compliance obligations at the municipal, provincial and federal levels that include protection of land, water, air, living organisms and natural systems. A failure to comply with applicable environmental laws may result in enforcement actions, remediation actions or restrictions to operations. Changes in compliance obligations can result in new operational requirements and increased costs.

OPG has an ISO 14001 registered EMS to manage its environmental responsibilities. For further information, see discussion in the section, *Core Business, Strategy, and Outlook* under the heading, *Environmental Performance*.

OPG recognizes that efforts are required to plan for the impacts of climate change and has identified climate change adaptation as a strategic priority for the company. OPG monitors developments in climate science, adaptation activities, and potential changes to policy and regulatory requirements. OPG continues to work with stakeholders to better define adaptation requirements through analysis and understanding of impacts on watersheds, equipment and the electricity market. OPG undertakes a risk-based analysis to determine the extent of adaptation requirements to reduce the impact of climate change on its operations, and also collaborates with all levels of government and industry to increase the resiliency of the electricity infrastructure.

A carbon cap and trade program became effective in Ontario in January 2017. The program is not expected to have a material adverse economic impact on OPG due to the Company's low GHG emissions. Further details can be found in the section, *Core Business, Strategy and Outlook* under the heading, *Environmental Performance*.

RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One, the IESO and the OEFC. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly-owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions for the years ended December 31 are summarized below:

	2017		2016	
(millions of dollars)	**Revenue**	**Expense**	**Revenue**	**Expense**
Hydro One				
Electricity sales	**8**	**-**	6	-
Services	**1**	**10**	1	5
Dividends	**7**	**-**	6	-
Province of Ontario				
Change in Decommissioning Segregated Fund amount due to Province [1]	**-**	**456**	-	192
Change in Used Fuel Segregated Fund amount due to Province [1]	**-**	**591**	-	235
Hydroelectric gross revenue charge	**-**	**110**	-	120
ONFA guarantee fee	**-**	**8**	-	8
Other	**-**	**2**	-	-
OEFC				
Hydroelectric gross revenue charge	**-**	**216**	-	203
Interest expense on long-term notes	**-**	**158**	-	169
Income taxes, net of investment tax credits	**-**	**246**	-	104
IESO				
Electricity related revenue	**4,802**	**-**	5,082	-
Fair Hydro Trust	**4**	**3**	-	-
	4,822	**1,800**	5,095	1,036

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at December 31, 2017 and December 31, 2016, the Nuclear Segregated Funds were reported net of amounts due to the Province of $4,462 million and $3,415 million, respectively.

The receivable, AFS securities, payable and long-term debt balances between OPG and its related parties are summarized below:

(millions of dollars)	**December 31 2017**	**December 31 2016**
Receivables from related parties		
Hydro One	**1**	1
IESO – Electricity related receivables	**354**	421
IESO – Fair Hydro Trust [1]	**7**	-
OEFC	**-**	1
PEC	**4**	4
Province of Ontario	**3**	2
Financing receivables		
IESO – Fair Hydro Trust	**1,179**	-
Available-for-sale securities		
Hydro One shares	**188**	212
Accounts payable and accrued charges		
Hydro One	**1**	-
OEFC	**52**	61
Province of Ontario	**9**	2
IESO – Electricity-related payables	**5**	2
IESO – Fair Hydro Trust	**3**	-
Long-term debt (including current portion)		
Notes payable to OEFC	**3,195**	3,295

[1] Balance consists of unbilled revenue.

OPG holds interest-bearing Province of Ontario bonds in the Nuclear Segregated Funds and the OPG registered pension fund. As at December 31, 2017, the Nuclear Segregated Funds held $1,503 million of interest-bearing Province of Ontario bonds. As at December 31, 2016, the Nuclear Segregated Funds and the registered pension fund held $1,652 million and $284 million of interest-bearing Province of Ontario bonds, respectively. These bonds are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

In December 2017, the Trust purchased its first tranche of Investment Interest from the IESO for an exchange amount of $1.18 billion, which has been classified as a financing receivable on OPG's consolidated balance sheet. The transaction was settled in cash using proceeds from the Trust's issuance of senior and subordinated debt. Pursuant to the general regulation of the Act, the IESO is required to pay and remit carrying costs of the Trust, excluding repayment of principal on any debt obligations, up to July 31, 2021. Commencing May 1, 2021, Specified Consumers will be invoiced by their local distribution company for the Clean Energy Adjustment to pay financing and other costs of the Trust. These funds will be remitted to the Trust through the IESO and will be used to settle all funding and other related expenses of the Trust that underlie the financing receivable.

As at December 31, 2017, OPG's consolidated balance sheet included approximately $7 million of unbilled revenue from the IESO primarily for OPG's general fee for 2017 as Financial Services Manager relating to incurred third-party and certain direct labour costs. In February 2018, OPG submitted to the OEB its proposed general fee for 2017 in the amount of approximately $6 million for review pursuant to the requirements of the general regulation of the Fair Hydro Act. Once approved, the fees will be remitted to the Trust by the IESO and the Trust will pay OPG's fees as Financial Services Manager.

INTERNAL CONTROLS OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

Management, including the President and Chief Executive Officer (President and CEO) and the Chief Financial Officer (CFO), are responsible for maintaining Disclosure Controls and Procedures (DC&P) and Internal Controls over Financial Reporting (ICOFR). DC&P is designed to provide reasonable assurance that all relevant information is gathered and reported to senior management, including the President and CEO and the CFO, on a timely basis so that appropriate decisions can be made regarding public disclosure. ICOFR is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the financial statements in accordance with US GAAP.

There were no changes in OPG's ICOFR during the year ended December 31, 2017 that have materially affected or are reasonably likely to materially affect OPG's ICOFR.

Management, including the President and CEO and the CFO, concluded that, as of December 31, 2017, OPG's DC&P and ICOFR (as defined in National Instrument 52-109 – *Certification of Disclosure in Issuers' Annual and Interim Filings*) were effective.

FOURTH QUARTER

Discussion of Results

(millions of dollars) (unaudited)	Three Months Ended December 31 2017	2016
Revenue	**1,619**	1,388
Fuel expense	**171**	186
Gross margin	**1,448**	1,202
Operations, maintenance and administration	**770**	686
Depreciation and amortization	**162**	316
Accretion on fixed asset removal and nuclear waste management liabilities	**251**	233
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(222)**	(126)
Earnings from Fair Hydro Trust	**(1)**	-
Income from investments subject to significant influence	**(9)**	(9)
Property taxes	**10**	11
Restructuring	**-**	6
Income before other losses, interest, and income taxes	**487**	85
Other losses	**1**	6
Income before interest and income taxes	**486**	79
Net interest expense	**39**	28
Income before income taxes	**447**	51
Income tax expense	**81**	59
Net income (loss)	**366**	(8)
Net income (loss) attributable to the Shareholder	**362**	(13)
Net income attributable to non-controlling interest	**4**	5

Net income attributable to the Shareholder for the fourth quarter was $362 million, compared to a net loss of $13 million for the same quarter in 2016.

Income before interest and income taxes was $486 million during the fourth quarter of 2017, an increase of $407 million compared to income before interest and income taxes of $85 million during the same period in 2016. The following summarizes the significant factors which contributed to the variance:

Significant factors that increased income before interest and income taxes:

- Higher revenue from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments totaling approximately $480 million recorded in the fourth quarter of 2017 to reflect the OEB's decision on OPG's application for new regulated rates issued in December 2017 with a retrospective effective date of June 1, 2017.
- Higher earnings of $77 million from the Regulated – Nuclear Waste Management segment, primarily due to higher earnings from the Nuclear Segregated Funds reflecting the growth rate in the present value of the funding liabilities, partially offset by an increase in accretion expense on the Nuclear Liabilities.

Significant factors that decreased income before interest and income taxes:

- Lower revenue from the nuclear base regulated price of approximately $55 million, partially offset by a decrease in fuel expense of $9 million, reflecting lower electricity generation of 0.9 terawatt hours (TWh) from the Regulated – Nuclear Generation segment. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS since October 2016, partially offset by an increase in generation from the Pickering GS. The increase in generation from the Pickering GS was primarily due to outage cycle optimization, favourable unit conditions and execution of planned outage work resulting in fewer unplanned and planned outage days at the station.
- Higher OM&A expenses of $55 million, mainly in the Regulated – Nuclear Generation segment, reflected planned expenditures related to the major maintenance expenditures occurring at the nuclear stations.

The increase in income tax expense during the fourth quarter of 2017, compared to the same quarter in 2016, was primarily due to higher income before income taxes, partially offset by a higher amount of tax expense deferred in regulatory assets in 2017.

Average Sales Prices

The average sales price for the Regulated – Nuclear Generation segment during the fourth quarter of 2017 was 11.0 ¢/kWh, compared to 6.9 ¢/kWh during the same quarter in 2016. The increase in the average sales price was primarily due to the OEB ruling issued in December 2017, in which OPG received a base rate increase, retroactive to June 1, 2017. The average sales price for the Regulated – Hydroelectric segment during 2017 was 4.3 ¢/kWh, compared to 4.4 ¢/kWh during 2016. The decrease in this average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized regulated hydroelectric rate rider of $3.19/MWh for the recovery of variance and deferral account balances. The rate riders were established to recover approved balances recorded in the variance and deferral accounts in prior years. As such, the year-over-year changes in revenue from the rate riders were largely offset by changes in amortization expense related to these balances.

Electricity Generation

OPG's electricity generation for the three months ended December 31, 2017 and 2016 was as follows:

(TWh)	Three Months Ended December 31 2017	2016
Regulated – Nuclear Generation	**10.1**	11.0
Regulated – Hydroelectric	**7.2**	6.7
Contracted Generation Portfolio [1]	**0.8**	0.6
Total OPG electricity generation	**18.1**	18.3
Total electricity generation by all other generators in Ontario [2]	**18.8**	18.9

[1] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

[2] Non-OPG generation is calculated as the Ontario electricity demand plus net exports, as published by the IESO, minus OPG electricity generation.

The decrease in OPG's electricity generation of 0.2 TWh during the fourth quarter of 2017, compared to the same quarter in 2016, was mainly due to lower electricity generation of 0.9 TWh from the Regulated – Nuclear Generation segment. This was mainly the result of more planned outage days at Pickering in 2017 as well as the refurbishment of Unit 2 at the Darlington GS, which began in mid-October 2016 and continued for all of 2017. This was largely offset by higher production from the Regulated - Hydroelectric and Contracted Generation Portfolio segments mainly due to higher water flows on the eastern Ontario river systems.

Ontario's electricity demand as reported by the IESO was 33.6 TWh during the fourth quarter of 2017, compared to 33.2 TWh during the fourth quarter of 2016.

Liquidity and Capital Resources

Cash flow provided by operating activities during the three months ended December 31, 2017 was $246 million, compared to $606 million for the same period in 2016. The decrease in cash flow was primarily due to lower generation revenue receipts and higher OM&A expenditures during the fourth quarter of 2017.

Cash flow used in investing activities during the three months ended December 31, 2017 was $1,758 million, compared to $666 million during the same period in 2016. The increase was primarily due to the acquisition of the Fair Hydro Trust financing receivables and higher expenditures on the Darlington Refurbishment project in 2017.

Cash flow provided by financing activities during the three months ended December 31, 2017 was $1,466 million, compared to cash flow used in financing activities of $180 million for the same period in 2016. The increase in cash flow provided by financing activities was primarily due to higher net issuance of long-term debt and short-term notes by the Trust, as well as issuance of Class A shares in the four quarter of 2017. The increase was partially offset by the repayment of short term notes.

QUARTERLY FINANCIAL HIGHLIGHTS

The following tables set out selected annual financial information for the last three years and financial information for each of the eight most recently completed quarters. This information is derived from OPG's unaudited interim consolidated financial statements and the audited consolidated financial statements, and has been prepared in accordance with US GAAP.

Annual Financial Information

(millions of dollars – except where noted)	**2017**	**2016**	**2015**
Revenue	**5,158**	5,653	5,476
Net income attributable to the Shareholder	**860**	436	402
Earnings per common share *(dollars)*	**$3.35**	$1.70	$1.57
Total assets	**48,822**	44,372	44,250
Total long-term liabilities	**34,933**	31,460	32,404
Weighted average common shares outstanding *(millions)*	**256.7**	256.3	256.3

Quarterly Financial Information

(millions of dollars – except where noted) *(unaudited)*	**2017 Quarters Ended**				
	December 31	**September 30**	**June 30**	**March 31**	**Total**
Revenue	**1,619**	**1,217**	**1,146**	**1,176**	**5,158**
Net income	**366**	**140**	**307**	**68**	**881**
Less: Net income attributable to non-controlling interest	**4**	**9**	**4**	**4**	**21**
Net income attributable to the Shareholder	**362**	**131**	**303**	**64**	**860**
Earnings per common share, attributable to the Shareholder *(dollars)*	**$1.41**	**$0.51**	**$1.18**	**$0.25**	**$3.36**

Quarterly Financial Information

(millions of dollars – except where noted) *(unaudited)*	**2016 Quarters Ended**				
	December 31	**September 30**	**June 30**	**March 31**	**Total**
Revenue	1,388	1,400	1,387	1,478	5,653
Net (loss) income	(8)	198	135	128	453
Less: Net income attributable to non-controlling interest	5	4	3	5	17
Net (loss) income attributable to the Shareholder	(13)	194	132	123	436
Per common share, attributable to the Shareholder *(dollars)*	($0.05)	$0.76	$0.51	$0.48	$1.70

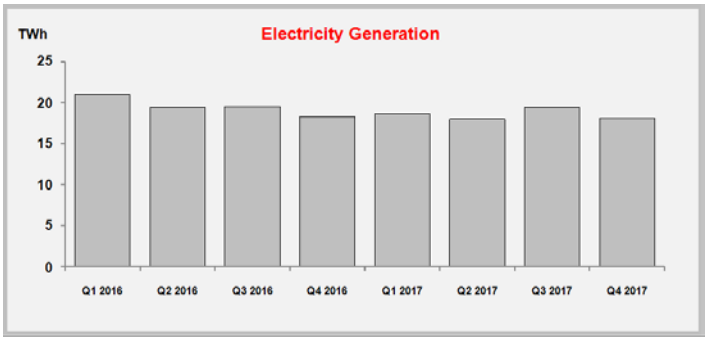
Trends

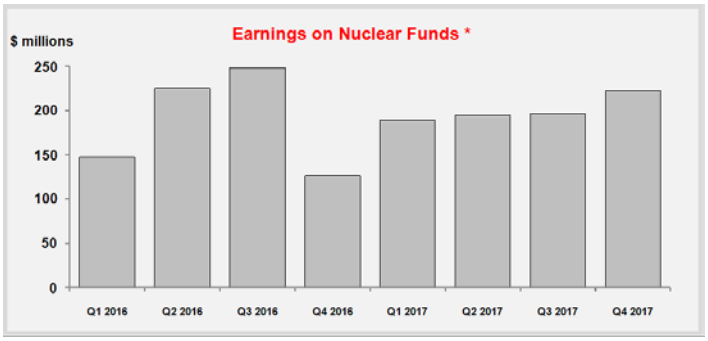
OPG's quarterly results are affected by changes in grid-supplied electricity demand, primarily resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. Weather conditions affect water flows, electricity demand, and prevalence of SBG conditions. Historically, OPG's revenues have been higher in the first quarter of a fiscal year as a result of winter heating demands and in the third quarter due to air conditioning and cooling demands. The financial impact of forgone production due to SBG conditions at the regulated hydroelectric stations and the financial impact of differences between forecast water flows reflected in OEB-approved regulated prices and the actual water flows are offset by regulatory variance accounts authorized by the OEB.

The timing of planned outages at a nuclear generating station during the year can cause variability in year-over-year operating results for partial periods of a fiscal year, including the impact on revenue and OM&A expenses, but is not a significant driver of variability for full fiscal year results.

OPG's electricity generation was reduced as a result of the Unit 2 refurbishment outage at the Darlington GS, which began in October 2016 and is expected to continue until early 2020.

OPG's financial results are also affected by the earnings on the Nuclear Segregated Funds, net of the impact of the Bruce Lease Net Revenues Variance Account. The volatility of the earnings on the Nuclear Segregated Funds is mitigated by their funded status.





*net of regulatory variance account

SUPPLEMENTARY NON-GAAP FINANCIAL MEASURES

In addition to providing net income and other financial information in accordance with US GAAP, certain non-GAAP financial measures are also presented in OPG's MD&A. These non-GAAP measures do not have any standardized meaning prescribed by US GAAP and, therefore, may not be comparable to similar measures presented by other issuers. OPG utilizes these measures to make operating decisions and assess performance. Readers of the MD&A would utilize these measures in assessing the Company's financial performance from ongoing operations. The Company believes that these indicators are important since they provide additional information about OPG's performance, facilitate comparison of results over different periods, and present measures consistent with the Company's strategies to provide value to the Shareholder, improve cost performance, and ensure availability of cost effective funding. These non-GAAP financial measures have not been presented as an alternative to net income, cash flow provided by operating activities, or any other measure in accordance with US GAAP, but as indicators of operating performance.

The definitions of the non-GAAP financial measures are as follows:

(1) ROE Excluding AOCI is defined as net income attributable to the Shareholder divided by average equity attributable to the Shareholder excluding AOCI, for the period.

ROE Excluding AOCI is measured over a 12-month period and is calculated as follows for the period ended December 31:

(millions of dollars – except where noted) (unaudited)	**2017**	**2016**
ROE Excluding AOCI		
Net income attributable to the Shareholder	**860**	436
Divided by: Average equity attributable to the Shareholder, excluding AOCI	**11,498**	10,442
ROE Excluding AOCI *(percent)*	**7.5**	4.2

(2) **FFO Adjusted Interest Coverage** is defined as FFO before interest divided by adjusted interest expense. FFO before interest is defined as cash flow provided by operating activities adjusted for interest paid, interest capitalized to fixed and intangible assets, and changes to non-cash working capital balances for the period. Adjusted interest expense is calculated as net interest expense plus interest income, interest capitalized to fixed and intangible assets, interest related to regulatory assets and liabilities, and the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets, for the period.

FFO Adjusted Interest Coverage is measured over a 12-month period and is calculated as follows for the period ended December 31:

(millions of dollars – except where noted) (unaudited)	**2017**	**2016**
FFO before interest		
Cash flow provided by operating activities	**944**	1,817
Add: Interest paid	**258**	269
Less: Interest capitalized to fixed and intangible assets	**(162)**	(141)
Less: Changes to non-cash working capital balances	**(54)**	(180)
FFO before interest	**986**	1,765
Adjusted interest expense		
Net interest expense	**95**	120
Add: Interest income	**9**	7
Add: Interest capitalized to fixed and intangible assets	**162**	141
Add: Interest related to regulatory assets and liabilities	**30**	30
Add: Excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets [1]	**-**	45
Adjusted interest expense	**296**	343
FFO Adjusted Interest Coverage *(times)*	**3.3**	5.1

[1] A value of nil is used in the calculation when interest on pension and OPEB projected benefit obligations is equal to, or lower than, expected return on pension plan assets.

(3) **Enterprise Total Generating Cost per MWh** is used to measure OPG's overall organizational cost performance. Enterprise TGC per MWh is defined as OM&A expenses (excluding the Darlington Refurbishment project and other generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to OPG's electricity generation business), fuel expense for OPG-operated stations including hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures (excluding the Darlington Refurbishment project and other generation development projects) incurred during the period, divided by total electricity generation from OPG-operated generating stations plus electricity generation forgone due to SBG conditions during the period.

Enterprise TGC per MWh is calculated as follows for the 12-month period ended December 31:

(millions of dollars – except where noted)	**2017**	**2016**
Enterprise TGC		
Total OM&A expenses	**2,824**	2,747
Total fuel expense	**689**	727
Total capital expenditures	**1,926**	1,704
Less: Darlington Refurbishment capital and OM&A costs	**(1,285)**	(1,022)
Less: Other generation development project capital and OM&A costs	**(65)**	(163)
Add: OM&A and fuel expenses (refundable through) deferred in regulatory variance and deferral accounts	**(1)**	62
Less: Nuclear fuel expense for non OPG-operated stations	**(57)**	(67)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**69**	49
Less: OM&A expenses ancillary to electricity generation business	**(18)**	(28)
Other adjustments	**(43)**	(19)
	4,039	3,990
Adjusted electricity generation *(TWh)*		
Total OPG electricity generation	**74.1**	78.2
Adjust for electricity generation forgone due to SBG conditions and OPG's share of electricity generation from co-owned facilities	**5.6**	4.1
	79.7	82.3
Enterprise TGC per MWh *($/MWh)* [1]	**50.66**	**48.45**

[1] Amounts may not calculate due to rounding.

(4) **Nuclear Total Generating Cost per MWh** is used to measure the cost performance of OPG's nuclear generating assets. Nuclear TGC per MWh is defined as OM&A expenses of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the nuclear electricity generation business), nuclear fuel expense for OPG-operated stations (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs) incurred during the period, divided by nuclear electricity generation for the period.

Nuclear TGC per MWh is calculated as follows for the 12-month period ended December 31:

(millions of dollars – except where noted)	**2017**	**2016**
Nuclear TGC		
Regulated – Nuclear Generation OM&A expenses	**2,293**	2,210
Regulated – Nuclear Generation fuel expense	**284**	315
Regulated – Nuclear Generation capital expenditures	**1,631**	1,338
Less: Darlington Refurbishment capital and OM&A costs	**(1,285)**	(1,022)
Add: Regulated – Nuclear Generation OM&A and fuel expenses deferred in regulatory variance and deferral accounts	**35**	81
Less: Nuclear fuel expense for non OPG-operated stations	**(57)**	(67)
Less: Regulated – Nuclear Generation OM&A expenses ancillary to electricity generation business	**(6)**	(10)
Other adjustments	**(10)**	(4)
	2,885	2,841
Nuclear electricity generation *(TWh)*	**40.7**	45.6
Nuclear TGC per MWh *($/MWh)* [1]	**70.95**	62.30

[1] Amounts may not calculate due to rounding.

(5) **Hydroelectric Total Generating Cost per MWh** is used to measure the cost performance of OPG's hydroelectric generating assets. Hydroelectric TGC per MWh is defined as OM&A expenses of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the hydroelectric electricity generation business), hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding expenditures related to the Peter Sutherland Sr. GS, Ranney Falls GS, and other hydroelectric generation development projects) incurred during the period, divided by total hydroelectric electricity generation plus hydroelectric electricity generation forgone due to SBG conditions during the period. OPG reports hydroelectric gross revenue charge and water rental payments as fuel expense.

Hydroelectric TGC per MWh is calculated as follows for the 12-month period ended December 31:

(millions of dollars – except where noted)	**2017**	**2016**
Hydroelectric TGC		
Regulated – Hydroelectric OM&A expenses	**330**	325
Regulated – Hydroelectric fuel expense	**351**	353
Contracted Generation Portfolio OM&A expenses	**169**	178
Contracted Generation Portfolio fuel expense	**53**	58
Regulated – Hydroelectric and Contracted Generation Portfolio capital expenditures	**226**	330
Less: Regulated – Hydroelectric and Contracted Generation Portfolio Generation Portfolio generation development project capital and OM&A costs	**(63)**	(158)
Less: Thermal OM&A and fuel expenses and capital expenditures in the Contracted Generation Portfolio	**(166)**	(177)
Less: Regulated – Hydroelectric OM&A and fuel expenses refundable through regulatory variance and deferral accounts	**(36)**	(24)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**69**	49
Other adjustments	**(1)**	(1)
	932	933
Adjusted hydroelectric electricity generation *(TWh)*		
Regulated – Hydroelectric electricity generation	**30.7**	29.5
Contracted Generation Portfolio electricity generation	**2.7**	3.1
Adjust for hydroelectric electricity generation forgone due to SBG conditions and non-hydroelectric electricity generation of the Contracted Generation Portfolio, including OPG's share of electricity generation from co-owned facilities	**5.5**	4.0
	38.9	36.6
Hydroelectric TGC per MWh *($/MWh)* [1]	**23.91**	25.49

[1] Amounts may not calculate due to rounding.

(6) **Gross margin** is defined as revenue less fuel expense**.**

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	Media Relations	416-592-4008
		1-877-592-4008

www.opg.com

www.sedar.com

ONTARIO POWER GENERATION INC.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2017

[DRAFT]

March 8, 2018

ANNUAL INFORMATION FORM
FOR THE YEAR ENDED DECEMBER 31, 2017

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PRESENTATION OF INFORMATION

References in this Annual Information Form (AIF) to the "Company", the "Corporation" or "OPG" are made to Ontario Power Generation Inc. Unless otherwise noted, the information contained in this AIF is as at or for the year ended December 31, 2017. Amounts are expressed in Canadian dollars unless otherwise indicated. Financial information is presented in accordance with United States generally accepted accounting principles (US GAAP). This AIF is dated March 8, 2018.

ADDITIONAL INFORMATION

Additional information relating to the Company may be found on SEDAR at www.sedar.com. Additional financial information relating to the Company is provided in the Company's annual Management's Discussion and Analysis (MD&A) and audited consolidated financial statements as at and for the year ended December 31, 2017, which is available on SEDAR at www.sedar.com or on the Company's website at www.opg.com. ***The above information is made available in accordance with legal requirements of an AIF and is not, unless otherwise specifically stated, incorporated by reference into this AIF.***

Details regarding compensation paid to directors and executive officers of the Company during the financial year ended December 31, 2017 is included in OPG's Statement of Executive Compensation (Form 51-102F6), which is available on SEDAR at www.sedar.com and is incorporated by reference herein.

FORWARD-LOOKING INFORMATION

This AIF contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could", and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

All forward-looking statements involve inherent assumptions, risks, and uncertainties. All forward-looking statements could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's generating station performance and availability, fuel costs, surplus baseload generation (SBG), cost of fixed asset removal and nuclear waste management, performance and earnings of investment funds, refurbishment of existing facilities, development and construction of new facilities, pension and other post-employment benefit (OPEB) obligations and funds, income taxes, proposed new legislation, the ongoing evolution of Ontario's electricity industry, environmental and other regulatory requirements, health, safety and environmental developments, business continuity events, the weather, financing and liquidity, applications to the Ontario Energy Board (OEB) for regulatory prices, the impact of regulatory decisions by the OEB, Ontario's Fair Hydro Plan (Fair Hydro Plan or the Plan), OM&A expenditures, retention of critical talent, supplier and third party performance, and project expenditures. Accordingly, undue reliance should not be placed on any forward-looking statement. The forward-looking statements included in this AIF are made only as of the date of this AIF. Except as required by applicable securities laws, OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events, or otherwise.

OPG faces various risks that could have a material adverse effect on its business, strategy, generating stations, reputation, financial condition, operating results, generation development and other projects. There may be further risks and uncertainties that are not presently known, or that are not currently believed to be material, that may in the future adversely affect the Company's performance or financial condition. OPG may be exposed to a significant event that it is not fully insured or indemnified against, or to a party that fails to meet its indemnification obligations. For details on risks faced by OPG, refer to the section, *Risk Management*, in the Company's 2017 year-end MD&A.

CORPORATE STRUCTURE

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG was formed in April 1999 through the restructuring of Ontario Hydro's integrated electricity business. OPG was established under the *Business Corporations Act* (Ontario) (OBCA) and is wholly owned by the Province of Ontario (Province or Shareholder). OPG and the Province are parties to a Memorandum of Agreement (MOA) that sets out OPG's role and responsibilities. The current MOA was executed in July 2015 and reaffirmed for continuance by both the Ontario Minster of Energy and the OPG Board of Directors' Chair in the fourth quarter of 2016, as required by the MOA following a change in the Minister of Energy. Further details on the MOA are discussed in the section, *Interest of Management and Others in Material Transactions* under the heading, *Relationship with the Province and the OEFC*.

OPG's registered head office is located at 700 University Avenue, Toronto, Ontario, M5G 1X6, Canada.

OVERVIEW OF OPG

OPG is Ontario's largest clean energy generator. As at December 31, 2017, OPG operated two nuclear generating stations, three thermal generating stations, 66 hydroelectric generating stations, and one wind power turbine. The majority of OPG's generation is from its rate-regulated nuclear and rate-regulated hydroelectric stations. In addition, OPG and TransCanada Energy Ltd. co-own the 550 megawatt (MW) Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS). OPG and ATCO Power Canada Ltd. co-own the 560 MW Brighton Beach gas-fired combined cycle GS (Brighton Beach). Including its share of the co-owned facilities, OPG's total in-service generating capacity was 16,210 MW as at December 31, 2017, which represented approximately 45 percent of installed generation capacity in Ontario's electricity grid as reported by the Independent Electricity System Operator (IESO). OPG's in-service generating capacity as of December 31, 2017 excludes Unit 2 of the Darlington Nuclear GS. The unit, which has a generating capacity of 878 MW, was taken offline in mid-October 2016 and is currently undergoing refurbishment. OPG operates under an electricity generation licence issued by the OEB, which is valid until October 30, 2023. OPG expects the licence to be renewed in the future.

OPG also owns two other nuclear generating stations, the Bruce A GS and the Bruce B GS, which are leased on a long-term basis to Bruce Power L.P. (Bruce Power) and are not included in the generation and other operating statistics set out in this AIF.

All of OPG's owned and co-owned generating facilities are located in Ontario.

Effective in the fourth quarter of 2017, following the establishment of the Fair Hydro Trust (the Trust) as the financing entity to implement the Fair Hydro Plan under the *Ontario Fair Hydro Plan Act, 2017* (the Fair Hydro Act or the Act), OPG has modified its reportable business segments to include the Fair Hydro Trust segment. Through its control over the key activities of the Trust and its obligation to absorb losses through ownership of the Trust's subordinated debt, the Company consolidates the financial results of the Trust in accordance with US GAAP. The Fair Hydro Trust segment reports the income related to OPG's role as Financial Services Manager under the Act and holder of subordinated debt issued by the Trust, including the financial results of the Trust. The Fair Hydro Plan and the Fair Hydro Trust are discussed in the section, *General Development of the Business* under the heading, *General Development* and in the section, *Description of the Business* under the heading, *Fair Hydro Trust Segment*.

OPG's business operations are divided into six business segments and are discussed under the heading, *General Development* and in their respective sections. The six business segments are as follows:

- Regulated – Nuclear Generation
- Regulated – Nuclear Waste Management
- Regulated – Hydroelectric
- Contracted Generation Portfolio
- Services, Trading, and Other Non-Generation
- Fair Hydro Trust

Pursuant to the *Ontario Energy Board Act, 1998* and *Ontario Regulation 53/05,* OPG receives OEB-authorized regulated prices for electricity generated from the Pickering and Darlington nuclear generating stations and the 54 hydroelectric facilities prescribed for rate regulation (collectively, prescribed facilities or regulated facilities). The OEB is an independent, quasi-judicial tribunal that regulates market participants in Ontario's natural gas and electricity industries, and reports to the Legislature of the Province through the Ontario Ministry of Energy. OPG is Ontario's only electricity generator subject to rate regulation by the OEB.

Of OPG's 54 regulated hydroelectric facilities, 48 facilities were prescribed for rate regulation effective July 1, 2014 pursuant to a November 2013 amendment to *Ontario Regulation 53/05*. The remaining six regulated hydroelectric facilities and the Pickering and Darlington nuclear generating stations have been subject to rate regulation by the OEB since 2008.

Electricity generated from most of OPG's non-regulated assets is subject to Energy Supply Agreements (ESAs) with the IESO. The IESO is a non-profit corporate entity governed by an independent Board of Directors appointed by the Province and is responsible for operating the electricity market and directing the operation of the bulk electrical system in Ontario. Effective January 1, 2015, the Ontario Power Authority (OPA), an organization previously established by the Province with a mandate to contribute to the development of a reliable and sustainable electricity system in Ontario, merged with the IESO. The new entity continued under the name IESO. The IESO is the counterparty to the ESAs and other agreements that were previously executed with the OPA.

ESAs are in effect for the capacity and production from OPG's three operating thermal generating stations – the oil/gas dual-fuelled Lennox GS, the biomass powered Atikokan GS and the advanced biomass fuelled unit at the Thunder Bay GS. The results of these stations are reported under the Contracted Generation Portfolio segment. The expiry dates of these ESAs range from January 2020 to July 2024. In addition, 50-year ESAs are in place for the hydroelectric facilities reported under the Contracted Generation Portfolio segment. The hydroelectric ESAs for the operating stations have expiry dates ranging from February 2059 to March 2067. The ESAs for the contracted generating stations result in a relatively stable stream of revenues from the Contracted Generation Segment.

OPG's revenue and electricity generation by business segment for the years ended December 31, 2017, 2016 and 2015 and OPG's in-service generating capacity as at December 31, 2017, 2016 and 2015 are summarized in the table below.

		Regulated – Nuclear Generation	Regulated – Nuclear Waste Management	Regulated – Hydroelectric	Contracted Generation Portfolio [1]	Services, Trading, and Other Non-Generation	Fair Hydro Trust
2017	Revenue *(millions of dollars)* [2]	**3,095**	**121**	**1,436**	**579**	**43**	**1** [4]
	Electricity Generation *(terawatt hours)*	**40.7**	**N/A**	**30.7**	**2.7**	**N/A**	**N/A**
	In-service Generating Capacity *(MW)* [3]	**5,728**	**N/A**	**6,426**	**4,056**	**N/A**	**N/A**
2016	Revenue *(millions of dollars)* [2]	3,481	138	1,527	573	68	N/A
	Electricity Generation *(terawatt hours)*	45.6	N/A	29.5	3.1	N/A	N/A
	In-service Generating Capacity *(MW)* [3]	5,728	N/A	6,421	4,028	N/A	N/A
2015	Revenue *(millions of dollars)* [2]	3,245	122	1,619	535	73	N/A
	Electricity Generation *(terawatt hours)*	44.5	N/A	30.4	3.1	N/A	N/A
	In-service Generating Capacity *(MW)*	6,606	N/A	6,428	4,021	N/A	N/A

[1] The in-service generating capacity includes OPG's share of 275 MW for PEC and 280 MW for Brighton Beach, and the electricity generation includes OPG's share of its 50 percent ownership in these stations.
[2] Revenue for each segment is shown before inter-segment elimination.
[3] Regulated – Nuclear Generation segment excludes the generating capacity of 878 MW from Unit 2 of the Darlington GS, which has been undergoing refurbishment since mid-October 2016.
[4] This represents OPG's earnings from the Fair Hydro Trust, which consist of income related to OPG's role as Financial Services Manager under the Act and holder of subordinated debt issued by the Trust, including the financial results of the Trust.

For the year ended December 31, 2017, OPG's electricity generation accounted for over 50 percent of the total energy generated on Ontario's electricity grid, as reported by the IESO.

OPG is subject to a number of provincial and federal legislation and regulations, including the decisions of administrative tribunals or other regulatory bodies, and to Canada's international obligations under certain international treaties. Collectively, these sources dictate many of the constraints within which OPG is permitted to operate its facilities and manage its business.

Strategic Imperatives

OPG's mission is to provide low cost power in a safe, clean, reliable and sustainable manner for the benefit of its customers and its Shareholder. OPG also seeks to pursue, on a commercial basis, generation development projects and other business growth opportunities to the benefit of the Shareholder. The four strategic imperatives of OPG are briefly described below.

Operational Excellence

Operational excellence at OPG is accomplished by the safe and environmentally responsible generation of reliable and cost-effective electricity from the Company's generating assets through a highly trained and engaged workforce. Workplace safety and public safety are overriding priorities in all activities performed at OPG.

Project Excellence

OPG is pursuing a number of generation development and other projects in support of Ontario's electricity planning initiatives. OPG's major generation projects include the refurbishment of the Darlington GS, the expansion of the Ranney Falls hydroelectric GS, and the construction of a solar facility at the Nanticoke GS site. OPG aims to be an industry leader in project management capability and performance.

Financial Strength

As a commercial enterprise, OPG's financial priority is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future growth. Inherent in this priority are the following objectives:

- Increasing revenue, reducing costs and achieving appropriate return;
- Ensuring availability of cost effective funding for operational needs, generation development projects and other business opportunities, and long-term obligations;
- Pursuing opportunities to expand the existing core business and capitalize on new growth paths including emerging renewable energy opportunities; and
- Managing risks. Refer to the section, *Risk Management*, in the Company's 2017 year-end MD&A for more details.

Social Licence

As the largest, publicly-owned electricity generator in Ontario with geographically diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust. OPG is committed to maintaining high standards of public safety and corporate citizenship, including environmental stewardship, transparency, community engagement, and Indigenous relations.

OPG has in place a Code of Business Conduct that establishes the standards, expectations, and accountabilities for ethical behaviour. All employees and all parties with whom the Company does business are expected to abide by OPG's Code of Business Conduct. A copy of the Code of Business Conduct can be found on SEDAR at www.sedar.com and also is available on the Company's website at www.opg.com.

Further details on OPG's strategic imperatives can be found in the corresponding sections of the Company's 2017 year-end MD&A in the section, *Core Business, Strategy, and Outlook.*

GENERAL DEVELOPMENT OF THE BUSINESS

The following is a summary of key developments in OPG's business since January 2015.

General Development

OPG's Regulated Prices and Other OEB-Related Developments

Energy revenue generated from the Company's regulated nuclear and regulated hydroelectric facilities is based on regulated prices determined by the OEB through public proceedings. To date, the regulated prices have included a volumetric base regulated price, and volumetric rate riders for the recovery or repayment of approved variance and deferral account balances. As the regulated operations account for the majority of the Company's electricity generation, the outcomes of OPG's applications for regulated prices to the OEB determine a large portion of the Company's revenues and can have a significant impact on the Company's financial performance.

The following are the OEB-authorized regulated prices for electricity generated from the Company's regulated facilities in effect during the years ended December 31:

	2017		2016	2015	
($/megawatt hour)	**January 1 to May 31**	**June 1 to December 31** [1]		**January 1 to June 30**	**July 1 to December 31**
Regulated – Nuclear Generation					
Base regulated price	**59.29**	**80.65**	59.29	59.29	59.29
Variance and deferral account rate riders	**-**	**-**	10.84 [2]	1.33	12.17 [2]
	59.29	**80.65**	70.13	60.62	71.46
Regulated – Hydroelectric					
Hydroelectric generating stations prescribed for rate regulation prior to 2014					
Base regulated price	**40.20**	**41.67**	40.20	40.20	40.20
Variance and deferral account rate riders	**-**	**-**	3.19 [2]	6.04	9.23 [2]
	40.20	**41.65**	43.39	46.24	49.43
Hydroelectric generating stations prescribed for rate regulation effective in 2014					
Base regulated price	**41.93**	**41.67**	41.93	41.93	41.93
Variance and deferral account rate riders	**-**	**-**	3.19 [2]	-	3.19 [2]
	41.93	**41.67**	45.12	41.93	45.12

[1] Regulated prices for the June 1, 2017 to December 31, 2017 period were calculated and submitted to the OEB by OPG in January 2018 based on the OEB's December 28, 2017 decision on OPG's 2017-2021 application for new regulated prices. The final regulated prices will be determined by the OEB as part of the final payment amounts order process, which is expected to be completed in the first half of 2018. As part of the process, the OEB is expected to authorize separate rate riders to allow for the recovery of the shortfall between the new regulated prices and the previous regulated prices that OPG continues to receive during the period between June 1, 2017 and the implementation date of the new regulated prices pending the issuance of the final payment amounts order. The incremental revenue for the period between June 1, 2017 and December 31, 2017 arising from this retrospective application of new regulated prices was accrued in 2017. **[MONITOR]**

[2] The OEB authorized interim period rate riders for the period from October 1, 2015 to December 31, 2016 to allow for the recovery of the riders effective July 1, 2015 for the period from July 1, 2015 to September 30, 2015. The nuclear interim period rate rider was $2.17 per megawatt hour (MWh) and the regulated hydroelectric interim period rate rider was $0.64/MWh. These interim period rate riders have not been included in the above table. All rate riders in effect during 2016 expired on December 31, 2016.

Base Regulated Prices

The OEB's decision on OPG's May 2016 five-year application for new regulated prices for its nuclear and regulated hydroelectric generation was issued on December 28, 2017, following a public hearing process. Based on the OEB's December 2017 decision, the new base regulated prices are determined on an incentive ratemaking methodology for the hydroelectric operations and under a custom incentive regulation framework for the nuclear operations. For the hydroelectric facilities, the new base regulated price is determined using a formula that annually escalates the previous regulated prices, subject to some adjustments, based on inflation less a stretch factor to incent additional innovation and efficiency. For the nuclear facilities, the new regulated price is determined under a rate smoothing approach that defers a portion of the approved nuclear revenue requirement for future collection, with the aim of making more stable changes in OPG's production-weighted regulated prices year over year. The nuclear revenue requirement is based on the OEB-approved forecasts of operating costs as reduced by a stretch factor and a return on rate base. Rate base for OPG represents the average net level of investment in regulated fixed and intangible assets in service and an allowance for working capital.

For the first time since OPG's prescribed facilities became subject to rate regulation, the new prices have been determined on an incentive ratemaking methodology for the hydroelectric operations and a custom incentive regulation framework for the nuclear operations.

For the hydroelectric facilities, effective June 1, 2017, the base regulated prices in effect prior to June 1, 2017, with some adjustments, will be escalated for each of years 2017 to 2021 using a formula equal to an industry-specific weighted inflation factor based on indices published annually by the OEB for use in incentive regulation formulas, less a stretch factor adjustment. The OEB accepted OPG's proposal to set the annual stretch factor adjustment at 0.3 percent. Based on the approved formula, the 2017 increase in the base regulated price for the regulated hydroelectric facilities is 1.4 percent as of June 1, 2017 and the 2018 increase is 0.9 percent as of January 1, 2018. For the 2019-2021 period, the base regulated price for the regulated hydroelectric facilities will be determined annually before the beginning of each year using the approved formula and inflation indices published by the OEB.

For the nuclear operations, a revenue requirement is determined for each of the years 2017 to 2021 based on the OEB-allowed level of OPG's forecast operating costs, reduced by a stretch factor amount, as well as a return on rate base determined using OEB's generic prescribed rate of return and an OPG-specific deemed capital structure. OPG has calculated that the findings of the OEB's December 2017 decision with respect to the forecast operating costs, rate base and deemed capital structure for the nuclear generating facilities will result in nuclear revenue requirements totalling $15.9 billion over the five years.

The OEB's findings with respect to the nuclear revenue requirement include approval for inclusion in rate base of in-service amounts related to the Darlington Refurbishment of $5.5 billion by 2021, including $4.8 billion forecast in the first quarter of 2020 upon return to service of Unit 2, $0.4 billion forecast for pre-requisite projects excluding the construction of the Heavy Water Storage and Drum Handling Facility (HWSF) over the 2016-2021 period and $0.3 billion for pre-requisite projects placed in service prior to 2016. The OEB is expected to review the HWSF project as part of a future application. In the decision, the OEB concluded that it is appropriate to evaluate OPG's performance on the Darlington Refurbishment project at an overall level rather by individual cost component, with recovery of any increases over the approved in-service amounts subject to a future prudence review. The revenue requirement impact of differences between the approved in-service additions and the actual in-service additions will be recorded in the Capacity Refurbishment Variance Account authorized by the OEB pursuant to *Ontario Regulation 53/05*. The $4.8 billion forecast in-service amount upon return to service of Unit 2 includes expenditures incurred during the definition and planning phase of the project.

The OEB also approved OPG's requested forecast costs of approximately $292 million for activities to enable Pickering commercial operations beyond 2020 and agreed to inclusion of operating cost and generation impacts associated with continued operation of Pickering in 2021 in nuclear regulated prices. The differences between approved forecast enabling costs for continued Pickering operations and the actual amounts will be recorded in the Capacity Refurbishment Variance Account for future review and disposition by the OEB.

Excluding amounts that otherwise would have been recorded in OEB-authorized regulatory accounts for repayment to, or recovery from, customers in the future, the OEB's decision reduced OPG's proposed five-year nuclear revenue requirement by $0.6 billion. The main adjustments made by the OEB included a reduction of $100 million per year to requested OM&A costs , a reduction of 10 percent per year to forecast non-Darlington refurbishment capital in-service additions entering rate base over the 2017-2021 period, an increase and expansion of the scope of the stretch factor for nuclear costs that further reduced the revenue requirement, and a rejection of OPG's request to increase the equity component of the existing deemed capital structure of 45 percent equity and 55 percent debt. The OEB increased and expanded the annual stretch factor to 0.6 percent to most of OPG's OM&A expenses incurred directly for, or allocated to, the nuclear facilities, as well as to non-Darlington refurbishment capital in-service additions. The stretch factor is applied starting in 2018 and compounds in each year to 2021.

In accordance with *Ontario Regulation 53/05*, the nuclear revenue requirement continues to be adjusted by the amount of OPG's revenues, net of costs, from leasing the Bruce nuclear generating stations to Bruce Power. As directed by the OEB, OPG's revenues and costs related to the Bruce nuclear generating stations continue to be determined in accordance with US GAAP for the purposes of establishing the nuclear revenue requirement and are subject to the Bruce Lease Net Revenues Variance Account in accordance with *Ontario Regulation 53/05*. This includes costs related to the portion of the Nuclear Liabilities associated with the Bruce nuclear generating stations. The OEB's decision maintained the previously approved cost recovery methodology for the costs of the Nuclear Liabilities for the prescribed facilities and for the Bruce facilities, directing OPG to file a future study examining such methodologies jurisdictionally and for OPG's assets specifically. The decision fully incorporated the impacts of the updated estimate of OPG's obligations for nuclear waste management and nuclear facilities decommissioning as at December 31, 2016, including through a new ONFA reference plan effective January 1, 2017 and the change in the Nuclear Liabilities recorded on December 31, 2016.

As proposed by OPG, the OEB set recovery of pension and OPEB costs in the nuclear revenue requirement on the basis of OPG's cash payments for pension and OPEB plans, with differences between pension and OPEB accrual costs and cash payments continuing to be recorded in the Pension & OPEB Cash to Accrual Differential Deferral Account. The regulatory treatment of pension and OPEB costs is discussed further under the heading, *Pension and OPEB Cost Recovery Methodology*.

To reflect the OEB's decision, in the fourth quarter of 2017, OPG recorded incremental revenue of approximately $480 million for the period June 1, 2017 to December 31, 2017 based on the draft payment amounts order. The revenue was recorded as an increase in regulatory assets for the June 1, 2017 to December 31, 2017 revenue shortfall based on proposed new regulated prices for nuclear facilities and regulated hydroelectric facilities, net of a regulatory liability recognized in relation to OPG's rate smoothing proposal. The OEB's approval of the final payment amounts order, including the allocation of the approved revenue requirement between nuclear regulated prices and rate smoothing deferrals, is not expected to have a material impact on the net revenue increase recorded in the fourth quarter of 2017. The OEB is expected to issue the final payment amounts order and implement new regulated prices in the first half of 2018. **[MONITOR]**

The base regulated prices in effect from January 2015 through May 2017 were established by the OEB's November 2014 decision and December 2014 order on OPG's September 2013 rate application. This included regulated prices effective November 1, 2014 for the 48 hydroelectric facilities that were prescribed for rate regulation effective July 1, 2014. Prior to November 1, 2014, the generation revenue for these hydroelectric facilities was based on the Ontario electricity spot market price, including for the period from

July 1, 2014 to November 1, 2014 as determined by the OEB. The base regulated prices effective November 1, 2014 remained in effect until May 31, 2017.

The regulated prices in effect from January 2015 through May 2017 for the nuclear facilities and the hydroelectric facilities prescribed for rate regulation prior to 2014 were determined by the OEB based on approved 24-month revenue requirements for the 2014 to 2015 period totaling approximately $7.3 billion. This reflected a reduction of $833 million from the revenue requirements submitted by OPG. The regulated price for the 48 hydroelectric facilities prescribed for rate regulation beginning in 2014 was established based on an approved 18-month revenue requirement for the period from July 1, 2014 to December 31, 2015 of approximately $750 million, a reduction of $101 million from OPG's submission. The most significant adjustments made by the OEB to OPG's September 2013 rate request included the following:

- Allowed pension and OPEB costs were limited to the forecast 2014 and 2015 cash expenditures for these plans, which were approximately $600 million lower, including related tax impacts, than the forecast accrual costs submitted by OPG. The difference between accrual costs and cash expenditures is being recorded in a deferral account authorized by the OEB. For further details, see *Pension and OPEB Cost Recovery Methodology* in this section. **[CONFIRM]**
- A reduction in overall forecast compensation costs of $100 million in each of 2014 and 2015 across all of OPG's regulated facilities.
- An increase in the forecast nuclear production of 0.5 terawatt hours (TWh) annually used to set the nuclear regulated prices, which had the effect of reducing the approved nuclear regulated price.
- The rate base addition for the Niagara Tunnel project to construct a third tunnel to divert additional water to OPG's generating stations on the Niagara River was limited to $1,365 million, which resulted in a write-off of $77 million being charged to operations in 2014.
- A reduction in the 2014 income tax expense included in the regulated prices by the amount of the regulatory tax loss calculated for 2013, which reduced the 2014/2015 revenue requirement by approximately $70 million.

In December 2014, OPG filed a motion with the OEB asking it to review and vary the parts of its November 2014 decision related to the disallowance of the Niagara Tunnel project expenditures and the application of the 2013 regulatory tax loss against the 2014/2015 revenue requirement. In its January 2016 decision on the motion, the OEB reversed a portion of the Niagara Tunnel project disallowance and upheld the original tax loss decision. In the first quarter of 2016, OPG recorded a gain of $22 million to recognize the expected future recovery from customers of the reversed portion of the Niagara Tunnel project disallowance.

In its November 2014 decision, the OEB adjusted the deemed capital structure applied to OPG's total regulated rate base to 45 percent equity and 55 percent debt, from 47 percent equity and 53 percent debt used previously. In making this adjustment, the OEB found that there had been an overall improvement in the risk profile of OPG's regulated operations, based on the increased proportionate share of rate base related to hydroelectric facilities. This reduced the 2014/2015 revenue requirements. In general, OPG's actual capital structure contains a significantly higher proportion of equity than has been reflected in the OEB-approved deemed capital structure, which has had the effect of reducing OPG's return on shareholder's equity.

Variance and Deferral Accounts and Rate Riders

Consistent with the requirements of *Ontario Regulation 53/05*, OPG's overall production-weighted regulated prices will be smoothed, with a resulting portion of the approved annual nuclear revenue requirements for the 2017-2021 period deferred in the Rate Smoothing Deferral Account for future collection. The non-deferred portion of each year's nuclear revenue requirement is divided by the OEB-approved forecast of OPG's nuclear electricity generation for the corresponding year to determine the base nuclear regulated price. The OEB approved the nuclear electricity generation forecast as requested by OPG.
As amended in March 2017, *Ontario Regulation 53/05* requires rate smoothing to be applied in a manner that makes changes in OPG's weighted-average nuclear and hydroelectric regulated prices more stable year over year. Previously, the regulation required that rate smoothing be applied with a view of making

more stable year-over-year changes in OPG's nuclear regulated prices only. Per the regulation, the deferral account records interest at a long-term debt rate reflecting OPG's cost of long-term borrowing approved by the OEB, compounded annually. The regulation requires the OEB to authorize recovery of the balance in the account on a straight line basis over a period not to exceed 10 years following the end of the Darlington Refurbishment project. OPG recognizes positive amounts deferred under rate smoothing as an increase in net regulatory assets and an increase in revenue in the period to which the underlying approved revenue requirement relates. Negative amounts determined under rate smoothing are correspondingly recorded as a decrease in net regulatory assets and a decrease to revenue.

On January 17, 2018, OPG submitted a draft payment amounts order to the OEB that proposed nuclear base regulated prices for each year of the 2017-2021 period, including a rate smoothing proposal, based on the December 2017 decision's findings. The rate smoothing proposal takes into account the near-term and future impacts on customers, while seeking to ensure that resulting nuclear regulated prices allow for sufficient cash flow to maintain the Company's investment grade credit rating and support availability of cost effective funding, while taking into account both near-term and future impacts on customers. Based on the OEB's direction, the draft payment amounts order also included proposed periods for recovery, through interim period shortfall rate riders, of the retrospective revenue shortfall for the period between June 1, 2017 and the implementation date of the new regulated prices based on proposed new regulated prices that would have been in effect during that period. The draft payment amounts also included proposed recovery periods, through variance and deferral account rate riders, for regulatory account balances approved for recovery in this application. **[MONITOR]**

Variance and deferral accounts are typically established by the OEB to capture, for subsequent review and approval, differences between actual costs and revenues and the corresponding forecast amounts approved by the OEB in setting regulated prices, or to record the impact of items not reflected in the approved regulated prices. Such accounts generally help to mitigate risks and uncertainties to the regulated entity and its customers.

The OEB has authorized several variance and deferral accounts for OPG, including those required by *Ontario Regulation 53/05*. The authorized accounts include, among others, those related to the gross margin impact of variability in regulated hydroelectric electricity production due to differences between the forecast and actual water conditions and due to the effect of SBG conditions, changes in liabilities for nuclear waste management and nuclear facilities decommissioning, changes in revenues and costs related to the lease and related agreements with Bruce Power for the Bruce nuclear generating stations, and variances in the revenue requirement impact of capital and non-capital costs incurred to increase the output of, refurbish, or add operating capacity to the regulated facilities, including the Darlington Refurbishment project. A number of these accounts are subject to an OEB prudence review. There is currently no regulatory variance or deferral account related to the impact of generation performance of OPG's nuclear stations on revenue from the base regulated prices. The Darlington Refurbishment project is discussed in the section, *General Development of the Business* under the heading, *Nuclear Business Development – Darlington Refurbishment*.

Approved balances in the regulatory variance and deferral accounts authorized by OPG are recovered or refunded through volumetric rate riders. The additional revenue from the riders is largely offset by a corresponding increase in amortization expense related to the variance and deferral account balances, which are typically recognized as assets (amounts recoverable from customers) or liabilities (amounts payable to customers) on the Company's balance sheet. Differences in amounts recovered or repaid through rate riders due to differences between actual and forecast production volumes are recorded in separate variance accounts for future disposition. **[MONITOR]**

The OEB accepted all variance and deferral account balances proposed for recovery that were not already accepted as part of the Settlement Agreement, resulting in approval of recovery of $305 million recorded in variance and deferral variance accounts as at December 31, 2015, without adjustments. The Settlement Agreement provided for the continuation of all applicable existing variance and deferral accounts. In addition to the Rate Smoothing Deferral Account, the OEB established, as of the effective date of the new regulated prices, new variance and deferral accounts to record costs related to implementing the Canadian

Nuclear Safety Commission's (CNSC) Fitness for Duty program and to record differences between forecast and actual amount of Scientific Research & Experimental Development investment tax credits attributable to the nuclear facilities. In January 2018, OPG filed a motion asking the OEB to review and vary the effective date of the new regulated prices to January 1, 2017. The motion did not impact OPG's financial results for the year ended December 31, 2017.

Consistent with the effective date of the OEB's December 2017 decision, for the period from January 1, 2017 to May 31, 2017, OPG continued to record additions to the existing variance and deferral accounts for the nuclear and regulated hydroelectric facilities pursuant to the OEB's previous decisions and orders. These additions reflected differences between actual and forecast amounts embedded in the regulated prices in effect prior to the June 1, 2017 effective date.

The rate riders in effect in 2015 and 2016 included those authorized by the OEB's October 2015 order on OPG's application in 2014 to recover or repay most of the December 31, 2014 variance and deferral account balances, discussed below. The 2015 rate riders also included those established by the OEB's December 2014 order on OPG's September 2013 rate application for the period January 1, 2015 to December 31, 2015. The December 2014 order allowed for recovery of $189 million recorded in certain variance and deferral accounts as at December 31, 2013, without adjustments.

The total balances approved for recovery by the OEB's October 2015 order were approximately $1.8 billion, of which approximately $1.5 billion was the subject of an OEB-approved partial settlement agreement reached by OPG and intervenors. The remaining balances of $263 million were approved by the OEB's September 2015 decision, without adjustments. The rate riders authorized by the October 2015 order were in effect from July 1, 2015 to December 31, 2016 and allowed for recovery of $933 million of the total approved balances.

Amendments to Ontario Regulation 53/05

In November 2015, the Province amended *Ontario Regulation 53/05* to establish a deferral account, effective January 1, 2017, that will record, for future recovery, a portion of the annual OEB-approved revenue requirements for OPG's regulated nuclear facilities during the period from January 1, 2017 to the end of the Darlington Refurbishment project. The amended regulation requires the OEB to determine the revenue requirements for OPG's nuclear facilities on a five-year basis for the ten-year period beginning on January 1, 2017. The portion of the approved revenue requirement deferred in the new account each year also will be determined by the OEB on a five-year basis during this ten-year period. The regulation stipulates that the deferral account will record interest at a long-term debt rate reflecting OPG's cost of long-term borrowing approved by the OEB, compounded annually, and that the OEB shall authorize recovery of the balance in the account on a straight line basis over a period not to exceed 10 years following the end of the Darlington Refurbishment project. OPG expects to recognize the deferred amounts as income in the period to which the underlying approved revenue requirements relate.

The November 2015 amendment required the portion of the approved annual nuclear revenue requirements deferred for future recovery to be determined with a view of making more stable year-over-year changes in OPG's nuclear regulated prices only. In March 2017, the Province amended *Ontario Regulation 53/05* to require that the deferred portion of the approved annual nuclear revenue requirements be determined with a view of making more stable year-over-year changes in OPG's weighted-average nuclear and hydroelectric regulated prices, including rate riders. The amendment is intended to make more predictable the impact on customer bills resulting from changes in OPG's overall regulated prices, reducing the average year-over-year change in customer bills over the term of OPG's May 2016 application for new regulated prices.

The regulation was also amended in November 2015 to require the OEB to accept the need for the Darlington Refurbishment project in light of Ontario's 2013 Long-Term Energy Plan (LTEP) and the related policy of the Province endorsing the need for nuclear refurbishment. Furthermore, the 2017 LTEP reaffirms the Province's support for nuclear refurbishment. The 2017 LTEP is discussed in the section, *General*

Development of the Business under the heading, *General Development – Ontario's Long-Term Energy Plan*.

Pension and OPEB Cost Recovery Methodology

Using the methodology previously applied by the OEB in setting OPG's regulated prices, the revenue requirements submitted by OPG in its September 2013 rate application included a forecast of 2014 and 2015 pension and OPEB costs determined on an accrual basis in accordance with US GAAP. In its November 2014 decision and December 2014 order on the application, the OEB approved revenue requirements based on OPG's estimated minimum required contributions to its registered pension plan, and a forecast of OPG's expenditures on the OPEB and supplementary pension plans. In directing this reduction in the revenue requirement, the OEB agreed with OPG and certain other parties that a generic proceeding on the regulatory treatment and recovery of pension and OPEB costs would be beneficial. The OEB also indicated that a change in the recovery methodology for OPG's pension and OPEB amounts from the accrual basis, if required, would be addressed in a future OPG rate proceeding, informed by the outcome of the generic proceeding.

Pending the generic proceeding, the OEB established the Pension & OPEB Cash Versus Accrual Differential Deferral Account. Effective November 1, 2014, this deferral account records the difference between OPG's actual pension and OPEB costs for the regulated business determined on an accrual basis and the corresponding actual cash expenditures for these plans. The OEB's November 2014 decision indicated that the future recovery, if any, of amounts recorded in the deferral account would be subject to the outcome of a future generic OEB proceeding on the regulatory treatment and recovery of pension and OPEB costs. The balance in the account is recognized as a regulatory asset on OPG's balance sheet.

On September 14, 2017, the OEB issued its final report on the guiding principles and policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the Ontario electricity and natural gas sectors. The report establishes the accrual basis of accounting as the method of determining pension and OPEB amounts for rate-setting purposes, unless the OEB finds that this method does not result in just and reasonable rates in the circumstances of a particular utility. The report also provides for the establishment of a generic variance account to record asymmetric carrying charges in favour of ratepayers on the differences between the accrual costs recovered and cash payments made by a utility in respect of pension and OPEB plans. Carrying charges on this differential are to be assessed at the OEB's prescribed interest rate, on a prospective basis from the effective date of the new variance account. For OPG, this differential will include amounts going back to November 1, 2014, with the charges calculated on the portion of the differential that has been recovered through regulated prices. None of this differential has been recovered to date. The prescribed interest rate is set quarterly by the OEB based on the quarterly return of a mid-term corporate bond index yield.

The OEB's September 2017 report and the OEB's December 2017 decision on OPG's application for new regulated prices require OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the Pension & OPEB Cash to Accrual Differential Deferral Account in effect since November 1, 2014, until such time as the OEB approves resumption of the accrual basis of recovery for OPG. The future recovery of amounts recorded in the account will be subject to this approval. The OEB's report did not impact OPG's financial results for the year ended December 31, 2017.

The Company recognizes the amount set aside in the Pension & OPEB Cash Versus Accrual Differential Deferral Account as a regulatory asset. As at December 31, 2017, the regulatory asset had a balance of $614 million. Consistent with the expectations set out in the OEB's December 2017 decision, in 2018, OPG plans to file an application with the OEB requesting disposition of the Pension & OPEB Cash Versus Accrual Differential Deferral Account balance as well as balances accumulated since December 31, 2015 in other regulatory accounts.

Supreme Court of Canada's Decision on 2011 OEB Ruling

In September 2015, the Supreme Court of Canada (Supreme Court) issued its decision upholding the OEB's disallowance of $145 million of OPG's forecast nuclear compensation costs for the 2011 to 2012 period. The majority of these costs were based on previously negotiated collective bargaining agreements. This disallowance was part of the OEB's March 2011 decision on OPG's application for regulated prices effective March 1, 2011. The Supreme Court decision underscores that OPG must continue to establish the reasonableness of both committed and future costs as part of the rate-setting process.

Ontario's Fair Hydro Plan

On March 2, 2017, the Province announced the Fair Hydro Plan aimed at reducing electricity bills for eligible residential, farm, small businesses ~~and other eligible~~ consumers (Specified Consumers) in the province by refinancing a portion of the Global Adjustment costs over a longer period of time. The Global Adjustment includes the difference between Ontario's electricity market clearing price used to dispatch generation and the prices paid to contracted and regulated generators in the province, and the cost of conservation and demand management programs. On June 1, 2017, the Fair Hydro Act received Royal Assent and the associated general regulation came into force in June 2017. The Act established a framework under which the costs and benefits associated with the Government of Ontario's clean energy initiatives are to be allocated between present and future consumers of electricity under the Fair Hydro Plan. The general regulation provides details on the structural, operational and financial elements required to implement the Fair Hydro Plan.

Pursuant to the Act, effective May 1, 2017, the IESO began to defer a portion of the Global Adjustment costs. The Act allows the IESO to transfer a portion of the deferred balance to a financing entity that would fund the deferral in exchange for an irrevocable right to recover the balance and associated financing and other costs from Specified Consumers in the future (Investment Interest). The legislation appointed OPG as the Financial Services Manager under the Act and conveyed upon the Financial Services Manager statutory obligations, including the creation of one or more financing entities that may acquire Investment Interests from the IESO.

In November 2017, OPG's Board of Directors provided its final approval regarding OPG's involvement with the Trust on commercial terms following the fulfilment of all conditions it established in May 2017. Accordingly, the Fair Hydro Trust was established as the financing entity contemplated by the Act in December 2017. The majority unitholder and beneficiary of the Trust is a wholly-owned subsidiary of OPG. The Trust is structured to be bankruptcy remote and ring fenced from OPG in order to protect the Company's assets and operations.

In order for the Trust to finance the Investment Interest acquired from the IESO, it will incur senior debt from capital markets and subordinated debt from OPG. The Trust's investment will attract financing amounts and other related fees, which, under the general regulation, will be payable by the IESO as carrying costs until July 2021 and by Specified Consumers through the Clean Energy Adjustment to be invoiced by local distribution companies commencing in May 2021, with the three-month lag in 2021 intended to cover the billing and collection lag from the introduction of the Clean Energy Adjustment. The carrying costs include all financing and third-party costs other than payment of principal on debt.

Concurrent with every issuance of the Trust's senior notes, it is expected that OPG will purchase subordinated debt of the Trust in an aggregate amount not to exceed 49 percent of the Trust's total outstanding debt, with 44 percent of the funding to be provided by the Province through equity injections and five percent to be provided by OPG. The subordination level may vary over time, but must at least equal to, or be greater than 35 percent of all outstanding debt. Through OPG's control over the key activities of the Trust and its obligation to absorb losses through ownership of the Trust's subordinated debt, the Company consolidates the financial results of the Trust in accordance with US GAAP.

On December 21, 2017, the Trust purchased its first tranche of Investment Interest from the IESO in the amount of approximately $1.18 billion. Fifty-one percent of the funding requirement or $601 million was financed by the Trust through a revolving warehouse facility ranked as senior notes, and the remaining 49

percent was funded through the issuance of short-term subordinated debt to OPG. The Investment Interest has been classified as a financing receivable on OPG's consolidated balance sheet.

OPG's subordinated debt investment in the Trust was funded through the following sources:

- The Province provided 44 percent of the total funding requirement or $519 million, through an equity injection in OPG in exchange for approximately 12.2 million non-voting Class A common shares at a price of $42.46 per share. The Company's Articles of Amalgamation were amended effective December 1, 2017 to allow for the creation and issuance of Class A shares. Refer to Note 14 to the Company's audited annual financial statements as at and for the year ended December 31, 2017 for further details; and
- OPG provided five percent of the total funding requirement or approximately $60 million.

In February 2018, the Trust issued $500 million of senior notes payable with a coupon interest rate of 3.36 percent and an effective interest rate of 3.42 percent, payable semi-annually until maturity on May 15, 2033. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility issued in December 2017. By the end of the first quarter of 2018, the Trust is expected to acquire another tranche of Investment Interest from the IESO, which is expects to fund using its revolving warehouse facility.

Refer to the section, *Liquidity and Capital Resources* under the heading, *Financing Activities* for further details on the Trust's financing arrangements and OPG's public debt offering in the Company's 2017 year-end MD&A.

Ontario's Long-Term Energy Plan

On October 26, 2017, Ontario's Ministry of Energy issued the 2017 LTEP that outlines the Province's plans for the future development of Ontario's electricity system. The 2017 LTEP focuses on the affordability, reliability and flexibility of a clean energy supply in the province. The 2017 LTEP replaces the previous LTEP issued in 2013.

As it relates to the supply of electricity, the 2017 LTEP recognizes the refurbishment of Ontario's nuclear generating stations as the most cost-effective option for producing emission-free baseload generation to meet Ontario's needs and reaffirms the Province's support for the refurbishment of the four units at the Darlington GS and the six units at the Bruce generating stations, subject to the principles established in the 2013 Long-Term Energy Plan. The 2017 LTEP also recognizes the value to customers of continuing to operate the Pickering GS until 2024, as planned. With respect to hydroelectric electricity generation, the 2017 LTEP highlights the opportunity to continue to invest in optimizing existing hydroelectric facilities, noting that pumped hydroelectric storage could play an important role in the reliability of the electricity system.

Additionally, the 2017 LTEP discusses the potential impact of a number of innovative technologies on the future of the electricity system. Among others, these include the increased electrification of the transportation sector, the emergence of energy storage, and the opportunity for Ontario to foster nuclear innovation technologies. OPG continues to assess how best to capitalize on potential business opportunities in these and other areas. The 2017 LTEP also recognizes the importance of Indigenous peoples' continuing role in shaping Ontario's energy planning, projects and policies.

Renewal of Collective Agreements and Acquisition of Hydro One Limited Shares

Most of OPG's regular employees are represented by one of two unions: the Power Workers' Union (PWU) and The Society of Energy Professionals (The Society). As at December 31, 2017, the PWU represented approximately 53 percent of OPG's regular workforce, while The Society represented approximately 35 percent of the regular workforce.

The previous collective agreement between OPG and the PWU expired on March 31, 2015. In May 2015, the parties agreed to renew the collective agreement for a three-year term, expiring on March 31, 2018.

The changes to the collective agreement included increases to employee pension plan contributions in each year of the agreement. Negotiations for a new labour agreement with the PWU are underway. **[MONITOR]** The previous collective agreement between OPG and The Society expired on December 31, 2015. In November 2015, the parties agreed to renew the collective agreement for a three-year term, expiring on December 31, 2018. Changes to the collective agreement included increases to employee pension plan contributions in each of the first two years of the agreement. The changes in pension plan contributions apply to current employees and future employees of both unions, and do not have an end date.

The changes to both collective agreements provided existing employees with lump sum payments for each of the first two years of the respective contract and eligibility to annually receive shares in Hydro One Limited (Hydro One) for up to 15 years starting in the third year of the contract, as long as these employees continue to make contributions to the OPG pension plan and have less than 35 years of pensionable service. The lump sum payments and future share awards are intended to compensate current eligible employees, over a defined period, for their increased pension plan contributions.

In April 2016, OPG acquired nine million common shares of Hydro One at $23.65 per share as part of a secondary share offering by the Province through a syndicate of underwriters. The acquisition, totaling $213 million, was made for investment purposes to mitigate the risk of future price volatility related to OPG's future share delivery obligations under the collective agreements. The shares acquired in this transaction represent the substantial majority of OPG's currently anticipated purchases of Hydro One shares.

In addition to the regular workforce, construction work is performed through 19 craft unions with established bargaining rights at OPG facilities. These bargaining rights are established either through the Electrical Power Systems Construction Association (EPSCA) or directly with OPG. Collective agreements between the Company and its construction unions are negotiated either directly or through EPSCA. All of these collective agreements currently have multi-year terms, expiring on April 30, 2020.

Shareholder Declarations and Shareholder Resolutions to Sell Certain Non-Core Real Estate Properties

In December 2015, OPG received a Shareholder Declaration and a Shareholder Resolution requiring the Company to sell its head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street in Toronto, Ontario. The sale was completed in April 2017, with a gain on sale of $283 million, which is net of tax effects of $95 million, recognized in net income in the second quarter of 2017. The pre-tax gain on sale was recorded as an item of Other gains in the consolidated statement of income in the Services, Trading and Other Non-Generation segment. Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. The amount of designated proceeds transferred into the Consolidated Revenue Fund are expected to approximate ~~will be equal to~~ the after-tax gain on sale. **[MONITOR]** The transfer is expected to take place in the first quarter of 2018, through a special dividend authorized by OPG's Board of Directors in March 2018. **[MONITOR]**

Commented [DS1]: The amount of designated proceeds will be determined by regulation and therefore uncertain until the regulation is filed and made public.

In June 2016, OPG received a Shareholder Declaration and a Shareholder Resolution that requires the Company to sell its former Lakeview GS site located in Mississauga, Ontario. OPG has entered into a purchase and sale agreement with a purchaser with the sale scheduled to close in March 2018. An estimated after-tax gain on sale of approximately $200 million is expected to be recognized in net income upon completion of the transaction in the first quarter of 2018. **[MONITOR]** Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. OPG anticipates the amount of designated proceeds transferred into the Consolidated Revenue Fund to approximate the after-tax gain on the sale. In accordance with the Shareholder Resolution, approximately one-third of the site is to be transferred to the City of Mississauga, by the purchaser, for parkland, institutional, and cultural uses.

Neither the former Lakeview GS site nor the Company's head office premises and associated parking facility are considered core assets to OPG's business.

For a complete list of Shareholder directives, refer to the section, *Interest of Management and Others in Material Transactions* under the heading, *Relationship with the Province and the OEFC – Shareholder Directives*.

Business Transformation **[UPDATE]**

OPG has completed a multi-year initiative with the objective of transforming itself into a more streamlined, agile and efficient organization. The business transformation initiative was intended to drive sustainable change across the Company, while ensuring that there is no adverse impact on the safety, reliability and environmental sustainability of OPG's operations. OPG's cumulative savings from reductions in regular headcount from ongoing operations, through the business transformation and other initiatives, since the beginning of 2011, reached $1 billion in 2016.

The business transformation initiative involved aggressively pursuing cost control and efficiency improvements at the enterprise and business unit level, including realignment of work, streamlining of processes and leveraging workforce attrition. As part of the initiative, OPG implemented a centre-led organizational model intended to more efficiently utilize resources. In 2015, OPG successfully completed a large-scale initiative, the Enterprise System Consolidation Project, to streamline the company's software systems and improve business processes by implementing a common enterprise software platform.

Although business transformation has concluded as a discrete initiative, improving organizational performance and building on efficiency gains achieved to date remains a key priority for the Company. OPG continues to review its cost structure, identify cost improvement strategies and embed an outcomes-driven culture that reinforces low cost, efficiency, and organizational agility as part of business decision-making.

Nuclear Business Development

Darlington Refurbishment

Government's Endorsement and Execution Phase

The Darlington generating units are approaching their originally designed end-of-life. Refurbishment of the four generating units to extend the operating life of the station by approximately 30 years, into the 2050s. In January 2016, the Government of Ontario's support for the Darlington Refurbishment project was affirmed through the Ontario Minister of Energy's announcement endorsing OPG's plan to refurbish the four Darlington units at a total project budget of $12.8 billion, including capitalized interest and escalation. The Province's announcement followed the approval of the project budget and schedule by OPG's Board of Directors in November 2015. The refurbishment of the last unit is scheduled to be completed by 2026. *Ontario Regulation 53/05* requires the OEB to ensure that OPG recovers capital and non-capital costs and firm financial commitments in respect of the Darlington Refurbishment project, if the OEB is satisfied that the costs were prudently incurred and that the firm financial commitments were prudently made.

The refurbishment project is a multi-phase program comprising several sub-projects. The major work streams include: de-fuelling of reactors and refurbishment of the fuel handling equipment; removal and replacement of feeder tubes and fuel channel assemblies in each reactor (Retube and Feeder Replacement or RFR); inspections and repairs of turbine generator sets and replacement of associated control systems; mechanical cleaning, water lancing, and inspection and maintenance work on steam generators; and replacement or repairs of certain other station components referred to as balance of plant. The RFR is the largest sub-project and represents a majority of the critical path schedule.

In 2016, the Darlington Refurbishment project transitioned from the planning phase to the execution phase, as OPG commenced the refurbishment of the first unit, Unit 2, in October 2016 as planned. The unit was

taken offline on October 15, 2016. De-fuelling of the reactor was completed in January 2017, with a total of 480 fuel channels de-fuelled. Islanding of Unit 2, the physical separation of the unit under refurbishment from the three operating units, was completed in April 2017, signifying the completion of the first major segment of the project.

The second major segment includes preparatory work to support the removal of feeder tubes and fuel channel assemblies, followed by the removal of reactor components. The preparatory work was completed in the second quarter of 2017. The Re-tube Tooling Platform for hosting the tooling for the removal, inspection and installation activities, and the setup of specialized tooling and equipment needed for the removal and replacement of the reactor components were completed in the third quarter of 2017. The disassembly of reactor components commenced in August 2017, with the removal of all 960 feeder tubes completed safely in September 2017. The removal of fuel channel assemblies commenced in October 2017. As part of the fuel channel assemblies, the removal of pressure tubes is in progress and will be followed by the removal of calandria tubes. The second major segment and the removal of all reactor components is expected to be completed by mid-2018. Key projects in the second major segment finished in 2018 include the completion of the primary side steam generator layup and installation of steam generator access ports to support future inspections. Other key project activities being executed during the second segment include the continuation of the major turbine generator overhaul, which will be completed in the second quarter of 2018, and continued execution of the major electrical scope. OPG is also continuing to execute work to support the requirements set out in the CNSC-approved Integrated Implementation Plan (IIP) for the station.

Most of the pre-requisite projects, including construction of facilities, infrastructure upgrades and installation of safety enhancements, have been completed and placed in-service. The Re-tube Waste Processing Building was completed in November 2017. Completion of the HWSF has been delayed due to challenges with construction. OPG suspended the project in the second quarter of 2017 to evaluate the best approach to optimize cost and schedule and complete the project. Construction to complete the facility recommenced in the fourth quarter of 2017. The HWSF is expected to be completed by the second quarter of 2019 and is not on the critical path for the Darlington Refurbishment project, which continues to track on schedule. The increase in the cost estimate for the HWSF will be accommodated within the overall Darlington Refurbishment budget of $12.8 billion. Taking into account the execution performance of the Unit 2 refurbishment, the overall Darlington Refurbishment project continues to track on budget.

The OEB accepted OPG's rate application with respect to the refurbishment of the Darlington units including an increase in the nuclear rate base, effective in the first quarter of 2020, to reflect the planned in service of $4.8 billion in capital expenditures upon the return to service of Unit 2, which includes expenditures incurred during the definition and planning phase of the project. Based on OPG's proposal in the application, the revenue requirement impact of the differences between the forecast Unit 2 in-service amount included in the regulated prices and the actual amounts placed in service would be subject to true up via the Capacity Refurbishment Variance Account established by the OEB pursuant to *Ontario Regulation 53/05*.

In addition to the execution of refurbishment activities on Unit 2, OPG is continuing planning activities for the refurbishment of the second unit, Unit 3, and is entering into associated commitments to procure major components that require long lead times. These planning activities are being undertaken in accordance with the refurbishment project schedule. In February 2018, the Province confirmed its commitment to proceed with Darlington's Unit 3 refurbishment in 2020. **[MONITOR]**

On November 21, 2017, the Financial Accountability Office of Ontario issued a report, "*An Assessment of the Financial Risks of the Nuclear Refurbishment Plan*". The report assesses the impact of OPG and Bruce Power's nuclear refurbishments on customers and the Province based on mechanisms in place for the recovery of the costs to refurbish and subsequently operate the nuclear stations. The report concludes that refurbishment of the four units at the Darlington GS and the six units at the Bruce nuclear generating stations provides the most cost effective, low emission generation source available to meet Ontario's baseload electricity requirements.

CNSC Regulatory Approvals

In December 2013, OPG submitted an application to the CNSC for the operating licence renewal for the Darlington GS. The CNSC granted the Darlington GS a ten-year operating licence in December 2015, which is the longest licence ever granted by the CNSC to a Canadian nuclear power plant. The new licence, which is effective from January 1, 2016 to November 30, 2025, spans most of the planned duration of the Darlington Refurbishment project.

In line with the CNSC's regulatory requirements related to life extensions of nuclear power plants in effect at the time that OPG began to undertake the Darlington Refurbishment project, OPG completed a series of assessments, including an environmental assessment (EA), an Integrated Safety Review, and a Global Assessment Report (GAR). The EA decision, issued by the CNSC and Fisheries and Oceans Canada in March 2013 following public hearings, confirmed that, taking into account identified mitigation measures, the project was not likely to cause significant adverse environmental effects. In April 2014, the CNSC accepted the GAR as meeting all regulatory requirements related to life extensions of nuclear power plants. In November 2014 and April 2016, respectively, certain intervenors' request for a judicial review and subsequent appeal to the Federal Court of Appeal related to the EA decision were dismissed by the courts.

Actions identified as part of the above assessments to meet updated codes, standards and practices, and to ensure that the operation of the station continues to pose minimal risk to health, safety, security and the environment, were integrated into the IIP. As part of the Darlington operating licence renewal in December 2015, the CNSC approved the regulatory scope defined in the IIP. OPG has been undertaking activities in support of the IIP requirements, including the commissioning of two safety enhancements at the station, the Third Emergency Power Generator and the Containment Filtered Venting System, which were placed in-service in April 2017. There were 17 IIP commitments scheduled and completed for 2017.

Extension of Commercial Operations at Pickering to 2024

In 2015, OPG completed the necessary work to demonstrate with sufficient confidence that the Pickering fuel channel life, a key life-limiting component of the station, will allow all six operating units of the station to operate to the end of 2020. OPG's early technical work at that time also showed that the Pickering GS can be operated safely beyond 2020. OPG's objective is to maximize the safe and reliable operating life of the Pickering units. As announced in 2016 and approved by the Province, OPG is continuing to execute on a plan to extend safe and reliable operation of the Pickering GS to 2024. Extending operations at the Pickering GS will provide Ontario with a clean, reliable source of baseload electricity during the Darlington GS and initial Bruce nuclear unit refurbishments, providing continued employment for up to 4,000 full-time employees at OPG.

OPG's current five-year operating licence for the Pickering GS was approved by the CNSC in 2013 and expires on August 31, 2018. This current licence was issued assuming that the station would shut down in 2020. On June 28, 2017, OPG confirmed to the CNSC that it intends to cease commercial operation of all Pickering units on December 31, 2024. On August 28, 2017, OPG submitted a ten-year licence renewal application to the CNSC. The requested licence term spans the planned extended commercial operations period, through to the planned period of de-fuelling, de-watering and beginning to place the station in a safe storage state in 2028. In support of the licence renewal, OPG undertook a Periodic Safety Review (PSR), a comprehensive assessment of the station's design and operation to confirm that there is a high level of safety throughout the operating life and to determine what reasonable and practical enhancements can be made to further improve safety. The PSR also includes a component condition assessment of the station to identify the work required to support the station's continued operation. The PSR has confirmed that extending operations of the Pickering units will continue to pose minimal risk to the health, safety and security of workers, the public and the environment. The final major component of the PSR was submitted to the CNSC in November 2017. The CNSC's review of the PSR submission and licence application is in progress. Based on the evidence and documentation submitted to the CNSC, OPG is confident in obtaining a licence renewal that would support our extended operations plan for Pickering GS.

As part of the plan to extend Pickering operations, OPG has been continuing to undertake the required technical work to confirm that the station's pressure tubes, a key life-limiting component of the station, will remain fit for service for operation to 2024. In the fourth quarter of 2017, OPG has confirmed that technical assessments completed to date provide sufficient confidence in the programs and provisions in place to assure fitness-for-service of fuel channel components in line with the planned extended operations period. This evaluation is consistent with the safety case reflected in OPG's operating licence renewal application for the Pickering GS submitted to the CNSC in 2017, discussed above. Taking these factors into account, OPG revised the accounting end-of-life assumptions for the Pickering GS from December 31, 2020 for all units to December 31, 2022 for Units 1 and 4 and December 31, 2024 for Units 5 to 8, effective December 31, 2017.

The change in the Pickering GS accounting end-of-life assumptions did not impact OPG's net income in 2017. The change is expected to decrease depreciation expense by $77 million in 2018, including the associated impact on the nuclear asset retirement obligation recorded as of December 31, 2017 but before the impact of regulatory accounts. Regulatory accounts, including a new deferral account proposed by OPG in a December 2017 application to the OEB, are expected to largely offset the decrease in depreciation expense. As of December 31, 2017, OPG recorded an increase of $188 million in the Nuclear Liabilities and associated asset retirement costs capitalized as part of carrying value of property, plant and equipment reflecting the change in the Pickering GS accounting end-of-life assumptions from December 31, 2020 for all operating units to December 31, 2022 for Units 1 and 4 and December 31, 2024 for Units 5 to 8. The increase in the liabilities is primarily due to higher fixed costs associated with the Used Fuel Disposal and L&ILW Storage programs, discounted using the current credit-adjusted risk-free rate of 2.94 percent. The adjustment did not impact net income for 2017. The adjustment is not expected to have a material impact on net income in 2018 as the associated impact on expenses is expected to be largely offset by OEB-authorized regulatory accounts. On December 29, 2017, OPG applied for an accounting order to establish a variance account to record, from January 1, 2018 until the effective date of the OEB's next payment amounts order, the revenue requirement impact of changes to nuclear liabilities and depreciation and amortization expense resulting from changes to station end-of-life dates for OPG's Pickering prescribed nuclear facilities that will be effective December 31, 2017. Pending the OEB's review of the application, an interim order was issued January 31, 2018 establishing the proposed variance account effective January 1, 2018. The OEB's final decision in the account is expected later in 2018.

The income statement impacts associated with the changes to the Nuclear Liabilities are offset by the Bruce Lease Net Revenues Variance Account and the Nuclear Liability Deferral Account authorized by the OEB or new variance account to be authorized by OEB for the prescribed facilities.

Bruce Power Refurbishment and Bruce Lease Agreement

OPG leases the four-unit Bruce A (Units 1 to 4) and the four-unit Bruce B (Units 5 to 8) nuclear generating stations and associated lands and facilities to Bruce Power on a long-term basis. Bruce Units 1 and 2 were refurbished by Bruce Power under a refurbishment agreement with the IESO and returned to service in 2012. While Bruce Power is responsible for operating all of the leased units, OPG is primarily responsible for the management of the nuclear used fuel and other nuclear waste associated with the Bruce nuclear generating facilities, as well as the decommissioning of the facilities at the Bruce site. Under the lease agreement between Bruce Power and OPG (Bruce Lease) and related agreements, OPG receives base rent and supplemental rent payments from Bruce Power, fees for nuclear waste management other than used fuel, and fees for certain other services. The output from the Bruce nuclear generating stations is not subject to rate regulation by the OEB.

In December 2015, the Province announced that the refurbishment agreement between the IESO and Bruce Power had been updated and that Bruce Power will proceed with the refurbishment of the six un-refurbished units of the Bruce nuclear generating stations. In order to facilitate Bruce Power's refurbishment plans, the Bruce Lease and related agreements were amended in December 2015 to extend Bruce Power's future options to renew the lease up to the end of 2064. To achieve better alignment with OPG's costs, the agreements were also amended to revise, starting in 2016, the approach for calculating supplemental rent payments and fees for nuclear waste management other than used fuel, and to modify the fee structure for

OPG's heavy water detritiation services starting in 2017. Beginning in 2016, supplemental rent payments wholly represent fees for nuclear used fuel management. Amendments were also made to enable certain adjustments to future base rent, supplemental rent and other fees for potential future changes in OPG's decommissioning and nuclear waste management cost estimates related to the Bruce facilities, and to remove a conditional supplemental rent rebate provision effective December 4, 2015. Certain of the above amendments were executed by OPG pursuant to a Shareholder Declaration and Shareholder Resolutions issued in November 2015. For a complete list of Shareholder directives, refer to the section, *Interest of Management and Others in Material Transactions* under the heading, *Relationship with the Province and the OEFC – Shareholder Directives*.

The refurbishment of Bruce Power's Unit 6 is scheduled to commence on January 1, 2020. As part of the preparation activities, OPG is working with Bruce Power to develop a fixed price cost estimate for the non-routine nuclear waste that will be generated from the Unit 6 refurbishment. The parties will execute a separate agreement that sets out the terms and conditions that will apply to this refurbishment waste. Pursuant to a Memorandum of Understanding dated November 12, 2015, OPG and Bruce Power have committed to ongoing collaboration to improve their respective refurbishment programs.

Ontario Nuclear Funds Agreement Reference Plan Update

OPG is responsible for the management of radioactive used nuclear fuel and low and intermediate level radioactive waste material (L&ILW) and the decommissioning of its nuclear stations and waste management facilities. Pursuant to the Ontario Nuclear Funds Agreement (ONFA), OPG is required to set aside monies into two segregated funds, the Used Fuel Segregated Fund and the Decommissioning Segregated Fund, to fund the future life cycle costs of long-term nuclear used fuel and L&ILW management and nuclear facilities decommissioning. OPG's required contributions to the Nuclear Segregated Funds are determined based on periodically updated reference plans approved by the Province under the ONFA, at least once every five years. As part of the reference plan update process, OPG estimates the total funding liabilities for future nuclear waste management and nuclear decommissioning based on life cycle cost estimates and a set of underpinning assumptions, including remaining useful lives of the nuclear stations, proposed methods and timing of nuclear waste disposal, and economic indicators. In accordance with US GAAP, OPG carries a present value asset retirement obligation on the balance sheet related to its nuclear waste management and nuclear decommissioning liabilities. In accordance with *Ontario Regulation 53/05*, the OEB is required to ensure that OPG recovers the revenue requirement impact of its nuclear waste management and nuclear decommissioning liabilities arising from the current approved ONFA reference plan. The current methodology applied by the OEB for including OPG's costs associated with these liabilities in the regulated prices was established by the OEB in its 2008 decision on OPG's first application for new regulated prices.

In 2016, OPG completed a comprehensive update of the estimate for its obligations for nuclear waste management and nuclear facilities decommissioning, in line with the required ONFA reference plan update process. The results of the update were reflected in a new ONFA reference plan as well as a downward adjustment in the asset retirement obligation carried on OPG's balance sheet as at December 31, 2017. The new ONFA reference plan was approved by the Province in December 2016, with an effective date of January 1, 2017 (the 2017 ONFA Reference Plan). Reflecting the funded status of the Used Fuel Segregated Fund and the Decommissioning Segregated Fund based on the revised lower life cycle liability estimates per the 2017 ONFA Reference Plan, no overall contributions to either the Used Fuel Segregated Fund or the Decommissioning Segregated Fund are currently required starting in 2017. Contributions may be required in the future should either or both of the funds be in an underfunded position when a new reference plan is approved. Such may be the case as a result of future variability in asset performance due to volatility inherent in financial markets and economic conditions. Future contribution levels also are dependent on changes in baseline cost estimates and underpinning planning assumptions used to establish the funding obligations in subsequent ONFA reference plans.

The overall reduction in OPG's nuclear waste management and nuclear decommissioning liabilities resulting from the comprehensive update was mainly due to a decrease in cost estimates to reflect a proposed new, more cost effective container design and engineered barrier concept to house used nuclear fuel for disposal, updated cost escalation rates, and a later expected in-service date for Nuclear Waste Management Organization's (NWMO) planned deep geologic repository for the long-term permanent disposal of Canada's used nuclear fuel. These decreases were partly offset by higher cost estimates related to station decommissioning, primarily due to a better definition of work required during the preparation for safe storage after station shutdown and a higher volume of waste expected to be generated during the decommissioning.

Further details on OPG's nuclear waste management and nuclear decommissioning obligations, the ONFA and proposed methods for long-term used fuel and L&ILW disposal are discussed in the section, *Description of the Business* under the heading, *Regulated – Nuclear Waste Management Segment.*

Hydroelectric Business Development

Peter Sutherland Sr. Hydroelectric Generating Station

In March 2015, OPG's Board of Directors approved a project to construct the Peter Sutherland Sr. GS, a new 28 MW hydroelectric station on the New Post Creek near its outlet to the Abitibi River, with a budget of $300 million. The station was constructed through PSS Generating Station LP, a partnership between OPG and Coral Rapids L.P., a wholly owned subsidiary of the Taykwa Tagamou Nation.

In March 2017, final testing and commissioning of the turbine and generator units were successfully completed and both units were declared substantially complete. On March 31, 2017, the project received a permit from the Ontario Ministry of the Environment and Climate Change (MOECC) to take water for operations to allow the station to operate commercially. The project is expected to close below the approved budget of $300 million. Project close-out activities are in progress. OPG began to receive contracted revenue for the project following the IESO's confirmation of the station's commercial operations as of March 31, 2017, under a 50-year hydroelectric ESA.

In April 2017, Coral Rapids Power Corporation (CRP) exercised its right under the partnership agreement to increase its interest in PSS to 33 percent.

Sir Adam Beck Pump Generating Station Reservoir Refurbishment

In August 2015, OPG's Board of Directors approved a project to refurbish the 300-hectare storage reservoir at the Sir Adam Beck Pump GS. The Sir Adam Beck Pump GS facility allows OPG to pump and store water diverted from the Sir Adam Beck generating complex during periods of low electricity demand to be used to generate up to 600 MW of electricity during subsequent periods of high electricity demand.

The refurbishment construction began in April 2016 and was completed in February 2017, ahead of the originally planned schedule date of April 2017 and below the approved budget of $58 million. The reservoir refurbishment work included the installation of a partial new reservoir liner and construction of a grout curtain in the bedrock foundation of the reservoir dyke. The refurbishment is expected to add approximately 50 more years to the reservoir's life. The Sir Adam Beck Pump GS is reported in the Regulated – Hydroelectric segment.

Ranney Falls Hydroelectric Generating Station

In 2017, OPG began construction work on a 10 MW single-unit powerhouse on the existing Ranney Falls GS site, as part of the Regulated – Hydroelectric segment. The new unit will replace an existing unit that reached its end of life in 2014. The existing forebay structure has been demolished and the new concrete structure has been completed. Excavation has been completed and construction continues in the expanded forebay, powerhouse and spillway area. The new forebay concrete wall has been completed, and concrete placement of the new powerhouse and the spillway integrated structure is in progress. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget.

Thermal and Solar Business Development

Nanticoke Solar Facility

In March 2016, Nanticoke Solar LP, then a partnership between OPG, SunEdison Canadian Construction LP (SECCLP) and a subsidiary of Six Nations of the Grand River Development Corporation, was selected through the first phase of IESO's Large Renewable Procurement (LRP) program to develop a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands in Haldimand County, Ontario. The LRP program was a competitive bidding process for procuring large renewable energy projects in Ontario. In March 2016, Nanticoke Solar LP and the IESO executed a 20-year LRP contract, which formalized the terms and conditions for the development and operation of the new solar facility. In the first quarter of 2017, OPG purchased SECCLP's interests in Nanticoke Solar LP and is working to obtain approvals and permits required to enable the commencement of construction planned for the first quarter of 2018. Significant contracts for equipment and engineering construction services were executed in the first quarter of 2018. The 20-year term of the LRP contract takes effect once the station achieves commercial operation, which is expected in the first quarter of 2019. The facility is expected to be completed in the first quarter of 2019, with a budget of $107 million. **[MONITOR]**

Decommissioning of Lambton and Nanticoke Coal-Fired Generating Stations

OPG ceased coal-fired generation at the Lambton and Nanticoke generating stations in September 2013 and December 2013, respectively. In November 2016 and July 2015, respectively, OPG announced that it would decommission the Lambton and Nanticoke generating stations as it could not commercially support continued preservation of these sites in light of the outlook for long-term electricity demand in the province that does not support the need for their future conversion. OPG has begun executing decommissioning plans for these two stations, which will ensure that they are closed safely, securely, and in an environmentally responsible manner. The decommissioning of the Nanticoke GS will accommodate the construction and operation of the Nanticoke solar facility.

During 2017, OPG substantially completed the demolition of the Nanticoke coal yard equipment and structures and issued a contract for the demolition of the Nanticoke powerhouse and associated structures. In the fourth quarter of 2017, the demolition contractor had been mobilized to prepare for the removal of the powerhouse and associated structures and initiated the preparatory work for the demolition of the stacks. The demolition of the stacks took place in February 2018. **[MONITOR]** A competitive bidding process for the demolition of the Lambton GS is in progress, with a contract for the removal of the powerhouse and associated structures expected to be issued during 2018. An update of the associated asset retirement obligations related to the Nanticoke and Lambton sites has been completed. For a discussion of the revaluation of this liability for non-nuclear fixed asset removal as at December 31, 2017, refer to the section, *Critical Accounting Policies and Estimates* under the heading, *Asset Retirement Obligations* in the Company's 2017 year-end MD&A.

DESCRIPTION OF THE BUSINESS

The Electricity Industry

The electricity industry is principally comprised of four components: generation, transmission, distribution, and marketing of energy and other services in wholesale and retail markets.

Generation is the production of electricity. Transmission is the transfer of electricity across high-voltage power lines from generating facilities to local areas. Distribution is the delivery of electricity within local areas to homes and businesses using relatively low-voltage power lines. Energy marketing relates to the purchase of large amounts of electricity or equivalent financial products, and the subsequent re-selling in smaller quantities to third parties in either the wholesale or retail markets.

Electricity has traditionally been generated in large, multi-unit, centralized facilities. These facilities are usually classified by: (i) the type of fuel used; (ii) capacity, typically expressed in MW; and (iii) dispatch mode (being whether or not the electricity generated by a particular facility is dispatched to meet peak, intermediate or baseload demand). The energy produced by a facility is generally expressed as its output over the time the facility operates, typically in terms of MWh. New supply from smaller scale, largely intermittent, renewable sources such as wind, solar, and bio-energy is being integrated into the power system, connected either directly to the transmission system or embedded in distribution networks. Distributed generation involves production of electricity closer to end users and away from large scale production facilities that require more transmission. Electricity systems typically require new capital expenditures and processes in order to accommodate intermittent generators.

Electricity is an essential commodity that cannot be stored without converting to other forms, a process that is more difficult in large volumes. Therefore, electricity supply must instantaneously match demand to maintain the stability and reliability of the electrical power system. This is accomplished by coordinating the supply of and demand for electricity, a responsibility typically assigned to regulated regional system operators. Electricity systems have evolved on a regional basis and are connected to neighbouring regional power grids. Such connections enhance system reliability and permit the economic purchase and sale of electricity between electricity markets.

Ontario's Electricity Industry

OPG's predecessor, Ontario Hydro, served as a vertically integrated electric utility in Ontario. Following the adoption of a restructuring plan for Ontario's electricity industry pursuant to the *Energy Competition Act, 1998,* five principal successors to Ontario Hydro's integrated electricity business began operating as separate entities on April 1, 1999:

- OPG, which purchased and assumed the electricity generation, wholesale energy, and ancillary services businesses of Ontario Hydro;
- Hydro One, which purchased and assumed the transmission, distribution, and retail energy services businesses of Ontario Hydro;
- the Independent Electricity Market Operator (later renamed the IESO), which was formed to act as both the independent electricity system operator and the market operator. The IESO is responsible for the dispatch of generation to meet demand, the control of the Ontario transmission grid, and the operation of energy and ancillary markets;
- the Electrical Safety Authority, which was established to carry out electrical equipment and electrical wiring safety and inspection functions; and
- the Ontario Electricity Financial Corporation (OEFC), which is the legal continuation of the former Ontario Hydro and is responsible for managing the debt and certain other obligations not transferred to other successor companies of Ontario Hydro.

OPG purchased and assumed all of the interest of Ontario Hydro in and to all officers, employees, assets, liabilities, rights and obligations of Ontario Hydro directly or indirectly relating in any manner to the applicable activities carried on by Ontario Hydro as of April 1, 1999, pursuant to the transfer orders made

by Order-in-Council under the *Electricity Act, 1998*. The transfer orders provide that if they fail for any reason to fully and effectively in law transfer any such asset, right, liability or obligation or that if such transfer would constitute a breach of the terms of the asset, right, liability or obligation or of any applicable law, such assets, rights, liabilities or obligations are not transferred, but are held by the OEFC for the benefit of OPG.

Ontario's competitive electricity market was opened by the IESO in 2002. The market is used to manage the purchase and sale of wholesale electricity in the province.

Since the opening of the competitive market, Ontario's power supply mix has experienced significant change. A significant amount of new capacity has been added, while coal-fired generation, which at its peak accounted for approximately 6,500 MW of capacity, has been eliminated. New natural gas powered capacity of approximately 5,000 MW as of the end of 2017 has largely replaced the peaking capacity previously provided by coal-fired generation, while the return to service of Units 1 and 2 at the Bruce A GS in 2012 added approximately 1,500 MW of baseload nuclear generation. New wind and solar capacity of over 7,000 MW has also been added as of the end of 2017, toward Ontario's longer-term target for total wind and solar capacity of about 10,000 MW.

While electricity supply in Ontario has increased, the province's electricity demand as reported by the IESO has fallen, by approximately 13 percent over the last decade, largely due to changes in economic conditions and conservation measures, and also in part due to the addition of small scale solar generation embedded in the distribution system. Embedded generation reduces the demand supplied by grid-connected generation. Reducing electricity demand by encouraging conservation and demand management has been a key part of the Government of Ontario's plan to reduce greenhouse gas (GHG) emissions from the province's electricity sector. Shorter-term fluctuations in electricity demand are impacted by variations in seasonal weather conditions. Ontario's electricity demand as reported by the IESO was 132 TWh in 2017, which excludes electricity exports out of the province.

In October 2017, Ontario's Ministry of Energy issued the 2017 LTEP that outlines the Province's plans for the future development of Ontario's electricity system. The 2017 LTEP focuses on the affordability, reliability and flexibility of a clean energy supply in the province. For further details on the LTEP, refer to the section, *General Development of the Business* under the heading, *General Development – Ontario's Long-Term Energy Plan.*

Ontario Electricity Market Activities

Real-time energy supply needs are met through the wholesale electricity market administered by the IESO, with the market clearing price, the Hourly Ontario Energy Price, set by offers or bids into the market. OPG offers its generation into this real-time energy market, or spot market, to be dispatched by the IESO. The IESO receives hourly offers from electricity generators and importers to provide energy, along with bids to withdraw energy from a few flexible loads and exporters, and then schedules the lowest-cost offers and bids needed to meet demand every five minutes.

Virtually all non-OPG generators in Ontario have bilateral contracts with the IESO that provide for payments that are different from the market price of electricity. In addition, the prices for all of OPG's nuclear and most of its hydroelectric stations are set by the OEB. The difference between the market price and the prices paid for regulated and contracted generation, as well the cost of conservation and demand management programs, are charged to Ontario electricity consumers through the Global Adjustment portion of the total price of electricity.

Maintaining power system reliability requires a continuous balance of supply and demand. Some generators are needed to produce a constant supply of energy to meet basic energy needs (baseload generation), while others are needed to adjust energy output to match changes in demand (peaking and intermediate generation). OPG's nuclear generating stations operate as baseload facilities, whereas its hydroelectric stations operate as baseload, intermediate or peaking stations, depending on their physical characteristics and hydrological conditions. OPG's thermal stations operate as peaking facilities.

SBG occurs when electricity production from the baseload facilities is greater than the market demand for electricity. Baseload generation supply surplus in Ontario is managed by the IESO, mainly through generation reductions at hydroelectric and certain nuclear stations and other grid-connected renewable resources. The prevalence of SBG conditions is impacted by weather conditions which affect electricity demand, wind and solar generation quantities, and through the impact on water flows, the availability of hydroelectric power. In 2017, OPG lost 5.9 TWh of hydroelectric generation due to SBG conditions. In each of 2016 and 2015, OPG lost 4.7 TWh and 3.2 TWh of hydroelectric generation due to SBG conditions. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions, which represents the majority of such production forgone by OPG to date, has been offset by a regulatory variance account authorized by the OEB. During 2017, 2016 and 2015, generation losses at OPG's regulated hydroelectric stations due to SBG conditions were 5.2 TWh, 4.3 TWh and 2.8 TWh, respectively.

The OEB has authorized an additional pricing mechanism for OPG's regulated hydroelectric generation that provides a financial incentive to OPG to shift hydroelectric generation from lower market price periods to higher market price periods. This is intended to benefit customers through the displacement of generation from the relatively higher cost sources such as natural gas. The time-shifting is made possible by the ability to store water in reservoirs located at a number of OPG's hydroelectric facilities, including the Sir Adam Beck Pump GS.

The IESO also administers the operating reserve market and a market for ancillary services. The objective of the operating reserve market is to ensure that additional supplies of energy are available to maintain power system reliability following an unforeseen event. Ancillary services include regulation service, reactive support, black start capacity, and other services required to maintain the reliability of the Ontario electricity system. OPG participates in these markets. Revenues earned by OPG's regulated facilities from providing services into these markets are applied by the OEB to reduce regulated prices for electricity generated from these facilities.

OPG and other Ontario electricity market participants are required to comply with market rules issued by the IESO. As an owner and operator of generating stations, OPG is also subject to reliability standards as set out by the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC) and the IESO. NERC, NPCC and IESO are standards authorities with the ability to create or modify reliability standards. Such standards are binding on OPG pursuant to the OEB-issued electricity generating license and the IESO market rules. The IESO monitors compliance with and enforces the market rules and coordinates with system operators and reliability agencies in other jurisdictions to ensure energy adequacy and security across the interconnected bulk electricity market in North America.

Interconnected Markets

The interconnected markets are electricity markets in neighbouring provinces and states whose transmission systems are connected to the Ontario power grid, either directly or through other contiguous interconnected markets. Ontario's market is interconnected with New York, Michigan, Minnesota, Manitoba, and Québec. Market intermediaries wishing to import or export electricity between Ontario and the interconnected markets are required to schedule these transactions through the Ontario spot market. OPG and its wholly owned subsidiary, OPG Energy Trading (OPGET), participate in the interconnected markets. Further details on OPGET are discussed under the heading, *Services, Trading, and Other Non-Generation Segment.*

Interconnection transmission capabilities between Ontario and the interconnected markets are subject to physical and weather dependent limitations. These limitations include planned or forced outages to transmission lines and other equipment that reduce transmission capacity. They also include wind and temperature conditions that affect the transfer capability of all transmission lines on the electrical system. For example, higher ambient air temperature lowers capacity, while higher wind speeds increase capacity. Overall power system parameters and conditions also can result in limitations on particular interties, being one or more transmission lines that connect Ontario to a neighbouring region. For example, high flow on one intertie may result in a reduction in the limit on another intertie.

Water Rights

OPG's management of available water resources directly affects the generation output, efficiency, and ultimately return on investment for the Company's hydroelectric assets. The watersheds on which OPG's hydroelectric generating facilities are located are shared by many users and are subject to various governance requirements, such as international, federal and provincial agreements, water power leases, and regulations. Accordingly, OPG must balance the economic, environmental, social and legal requirements associated with the watersheds when utilizing water to optimize electricity generation.

International Rivers

The six OPG hydroelectric generating stations subject to OEB rate regulation since 2008 are directly or indirectly supplied by two major international waterways, the Niagara River and the St. Lawrence River, and are subject to treaties with the U.S. relating to water use. These stations represent approximately 45 percent of OPG's total in-service hydroelectric capacity.

Through a series of agreements between the Government of Canada and the Province, and certain federal and provincial laws, OPG has been granted the right to exercise Canada's rights with respect to the construction, maintenance, and operation of generating facilities under the *Boundary Waters Treaty of 1909* and the *Niagara Diversion Treaty of 1950* between Canada and the U.S. Both of these treaties continue in perpetuity but are terminable by either party with 12 months prior written notice. Given the significance of these treaties, OPG does not expect either party to exercise their respective termination rights in the foreseeable future.

The *Boundary Waters Treaty of 1909* established the International Joint Commission with the mandate of regulating shared water uses and preventing and resolving disputes between U.S. and Canada. In December 2016, the International Joint Commission issued an order implementing a new plan to manage water levels and flows in Lake Ontario and the St. Lawrence River, effective January 7, 2017. The new plan, which replaced the existing plan in use since 1963, is intended to allow for more natural water levels, while minimizing impacts to other users, including hydroelectric power production. No significant changes in OPG's operations are expected as a result of the new plan.

The *Niagara Parks Act* (Ontario) gives the Niagara Parks Commission the authority to grant certain rights for the use of the waters of the Niagara River for purposes of power generation. By agreement with OPG, the Niagara Parks Commission has agreed not to grant any rights to third parties until after 2056.

Under an agreement between OPG and the St. Lawrence Seaway Management Corporation, a federal agency, the DeCew Falls generating stations use water that is transported along the Welland Canal from Lake Erie. The agreement has been renewed through June 30, 2038.

The Province has granted OPG the right to use water from the International Rapids section of the St. Lawrence River for power generation at the R.H. Saunders GS, subject to an agreement between the Government of Canada and the Province. The Government of Canada has the right, upon notice and after unsuccessful arbitration, to take over the operation of and title to the R.H. Saunders GS in the unlikely event of a breach of the agreement by the Province.

Interprovincial Rivers

Four of OPG's hydroelectric stations are located on the Ottawa River, which forms part of the Ontario-Québec border. These stations represent approximately 12 percent of OPG's total in-service hydroelectric capacity. Three of these stations are subject to 999-year leases with each of the Provinces of Ontario and Québec. The fourth station is subject to a water power lease with the Province of Ontario, which is renewable to 2031, subject to certain conditions. OPG's use of water from the Ottawa River basin is subject to guidelines established by the Ottawa River Regulation Planning Board, comprised of government and industry representatives.

Interior Rivers

Fifty-six of OPG's hydroelectric stations, representing approximately 43 percent of OPG's total in-service hydroelectric capacity, are located on 20 other Ontario river systems. OPG holds water power leases, Crown leases and licences with the Province on the river systems that supply 37 of these stations. A land use permit, issued for the Peter Sutherland Sr. GS, remains in effect while a water power lease for the site is prepared by the Ontario Ministry of Natural Resources and Forestry (MNRF). These leases and licences have expiry dates, including renewal periods, ranging between 2023 and 2075. Certain of these leases provide that the leased property and any fixed improvements, including generating stations and dams, will revert to the Province on the expiry of the lease. OPG intends to work towards new leases and licenses for these stations. OPG's use of Ontario's interior watersheds is constrained by restrictions contained in certain of the water power leases and licences. Eight of the 56 stations are located on the Trent and Rideau Waterways and are operated pursuant to licences from the federal government. These licences expire in February 2020. The process to renew the licences is currently underway with Parks Canada. Ten of the 56 stations are not subject to leases or licences.

The current provincial regulatory framework requires the development of Operational Plans for new storage dams and generating stations in Ontario, except for those on international rivers, interprovincial rivers, or rivers under federal jurisdiction. These plans include any limitations on water flows and elevations, and historically have been a component of formal Water Management Plans (WMPs). WMPs were established under the *Lakes and Rivers Improvement Act* (Ontario) and *Water Management Planning Guidelines for Waterpower (2002)*, on a watershed basis, in consultation with the Ontario Ministry of Natural Resources and Forestry, federal fisheries authorities, stakeholders, such as recreational and commercial users, local communities, environmental groups, and partners, such as Indigenous groups. In October 2016, the MNRF published a Technical Bulletin, *Maintaining Water Management Plans (2016),* eliminating the need for WMPs where they are not already in place, removing the expiry date from existing WMPs, and outlining the requirements for Operational Plans for new waterpower works going forward. Existing WMPs continue to be in effect. WMPs and Operational Plans may be amended as certain conditions change or new data becomes available. OPG operates in compliance with WMPs and Operational Plans.

The operations of certain OPG stations in northwestern Ontario can impact users in Manitoba and are subject to guidelines and directions provided by the Lake of the Woods Control Board, which is comprised of Ontario, Manitoba and federal government representatives.

Dams and Waterways

In Canada, dams fall under provincial jurisdiction, with the exception of dams situated in interprovincial and international boundary waters and canals, and those owned by the Government of Canada. The majority of OPG's dams fall within the jurisdiction of the Province, with approximately 20 dams falling within the jurisdiction of the Province of Québec and 13 dams associated with the Trent-Severn and Rideau Waterways falling under federal jurisdiction. The International Joint Commission has an oversight role for dams and associated works on international boundary waters, including the St. Lawrence River and the Niagara River.

The Province regulates dams under the *Lakes and Rivers Improvement Act* (Ontario) administered by the MNRF. The legislation requires MNRF approval for activities such as the construction, alteration, improvement, or repair of dams.

In August 2011, the MNRF published a revised set of Technical Guidelines for dams, following a period of public consultation. The Technical Guidelines represent the government standards for dam safety. OPG was an active participant in developing the Technical Guidelines through the MNRF's advisory panel. In general, OPG practices in the area of dam safety and public safety around dams exceed the minimum requirements outlined in the Technical Guidelines. In cooperation with the MNRF, OPG is developing a new risk-informed approach to prioritize the outcomes of dam safety assessments.

Currently, there is no federal or provincial regulation with respect to public safety around dams that addresses dam public safety issues relating to changes in operating water levels, discharges from the hydroelectric or dam facilities, and other waterways-based hazards posed by such facilities. The *Navigation Protection Act* (Canada) does, however, require OPG to obtain approvals for the installation of all in-water works, such as safety booms and buoys associated with the OPG Waterways Public Safety Program. Additional details on OPG's Dam Safety and Waterways Public Safety Programs are discussed under the heading, *Workplace Safety and Public Safety – Dam Safety and Waterways Public Safety*.

Generation Operations

Nuclear (Regulated – Nuclear Generation Segment)

Overview of Generating Facilities

OPG owns and operates two nuclear generating stations, the results of which are reported in the Regulated – Nuclear Generation business segment. The Pickering GS, comprised of six operating units and two units in a permanent safe shutdown state, is located on the shore of Lake Ontario in Pickering, Ontario. As at December 31, 2017, the station's total in-service capacity was 3,094 MW. Four of the eight Pickering units originally went into service in the 1970s. A decision was made by Ontario Hydro in the late 1990s to place these four units in voluntary lay-up. In 2003 and 2005, respectively, two of the four laid-up units were returned to commercial operation, with the two remaining units placed in a permanent safe shutdown state. The other four operating units have been in service since the mid 1980s.

The Darlington GS, comprised of three operating units and one unit, Unit 2, undergoing refurbishment as of mid-October 2016, is located on the shore of Lake Ontario in the Municipality of Clarington, Ontario. As at December 31, 2017, the total in-service capacity of the three operating units was 2,634 MW. Unit 2 has a capacity of 878 MW. All four Darlington units have been in service since the early 1990s. Both the Pickering GS and the Darlington GS have been designed to operate at full power as baseload facilities.

The performance of OPG-operated nuclear generating stations during 2017, 2016 and 2015 was as follows:

Regulated – Nuclear Generation Performance (2015 to 2017)

Station	No. of In-Service Units	Unit Capability Factor [1] (%)		
		2017	2016	2015
Darlington [2]	3	**85.2**	89.5	76.9
Pickering	6	**80.0**	75.2	79.4
Total	9			

[1] Unit capability factor is the amount of energy a generating unit is capable of producing as a percentage of its maximum output assuming no external constraints such as transmission limitations. The nuclear unit capability factor excludes unit(s) during the period in which they are undergoing refurbishment.

[2] Excluding Unit 2, which has been undergoing refurbishment since mid-October 2016.

The lower Unit Capability Factor at the Darlington GS in 2017, compared to 2016, reflected the higher number of planned outage days in 2017, largely driven by constraints related to the transition of the station's operating units toward refurbishment. The increase in the Unit Capability Factor at the Pickering GS in 2017, compared to 2016, was primarily due to outage cycle optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station compared to 2016.

OPG's Bruce A and Bruce B nuclear generating stations have been leased on a long-term basis to Bruce Power. The stations are located in the Municipality of Kincardine, Ontario on the shore of Lake Huron.

For additional information on OPG's nuclear operations, refer to the section, *Core Business, Strategy, and Outlook* under the heading, *Operational Excellence – Electricity Generation Production and Reliability* in the Company's 2017 year-end MD&A.

Nuclear Generation Technology

Nuclear generation harnesses the energy released during controlled nuclear fission reactions to produce steam that is used to drive turbines to generate electricity. Nuclear generation has two main advantages. It is a relatively low marginal-cost generation technology, and it produces virtually no GHG, sulphur dioxide, nitrogen oxide, or mercury emissions. The latter advantage has become more significant as governments implement climate change action plans and stricter air emission standards.

However, in contrast to other types of generating facilities, notwithstanding the lower fuel costs, nuclear generating stations incur nuclear waste management and decommissioning costs and greater operating and maintenance expenses. In addition, the construction of nuclear generating stations entails greater initial capital costs than other generation technologies. The higher initial costs reflect the complexity of the technical processes fundamental to nuclear electricity generation, and the additional design and safety precautions taken to protect the public from potential risks associated with nuclear operations.

All of OPG's nuclear generating stations use CANada Deuterium Uranium (CANDU) technology reactors. CANDU is a pressurized-heavy-water, natural-uranium power reactor, originally designed in the 1960s by a consortium of Canadian government agencies and private industry. CANDU reactors are unique in their use of natural-uranium fuel and deuterium oxide, or heavy water, as both a moderator to slow down the fission process and a coolant within the reactor. The refuelling system is also unique in that CANDU reactors can be refuelled at full power. This is due to the subdivision of the reactor core into hundreds of separate fuel channels, each holding a single string of natural uranium fuel bundles, allowing for greater fuel efficiency. In contrast, U.S. reactors, which use enriched uranium fuel, must be shut down during refuelling. All nuclear power reactors in Canada use CANDU technology. CANDU reactors are currently operating in Ontario, New Brunswick, Argentina, Romania, South Korea, India, Pakistan and China.

Nuclear Fuel Procurement

OPG's nuclear fuel supply chain engages in the purchase of uranium concentrate, the purchase of services for the conversion of uranium concentrate to uranium dioxide, and the purchase of services for the manufacture of fuel bundles containing uranium dioxide pellets. OPG currently establishes contractual arrangements with each of these components separately and as appropriate maintains ownership of the uranium throughout the supply chain. OPG maintains a portfolio of multi-year supply contracts for uranium concentrate with domestic and foreign suppliers and commodity traders. Occasionally, short-term spot market purchases are acquired to support a portion of its uranium concentrate needs. OPG's nuclear fuel bundles are supplied by a Canadian-based manufacturer.

Nuclear Regulation

The *Nuclear Safety and Control Act* (NSCA) establishes the mandate and authority of the CNSC to make regulations governing all aspects of the development and application of nuclear energy in Canada. The NSCA grants the CNSC the power to act as a court of record, the right to make regulations, the power to require financial guarantees for nuclear waste management and nuclear facilities decommissioning as a condition of granting a licence, order-making powers, and the power to impose monetary penalties for licence infractions. The NSCA also grants the CNSC the power to require periodic re-certification of nuclear operators and to set requirements for various nuclear facility security measures. It also provides for regulatory authority over environmental matters, including a requirement that licence applicants make adequate provision for the protection of the environment. The NSCA grants the CNSC licensing authority for all nuclear activities in Canada, including but not limited to the issuance of new licences to operators, the renewal of existing licences, protection of the environment arising from nuclear activities, and making regulations related to nuclear activities.

A fundamental principle in nuclear regulation is that the licensee bears the responsibility for safe operation, with the CNSC setting safety objectives in areas such as radiation protection and physical security for nuclear generating stations and the transport of radioactive materials. The CNSC verifies compliance with the licence and performs audits and inspections of the licensee's performance against these objectives. The CNSC also has issued guidance documents to assist licensees in complying with regulatory requirements. Requirements specified in these guidance documents have been incorporated into the design and operating documents for OPG's nuclear generating stations.

Since the operation and regulation of nuclear energy has transboundary impacts, Canada has become a signatory to various international conventions relating to nuclear energy and emergency responses and is bound by conventions that it has ratified. In addition, the CNSC has a bilateral information exchange and co-operation agreement with the U.S. Nuclear Regulatory Commission, which provides, among other things, for the prompt, reciprocal notification of reactor safety problems that could affect both U.S. and Canadian nuclear generation facilities.

The CNSC publishes an annual Regulatory Oversight Report on the safety performance of Canada's nuclear power plants. The report assesses how well plant operators are meeting regulatory requirements and program expectations in the areas of operational performance, safety analysis, radiation protection, waste management and conventional health and safety. On September 8, 2017, the CNSC issued an executive summary of its 2016 annual report, giving both the Darlington GS and the Pickering GS the highest possible safety rating of "Fully Satisfactory". The Darlington GS achieved this rating for the eighth consecutive year, while the Pickering GS achieved this rating for the second consecutive year.

In 2017, the CNSC approved regulatory document *REGDOC 2.2.4 – Fitness for Duty – Managing Alcohol and Drug Use* for use at Canadian nuclear power plants. This document sets out requirements for managing fitness for duty of workers in relation to alcohol and drug use at high-security sites, including for-cause alcohol and drug testing for workers in positions identified as safety-sensitive or safety-critical and random alcohol and drug testing for workers holding safety-critical positions. OPG intends to enhance its existing Fitness for Duty program to comply with these new requirements. OPG is working with its partners in the Canadian nuclear industry to develop a program suitable for Canada and its workers.

All of OPG's nuclear power reactor operating licences and waste facility licences are current and up to date. In 2016, OPG submitted applications with the CNSC seeking a ten-year licence renewal for the Western Waste Management Facility (WWMF), located at the Bruce generating stations' site, to May 31, 2027, and a ten-year licence renewal for the Pickering Waste Management Facility (PWMF) to August 31, 2028. The licence renewal applications were presented to the CNSC at public hearings in April 2017. On May 30, 2017, the CNSC announced that the WWMF licence was renewed for a ten-year period and will be valid until May 31, 2027. On February 7, 2018, the CNSC announced that the PWMF licence was renewed for a ten-year period and will be valid until August 31, 2028. Further details on the operating licence for the Darlington GS are found in the section, *General Development of the Business* under the heading, *Nuclear Business Development – Darlington Refurbishment* and for the Pickering GS in the section, *General Development of the Business* under the heading, *Nuclear Business Development – Extension of Commercial Operations at Pickering to 2024*.

Details on Canada's nuclear liability regime and related insurance coverage can be found under the heading, *Insurance*.

Fukushima Daiichi Response

In response to the 2011 Fukushima Daiichi incident in Japan, OPG has confirmed that its stations are safe and that systems and procedures are in place to withstand significant emergencies. In 2013, a systematic review and verification of defences against external hazards was completed at OPG-operated stations. The review showed that:

- the nuclear safety systems and multiple back-up power systems in place at the stations are effective; and
- the current design of the stations is strong and the stations are able to withstand extreme external events.

The review also provided recommendations for further opportunities to enhance the safety margin and to develop preparedness for unexpected events that go beyond the extreme events already considered in the design of the stations.

OPG's action plan in response to the Fukushima Daiichi event is well aligned with the CNSC's Fukushima Action Plan, issued in mid-2012. In 2013, OPG submitted its plans for the majority of the CNSC's Fukushima Action Plan items applicable to OPG-operated stations to the CNSC. In January 2015, the CNSC recognized OPG's efforts in this area and confirmed that all of the Fukushima action items were closed. OPG's Fukushima Implementation Plan included a number of key safety enhancements for providing additional back-up capability to increase OPG's flexibility to respond to unexpected and highly unlikely external events that can impact either a single unit or multiple units at the same time. CNSC staff concluded that OPG had strengthened reactor defence and enhanced its emergency response at both the Darlington GS and the Pickering GS in response to the lessons learned from the Fukushima Daiichi incident.

Nuclear Generating Station Life

Service life predictions for OPG-operated nuclear stations are developed by assessing the impacts of a number of operating, technical, and regulatory considerations on both unit and station economics. A decision by OPG to remove a unit from service would be primarily an economic decision that becomes more likely as the number of components requiring replacement and the frequency and duration of inspections required to ensure a unit's fitness for service increases. The key life-limiting components at OPG's nuclear stations include fuel channels, feeder tubes, steam generators, and other reactor components. End-of-service life predictions are reviewed as new information on possible degradation mechanisms becomes available and as future generation expectations are revised.

In December 2015, OPG revised the accounting assumptions for the estimated useful lives of the nuclear generating stations it operates. Effective December 31, 2015:

- the average service life of the Darlington GS was extended by one year to 2052 to reflect the approval of the refurbishment schedule in 2015; and
- the average service life of the Pickering GS was extended by less than one year to reflect the technical confidence that all six operating units of the station will operate to the end of 2020.

The accounting end of life assumptions for the Pickering GS have been reassessed in December 2017 based on the technical work performed to confirm that the longer fuel channel life necessary to extend Pickering operations can be achieved and that the units would be fit to operate beyond 2020, taking into account the requirement for the CNSC's approval. Further information can be found in the section, *General Development of the Business* under the heading, *Nuclear Business Development – Extension of Commercial Operations at Pickering to 2024*.

Nuclear Facility Planning

OPG uses a structured approach to identify and prioritize projects to optimize returns from nuclear station reinvestment within the constraints imposed by technical and financial requirements, while ensuring that safety, environmental, and other regulatory programs are of the highest priority. Input from predictive maintenance programs, life cycle management plans, and system health monitoring is used to determine the activities necessary to sustain and improve nuclear unit performance.

A structured framework modeled on the best practices identified by the Electric Power Research Institute, the Institute for Nuclear Power Operations and the World Association of Nuclear Operators (WANO) is used to optimize the maintenance of the nuclear generating stations and assess the health of the facilities. The structured framework includes predictive maintenance programs, which combine technologies and human expertise to analyze equipment performance, maintenance and design data in order to make timely decisions about the scope and timing of inspections and maintenance for major or critical equipment. The predictive maintenance program for each station is prioritized on the basis of the importance of the equipment for reactor safety. Life cycle management plans are maintained for critical station components and are updated annually to incorporate operating experience and new information. The life cycle plans define the inspection and maintenance programs required to ensure that these components perform in accordance with their design basis. In addition, system engineers conduct performance monitoring of station systems according to system performance monitoring plans that are based on a comparison of performance indicators against established targets to improve system performance. System performance is assessed by collecting, trending and analyzing station data. This information is reported in system health reports which are updated, at a minimum, annually.

OPG's practices impacting the performance of the nuclear stations are audited regularly by WANO, with identified areas for improvement acted upon with priority. In May 2016, OPG hosted a WANO peer evaluation that compared the Darlington GS against standards of excellence through an in-depth and objective review by an international panel of industry experts. The review maintained Darlington's excellent standing as one of the top performing nuclear plants in the world. In December 2017, OPG hosted a WANO peer evaluation for the Pickering GS, which focused on the safe and reliable operation of the station while evaluating the plant material condition, functional and cross-functional areas of the organization. Pickering showed significant improvement since its last review and has sustained its strong rating in 2018, resulting in its best ever WANO peer review.

In September 2016, OPG hosted a team of experts from the International Atomic Energy Agency (IAEA) at the Pickering GS to conduct a standard Operational Safety Review Team mission. The team conducted an in-depth review of performance and adherence to international safety standards. In the second quarter of 2017, the IAEA's Operational Safety Review Team released the final report and confirmed that the Pickering GS demonstrates strong commitment to safety.

Nuclear planned outages are necessary to execute inspection and maintenance work related to asset management and regulatory requirements for systems and equipment where access is not possible under normal operating conditions. Planned outages also give OPG an opportunity to perform system and equipment upgrades, project work, configuration changes, and other improvements and modifications. The nuclear generation plan, by reference to the station's life cycle management plans, establishes the number, frequency and duration of the outages for each year required to ensure the continued safe and reliable long-term operation of the plant and its compliance with CNSC regulatory requirements.

The outage cycle determines the number of planned outages at each station in a particular year. The Darlington GS is on a 36-month outage cycle, where each of the four units undergoes an outage every three years, resulting in one or two outages per year for the station. The Pickering GS was on a 24-month outage cycle. Supported by technical assessments undertaken for the extension of Pickering GS, the outage frequency has been optimized and extended from 24 to 30 months. In addition, on a periodic basis all units at each station are required to be shut down to allow for inspection and maintenance on the station vacuum building, containment systems and other safety systems. The CNSC currently requires these

outages every 12 years at the Darlington GS and every ten years at the Pickering GS. The most recent vacuum building outage took place at the Darlington GS in 2015 and at the Pickering GS in 2010.

Nuclear Ancillary Operations

OPG's nuclear generating units contain approximately 7,500 tonnes of deuterium oxide, or heavy water, not including heavy water contained at the leased Bruce stations. The heavy water is required to operate CANDU reactors. Ontario Hydro ceased the operation of its heavy water plants in 1997 and the plants were subsequently decommissioned. There are currently no heavy water plants in Canada. OPG believes that its existing inventory of heavy water will be sufficient to replenish supplies as a result of normal operating losses at its nuclear stations, including the refurbishment of the Darlington GS. OPG also believes that sufficient quantities of heavy water are available for possible changes in operating conditions or for new nuclear generating facilities. OPG seeks opportunities to sell available surplus quantities of heavy water from its inventory.

Tritium is a radioactive substance produced as a by-product of operating CANDU reactors, through the use of heavy water in the reactor moderator and heat transport systems. OPG operates a specialized facility at its Darlington site, the Darlington Tritium Removal Facility (TRF), which removes tritium from the tritiated heavy water (detritiation) used at the nuclear generating stations, in order to control the occupational dose exposure to employees and limit the amount of tritium released to the environment. The extracted tritium is chemically immobilized, placed in special containers, and safely stored in a vault. The Darlington TRF is also expected to be used to detritiate heavy water during the eventual decommissioning of OPG's nuclear generating stations. Some tritium is sold to government-approved organizations for authorized commercial and health industry uses. OPG also provides detritiation services to Bruce Power. Opportunities for providing detritiation services to other third parties are limited because of storage and capacity restrictions at the Darlington TRF.

Cobalt-60 produced and sold by OPG is used mainly in the health industry to sterilize surgical and medical supplies. Cobalt-60 is produced in Units 6, 7 and 8 at the Pickering GS. Cobalt-60 can be produced in reactors which, like the CANDU reactors, use adjuster rods to regulate power. The production process involves replacing the stainless steel rod by a rod containing Cobalt-59, which is isotopically converted into Cobalt-60 after lengthy exposure to the atomic reaction in the reactor core. During planned maintenance outages, the rods are removed, cut, and packaged for sale as Cobalt-60, and new rods are inserted in the reactor to continue the production cycle.

Hydroelectric (Regulated – Hydroelectric and Contracted Generation Portfolio Segments)

Overview of Generating Facilities

Hydroelectric generating stations use the energy of falling water to drive hydraulic turbines that generate electricity. OPG's hydroelectric stations provide one of the Company's competitive advantages – a reliable, relatively low-cost source of renewable energy free of air emissions. Electricity generation from OPG's hydroelectric facilities depends primarily upon the availability of water, which is affected largely by natural factors such as precipitation and evaporation. It is also impacted by the prevalence of SBG conditions.

OPG currently owns and operates 66 hydroelectric generating stations and 241 associated dams located on 24 river systems across Ontario. The results of 54 of these stations that are rate regulated by the OEB are reported in the Regulated – Hydroelectric segment. The results of the remaining 12 stations are subject to long-term ESAs with the IESO and are included in the Contracted Generation Portfolio segment. The 54 regulated hydroelectric stations include the 48 stations prescribed for rate regulation beginning in 2014 and the six stations that have been rate regulated by the OEB since 2008.

As at December 31, 2017, OPG's regulated hydroelectric facilities had a total in-service capacity of 6,426 MW and the non-regulated hydroelectric facilities had a total in-service capacity of 1,042 MW. OPG's hydroelectric generating stations range in age from the newly in-serviced Peter Sutherland Sr. GS to over 119 years and include the oldest assets in OPG's generation portfolio.

Hydroelectric ESAs with 50-year terms are in place for the following hydroelectric facilities:

- Lac Seul and Ear Falls generating stations, with an expiry date of February 2059;
- Healey Falls GS, with an expiry date of April 2060;
- Sandy Falls, Wawaitin, Lower Sturgeon, and Hound Chute generating stations, with an expiry date of December 2060;
- Little Long, Harmon, Smoky Falls, and Kipling generating stations, with an expiry date of January 2064; and
- Peter Sutherland Sr. GS placed in-service in March 2017, with an expiry date of March 2067.

In 2017, the number of regional groups was reduced from five to four, by integrating the central operations work centers into three of the other existing regional operations groups. The following are the four regional operations groups that operate and maintain OPG's hydroelectric facilities:

- Niagara Operations – includes the three Sir Adam Beck stations located on the Niagara River and the two DeCew Falls facilities located on the Welland River. These facilities have been rate regulated by the OEB since 2008. As part of the change in the regional groups, the Gravenhurst work centre joined with seven regulated stations on the Muskoka, Severn and Beaver Rivers. This operations group also includes OPG's wind turbine.
- Eastern Operations – includes the following ten regulated hydroelectric generating stations: the R.H. Saunders GS on the St. Lawrence River; the Otto Holden, Des Joachims, Chenaux, and Chats Falls generating stations on the Ottawa River; and the Mountain Chute, Barrett Chute, Calabogie, Stewartville, and Arnprior generating stations on the Madawaska River. The R.H. Saunders GS has been regulated by the OEB since 2008. As part of the change in the regional groups, the Campbellford work centre joined with eleven regulated stations and one non-regulated station on the Trent, Mississippi and Rideau Rivers.
- Northeast Operations – includes five regulated and eight non-regulated hydroelectric stations in northeastern Ontario. The regulated stations are the Chute and Lower Notch generating stations on the Montreal River; the Abitibi Canyon and Otter Rapids generating stations on the Abitibi River; and the Matabitchuan GS on the Matabitchuan River. The non-regulated stations are the Little Long, Harmon, Smoky Falls, and Kipling generating stations on the Lower Mattagami River; the Wawaitin, Sandy Falls, and Lower Sturgeon generating stations on the Upper Mattagami River; and the Hound Chute GS on the Montreal River. The North Bay and Coniston work centres joined this regional operations group with seven regulated stations on the Wanapitei and French Rivers.
- Northwest Operations – includes nine regulated and two non-regulated generating stations in northwestern Ontario. The regulated stations are the Pine Portage, Cameron Falls, and Alexander generating stations on the Nipigon River; the Silver Falls and Kakabeka Falls generating stations on the Kamanistikwia River; the Manitou Falls and Caribou Falls generating stations on the English River; the Aguasabon GS on the Aguasabon River; and the Whitedog Falls GS on the Winnipeg River. The non-regulated stations are the Lac Seul and Ear Falls generating stations on the English River.

These operations groups are also responsible for the operation and maintenance of OPG's thermal facilities discussed under the heading, *Generation Operations – Thermal (Contracted Generation Portfolio Segment)*.

The performance of OPG's hydroelectric generating stations during 2017, 2016 and 2015 was as follows:

Hydroelectric Generation Performance (2015 to 2017)

	Regulated – Hydroelectric			Contracted Generation Portfolio – Hydroelectric			Total Hydroelectric		
	2017	**2016**	**2015**	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Availability *(%)* [1]	**88.0**	89.0	91.2	**74.6**	77.3	88.6	**86.2**	87.5	90.9

[1] Availability is represented by the percentage of time the generating unit is capable of providing service, whether or not it is actually generating electricity, compared to the total time for the respective period.

Lower availability of the Regulated – Hydroelectric facilities during 2017 was primarily due to a higher number of unplanned outage days at the Northwestern Ontario, Niagara, and Eastern Ontario regions' hydroelectric stations, partially offset by higher availability from the Sir Adam Beck Pump GS due to a higher number of planned outages days in 2016 as a result of the refurbishment of the station's reservoir. Lower availability of the Contracted Generation Portfolio hydroelectric facilities in 2017 was primarily due to an increase in the number of planned outage days at the Lower Mattagami River hydroelectric generating stations.

Lower availability of the Regulated – Hydroelectric facilities during 2016 was primarily due to the planned reservoir refurbishment project at the Sir Adam Beck Pump GS. Lower availability of the Contracted Generation Portfolio hydroelectric facilities in 2016 was primarily due to a higher number of planned outage days at the Kipling and Harmon generating stations.

OPG's objectives for the hydroelectric operations include operating and maintaining the generating facilities in a safe, efficient and cost-effective manner, while increasing the output from the facilities and pursuing opportunities to increase capacity. OPG aims to increase the facilities' output by improving operational flexibility, enhancing reliability, optimizing outage planning and, subject to water conditions, increasing availability to meet electricity system demand. The Company continues to evaluate and implement plans to increase capacity, maintain and improve operational performance, and extend the operating life of its hydroelectric generating assets. These plans are accomplished through multi-year capital investment and other programs, including replacements and upgrades of turbine runners, and refurbishment or replacement of existing generators, transformers, and controls. Over the next four years, OPG plans to increase the total capacity of its renewable generating fleet by approximately 150 MW, which in addition to the runner replacement and upgrade program, includes the Ranney Falls GS and Sir Adam Beck frequency conversion projects. OPG is also planning to repair, rehabilitate, or replace a number of aging civil structures. Where economical and practical, OPG also pursues opportunities to refurbish, expand or redevelop its existing hydroelectric stations.

Additional information on OPG's hydroelectric operations are discussed in the section, *Core Business, Strategy, and Outlook* under the heading, *Operational Excellence – Electricity Generation Production and Reliability* in the Company's 2017 year-end MD&A.

Hydroelectric Facility Planning

Major components of hydroelectric facilities typically include: generating equipment such as turbines, generators and transformers; civil works such as powerhouses, dams, headworks, spillways and water conveyance canals and tunnels; and facilities required to operate and maintain the stations such as control rooms and work centres. Although there is a link between the age of a facility and the capital investment required to maintain that facility, age does not establish an upper limit on the expected useful life of hydroelectric facilities and dams. Regular maintenance and the replacement of specific components typically allow stations to operate for very long periods, especially for facilities built after 1925.

OPG operates six staffed control rooms across Ontario that provide remote control and monitoring for all of OPG's hydroelectric generating facilities. These control rooms are designed to minimize the number of staffed control rooms, reduce control system failures, and increase the amount of information available for production planning.

OPG uses a structured portfolio approach to identify and prioritize projects for its hydroelectric asset investment program. Engineering reviews and station condition assessments are performed to determine short-term and long-term expenditure requirements to sustain or improve the performance of each facility. These may be followed by the preparation of a facility life cycle plan, which is performed on an as-needed basis for marginal assets or assets potentially requiring significant expenditures relative to the value of the facility. This approach is designed to identify necessary capital, operating and maintenance expenditures for each facility and to direct resources towards those facilities that can best maintain or enhance their value.

OPG utilizes a preventive maintenance program that provides a consistent method of identifying, scheduling, and executing maintenance activities at the hydroelectric facilities. The maintenance program is based on the concept of streamlined reliability-centred maintenance, whereby the type and frequency of preventive maintenance applied to an individual component is determined based on the nature and consequences of failure, balancing cost and risk.

The cornerstone of OPG's project prioritization and preventive maintenance approaches for the hydroelectric assets is that safety, environmental, and other regulatory programs are of the highest priority.

Water Management

OPG's water management strategy for its hydroelectric facilities is to safely utilize available water for generation of electricity in conformance with legal, environmental, operational, and WMP and Operational Plan requirements. OPG uses hydrological and meteorological data to manage water levels, water flows and water storage, and strives to schedule water use for optimum utilization and to minimize controllable water spills due to SBG conditions.

Gross Revenue Charge and Water Rental Payments

Hydroelectric generating stations in Ontario are subject to taxes and charges as prescribed by *Ontario Regulation 124/02* under the *Electricity Act, 1998*. These taxes and charges, referred to as Gross Revenue Charge (GRC), are based on station gross revenue, which, for this purpose, is determined as the product of annual station energy generation and the prescribed revenue rate of $40/MWh (Gross Revenue). All OPG hydroelectric generating stations are subject to GRC Property Tax, which is determined by applying graduated tax rates, ranging from 2.5 percent to 26.5 percent through four tiers of production, to a station's annual Gross Revenue. GRC Property Tax payments are made to the OEFC. Hydroelectric generating stations that are subject to water power lease agreements with the MNRF are also subject to GRC Water Rental charges in addition to GRC Property Tax payments. The GRC Water Rental charge is determined as 9.5 percent of a station's annual Gross Revenue. GRC Water Rental payments are made to the Ontario Ministry of Finance.

Annual land rental fees are paid to the MNRF as prescribed by Crown leases and licences of occupation which authorize OPG's tenure (including flooding rights), typically at storage dam sites.

The eight OPG hydroelectric generating stations located on the Trent River and Rideau Canal are subject to rental charges prescribed by licences with Parks Canada. These licences authorize OPG to occupy the lands, maintain and operate the powerhouses and dams, and utilize water that is surplus to navigation needs for the generation of electricity.

Water conveyance charges are paid to the St. Lawrence Seaway Management Corporation as prescribed by a lease agreement providing for the withdrawal of water surplus to navigation needs from the Welland

Canal for utilization at the DeCew Falls generating stations. The water conveyance charges apply to the transport of water from Lake Erie through the Welland Canal to OPG's intakes at Allanburg.

Water rental payments are made to the Government of Québec, as prescribed by an agreement dated January 2, 1943 and a rate amending agreement effective January 2, 1993. These agreements pertain to the sharing of the water powers of the Ottawa River and were ratified by the Governments of Ontario and Québec. Water rental charges payable to the Province of Québec are based on one-half of the energy produced at the three regulated OPG hydroelectric generating stations located on the Ottawa River. The GRC payments made to the Province of Ontario with respect to these three sites are also based on one-half of the energy produced at the stations.

Under the aforementioned 1943 agreement, OPG also provides compensation to Hydro Québec for the generating value at OPG's stations on the Ottawa River attributed to the water diverted into the Ottawa River through the Dozois Reservoir in Québec. OPG shares in operation and maintenance costs pertaining to the dam enabling the Dozois diversion.

The GRC and water rental payments for the regulated hydroelectric stations are recoverable through OEB-approved regulated prices applicable to these stations.

Further details on water rights can be found in the section, *Description of the Business* under the heading, *Water Rights*.

Thermal (Contracted Generation Portfolio Segment)

Overview of Generating Facilities

Thermal generating stations use heat energy to drive steam turbines that generate electricity. OPG's wholly-owned operating thermal facilities are comprised of biomass-fuelled generating units at both Atikokan GS and Thunder Bay GS, and the dual-fuelled generating Lennox GS, which is capable of burning either oil or natural gas. The results of these facilities are reported in the Contracted – Generation Portfolio business segment.

The combined in-service capacity of the three operating thermal facilities was 2,458 MW as at December 31, 2017. The Lennox GS is located in Greater Napanee, Ontario and accounts for approximately 2,100 MW of this in-service capacity. The Atikokan GS is located in Atikokan, Ontario and has an in-service capacity of 205 MW. The Thunder Bay GS is located in Thunder Bay, Ontario and its advanced biomass fuelled unit has an in-service capacity of 153 MW.

Capacity and production from the Lennox GS are subject to an ESA with the IESO for the period from January 2013 to September 2022. Capacity and production from the Atikokan GS are subject to a ten-year ESA expiring in July 2024. For the Thunder Bay GS advanced biomass fuelled unit, capacity and production are subject to a five-year ESA expiring in January 2020.

OPG's three thermal generating stations operate as peaking facilities, depending on electricity demand. This provides Ontario's electricity system with the flexibility to meet changing daily system demand and capacity requirements and has enabled the system to accommodate the expansion of Ontario's renewable generation portfolio. The continued operation of these stations will continue to provide Ontario with capacity and peaking generation.

The three thermal generating stations are operated and maintained as part of regional operations groups used to operate and maintain the Company's hydroelectric facilities. The Lennox GS is operated under Eastern Operations, and the Atikokan and Thunder Bay generating stations are part of Northwest Operations.

Thermal stations that are no longer available to generate electricity are included in the Services, Trading, and Other Non-Generation business segment once they are removed from service. This includes the Lambton GS and Nanticoke GS sites, which ceased coal-fired generation in 2013.

Contracted Generation Portfolio – Thermal Performance (2015 to 2017)

	2017	2016	2015
Equivalent Forced Outage Rate (%) [1]	**2.4**	1.6	11.2

[1] Equivalent Forced Outage Rate is an index of the reliability of a generating unit at OPG's thermal stations. It is measured by the ratio of time a generating unit is forced out of service by unplanned events, including any forced deratings, compared to the amount of time the generating unit was available to operate.

The higher thermal EFOR in 2017, compared to 2016, was primarily due to a higher number of unplanned outage days at a Lennox GS unit as a result of a transmission outage and a generator-related outage in 2017. The change in thermal EFOR in 2016, compared to 2015, was primarily due to an outage in 2015 to perform repair work at the Lennox GS.

Additional information on OPG's thermal operations can be found in the section, *Core Business, Strategy, and Outlook* under the heading, *Operational Excellence – Electricity Generation Production and Reliability* in the Company's 2017 year-end MD&A.

Thermal Fuel Procurement

Due to the relatively low capacity factor of the Lennox GS, natural gas is purchased on the spot market, other than a small volume of fixed term natural gas required for non-generation operational services. Oil for the Lennox GS is contracted for and purchased on an as needed basis. Fuel switching at the station is based on market and fuel economics. Annual procurement of biomass fuel quantities for Atikokan GS and Thunder Bay GS is pre-determined by the corresponding ESAs. Agreements are in place with suppliers for the purchase of all biomass fuel pellets needed to provide fuel for the Atikokan GS for the duration of its ESA, and for most of the advanced biomass fuel pellets needed to provide fuel for the duration of the ESA for the Thunder Bay GS.

Thermal Facility Planning

OPG's facility planning approach is designed to identify necessary capital and operating and maintenance expenditures for each thermal facility. This planning approach aims to sustain facility availability for the remaining service life through station reinvestment within constraints imposed by technical, financial, safety, and system requirements, as well as regulatory and contractual limits. Periodic engineering reviews of major systems are conducted to identify performance issues, provide reinvestment recommendations where appropriate, and ensure that regulatory, safety and operating standards continue to meet expectations. OPG undertakes projects at thermal stations that are expected to achieve an appropriate return within the service life of the stations.

Thermal Station Decommissioning

OPG has recognized, and carries on its balance sheet, a liability to cover future expenditures to decommission and dismantle each of its thermal stations at the end of their estimated service lives. This provision is not funded and is estimated on the basis of station closure. Costs previously incurred by OPG to preserve Lambton and Nanticoke generating stations for potential conversion to natural gas in the future were not charged to the provision, as they were charged against net income as incurred.

Portlands Energy Centre Partnership

OPG has a 49.95 percent partnership interest in Portlands Energy Centre L.P., a limited partnership formed with TransCanada Energy Ltd. (49.95 percent) and the general partner of the partnership, Portlands Energy Centre Inc. (0.1 percent). The shareholders of Portlands Energy Centre Inc. are OPG (50 percent) and TransCanada Energy Ltd. (50 percent). PEC is a 550 MW combined cycle generation natural gas turbine electricity generating facility located on the former R. L. Hearn GS site in the port area of downtown Toronto, Ontario. The station was declared in-service in a combined cycle mode in April 2009. PEC operates under an Accelerated Clean Energy Supply contract with the IESO and trades electricity in the Ontario electricity market.

The Contracted Generation Portfolio segment includes OPG's share of equity income from its 50 percent ownership interest in the station. OPG's share of the in-service generating capacity and generation volume from its interest in the station are included in the operating statistics for the segment.

Brighton Beach Power Partnership

OPG has a 49.95 percent partnership interest in Brighton Beach Power L.P., a limited partnership formed with ATCO Power Canada Ltd. (49.95 percent) and the general partner of the partnership, Brighton Beach Power Ltd. (0.1 percent). The shareholders of Brighton Beach Power Ltd. are OPG (50 percent) and ATCO Power Canada Ltd. (50 percent). Brighton Beach is a 560 MW combined cycle gas turbine electricity generating facility located on the former J.C. Keith GS site in Windsor, Ontario. The station began commercial operation in July 2004. Brighton Beach operates under a tolling arrangement with Shell Energy North America (Canada) Inc. (Shell Energy), pursuant to which Shell Energy owns and trades the electricity produced by the facility in return for the supply of gas and the fees payable under the tolling agreement. Shell Energy's financial obligations are guaranteed by Shell Energy North America (US) L.P. (Shell L.P.), and Shell L.P.'s obligations are in turn guaranteed by Shell Oil Company.

The Contracted Generation Portfolio segment includes OPG's share of equity income from its 50 percent ownership interest in the station. OPG's share of the in-service generating capacity and generation volume from its interest in the station are included in the operating statistics for the segment.

Regulated – Nuclear Waste Management Segment

Overview

OPG is responsible for the ongoing management of radioactive wastes generated by its nuclear operations. In addition, OPG has the obligation for decommissioning its nuclear generating stations and nuclear waste facilities after the end of their useful lives and for managing radioactive wastes that arise in connection with the decommissioning. The handling and disposal of radioactive waste in Canada is subject to federal legislation.

The radioactive wastes generated by OPG's nuclear operations include the following:

- Used nuclear fuel bundles;
- Intermediate-level waste – material that has come in close contact with the reactors, but is less radioactive than used fuel, such as ion exchange resins and reactor equipment and components; and
- Low-level waste – material used in connection with station operation that is not highly radioactive, such as tools and protective clothing.

The Company's Regulated – Nuclear Waste Management segment reports the results of the Company's operations associated with the following:

- management of used nuclear fuel and L&ILW;

- decommissioning of OPG's nuclear generating stations including the stations on lease to Bruce Power and other nuclear facilities;
- management of the Nuclear Segregated Funds established under the ONFA to fund OPG's obligation for nuclear facilities decommissioning and the long-term management of nuclear waste; and
- Other related activities including the inspection and maintenance of the waste storage facilities.

The nuclear accretion expense, which is the increase in the carrying amount of the present value liabilities for nuclear fixed asset removal and nuclear waste management liabilities reported on the balance sheet due to the passage of time, and the earnings from the Nuclear Segregated Funds are reported under this segment. The Regulated – Nuclear Waste Management segment is considered rate regulated because OPG's costs associated with nuclear waste management and nuclear facilities decommissioning liabilities have been included by the OEB in the determination of regulated prices for production from the Pickering and Darlington nuclear generating stations.

Federal Government Policy

In accordance with the requirements of the *Nuclear Fuel Waste Act* (Canada) (NFWA), in 2002, OPG and the other owners of nuclear fuel waste in Canada established a separately incorporated NWMO, with a mandate to manage and coordinate the full range of activities relating to the long-term management of nuclear fuel waste in Canada. This includes the design and implementation of Canada's plan for the long-term management of used nuclear fuel. In 2007, the federal government approved NWMO's submitted option, the Adaptive Phased Management (APM) plan, as the long-term solution for nuclear fuel waste. The APM plan contemplates the eventual long-term permanent disposal of radioactive nuclear fuel waste in a deep geologic repository (DGR) after a collaborative process of communication and engagement with Canadians aimed at selecting a suitable geological site with an informed and willing host community. The NWMO is in the process of undertaking a multi-year site selection process for the used fuel DGR.

The NFWA also requires the nuclear fuel waste owners in Canada to establish and make payments into trust funds for the purpose of funding the implementation of the long-term management plan for used fuel. Accordingly, OPG has established the Ontario NFWA Trust (the NFWA Trust), which forms part of the Nuclear Segregated Funds under the ONFA. Additional details can be found in the section, *Description of the Business* under the heading, *Regulated – Nuclear Waste Management Segment – Funding Mechanisms.*

Current Practices

Used Nuclear Fuel

Used nuclear fuel bundles from OPG's reactors and leased reactors at the Bruce Nuclear site are temporarily stored at each nuclear generating station in water-filled pools, known as wet bays, for a cooling-off period of at least ten years, during which time their radioactivity is substantially reduced. Each nuclear generating station has sufficient capacity to store used nuclear fuel bundles in the wet bays for approximately 15 to 20 years of operation.

After the used nuclear fuel bundles have been stored for the cooling-off period, the bundles are transferred from the wet bays to above-ground dry storage containers at the corresponding nuclear station site. Currently, there is used nuclear fuel bundles in dry storage at the Pickering, Darlington and Bruce Nuclear sites.

OPG's planning assumption for the long-term management of used nuclear fuel bundles is consistent with the NWMO's APM concept of disposal in a deep geological repository. The NWMO has indicated that it currently expects an in-service date of 2043 at the earliest for the used fuel DGR.

Low and Intermediate Level Waste

The majority of OPG's L&ILW is stored at the radioactive waste management facility at WWMF located on the Bruce site. This facility, which continues to be owned and operated by OPG following the lease of the Bruce generating stations, operates under a separate licence issued by the CNSC. A smaller volume of ILW is stored at each of the radioactive waste management facilities at Pickering and Darlington sites. Respectively, these ILW storage facilities house the components from Pickering A's retube in the 1980's and from the recent Darlington Refurbishment of Unit 2. OPG's planning assumption for the long-term management of L&ILW is the placement of this nuclear waste in a separate L&ILW DGR.

Additional details can be found in the section, *Description of the Business* under the heading, *Regulated – Nuclear Waste Management Segment – Deep Geologic Repository for Low and Intermediate Level Waste.*

Station Decommissioning

OPG's planning assumption for the decommissioning of its nuclear generating stations is a deferred dismantlement strategy. Under this strategy, each station will be de-watered and de-fuelled immediately after it has ceased operations and prepared for safe storage and monitoring. Thereafter, OPG intends to monitor the station for approximately 30 years while in safe storage, after which time the station will be dismantled and the site restored over a period of approximately ten years. This strategy has been communicated to the CNSC through regular updates of OPG's preliminary decommissioning plans and liability estimates for the nuclear generating stations. Currently, OPG has received CNSC acceptance of the OPG Financial Guarantee for the five year period from 2018 to 2022 based on the fund performance and estimate for decommissioning the OPG nuclear assets. OPG's nuclear operating licences have been issued based on, amongst other things, CNSC's understanding of this strategy.

Deep Geologic Repository for Low and Intermediate Level Waste

OPG has proposed a deep geologic repository as the preferred solution for the safe long-term management of the L&ILW produced from the continued operation of OPG-owned nuclear generating stations and their eventual decommissioning. Agreement has been reached with local municipalities for OPG to develop the L&ILW DGR on lands adjacent to the WWMF in Kincardine, Ontario.

Under the NSCA, OPG requires licences from the CNSC for activities to be undertaken with respect to the L&ILW DGR project. Before the CNSC can make licensing decisions for the proposal, an EA must be conducted in compliance with the requirements of the *Canadian Environmental Assessment Act*. As part of the EA process for the L&ILW DGR, Environmental Impact Statement, Preliminary Safety Report, and Technical Support Documents were submitted to the CNSC in 2011. The purpose of these submissions was to obtain EA approval and a site preparation and construction licence from the Joint Review Panel (JRP) for the project. The responsibility of the JRP, which was appointed by the Canadian Environmental Assessment Agency (CEAA) and the CNSC in 2012, was to examine the environmental effects of the proposed DGR to meet the requirements of the *Canadian Environmental Assessment Act.* In May 2015, the JRP submitted its report and recommendations on the EA to the federal Minister of Environment. The report concluded that, given mitigation, there is unlikely to be significant environmental impact from the project and recommended that the Minister approve the EA. The report suggested that the project should be implemented expeditiously.

In August 2015, OPG responded to the CEAA's list of potential environmental conditions relating to the JRP report. In February 2016, the federal Minister of Environment and Climate Change requested additional information on certain aspects of the EA, including information related to alternate locations for the project and the impact on environmental effects if Canada's planned used fuel deep geologic repository being developed by the NWMO were to be located in close proximity to OPG's proposed L&ILW DGR. OPG has completed the requested studies and submitted the requested information in December 2016, as planned. Following its review of OPG's submission and a period of public comment, the CEAA requested further information that OPG subsequently provided in May 2017. In June 2017, the CEAA notified OPG that it had sufficient and adequate information to proceed with the next step of the environmental assessment

process and advised that a draft report and updated terms and conditions would be prepared for public review.

On August 21, 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of potential cumulative effects of the project on the Saugeen Ojibway Nation's (SON) physical and cultural heritage, including a description of the potential effects of the project on the Nation's spiritual and cultural connection to the land, taking into account the results of the SON Community Process. OPG is working closely with the SON to formulate a response to the information request.

The L&ILW DGR at the WWMF site remains OPG's preferred solution for the safe long-term management of the L&ILW. The in-service date of the L&ILW DGR is expected to be approximately six to seven years from the start of construction.

Funding Mechanisms

On April 1, 1999, Ontario Hydro's obligation for nuclear facilities decommissioning and nuclear waste management was transferred to OPG. The responsibility for funding the liabilities for nuclear facilities decommissioning and the long-term nuclear waste management between the Province and OPG is described in the ONFA. The key provisions of the ONFA are: (i) for OPG to establish two segregated funds, the Used Fuel Segregated Fund to fund the future costs of long-term nuclear used fuel waste management and certain costs of used fuel storage incurred after the stations are shut down, and the Decommissioning Segregated Fund to fund the future costs of nuclear decommissioning and long-term L&ILW management, and certain costs of used fuel storage incurred after the stations are shut down; (ii) for the OEFC to be responsible for funding approximately $2.4 billion present value as at April 1, 1999 that had been an accumulated liability of Ontario Hydro, which the OEFC has since then fully funded through an initial contribution to the Decommissioning Segregated Fund; (iii) for the Province to limit OPG's financial exposure in relation to the cost of used fuel management for the first 2.23 million bundles of used fuel; and (iv) for the Province to provide financial guarantees to the CNSC for OPG's nuclear decommissioning and nuclear waste management obligations, as required by the CNSC.

The Used Fuel Segregated Fund and the Decommissioning Segregated Fund are administered by a third party custodian and held in accounts segregated from OPG's other assets. OPG has granted a security interest in both funds to the Province. As a result, these funds are not available to satisfy the claims of OPG's creditors.

OPG's required contributions to the Used Fuel Segregated Fund and the Decommissioning Segregated Fund are determined based on reference plans and associated life cycle cost estimates periodically approved by the Province under the ONFA. These reference plans are prepared by OPG with the assistance of external consultants and based on external practices and international benchmarks. Under the ONFA reference plans, the total present value of OPG's future nuclear facilities decommissioning and nuclear waste management costs is determined based on baseline cost estimates and a set of underpinning major planning assumptions, including remaining useful lives of the nuclear stations, proposed methods and timing of nuclear waste disposal, and economic indicators. Given the long-term duration of these life cycle programs, the multiple assumptions involved and the evolving technology to handle nuclear waste, there is a significant degree of inherent uncertainty surrounding the measurement of the underlying costs, which may increase or decrease over time.

The limits to OPG's financial exposure under the ONFA with respect to the life cycle cost of long-term management of the first 2.23 million bundles of used fuel are as follows (all amounts are expressed in January 1, 1999 present value dollars): (i) OPG will bear all costs up to $4.6 billion; (ii) OPG and the Province will share, on an equal basis, costs incurred between $4.6 billion and $6.6 billion; (iii) OPG will be responsible for 10 percent of the costs incurred between $6.6 and $10 billion, and the Province will be responsible for the remaining 90 percent; (iv) the Province will be wholly responsible for any costs above $10 billion. As a result, OPG's funding liability for these used fuel costs under the ONFA is capped at $5.9 billion in January 1, 1999 present value dollars, which is equivalent to approximately $15.7 billion in December 31, 2017 present value dollars. OPG is responsible for all incremental costs

relating to the management of used fuel bundles in excess of the 2.23 million threshold. As at December 31, 2017, approximately 2.6 million bundles of used fuel waste had been produced. The 2.23 million fuel bundles threshold represents the estimated total life cycle bundles based on the initial estimated useful lives of the nuclear stations assumed in the ONFA.

Under the ONFA, the Province guarantees OPG's annual return earned in the Used Fuel Segregated Fund at 3.25 percent plus the rate of change in the Ontario Consumer Price Index, as defined in the ONFA, for funding related to the first 2.23 million used fuel bundles. Upon approval of a new or amended ONFA reference plan, the Province is obligated to make an additional contribution to the Used Fuel Segregated Fund in relation to the first 2.23 million bundles if the fund's assets earned a rate of return that is less than the guaranteed rate of return. If the return on the fund's assets exceeds the Province's guaranteed rate of return, the Province is entitled to withdraw any portion of the excess related to the first 2.23 million bundles, upon approval of a new or amended ONFA reference plan. OPG is responsible for cost increases and investment returns for the portion of the fund attributable to the used fuel bundles in excess of the 2.23 million threshold. OPG also is responsible for cost increases and investment returns for the Decommissioning Segregated Fund.

The investments in the Nuclear Segregated Funds include a diversified portfolio of equities and fixed income securities that are invested across geographic markets, as well as investments in real assets including infrastructure, real estate and agriculture. As the Nuclear Segregated Funds are invested to fund long-term liability requirements, the portfolio asset mix is structured to achieve the required return over a long-term horizon. While the Nuclear Segregated Funds are manage to achieve, in the long term, the target return rate based on the discount rate specified in the ONFA, the rates of return earned in a given period may be subject to various external factors including financial market conditions and changes in the Ontario Consumer Price Index, which, in the short-term, can be volatile and cause fluctuations in the Company's financial results. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

Under the current OEB-approved cost recovery methodology for OPG's nuclear waste management and nuclear facilities decommissioning liabilities, OPG's income is exposed to the rate of return risk for the portion of the Nuclear Segregated Funds related to the Pickering and Darlington nuclear generating stations.

Contributions to the Nuclear Segregated Funds

OPG's contribution requirements under the ONFA are recalculated each time there is an approved new or amended reference plan and under certain other events. Reference plans are required to be prepared at least every five years, or more frequently if there is an underlying change in the assumptions of the reference plan that both OPG and the Province agree are significant enough to trigger a recalculation of the contribution levels during the five-year period.

Prior to 2017, OPG made contributions to the Used Fuel Segregated Fund every quarter, including a one-time special payment in earlier years, as required by the ONFA. These contributions reflected ONFA requirements to fund the majority of the underlying used fuel liability by the end of the initial estimated useful lives of the nuclear stations assumed in the ONFA, resulting in significantly higher contributions to the Used Fuel Segregated Fund in the earlier years of OPG's existence. OPG has not been required to make contributions to the Decommissioning Segregated Fund, which was fully funded at its inception through the initial contribution made by the OEFC and, taking into account asset performance and changes in underlying funding obligations over time, at the time of every subsequent approved ONFA reference plan.

Based on the funded status of the Used Fuel Segregated Fund and the Decommissioning Segregated Fund reflecting the lower life cycle liability estimates per the 2017 ONFA Reference Plan, no overall contributions to either fund were required starting in 2017. Contributions to either or both funds may be required in the future should the funds be in an underfunded position when a new reference plan is approved. Such may be the case as a result of future variability in asset performance due to volatility inherent in financial markets and economic conditions. Future contribution levels also are dependent on changes in baseline cost

estimates and underpinning planning assumptions used to establish the funding obligations in subsequent ONFA reference plans, as well as any changes in the tax treatment of fund earnings. OPG's required contributions could increase, for example, if cost estimates increased, if the operating lives of the nuclear stations were revised, if fund assets earned less than the target rate of return, if the income earned in the funds became subject to tax, or if the NWMO were unable to receive the same sales tax treatment that OPG would be entitled to receive if the NWMO had not been established.

OPG is required to make annual contributions to the NFWA Trust based on a funding formula approved by the federal Minister of Natural Resources for OPG and the other nuclear fuel waste owners in Canada. The NFWA Trust forms part of the Used Fuel Segregated Fund. Any OPG contributions to the Used Fuel Segregated Fund as well as any portion of the Used Fuel Segregated Fund currently not in the NFWA Trust can be applied to satisfy the trust's annual contribution requirements. The funds in the Ontario NFWA Trust will be used for the purposes of long-term management of nuclear used fuel waste, in accordance with the NFWA. OPG and the Province are beneficiaries of the NFWA Trust.

If there is a surplus in the Decommissioning Segregated Fund such that the funding liabilities, as defined by the most recently approved ONFA Reference Plan, are at least 120 percent funded, OPG may direct, at the time a new or amended reference plan is approved, up to 50 percent of the surplus over 120 percent to the Used Fuel Segregated Fund, with the OEFC entitled to a distribution of an equal amount.

If there is a surplus in the Used Fuel Segregated Fund such that the funding liabilities, as defined by the most recently approved ONFA Reference Plan, are at least 110 percent funded, the Province has the right, at any time, to access the excess amount greater than 110 percent. Neither OPG nor the Province have a right to direct any amounts from the Used Fuel Segregated Fund to the Decommissioning Segregated Fund.

Upon termination of the ONFA, the Province has the sole right to any excess funds in the Decommissioning Segregated Fund and the Used Fuel Segregated Fund.

OPG has the responsibility for the management and disposal of the used nuclear fuel and L&ILW generated by the Bruce generating stations and for the eventual decommissioning of these stations. These obligations on the part of OPG are recovered from Bruce Power through annual rent payments and volume based fees per the Bruce Lease and related agreements. Pursuant to the lease agreement, Bruce Power must return the two Bruce stations to OPG together, in a de-fuelled and de-watered state. As such, these de-watering and de-fuelling costs will not be funded by OPG. Further details on the 2015 amendments to these agreements are found in the section, *General Development of the Business* under the heading, *Nuclear Business Development – Bruce Power Refurbishment and Bruce Lease Agreement*.

Provincial Guarantee

In accordance with the NSCA, the CNSC requires OPG to have sufficient funds available to discharge its existing nuclear waste management and nuclear decommissioning obligations. The CNSC process requires the CNSC financial guarantee requirement to be updated once every five years and for OPG to provide an annual report to the CNSC on the assumptions, asset values, and resulting financial guarantee requirements. The CNSC financial guarantee requirement calculation takes into account nuclear waste expected to be generated to the end of each year.

In November 2017, the CNSC accepted OPG's proposed 2018-2022 CNSC financial guarantee requirement to be satisfied by the forecast fair market value of the Nuclear Segregated Funds without the requirement of a Provincial Guarantee for the 2018-2022 period. As required by the terms of the ONFA, the Province is committed to provide a Provincial Guarantee to the CNSC, on behalf of OPG, should there be a shortfall between the CNSC financial guarantee requirement and the value of the Nuclear Segregated Funds in the 2018-2022 period, as it has been done in the past. OPG pays the Province an annual guarantee fee equal to 0.5 percent of the outstanding amount, if any, of the Provincial Guarantee.

Services, Trading, and Other Non-Generation Segment

The Services, Trading, and Other Non-Generation segment is a non-generation segment that is not subject to rate regulation. It includes the revenue and expenses related to OPG's trading and other non-hedging activities. As part of trading activities, OPG transacts with counterparties in Ontario and neighbouring energy markets in predominantly short-term trading activities of typically one year or less in duration. These activities relate to electricity that is purchased and sold at the Ontario border, financial energy trades, financial risk management energy product revenues, and sales of energy-related products.

In addition, the segment includes the results of OPGET, which engages in U.S.-based wholesale energy trading activities in the U.S. northeast. The activities of OPGET include trading electricity in the U.S. using over-the-counter energy-related derivatives. OPGET retains Federal Energy Regulatory Commission market-based rate authorization.

The segment also includes revenue from real estate rentals and non-regulated services, gains or losses on disposition of non-regulated real estate assets, costs associated with non-regulated business development activities, and costs related to the Lambton GS and Nanticoke GS sites.

Fair Hydro Trust Segment

The Fair Hydro Trust segment is a non-generation segment that is not subject to rate regulation. It includes OPG's earnings from the Fair Hydro Trust, which includes the financial results of the Trust, as well as income related to OPG's role as Financial Services Manager of the Fair Hydro Trust and holder of subordinated debt issued by the Trust. Earnings include interest income from OPG's investment in subordinated debt of the Trust of up to 49 percent of the Trust's total outstanding debt, recovery of related to third-party costs and fees for financial management and ongoing administration services, partially offset by interest costs on debt issued by OPG to fund five percent of the subordinated investment in the Trust, incurred third-party costs, and other incurred costs related to the management and administration of the Trust.

Indigenous Relations

The Aboriginal and treaty rights of Indigenous communities are recognized and affirmed in the *Constitution Act, 1982*. OPG's corporate governance includes an Indigenous Relations policy to help build and develop mutually beneficial working relationships with Indigenous communities proximate to the Company's present and future operations. The policy focuses on building respectful relationships with Indigenous communities, businesses and organizations through partnership, collaboration, and support for procurement, employment and educational opportunities. The Company seeks to establish and maintain these relationships based on a foundation of respect for the languages, customs, and political, social and cultural organizations of the indigenous communities.

OPG may be subject to claims by Indigenous communities or other Indigenous groups and individuals. These claims may stem from generation development activities, historic operations of Hydro Electric Power Commission of Ontario and Ontario Hydro that may have impacted Aboriginal and treaty rights, or the absence of legal permits, rights-of-way, or easements. Legal precedents created by court rulings may impact negotiations and resolution of past grievances. To date, OPG has resolved 23 past grievance claims with 21 communities, achieving final settlement agreements.

In line with the company's Indigenous Relations policy, OPG is pursuing prospective generation-related developments and other joint projects with Indigenous communities. OPG currently has four generation development partnerships with Indigenous communities. OPG's first such partnership became operational in early 2009 as part of the Obishikokaang Waasiganikewigamig/Lac Seul GS project. The signing of the "*Amisk-oo-Skow*" Agreement with the Moose Cree First Nation (MCFN) in early 2010 marked the second such partnership. In 2011, the Lower Mattagami Limited Partnership agreement was amended and restated to include the MCFN and their wholly owned Amisk-oo-Skow Finance Corporation as limited partners and to enable the MCFN to acquire up to 25 percent limited partnership interest in the Lower Mattagami River

project. During 2014, the MCFN acquired a 25 percent interest in the assets through its investment in the Lower Mattagami Limited Partnership as incremental units of the project were placed in-service.

OPG and CRP, a wholly owned corporation of the Taykwa Tagamou Nation, established Peter Sutherland Sr. GS Limited Partnership in January 2015. In March 2017, the Peter Sutherland Sr. GS was placed in-service and, in April 2017, the Taykwa Tagamou Nation, through CRP, increased their partnership interest in PSS to 33 percent under the partnership agreement.

Following selection by the IESO in March 2016, OPG and a subsidiary of the Six Nations of Grand River Development Corporation have partnered to develop a new 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands. The Nanticoke Solar Limited Partnership was formed in July 2015, and the Six Nations of Grand River Develop Coproration through its subsidiary acquired a 10 percent ownership interest in August 2015.

Other recent joint projects with Indigenous partners include two shoreline remediation projects completed in 2016. The Whitesand First Nation, working closely with OPG, completed a project to remediate nearly two kilometers of shoreline, while the Long Lake #58 First Nation undertook the management of a five-year shoreline remediation project. OPG also engaged the Mississaugas of New Credit regarding the sale of the Lakeview generating station site. OPG also has been engaging proactively with Indigenous communities regarding the Company's nuclear waste management operations, through regularly scheduled meetings and an ongoing dialogue in connection with OPG's proposed L&ILW DGR, the re-licensing of the PWMF and the WWMF, and the Pickering generating station's relicensing. Further engagement was conducted with First Nations in southwestern Ontario regarding the demolition of the Lambton and Nanticoke generating stations.

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OPG is also committed to improving Indigenous access to procurement and employment opportunities, including increasing the profile of the nuclear generation industry in Indigenous communities. In 2017, OPG launched an Indigenous Business Engagement (IBE) Initiative. The purpose of this initiative is to increase access to procurement opportunities for Indigenous businesses interested in supplying materials and services to OPG. The IBE Initiative is based on a strategy that will identify opportunities in contracts, scopes of work and business plans for potential Indigenous business engagement; include criteria related to suppliers' ability to engage or partner with Indigenous people or businesses in assessing procurement proposals; and invest in relationships with Indigenous communities by increasing outreach efforts to enhance understanding of how to do business with OPG. OPG has been engaging with Indigenous businesses and communities as well as its suppliers to promote the IBE Initiative including the Mohawk Council of Akwesasne as well as the Williams Treaties First Nations, located proximate to the Pickering and Darlington nuclear generating stations.

OPG has been actively developing recruitment plans targeting Indigenous peoples. As part of this initiative, during the fourth quarter of 2017, OPG participated in several Indigenous-specific career fairs, hosted a Day in the Trades event for Indigenous students and job seekers as part of an open house at the Darlington Energy Centre, and approved additional plans aimed at increasing the number of Indigenous apprentices as part of the nuclear operations' recruitment program.

In November 2016, OPG was recognized for its ongoing commitment to engaging local Indigenous communities with the Canadian Electricity Association's (CEA) 2016 Sustainable Electricity award for Leadership in External Collaboration and Partnerships.

Workplace Safety and Public Safety

Workplace Health and Safety

In the area of workplace safety, OPG is committed to achieving excellent performance through continuous improvement and a strong safety culture, with the ultimate goal of zero injuries. OPG utilizes an integrated health and safety management system and a set of operational risk control procedures to ensure continued monitoring of health and safety performance and to support continuous learning and improvement in this area. Over the past five years, OPG has repeatedly stood in the top quartile of its comparator Canadian electrical utilities in various safety performance metrics.

Workplace safety performance is measured using two primary indicators at OPG, All Injury Rate (AIR) and Accident Severity Rate (ASR). OPG's AIR and ASR results for employee workplace safety were as follows for the year ended December 31:

	2017	2016	2015
AIR *(injuries per 200,000 hours worked)*	**0.48**	0.56	0.39
ASR *(days lost per 200,000 hours)*	**3.57**	2.59	0.50

In 2017, OPG's AIR improved from 2016 and was the third-best performance year in the history of the company. For those employee injuries that caused lost time from work, the total time lost from work in 2017 was greater than the previous year. OPG's analysis of the underlying safety events indicated that major contributors to the injuries and near misses included inadequate situational awareness and attention to detail, and suboptimal risk-based decisions, rather than missing or inadequate standards or programs. OPG continues to implement a number of initiatives to target the injury trends based on the analysis of the safety events, with a focus on the use of human performance tools including increased field supervisory oversight, situational awareness, communication, and procedural use and adherence.

In order to strengthen its safety performance, OPG continues to progress an organization-wide "iCare Enough to Act" initiative launched in 2016 and aimed at renewing employees' commitment to their own and each other's safety and well-being. Approaches to supervisory oversight, communication and safe work planning are being modified and updated to further strengthen safety as a foundational element of the Company's values-based culture.

Contractors are required to conduct work safely at OPG sites. In support of this requirement, OPG utilizes an independent contractor pre-qualification process, provides on-site safety support for many of its major projects, and works with contract partners to improve their health and safety programs to meet OPG's requirements. In the past nine years, OPG has consistently shown a better than average Construction Contractor AIR as compared to the Infrastructure Health and Safety Association Contractor AIR, a metric of construction contractor safety performance across Ontario. OPG has maintained this performance while engaging in the refurbishment of the Darlington GS, one of the largest infrastructure projects in Canada. The hours worked by contractors in 2017 were the largest in OPG's history, largely attributable to this project.

Since 2014, OPG has been operating under a single integrated health and safety management system and set of operational risk control procedures across the Company, providing consistent performance expectations for all employees. The control procedures are designed to ensure continued enterprise-wide monitoring of health and safety performance and to support continuous learning and improvement in these areas. Oversight and reporting by corporate and site safety functions is in place to provide senior management with regular information on the effectiveness of the safety management efforts, compliance with legal and corporate requirements, and safety performance trends. OPG's incident management system requires that all incidents, including near misses, be reported and investigated and that where beneficial, corrective action plans be developed and completed in order to prevent reoccurrences.

In 2014, OPG launched a Total Health initiative that aims to embed a health culture that supports employees and their families in their efforts to achieve an optimal level of health and functioning, through health education, health promotion, disease and injury prevention, and crisis intervention. In 2016, the Company launched the Mental Health First Aid training course for employees, an accredited training program facilitated by the Mental Health Commission of Canada. The training aims to increase awareness and empathy for mental illness, reduce stigma, support affected employees, and improve return to work outcomes. By the end of 2017, over 1600 "people leaders" had participated in this training.

Nuclear Radiation Safety

OPG manages a radiation protection program designed to minimize detrimental health effects to employees and members of the public. OPG follows developments in the field of radiation protection as documented by the International Commission on Radiological Protection (ICRP), the United Nations Scientific Committee on the Effects of Atomic Radiation, and the U.S. National Council on Radiation Protection and Measurements. Widely recognized as the main source of expert advice regarding protection from the harmful effects of ionizing radiation, the ICRP periodically issues recommendations concerning principles of radiation protection. These recommendations are usually adopted by most countries without significant modification and are incorporated into the applicable laws. The Canadian Radiation Protection Regulations are based on the recommendations of the ICRP, and OPG's nuclear facilities conform to these regulations. The CNSC is the federal agency that regulates radiation protection in Canada.

Radiation exposures to station personnel and the public are limited by station design and adherence to approved operating procedures. Over the years, OPG has been a leader in applying the principles of keeping radiation doses as low as reasonably achievable. OPG's internal operating limits for occupational exposure are set well below the regulatory limits to ensure that the regulatory limits are not exceeded. OPG's operating targets for radiological emissions are set at even more restrictive levels and typically represent small fractions of the regulatory limits.

To ensure continued public safety, radiation exposure to members of the public resulting from the operation of OPG's nuclear generating stations is estimated on an annual basis for individuals living or working near the stations. The annual dose to the public resulting from operations of each nuclear facility is expressed in microsieverts (μSv), an international unit of radiation dose measurement. For 2015, the annual public doses resulting from the Darlington GS operations and the Pickering GS operations were 0.5 μSv and 1.2 μSv, respectively, which is approximately 0.1 percent of the annual legal limit of 1,000 μSv. For 2016, the annual public doses resulting from the Darlington GS operations and the Pickering GS operations were 0.6 μSv and 1.5 μSv, respectively, which is less than 0.1 and 0.2 percent of the annual legal limit of 1,000 μSv, respectively. While the public doses from OPG's nuclear operations for the 2017 operating year will not be finalized until the second quarter of 2018, they are not expected to differ significantly from the 2016 levels.

As a condition of receiving operating licences for its nuclear facilities, OPG has developed comprehensive emergency plans that detail the Company's planned response to reactor accidents, as well as accidents involving the transportation of radioactive materials. These plans dictate how OPG will work with municipal, regional, provincial, and federal agencies to safeguard station personnel and members of the public in the unlikely event of a radiation emergency at one of OPG's facilities. Station staff are required to regularly participate in emergency exercises to maintain and continuously improve response capability for such events.

Dam Safety and Waterways Public Safety

OPG manages dam safety and other risks associated with the production of hydroelectric power through OPG's Safe Operations Policy and Dam Safety Program. The Safe Operations Policy directs that dams be designed, constructed, operated, and maintained in a manner that meets all regulatory requirements, or, in the absence of regulations, the safety guidelines published by the Canadian Dam Association or other industry best practices. OPG is one of the first dam owners in Canada to have developed and implemented a dam safety program and is considered an industry leader in many aspects of the program.

In addition to effectively managing the safety of dams against catastrophic failure, OPG has developed a number of technical standards and procedures concerning public safety around dams, and materials to educate the public and raise awareness of the hazards associated with the operation of the hydroelectric facilities. This includes the implementation of control measures in the form of signage, safety booms, buoys, fencing and audible alerts at the appropriate facilities. These measures are actively managed to maintain their effectiveness. OPG also strives to entrench a "Stay Clear – Stay Safe" message as part of its public education program, through strategically placed advertisements and engagement of other agencies, such as the MNRF, Ontario Provincial Police, Life Saving Society, Ontario Waterpower Association, and other stakeholders.

Since 2007, OPG has engaged an independent advisory panel consisting of internationally recognized experts to conduct an annual review of its Dam Safety Program. The Chair of the independent panel establishes areas of in-depth review and presents the observations to OPG's Board of Directors. The panel has consistently found that the risks associated with the dams owned and operated by OPG are being managed in alignment with industry best practices and guidelines. OPG remains committed to high standards of public safety on waterways around hydroelectric generating stations and dams, and continues to make investments in waterway and dam safety upgrades.

Additional details on the regulatory regime related to dams and waterways can be found in the section, *Description of the Business* under the heading, *Water Rights.*

Environment

Overview

OPG is committed to meeting compliance obligations, including any environmental commitments that it makes, with the objective of exceeding these compliance obligations where it makes business sense. OPG's Environmental Policy specifically commits the Company to:

- Establish an environmental management system (EMS) and maintain registration for this system to the ISO 14001 Environmental Management System standard;
- Work to prevent or mitigate adverse impacts on the environment with a long-term objective of continual improvement;
- Strive to be a leader in climate change mitigation; and
- Manage sites in a manner that strives to maintain, or enhance where it makes business sense, significant natural areas and associated species of concern.

The policy is implemented through OPG's EMS. Within the EMS, OPG sets environmental objectives and maintains planning, operational control, and monitoring programs to manage its negative and positive impacts on the environment. The most significant environmental aspects of OPG's operations include: chemical emissions to water, spills, fish impingement and entrainment, thermal effluent emissions, displacement of fossil fuels, enhancement and disruption of wildlife habitat, radiological emissions, radioactive waste generation, and water flow and level changes. The policy is reviewed annually as part of the EMS to ensure that it remains appropriate to the nature, scale and environmental impacts of OPG's activities.

OPG communicates its environmental performance to external and internal stakeholders through a range of engagement methods such as reports and correspondence to regulators, meetings, newsletters, open houses, consultations, news releases, advertising campaigns, social media, and participation in community events.

Details of OPG's environmental performance and initiatives to fulfill the Environmental Policy can be found in OPG's annual *Sustainability Report*, which is available on the Company's website at www.opg.com. ***Unless otherwise specifically stated, none of the information contained on, or connected to the Company's website nor any of the contents of the Sustainability Report are incorporated by reference herein.***

Environmental Compliance

OPG must comply with a large number of environmental requirements contained in statutes, regulations, by-laws, licences, permits and approvals. Failure to comply with applicable environmental laws may result in enforcement action, including the potential for orders or charges. OPG reports any incidents of non-compliance to the appropriate federal, provincial or municipal authorities as required, with corrective action plans developed and implemented accordingly.

Changes in environmental regulatory requirements may result in existing operations being in a state of non-compliance, a potential inability to comply, and potential costs and liabilities for OPG. To ensure compliance, such circumstances may require OPG to install control technologies, develop new processes, allowances or offsets, or place constraints on electricity production.

Protection of Fish

Electricity generating facilities located on waterways can impact fish in a number of ways. At nuclear and thermal stations, the intake of water for cooling purposes can result in fish being impinged on station equipment and fish larvae and eggs being entrained in the water as it passes through the station. The warmer water returned to the water body also has the potential to impact aquatic organisms and habitat near the station. At hydroelectric stations, the flow of water through the station turbines can result in fish entrainment and mortality, while physical barriers such as dams can prevent the migration of fish.

OPG utilizes measures such as fish ladders, trap and transport programs, stocking programs, barriers and deterring structures, water flow alterations, habitat protection and creation, and station effluent temperature limits to manage and mitigate impacts to fish. Potential regulatory changes being monitored and managed as risks by the Company include electricity production constraints and water flow management requirements to protect fish and fish habitat, and expanded fish passage requirements.

Biodiversity and Habitat Stewardship

The generation of electricity can have an impact on biodiversity, either directly through habitat loss and fragmentation or indirectly through emissions to the environment. OPG is committed to managing its sites in a manner that strives to maintain significant natural areas and associated species of concern. OPG also works with its community partners to support regional ecosystems and biodiversity through science-based habitat stewardship. OPG's regional biodiversity program strategically funds and promotes efforts to protect and restore biodiversity in areas of Ontario where genetic, species or ecosystem diversity have been most impacted, and substantive threats remain. In 2017, OPG continued efforts to protect and restore habitat, promote biodiversity education and awareness, and help the recovery of species at risk. In November 2017, OPG's biodiversity program was recognized by the CEA with the 2017 Sustainable Electricity award for Commitment to Continuous Performance Improvement.

Climate Change Mitigation and Air Quality

OPG's operational and growth strategies support reductions in GHG emissions and improved air quality. After safely ending coal-fired generation in the province, OPG has become Ontario's largest clean energy provider, producing and selling electricity that is 99 percent free of GHG and smog-causing emissions. The elimination of coal-fired electricity production at OPG's generating stations resulted in coal being reduced from one-quarter of Ontario's energy supply mix in 2003 to zero in 2014.

OPG monitors and reports GHG emissions from its facilities in accordance with the regulatory requirements set out by Environment and Climate Change Canada and the MOECC. In 2016, the Government of Ontario passed the *Climate Change Mitigation and Low-Carbon Economy Act, 2016* and the associated *Cap and Trade Program Regulation*. The legislation provides the foundation for regulating GHG emissions in Ontario and includes a cap and trade program, with the first compliance period being from January 1, 2017 to December 31, 2020. The cap and trade program is a market mechanism intended to give Ontarians an

incentive to reduce GHG emissions by putting a price on carbon. The program requirements are expected to result in increased fuel costs for some OPG-owned and co-owned generating facilities. Fuel costs for these stations are generally recovered from the electricity market. With OPG's low GHG emitting fleet, this is not expected to have a material adverse financial impact on the Company. OPG has established the necessary processes to comply with the cap and trade program requirements.

OPG is monitoring actions being taken by the Government of Ontario and the Government of Canada to reduce GHG emission levels and transition to a low-carbon economy. In support of efforts to mitigate climate change, the Company continues to evaluate and implement plans to increase the generation capacity of its hydroelectric generating fleet, where economical, and invest in other low-carbon technologies. OPG also has a strategy to help position the Company as a leader in transportation electrification in the province. The strategy aims to leverage the Company's clean, reliable and cost-effective electricity to power transportation, capitalize on future commercial growth opportunities, and enhance the Company's social licence. OPG is pursuing initiatives to increase the use of electric vehicles within its operations, and is assessing vehicle grid integration and hydrogen applications for the transportation sector. Ontario's climate change plan aims for electric and hydrogen passenger vehicles to represent five percent of new vehicle sales in the province by 2020.

As part of its commitment to help de-carbonize Ontario's transportation sector, OPG is a founding sponsor of Plug'n Drive, a non-profit organization working to accelerate the adoption of electric vehicles and to maximize their environmental and economic benefits. In May 2017, Plug'n Drive announced the opening of the world's first experiential learning facility dedicated to electric vehicle education and awareness, with OPG sponsoring the Centre's training facility.

Radiological Emissions

Very low levels of radioactivity are released to air and water as a result of operating the reactors at OPG's nuclear generating stations. OPG maintains an effluent monitoring and control program to ensure radiological emissions are kept well below the release limits specified in the station operating licences. OPG also has environmental monitoring programs in the vicinity of the nuclear stations to ensure operations have no adverse impacts on human health and the environment. These programs are designed to assess impacts, demonstrate compliance with regulatory limits, validate the effectiveness of containment and effluent controls, and verify predictions made by environmental risk assessments. Results from the monitoring programs have confirmed OPG's radiological emissions are a small fraction of the regulatory release limits.

In June 2016 and August 2016, the CNSC released sampling results from its independent environmental monitoring program, which confirmed that the public and the environment around OPG's nuclear generating stations continued to be safe.

Further details are discussed under the heading, *Workplace Safety and Public Safety – Nuclear Radiation Safety.*

People and Culture

Workforce Resourcing Strategies

Electricity generation involves complex technologies that require highly skilled and trained workers, and a well trained and engaged workforce is fundamental to the achievement of OPG's strategic imperatives. The Company is focused on improving the capability of its workforce through leadership development, knowledge management, diversity and inclusion programs, and hiring in key areas. Ability to secure the right talent mix in order to effectively meet the Company's immediate and longer term business needs on a timely basis is supported through workforce planning, resourcing and on-boarding strategies, both to acquire external talent into the organization and to develop existing employees. The goal of resourcing strategies and workforce planning is to ensure that the Company's workforce is diverse and has the right skill set and capability for the safe and effective operation of the generating facilities and successful delivery

of major projects, including the Darlington Refurbishment. These strategies are being designed to take into account anticipated staffing requirements to the end of planned commercial operations of the Pickering GS, through to the end of the planned period to de-fuel, de-water and place the station in a safe state condition.

As part of the strategy to develop and engage employees and to build leadership talent in support of the Company's long-term success, OPG has an active succession planning program with a focus on accelerating development. This includes a company-wide high potential leadership development program for qualified internal candidates. This 14-month cross-functional, competitive-entry program is designed to identify and develop candidates for future leadership positions while they are relatively early in their careers. OPG also has a talent management monitoring process to proactively assess staffing risks, challenges and opportunities.

Many positions at OPG have significant educational prerequisites and rigorous requirements for continuous training and periodic requalification. In addition to maintaining its internal training infrastructure, OPG relies on partnerships with government agencies, other electrical industry partners, and educational institutions to meet the required level of qualification.

Effective January 1, 2017, OPG implemented an Executive Compensation Program that is compliant with *Ontario Regulation 304/16: Executive Compensation Framework*, introduced in September 2016. While the Province released two subsequent amendments, *Ontario Regulation 187/17* and *Ontario Regulation 400/17* in June 2017 and November 2017, respectively, OPG's Executive Compensation Program continues to be subject to the original regulation's requirements. The regulation sets out how all employers designated under the *Broader Public Sector Executive Compensation Act, 2014*, including OPG, must establish and post compensation programs for executives. The program must include the compensation philosophy, salary and performance-related pay caps, comparative analysis details, and a description of other elements of compensation. OPG's Executive Compensation Program is designed to provide compensation that is at the 50th percentile of the market and focused on at-risk, performance based pay. The program will better enable OPG to attract, align and retain the executive talent critical to delivering Shareholder and customer value, while ensuring continued safe and reliable operations. For further information, refer to the section, *Corporate Governance* under the heading, *Compensation.*

Employees

OPG's average number of full-time employees and average number of seasonal, casual construction and non-regular staff (Other Staff) in 2017 were as follows:

Business Segment	**Full-time Employees**	**Other Staff**
Regulated – Nuclear Generation [1]	7,360	1,432
Regulated – Hydroelectric	1,125	54
Contracted Generation Portfolio	531	49
Services, Trading, and Other Non-Generation [2]	96	7
Total	**9,111**	**1,541**

[1] Including employees associated with the Regulated – Nuclear Waste Management segment.
[2] The Fair Hydro Trust, a non-generation segment that is not subject to rate regulation, was established in December 2017. As of December 31, 2017 there were 3 full-time employees in the Fair Hydro Trust segment.

The majority of OPG's employees are represented by the PWU and The Society. The PWU includes most workers below the level of first line manager – from clerical staff to technicians and trades staff and station operators. The Society includes supervisors, professional engineers, scientists, and other professionals. Bargaining rights with the 19 craft unions that perform construction work at OPG's generating facilities in addition to the regular workforce are established either through the EPSCA or directly with OPG. EPSCA is a voluntary association of owners and contractors who perform work in the electrical power systems sector. The primary purpose of EPSCA is negotiating and administering collective agreements on behalf of employers performing work on what is now OPG property. Collective agreements between the Company and its construction unions are negotiated either directly or through EPSCA. OPG currently has 17

agreements through EPSCA and two direct trade agreements. The two direct trade agreements are with the Canadian Union of Skilled Workers and the Brick and Allied Craft Union.

Insurance

The principal types of discretionary insurance carried by OPG include directors' and officers' liability, excess commercial general liability, all risks property, boiler and machinery breakdown, including statutory boiler and pressure vessel inspections, and business interruption. In addition to providing coverage for OPG's non-nuclear facilities, this insurance applies to the conventional operations at OPG's nuclear generating stations. OPG also maintains nuclear property insurance, including nuclear boiler and machinery breakdown, for damage to the nuclear portions of its generating stations and for perils propagating from the nuclear to the conventional side of its assets. This coverage complements the conventional property insurance program.

OPG also purchases or requires contractors to purchase discretionary insurance for construction projects. For the Darlington Refurbishment project, the insurance coverage for the pre-requisite construction works was placed in 2013 and for refurbishment execution in 2016. The owner-controlled insurance program for the refurbishment consists of wrap-up liability, course of construction and marine transit insurance.

OPG purchases certain insurance coverage as required by statute, namely owned and leased motor vehicle liability, aviation liability (for drone operations) and nuclear energy liability insurance. The federal *Nuclear Liability and Compensation Act* (NLCA) that came into effect on January 1, 2017, and its predecessor legislation, the *Nuclear Liability Act* (NLA), impose absolute liability on a licensed operator of a nuclear generating station for any damage to property of, or injury to, the public arising from a nuclear incident, other than damage resulting from sabotage or acts of war. As such, the legislation protects all other persons from liability, including suppliers of nuclear fuel and components used in nuclear reactors.

The NLCA requires all operators of nuclear generating stations in Canada to maintain specified amounts of nuclear liability insurance purchased from a federal government approved insurer or other equivalent forms of financial security approved by the federal government. Under the NLCA, OPG is required to maintain an initial $650 million per incident of nuclear energy liability insurance for each of its nuclear installations as defined by the NLCA effective in 2017, for which there is no deductible amount, with successive annual increases to $750 million, $850 million, and $1 billion over the 2018-2020 period. The Pickering GS site and the Darlington GS site are considered to be two separate nuclear installations under the NLCA. OPG is also required to maintain $13 million per incident of nuclear energy liability insurance for the WWMF. OPG is not responsible for purchasing nuclear liability insurance for the Bruce nuclear generating stations. Previously, the NLA required OPG to maintain $75 million per incident of nuclear energy liability insurance for each of the Pickering GS site and the Darlington GS site and $6 million for the WWMF, purchased from a federal government approved insurer. OPG continues to maintain nuclear liability insurance or other forms of financial security that have been approved by the federal government equal to the required liability limits.

Under Part I of the NLCA, an operator is liable for all damages resulting from a nuclear incident. If, in the opinion of the Governor in Council, OPG's liability could exceed the specified insured amount in respect of a nuclear incident, or it would be in the public interest to do so, the Governor in Council shall proclaim Part II of the NLCA as applicable in respect of a nuclear incident. Under Part II of the NLCA, OPG's liability would be effectively limited to the amount of required abovementioned insurance, and the Governor in Council may authorize additional funds to be paid by the federal government as may be specified in an order.

RISK FACTORS

For details on risks faced by OPG, see *Risk Management* in the Company's 2017 year-end MD&A.

DIVIDENDS

The declaration and payment of dividends remains at the sole discretion of OPG's Board of Directors and is dependent on the results of OPG's operations, the Company's financial condition and cash requirements, securities legislation requirements, and other factors considered relevant by the Board of Directors in exercising its discretion and judgment on an ongoing basis. OPG did not declare or pay any dividends for the years 2015 to 2017.

There are no restrictions in the articles of the Company that could prevent the Company from paying dividends. However, the declaration and payment of dividends are subject to financial tests set forth in the OBCA.

DESCRIPTION OF CAPITAL STRUCTURE

The authorized share capital of OPG consists of an unlimited number of common shares (the voting shares of the Company) and Class A shares. As at December 31, 2017, OPG had 256,300,010 common shares issued and outstanding, all of which are owned directly by the Province at a stated value of $5,126 million. As at December 31, 2017, OPG had 12,217,616 Class A shares issued and outstanding, all of which are owned directly by the Province at a stated value of approximately $519 million. OPG is authorized to issue an unlimited number of common shares and Class A shares without nominal or par value. Holders of common shares are entitled to one vote per share at meetings of the shareholders of the Company and, along with Class A shares, to receive dividends if, as, and when declared by the Board of Directors of the Company. Holders of common shares and Class A shares would participate, pro rata to their holding of common shares, and Class A share, in any distribution of the assets of the Company upon its liquidation, dissolution, or winding up. Any issuance of new shares is subject to the consent of all of OPG's shareholders.

All of the Company's voting securities are held by the Province. Accordingly, the Company is controlled by the Province.

CREDIT RATINGS

DBRS Limited (DBRS) and S&P Global Ratings (S&P) provide credit ratings for commercial entities. A credit rating generally provides investors with an independent measure of credit quality of an issue of securities. Credit rating categories for long-term debt instruments range from highest credit quality (generally 'AAA') to default in payment (generally 'D').

In April 2017, DBRS re-affirmed the long-term credit rating on OPG's debt at 'A (low)' and the commercial paper rating at 'R-1 (low)', each with a stable outlook. In July 2017, S&P re-affirmed OPG's long-term credit rating at BBB+ with a stable outlook. On July 7, 2015, S&P lowered OPG's long-term corporate credit rating from 'A-' to 'BBB+' with a stable outlook. S&P's rating action followed its July 6, 2015 downgrade to the Province's rating from 'AA-' to 'A+'. The link between the Province and OPG through ownership and financial support may impact OPG's credit rating. S&P's commercial paper rating for OPG is 'A-1 (low)'.

Long-term debt instruments that are rated in the 'A' category by DBRS are considered to be of good credit quality. The capacity for the payment of financial obligations by the obligor of such instruments is considered to be substantial, but of lesser credit quality than higher-rated entities. Entities in the 'A' category may be vulnerable to future events, but qualifying negative factors are considered manageable. The addition of a "high" or "low" modifier indicates relative standing within the rating category.

A 'BBB' rating category by S&P for long-term debt instruments means that the obligor has adequate capacity to meet its financial commitments, but is considered more subject to adverse economic conditions than higher-rated entities. The addition of a plus '+' or minus '-' designation after a rating indicates the relative standing within a particular rating category.

DBRS's commercial paper credit rating scale ranges from 'R-1(high)' to 'D', which represents the highest to lowest quality of such securities rated. The rating of 'R-1(low)' is the third highest and is considered to be of good credit quality. S&P's Canadian commercial paper rating scale ranges from 'A-1 (high)' to 'D', which represents the highest to lowest quality of such securities rated. The rating of 'A-1 (low)' is the third highest and is considered to be satisfactory.
There can be no assurance that a credit rating will remain in effect for any given period of time or that a credit rating will not be lowered, withdrawn or revised by either or both rating agencies if, in their judgment, circumstances so warrant. The rating of any securities is not a recommendation to buy, sell or hold such securities, and such ratings do not comment as to market price or suitability for a particular investor.

During the past two years, OPG has made payments to DBRS and S&P's credit rating agencies for their credit rating services and for other services. OPG reasonably expects such payments will continue in the future for the services acquired.

MARKET FOR SECURITIES

In October 2017, OPG issued Series 1 Notes with a coupon rate of 3.315 percent for a principal amount of $500 million are currently outstanding and are not listed on any exchange or similar market for securities. The Notes are due in 2027.

CORPORATE GOVERNANCE

National Instrument 58-101 *Disclosure of Corporate Governance Practices* (NI 58-101), has been implemented by Canadian securities regulatory authorities to provide greater transparency for the marketplace regarding issuers' corporate governance practices. OPG's corporate governance practices align with NI 58-101 and National Policy 58-201 *Corporate Governance Guidelines.* In addition, OPG has reviewed its governance practices against the principles discussed in the 2013 Report on Building High Performance Boards issued by the Canadian Coalition for Good Governance and concluded that OPG compares favourably to those principles that apply to OPG.

Information with respect to OPG's Board of Directors is as follows:

Board of Directors

OPG's Board of Directors (Board) is made up of 14 individuals with the following capabilities:

- managing large businesses;
- managing and operating nuclear stations;
- understanding of the Canadian nuclear environment;
- engineering and/or project management, including large infrastructure project management;
- managing capital intensive companies;
- knowledge and expertise in mergers and acquisitions;
- overseeing regulatory, government and public relations;
- human resources management;
- financial, investment, legal and corporate governance expertise;
- knowledge of information technology/cybersecurity;
- knowledge of Indigenous communities; and
- stakeholder management.

The Board exercises its independent supervision over management as follows: the majority of members of the Board are independent of the Company; meetings of the Board are held at least five times a year; a formal Charter for the Board and for each Board committee has been adopted and the charters are reviewed annually; the Board and each Board committee is chaired by an independent Director; and a portion of each Board and Board committee meeting is reserved for independent Directors to meet without management present.

OPG has a written position description for the Chief Executive Officer (CEO). This position is accountable to the Board for: ensuring a culture of integrity and ethical conduct; increasing Shareholder value; defining and executing a corporate strategy, including a sustainable business model that will service the long-term power generation needs of the province; and providing a standard of leadership that will achieve operational excellence with respect to matters of safety, stakeholder relationships, financial performance, asset reliability, and health, environmental and regulatory compliance. In addition, the Board delineates the President and CEO role and responsibilities through the By-laws, the Board Charter, the Board policies, and the corporate and CEO annual goals and objectives. The Board sets, and monitors performance against, annual corporate and CEO targets and objectives.

Director Independence

On an annual basis, the Compensation, Leadership and Governance Committee of the Board reviews the disclosures made by Directors in the annual Director Questionnaire and reviews each disclosed affiliation's relationship with OPG in order to determine whether the Director is (or remains) independent. The Compensation, Leadership and Governance Committee reports on its review to the Board.

Based on the meaning of Independence in Section 1.4 of National Instrument 52-110 *Audit Committees* (NI 52-110) and a review of the applicable factual circumstances against this standard, the Compensation, Leadership and Governance Committee has determined that all Directors listed are independent, except for Jeffrey Lyash, who is considered to have a material relationship with OPG by virtue of his position as President and CEO of OPG.

The Board has a Board of Directors Conflict of Interest Policy and Procedure that governs the disclosure and mitigation of Director conflicts or potential conflicts of interest and has adopted an annual process of written disclosure by Directors in order to:

(i) identify potential conflicts of interest for the purposes of complying with the Board of Directors Conflict of Interest Policy and the OBCA;
(ii) validate the Directors' independence and financial literacy for the purposes of complying with securities regulations related to boards of directors and audit committees; and
(iii) satisfy other disclosures and regulatory filings.

To further minimize potential conflicts of interest, the Board has a policy on interlocking directorships. This policy states that no more than two OPG Directors may sit on a board of directors of another reporting issuer at the same time. Directors must confirm that they are in compliance with OPG's policy on interlocking directorships when disclosing to the Board Chair appointments to other boards of directors.

Strategic Planning

OPG's Board holds an annual strategy session and devotes a significant portion of each regular Board meeting to discussion of strategic matters. Management is responsible for developing the strategy and presenting it to the Board for discussion.

In 2017, the Board received reports on key strategic issues, risks, competitive developments, and corporate opportunities facing the Company. Management ensures that the key strategic elements are incorporated into OPG's annual budget and business plan, which are reviewed and approved by the Board. The Board also periodically receives briefings from external advisors on broad energy industry developments and/or special strategic matters.

Overseeing the Management of Risk

The Board oversees OPG's approach of identifying, reporting and mitigating the risks that could significantly impact the Company's capacity to achieve its long-term strategic objectives, as well as specific business plan objectives. To fulfill its risk oversight responsibilities, the Board has established an Enterprise Risk Management Policy and an Audit and Risk Committee, comprised of independent Directors. The

committee's mandate includes oversight of the Enterprise Risk Management (ERM) framework that management uses to manage the Company's risk profile. The ERM framework assists the Board in understanding how risks may affect the Company and how they are being addressed by management. The Audit and Risk Committee receives quarterly reports from OPG's Chief Risk and Audit Executive (CRAE) on enterprise-wide risks.

Through the Compensation, Leadership and Governance Committee, the Board also monitors the risks associated with the executive compensation program, to preclude the Company's decision-makers from taking excessive risk in order to achieve incentives under the compensation plans. The CRAE and Senior Vice President, People & Culture and Chief Ethics Officer jointly review the executive compensation framework on an annual basis to identify any potential for unintended risk-taking. The CRAE and Senior Vice President, People & Culture and Chief Ethics Officer provide an annual joint report to the Compensation, Leadership and Governance Committee on the results of their review.

Directors

The following tables set forth the name, age, municipality of residence, position with the Company and principal occupation of each of the Directors of the Company as of March 8, 2018. Each Director holds office until he or she resigns or a successor is elected or appointed. For a discussion of the Board Committee structure, refer to the heading, *Committees of the Board of Directors*.

Bernard Lord
Age: 52
Moncton, New Brunswick, Canada

Bernard Lord was appointed Board Chair for Ontario Power Generation on April 1, 2014. Mr. Lord is the CEO of Médavie, a not-for-profit Canadian medical care insurance company headquartered in Moncton, New Brunswick.

Mr. Lord earned a bachelor's degree with a major in economics as well as a bachelor's degree in common law from l'Université de Moncton. He has also received honorary doctorate degrees from University of New Brunswick, l'Université de Moncton and Saint Thomas University. He was admitted to the New Brunswick Law Society in 1993 and was appointed as Queen's Counsel in 2011.

Mr. Lord was the CEO of the Canadian Wireless and Telecommunications Association from October 2008 until August 2016. He also served on several other boards of directors.

In 1999, Mr. Lord became one of Canada's youngest Premiers at the age of 33. His majority government was re-elected in 2003 and he served as Premier of New Brunswick until October 2006. He was elected four times as a Member of the New Brunswick Legislative Assembly.

Mr. Lord's government introduced several new initiatives to support the development of natural resources while also protecting the environment, including a new energy policy that lead to the restructuring of NB Power and the refurbishment of the Point Lepreau nuclear generating station.

During Mr. Lord's terms as Premier, New Brunswick saw the lowest unemployment rate in 30 years and tax cuts each year, combined with balanced budgets and debt reduction. His government made record investments in health care and education while strengthening local democracy and modernizing the Official Languages Act.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since November 2013) *****	8 of 8	100%
Special Committee (since March 2017)	14 of 15	93%
The Board Chair is not a member of any standing Committee. The Board Chair attends all Committee meetings.	18 of 18	100%

Principal Occupation: CEO of Médavie

Board Memberships for other Reporting Issuers: None

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

*Chair

Jeffrey Lyash
Age: 56
Toronto, Ontario, Canada

Jeff Lyash is the President and CEO of OPG. Mr. Lyash was formerly the president of CB&I Power, a position he held from 2013 to 2015, where he was responsible for a full range of engineering, procurement and construction of multi-billion dollar electrical generation projects in both domestic and international markets. He also provided operating plant services for nuclear, coal, gas, oil and renewable generation.

Prior to joining CB&I in 2013, Mr. Lyash served as Executive Vice President of Energy Supply for Duke/Progress Energy from 2008 to 2012. With Duke Energy, he led engineering, maintenance and operations of the company's 42,000-megawatt generation fleet, fuel procurement, power trading, major projects and construction, environmental programs, and health and safety programs.

Before the merger of Progress Energy and Duke Energy, Mr. Lyash served as Executive Vice President of Energy Supply for Progress Energy. In this role, he oversaw Progress Energy's diverse 22,000-megawatt fleet of generating resources including nuclear, coal, oil, natural gas and hydroelectric stations. In addition, he was responsible for generating fleet fuel procurement and power trading operations.

Mr. Lyash began his career in the utility industry in 1981, joining Progress Energy in 1993. Before assuming the role of Executive Vice President of Energy Supply, he served as Executive Vice President of Corporate Development, President and Chief Executive Officer of Progress Energy Florida, Senior Vice President of Energy Delivery Florida, and Vice President of Transmission. He also held a wide range of management and executive roles in Progress Energy's nuclear program, including Operations Manager, Engineering Manager, Plant Manager, and Director of Site Operations.

Before joining Progress Energy, Mr. Lyash worked for the U.S. Nuclear Regulatory Commission (NRC) in a number of senior technical and management positions throughout the northeast United States and in Washington, D.C, receiving the NRC Meritorious Service Award in 1987.

Mr. Lyash earned a Bachelor's Degree in Mechanical Engineering from Drexel University, and was honored with the Drexel University Distinguished Alumnus Award in 2009. He has held a Senior Reactor Operator License from the NRC, and is a graduate of the U.S. Office of Personnel Management Executive Training Program and the Duke Fuqua School of Business Advanced Management Program.

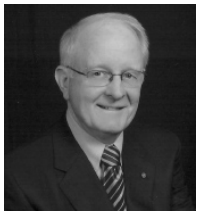
2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since August 2015)	8 of 8	100%
The President and CEO attends all Committee meetings, excluding independent Director in-camera meetings/sessions.	18 of 18	100%

Principal Occupation: President & Chief Executive Officer, Ontario Power Generation Inc.

Board Memberships for other Reporting Issuers: None

Independence from OPG: Not Independent

Interlocking Directorships on Boards of other Reporting Issuers: None



William Coley
Age: 74
Charlotte, North Carolina, U.S.A

Bill Coley served as Chief Executive of British Energy from 2005 to 2009 when he retired following the successful combination of British Energy and EDF Energy. He was President of Duke Power from 1997 until his retirement in February 2003, holding various officer level positions in engineering, operations and senior management during his 37-year career with the company.

Mr. Coley is a director of E.R. Jahna Industries. He also served on the WANO Fukushima Commission

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since January 2013)	8 of 8	100%
Compensation, Leadership and Governance Committee (since February 2016)	5 of 5	100%
Generation Oversight Committee (since February 2016)	4 of 4	100%
Darlington Refurbishment Committee (since May 2015)	4 of 4	100%
Special Committee (since March 2017)	15 of 15	100%

Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: None

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

Elisabeth (Lisa) DeMarco
Age: 50
Toronto, Ontario Canada

Lisa DeMarco is a senior partner at DeMarco Allan LLP with over two decades of experience in law, regulation, policy, and advocacy relating to energy and climate change. Ms. DeMarco was previously a partner at Macleod Dixon LLP from 2002 to 2012, partner at Norton Rose Canada LLP from 2012 to 2013 and partner at Norton Rose Fulbright LLP from 2013 to 2014. She represents several governments and leading energy companies in a wide variety of natural gas, electricity, pipeline and energy storage matters before various regulatory agencies, including the OEB and the National Energy Board. She has been an adjunct professor at Osgoode Hall Law School, is a guest lecturer at a number of law schools and presents regularly.

Ms. DeMarco also assists leading Canadian energy companies and Indigenous business organizations on domestic and overseas power project development, renewable power projects, alternative fuel projects, cleantech development and finance, energy storage, carbon capture and storage, corporate social responsibility, environmental disclosure, clean energy finance, and sustainable business strategy.

She is ranked by Chambers Global as one of the world's leading climate change lawyers and regularly attends and advises on related United Nations negotiations. She is ranked and repeatedly recommended by LEXpert, Expert Guide, International Who's Who, and Chambers Canada as a leading energy (oil, gas, and electricity) and environment lawyer. Ms. DeMarco has worked for multilateral development banks and energy companies on deals and projects in India, Brazil, Sri Lanka, Thailand, Argentina, Chile, Ireland, Africa, Mexico, China, Russia, California, Alberta, Ontario, Nova Scotia, British Columbia, Saskatchewan, Prince Edward Island and Québec. She plays an ongoing and active role in the development and drafting of energy and greenhouse gas emissions policy, regulation, and law throughout Canada, and in various countries around the world. She was also lead counsel on all aspects of the successful sale of an Ontario power distribution company to Hydro One. Lisa was an appointed member of Ontario Premier's Clean Energy Task Force and Climate Action Group.

Ms. DeMarco is a member of theBoard of Directors of the Advanced Energy Centre at MaRS, and Ontario Power Generation. She is a graduate of the University of Western Ontario (BSc Hon. – 1990), the University of Toronto (MSc. – 1992), Osgoode Hall Law School, York University (LLB – 1995) and the Vermont Law School (MSEL, summa cum laude – 1995) and is called to the bar in England and Ontario.

2017 Board/Committee Membership:	**2017 Attendance**	
Board (since April 2014)	8 of 8	100%
Audit and Risk Committee (since February 2016)	5 of 5	100%
Generation Oversight Committee (since February 2016)	4 of 4	100%
Special Committee (since March 2017)	15 of 15	100%

Principal Occupation: Senior Partner, DeMarco Allan LLP

Board Memberships for other Reporting Issuers: None

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

Jean Paul (JP) Gladu
Age: 44
Toronto, Ontario, Canada

JP Gladu is currently the President and CEO of the Canadian Council for Aboriginal Business (CCAB) based in Toronto. Anishinaabe from Thunder Bay, Mr. Gladu is a member of Bingwi Neyaashi Anishinaabek located on the eastern shores of Lake Nipigon. Mr. Gladu has over two decades of experience in the natural resource sector including work with Aboriginal communities and organizations, environmental non-government organizations, industry and governments from across Canada, including involvement in business development for the Bingwi Neyaashi Anishinaabek Nation from 2009 to 2012. He has produced a number of publications related to Aboriginal issues including: forest certification, Native values collection, biofuel opportunities, First Nation community land use plans, criteria and indicators for sustainable forestry, and cedar product development.

Mr. Gladu holds a Forest Technician Diploma from the Sault College of Applied Arts and Technology, a Bachelor of Science degree in forestry from Northern Arizona University, and an Executive Masters of Business Administration from Queens University in Kingston. In 2014, he was a recipient of the Community Service Award – Transformation Awards from Diversity Magazine. Mr. Gladu was nominated for the 2013 Premier's Award for Outstanding Ontario College Graduates, was recognized as one of five Northern Leaders in 2012 by Northern Ontario Business and was elected Class President of the 2012 Queens Executive Masters of Business Administration.

Mr. Gladu currently serves on the Canadian Electricity Associations' Public Advisory Panel, Noront Resources and Chancellor of St, Paul's University Board of Governors. He has also held previous board positions with Colleges and Institutes Canada (previously the Association of Canadian Community Colleges), Northern Policy Institute, Canadian Foundation for Economic Education boards of directors, Centre for Research and Innovation in the Bio-Economy, Papasay Management Corporation, and a board member of the Canadian Bioenergy Association. He also held advisory positions with the Canadian Association of Petroleum Producers Renewable Clean Energy Committee and the Ontario Provincial Forest Policy Committee.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since November 2015)	6 of 8	75%
Compensation, Leadership and Governance Committee (since February 2016)	5 of 5	100%
Generation Oversight Committee (since February 2016)	3 of 4	75%

Principal Occupation: President and CEO, Canadian Council for Aboriginal Business

Board Memberships for other Reporting Issuers: Noront Resources Ltd. *(TSX)*

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

John Herron
Age: 64
Punta Gorda, Florida, U.S.A.

John Herron retired from Entergy in April 2013 where he was the President, CEO and Chief Nuclear Officer of Entergy Nuclear, with responsibility for Entergy's nuclear plants located in New York, Massachusetts, Vermont, Michigan, Louisiana, Mississippi and Arkansas as well as the company's management service to the Cooper Nuclear Station for the state of Nebraska.

He previously served as Entergy's Senior Vice President for Nuclear Operations handling the operational side of fleet management. Mr. Herron joined Entergy in February 2001 as Vice President, Operations at the Waterford 3 Nuclear Station in Killona, Louisiana. He then moved to New York as the Senior Vice President of the Indian Point Energy Center in February 2002.

Mr. Herron began his career in nuclear operations in 1979 at Vermont Yankee Nuclear Power Corporation. His positions there included technical services superintendent, operations manager, technical programs manager, shift supervisor, and supervisory control room operator. In 1994, he moved to Brownville, Nebraska to become plant manager at Nebraska Public Power District's Cooper Nuclear Station.

Mr. Herron then joined the Tennessee Valley Authority as plant manager at Sequoyah Nuclear Plant in Soddy-Daisy, Tennessee, from October 1996 through July 1999. From July 1999 to February 2001, Mr. Herron served as site Vice President at TVA's Browns Ferry Nuclear Plant.

Prior to his career in utilities, Mr. Herron served in the U.S. Navy from 1972 to 1978. He was attached to the USS Tullibee and the S1C NPTU Windsor, where he was an instructor at the Nuclear Submarine Prototype School.

Mr. Herron holds a bachelor's degree in Business Management from Franklin Pierce College in Rindge, New Hampshire. He also attended the Advanced Management Program at the Harvard Business School in May 2005.

Mr. Herron currently serves on the board of directors for Duke Energy. He also served on the board of directors for the Institute of Nuclear Power Operations and on the Nuclear Strategic Issues Advisory Committee of the Nuclear Energy Institute. In the aftermath of Japan's 2011 earthquake, he was named to the WANO Post-Fukushima Commission and the U.S. nuclear industry's Fukushima response steering committee.

2017 Board/Committee Membership:	**2017 Attendance**	
Board (since November 2013)	8 of 8	100%
Generation Oversight Committee* (since February 2016)	4 of 4	100%
Darlington Refurbishment Committee (since May 2015)	4 of 4	100%

Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: Duke Energy (NYSE)

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

* Chair of Committee

Ani Hotoyan-Joly
Age: 56
Markham, Ontario, Canada

Ani Hotoyan-Joly is currently Chief Financial Officer and Corporate Secretary of Coventree Inc. Prior to Coventree, she was V.P. Finance and Chief Financial Officer at Swiss Reinsurance Company Canada (P&C) and prior to that held senior positions at Zurich Canada. Ms. Hotoyan-Joly is a member of the Board of Directors of Women's College Hospital and is a member of the Executive Committee and Chair of the Governance and Nominations Committee. She is currently a member of the Executive Board of Armenian Relief Society's Roubina (Toronto) Chapter and was the Past Chair of A.R.S. Armenian Private School's Board of Trustees.

Ms. Hotoyan-Joly is a Chartered Professional Accountant and Chartered Accountant and holds a Bachelor of Commerce degree from the University of Toronto and the ICD.D designation from the Institute of Corporate Directors. She was elected as a 2016 Diversity 50 Candidate by the Canadian Board Diversity Council.

2017 Board/Committee Membership:	**2017 Attendance**	
Board (since March 2017)	6 of 6	100%
Audit and Risk Committee (since March 2017)	4 of 4	100%
Compensation, Leadership and Governance Committee (since March 2017)	4 of 4	100%

Principal Occupation: Chief Financial Officer and Corporate Secretary, Coventree Inc.

Board Memberships for other Reporting Issuers: None

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

Wendy Kei
Age: 50
Toronto, Ontario, Canada

Ms. Wendy Kei currently serves on the Board of Guyana Goldfields, Inc., as the Chair of the Audit Committee, a member of the Human Resources & Compensation Committee and a member of the Corporate Governance & Nominating Committee. She is an accomplished Finance Executive with over 25 years of business experience in a variety of industries. For the past 14 years, Ms. Kei has been working within the mining industry and brings a strong focus on corporate governance, financial and risk management and a strong expertise in executing complex mergers and acquisitions.

Ms. Kei is a Chartered Professional Accountant and Chartered Accountant and previously served as Chief Financial Officer of Dominion Diamond Corporation (formerly Harry Winston Diamond Corporation and Aber Diamond Corporation).

Ms. Kei is a member of the Chartered Professional Accountants of Ontario, and holds a Bachelor of Mathematics from the University of Waterloo. Ms. Kei was selected as a Diversity 50 2016 Candidate by the Canadian Board Diversity Council.

2017 Board/Committee Membership:	**2017 Attendance**	
Board (since March 2017)	6 of 6	100%
Audit and Risk Committee (since March 2017)	4 of 4	100%
Generation Oversight Committee (since March 2017)	3 of 3	100%

Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: Guyana Goldfields Inc. *(TSX)*

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

M. George Lewis
Age: 57
Toronto, Ontario, Canada

From February 2007 until November 2015, George Lewis was a member of RBC's Group Executive, one of eight executives responsible for setting the overall strategic direction for Royal Bank of Canada, Canada's largest bank. In that capacity, he served as Group Head of RBC Wealth Management from 2007 and RBC Insurance from 2012. As Group Head, Wealth Management, Mr. Lewis led the RBC businesses that serve the wealth management needs of affluent clients globally, and units that provide asset management and trust products. He was also Chairman of RBC Global Asset Management Inc.

From July 2000 to May 2008, Mr. Lewis was Chief Executive Officer of RBC Global Asset Management, which under his leadership became Canada's largest single mutual-fund family (RBC Funds) and one of Canada's largest asset management firms. He previously served as Head of Wealth Management for the Canadian Personal and Business segment and, from 2003 to 2006, was Head of all banking and investment products for RBC's Canadian Business.

From 1998 to 2000, Mr. Lewis was Managing Director, Head of Institutional Equity with RBC Capital Markets, responsible for global institutional-equity sales, trading and research. He was previously a top-rated equity analyst and Director of Research. He began his career with RBC in 1986, in the investment banking division of RBC Capital Markets.

Mr. Lewis has extensive experience in the investment industry, has a Masters of Business Administration degree with distinction from Harvard University and a Bachelor of Commerce degree with high distinction from Trinity College at the University of Toronto. He is also a Chartered Financial Analyst and an FCA/FCPA and has been certified by the Institute of Corporate Directors.

Mr. Lewis serves on the board of directors of Enbridge Income Fund Holdings Inc., the Canadian Film Centre and the Anglican Diocese of Toronto Foundation. He is a current member and past chair of the Bishop's Company of the Anglican Diocese of Toronto, as well as a patron and member of the Cabinet of the United Way of Toronto and York Region. Mr. Lewis also serves as the Honorary Colonel Commandant of the Royal Canadian Chaplain Service of the Canadian Armed Forces.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since February 2005)	8 of 8	100%
Audit and Risk Committee* (since February 2016)	5 of 5	100%
Compensation, Leadership and Governance Committee (since February 2016)	5 of 5	100%
Special Committee* (since March 2017)	15 of 15	100%

Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: Enbridge Income Fund Holdings Inc. *(TSX)*

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

* Chair of Committee

Margaret (Peggy) Mulligan
Age: 59
Cameron, Ontario, Canada

Peggy Mulligan was the Executive Vice President and Chief Financial Officer, Valeant Pharmaceuticals International, Inc. until December 2010. Prior to this, she was a Principal at Priiva Consulting, and before that she served as Executive Vice President and Chief Financial Officer of Linamar Corporation. Prior to Linamar, Mrs. Mulligan was with the Bank of Nova Scotia for eleven years as Executive Vice President, Systems and Operations and Senior Vice President, Audit and Chief Inspector. Before joining Scotiabank, she was an Audit Partner with PricewaterhouseCoopers in Toronto. She holds a B. Math (Honours) from the University of Waterloo and was named a Fellow of the Institute of Chartered Professional Accountants of Ontario in 2003.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since December 2005)	7 of 8	88%
Compensation and Leadership and Governance Committee* (since February 2016)	5 of 5	100%
Darlington Refurbishment Committee (since May 2015)	4 of 4	100%
Special Committee (since March 2017)	14 of 15	93%

Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: Canadian Western Bank (*TSX),* ClearStream Energy Services Inc. *(TSX)* (*previously Tuckamore Capital*)

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

* Chair of Committee

Yezdi Pavri
Age: 68
North York, Ontario, Canada

Yezdi Pavri retired as Vice Chairman of Deloitte Canada in June 2012 after a career of more than 30 years. Prior to being named Vice Chairman, Mr. Pavri was a member of the firm's national Management Committee for over ten years and was the Managing Partner of the Toronto practice since June 2004. He founded Deloitte's national Enterprise Risk Services practice in 1990 and led it for 15 years. He was a founding member of the global firm's India Steering Committee and co-chaired the firm's first Diversity and Inclusion Committee.

Mr. Pavri holds a Bachelor's degree in Aeronautical Engineering from the Indian Institute of Technology in Bombay and a Master's degree in Thermal Power Engineering from Imperial College in London. He is a Fellow of the Chartered Professional Accountants of Ontario.

Mr. Pavri currently serves on the boards of ICICI Bank of Canada, Enterra Holdings Limited (the global parent of Golder Associates) and MD Financial Services, and is a past member of the board of directors of Hydro One. Mr. Pavri is also the immediate past chairman of the board of trustees of United Way Toronto.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since September 2015)	8 of 8	100%
Audit and Risk Committee (February 2016)	5 of 5	100%
Compensation, Leadership and Governance Committee (since February 2016)	5 of 5	100%
Special Committee (since March 2017)	15 of 15	100%

Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: None

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

Gerry Phillips
Age: 77
Ajax, Ontario, Canada

Gerry Phillips was the Member of Provincial Parliament in the Legislative Assembly of Ontario for the east Toronto riding of Scarborough-Agincourt from 1987 to 2011. He served in six cabinet portfolios, including twice as Ontario Minister of Energy, where he was OPG's Shareholder from 2007 to 2008 and again on an interim basis from November 2009 to January 2010, as well as, Minister responsible for Securities Regulation in Ontario. He was also the Chair of the Management Board of Cabinet from 2008 to 2011 and the Chair of the Select Committee on the TMX Transaction in 2011.

Before entering public life, Mr. Phillips graduated from the University of Western Ontario's School of Business and worked in the marketing department of Procter and Gamble. In 1970, he joined the consulting firm of Canadian Marketing Associates and became President in 1977. He later founded two successful spin-off companies – the Sales Development Group in 1979 and the Retail Resource Group in 1982. By 1987, he was Chair of all three companies, with a combined workforce of approximately 300.

Mr. Phillips has an Honours B.A. from the Western School of Business.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since January 2013)	8 of 8	100%
Audit and Risk Committee (since February 2016)	5 of 5	100%
Darlington Refurbishment Committee (since May 2015)	4 of 4	100%

Principal Occupation: Retired

Board Memberships for other Reporting Issuers: None

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

Jim Reinsch
Age: 74
Frederick, Maryland, U.S.A.

Jim Reinsch retired from the Bechtel Group where he was Senior Vice President and Partner, and past President of Bechtel Nuclear. In this role, he was responsible for the global profit/loss, customer relations, operations, project management, marketing and business development of Bechtel's three nuclear business segments: nuclear operating plant services, steam generator replacement, and operations of Bechtel's global nuclear activities. During his 40 years with Bechtel, he also presided over Bechtel Canada, and managed large regions in the United States and Asia. He served as the President of the American Nuclear Society, and was a member of the Nuclear Energy Institute as well as a member of their Executive Committee. Mr. Reinsch is also a member of several international nuclear energy organizations, including the WANO and the World Nuclear Association.

Mr. Reinsch holds a Bachelor of Science degree from the University of Maryland.

Mr. Reinsch currently serves on the board of directors for Frederick Memorial Hospital and the Hood College Board of Trustees, and is a past board member of Duke Energy and the Smithsonian National Portrait Gallery. Additionally, he serves on the Emirate Nuclear Energy Corporation's committee on nuclear power which reports to the board of directors, and is a member of the international advisory board of Terrestrial Power.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since August 2015)	7 of 8	88%
Generation Oversight Committee (since February 2016)	4 of 4	100%
Darlington Refurbishment Committee* (since August 2015)	4 of 4	100%

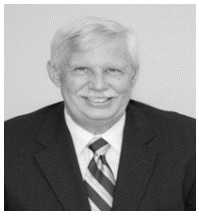
Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: None

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

*Chair of Committee



James Sheppard
Age: 69
Toronto, Ontario, Canada

Mr. Sheppard serves as an Independent Consultant. Mr. Sheppard served as Interim Senior Vice President for Southern California Edison Company and served as its Interim Chief Nuclear Officer from September 2010 to December 9, 2010. From 1993 to 2009, he held several senior positions associated with the South Texas Project nuclear power plant, including Chairman, President and Chief Executive Officer of STP Nuclear Operating Company, which operated the facility for its three owners. He served as Executive Officer of South Texas Project Electric Generating Station. He served as an executive at STP for ten years, he held the positions of Vice President and Assistant to the President and Chief Executive Officer; Vice President of Engineering and Technical Services; Vice President of Business Systems; Assistant to the executive vice president; and General Manager of Licensing. He has been an Independent Director at Xcel Energy Inc. since March 2011.

Mr. Sheppard holds a bachelor of science degree in aerospace engineering from the U.S. Naval Academy and a master's degree in business administration from the Duke University.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since March 2017)	6 of 6	100%
Darlington Refurbishment Committee (since March 2017)	3 of 3	100%
Generation Oversight Committee (since March 2017)	3 of 3	100%

Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: Xcel Energy Inc. *(NYSE)*

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

Nicole Boivin served as a Director from April 2014 to March 2017 and was a member of the Compensation, Leadership and Governance Committee and the Darlington Refurbishment Committee. Brendan Hawley was a Director from April 2014 to March 2017 and was a member of the Audit and Risk Committee and Darlington Refurbishment Committee. Ira Kagan was a Director from April 2014 to March 2017 and served as a member of the Audit and Risk Committee and the Generation Oversight Committee.

Orientation and Continuing Education

The Compensation, Leadership and Governance Committee is responsible for reviewing and recommending appropriate orientation programs for new Directors. New directors are provided relevant documentation relating to OPG's governance practices and policies and to its business. Directors attend plant tours of OPG generating facilities, where they also receive comprehensive introductory briefings from OPG senior executives on OPG's operations and business activities.

The Board supports and sponsors the continuing education of OPG Directors, both in the business of OPG and in their duties as Directors. This includes plant tours of OPG's major facilities, site visits to projects with OPG's Indigenous business partners, and special presentations by internal and external experts on topical business-related issues or on specific aspects of OPG's operations. In 2017, such topics included pension plan governance, the cap and trade program and OPG's dam safety program. Directors also are provided with articles and publications on current topics of interest. Board members have full access to all Board and Board committee materials and records. OPG has developed a Director Governance Handbook, which provides Directors with information necessary to fulfill their roles, including director duties and obligations under the OBCA, and relevant corporate policies and procedures. OPG also sponsors Director attendance at the Institute of Corporate Directors' Director Education Program, or equivalent, and sponsors attendance at the Goizueta Director program for members of Board committees responsible for oversight of nuclear operations.

Ethical Business Conduct

The Board has adopted a policy for ethical business behaviour and a Code of Business Conduct. The mandate of the Audit and Risk Committee requires that it receive regular reports throughout the year on the Code of Business Conduct in order to satisfy itself that appropriate code of conduct and compliance programs are in place and are being enforced, and remedial action is being taken. The Audit and Risk Committee receives quarterly reports from management on the Code of Business Conduct (including reports on any substantiated cases of fraud) and the disposition of cases including disciplinary action, as well as an annual report on the Code of Business Conduct and a report on the annual review of the Board policy. A copy of the Code of Business Conduct can be found on SEDAR at www.sedar.com and also is available on the Company's website at www.opg.com. The Audit and Risk Committee has procedures for the receipt, retention and treatment of complaints received pertaining to accounting, internal controls or auditing matters, and for the confidential anonymous submission by employees concerning such matters.

Nomination of Directors

The Compensation, Leadership and Governance Committee, which is comprised of six independent Directors within the meaning of NI 52-110, is responsible for conducting an annual review of the OPG Board's principles and systems of governance, and oversight of annual Board, Board committee and Director evaluations. The Compensation, Leadership and Governance Committee recommends candidates to the Shareholder. Nominations of Directors by the Shareholder also may be considered by the Compensation, Leadership and Governance Committee. When considering a potential candidate, the committee considers the qualities, experience, and skills that the Board, as a whole, should have in light of the business opportunities and risks facing OPG. The attributes the Compensation, Leadership and Governance Committee considers in a candidate include integrity, business judgment and experience, diversity, professional expertise, independence from management, financial literacy, and communication skills, as well as sufficient time available to fulfill his or her obligations as a Board member. The Board's policy on diversity is to interview a diverse candidate for every vacancy on the Board. OPG defines diversity to include: women, aboriginal peoples, people with disabilities, and visible minorities. These four

enumerated groups mirror the four enumerated groups in the definition of "designated groups" in the federal *Employment Equity Act*.

From time to time, the Compensation, Leadership and Governance Committee may engage outside advisors to assist in identifying potential candidates.

Director Tenure/Board Renewal

The OPG Board Charter guideline for board tenure is 10 to 15 years. When considering board renewal, the Compensation, Leadership and Governance Committee regularly reviews the OPG Board skills profile. The Board maintains an "evergreen list" of potential Board candidates. From time to time, the committee makes recommendations to add skills to the Board that reflect OPG's business opportunities and risks.

Diversity in Leadership

Board of Directors

As noted under the heading, *Nomination of Directors*, the Compensation, Leadership and Governance Committee interviews a diverse candidate for every vacancy on the Board, where diversity is defined as: women, aboriginal peoples, people with disabilities, and visible minorities. The Board has signed on to the Catalyst Accord, set a target for "diverse" representation on the Board of 50 percent, including 40 percent women by 2019 and adopted a target of 25 percent women on the Board by 2017. In 2017, three members were added to the Board, two of whom meet the diversity definition. As of the date of this AIF, overall diversity of the Board is at 50 percent. Representation of women on the Board is 29 percent (four Directors) as of the date of this AIF.

Senior Management

OPG strives to create a workforce that reflects diverse populations of the communities in which it operates. As of December 31, 2017, women filled 25 percent of Corporate Officer roles and 26 percent of senior management (senior managers and above) positions. In total, there were three women in Corporate Officer roles and 153 women in senior management positions. OPG tracks and monitors diversity succession planning metrics and strives to have a diverse candidates list for senior management positions.

Compensation

Executive Compensation Framework

In September 2016, the Government of Ontario introduced *Regulation 304/16: Executive Compensation Framework*. The regulation sets out how all employers, including OPG, designated under the *Broader Public Sector Executive Compensation Act, 2014* must establish and post compensation programs for executives. The regulation requires all designated employers to have a written Executive Compensation Program that describes the compensation they may provide to executives. The program must include the compensation philosophy, salary and performance-related pay caps, comparative analysis details, and a description of other elements of compensation. The regulation also requires that designated employers post their program on their website and provide a reasonable opportunity for members of the public to provide comments. OPG met the requirements of *Ontario Regulation 304/16* and posted its Executive Compensation Framework on the Company's website for public comment on November 30, 2016. OPG reviewed the comments received through the public consultation process and determined that there was no need to alter its Executive Compensation Program, which became effective on January 1, 2017. OPG's Executive Compensation Program applies to employees at the Vice President level and higher. A copy of OPG's Executive Compensation Program can be found on SEDAR at www.sedar.com and is also available on the Company's website at www.opg.com.

Director Compensation

As at March 8, 2018, OPG's Director compensation framework provides each Director who is not an employee of OPG with an annual retainer of $25,000. Directors also receive a $3,000 retainer for each Board committee of which they are a member. There are four standing committees of the Board and Directors serve on at least two committees. Directors receive an additional retainer for serving as committee chairs. The retainer for the chair of the Audit and Risk Committee is $8,000. The chairs of the other three committees receive retainers of $5,000.

In addition to the above, Directors are compensated for each regular and/or special meeting that they attend and receive a fee of $2,000 or $1,000 for a long or short meeting, respectively. The Board Chair may also determine that no fee is warranted.

In order to retain national and international expertise, non-resident Directors are compensated in U.S. dollars and Directors who travel over certain distances receive a travel fee to cover travel time related to Board and Board committee meetings they attend.

Since 2004, the Chair of the Board, in his role as non-executive Chair, receives an all-inclusive annual fee of $150,000 and is reimbursed for out-of-pocket expenses including travel and other expenses.

CEO Compensation

Among its other responsibilities, the Compensation, Leadership and Governance Committee oversees, on behalf of the Board, the setting of the CEO's annual goals and objectives and the annual review of CEO performance, and makes recommendations to the Board with respect to CEO compensation. The Committee may seek input from an independent advisor with regard to monitoring and benchmarking compensation trends.

In August 2015, when the current CEO was appointed, the CEO compensation terms were established based on the benchmarks recommended in the 2007 Report of the Agency Review Panel on Phase 1 of its Review of Ontario's Provincially Owned Electricity Agencies. The CEO's base pay and incentives compensation are compliant with *Ontario Regulation 304/16*. Other elements of the CEO's compensation will be compliant within the three-year period provided in the regulation to bring all elements of compensation into compliance.

For details regarding compensation paid to Directors and executive officers during the financial year ended December 31, 2017, see OPG's Statement of Executive Compensation (Form 51-102F6), which is available on SEDAR at www.sedar.com and incorporated by reference herein.

Committees of the Board of Directors

The following are the current standing Board committees as at March 8, 2018:

Audit and Risk Committee

This committee is responsible for the integrity, quality, and transparency of OPG's financial information, the adequacy of the financial reporting process, the systems of internal controls, and related principles, policies and procedures established by management. The Committee is responsible for the oversight of the Company's regulatory filings, financial statements, MD&A and press releases prior to their disclosures to the public, including approval of quarterly financial statements and recommending approval of the annual financial statements and various other annual disclosures to the Board. The committee is also responsible for recommending the appointment and compensation of the external auditor to the Board and for oversight of the external auditor.

The committee also provides oversight of OPG's corporate financing strategies including:

- policies related to financial exposure management;
- processes for identifying major financial risks;
- performance of the OPG Pension Fund, the Used Fuel Segregated Fund and the Decommissioning Segregated Fund;
- review and approval of the audited financial statements of the OPG Pension Fund, the Used Fuel Segregated Fund and the Decommissioning Segregated Fund; and
- review and approval of the statements of investment policies and procedures for the OPG Pension Fund and the Decommissioning Segregated Fund.

The Audit and Risk Committee also oversees risk and associated risk management activities, including the review of management's assessment of significant risks to achieving OPG's business plan objectives. The committee also is responsible for ensuring that an effective Code of Business Conduct is in place at OPG and monitors compliance with this code.

As of November 22, 2017, the Audit and Risk Committee assumed oversight of OPG's role as Financial Services Manager of the Fair Hydro Trust.

As of the date of this AIF, the Audit and Risk Committee consists of George Lewis (Chair), Elisabeth (Lisa) DeMarco, Ani Hotoyan-Joly, Wendy Kei, Yezdi Pavri, and Gerry Phillips.

For further details regarding the Audit and Risk Committee, see *Audit and Risk Committee Information*.

Compensation, Leadership and Governance Committee

This committee provides oversight of OPG's human resources and compensation policies and practices, including CEO objectives and compensation, disclosure on compensation and human resources matters, leadership talent review, succession planning, and collective bargaining negotiations. The committee also provides oversight of the design of OPG's benefit and pension plans.

The Compensation, Leadership and Governance Committee oversees the Board's governance program and practices to ensure that they are consistent with high standards of corporate governance, including annually reviewing and assessing the Board's system of corporate governance with a view to maintaining these high standards. The committee also is responsible for overseeing OPG's reputation management plan, and for identifying and recommending to the Board candidates for nomination to the Shareholder. Finally, the committee oversees OPG's processes for Board, Board committee, and Director assessments, as well as Director compensation and new Director orientation.

As of the date of this AIF, the Compensation, Leadership and Governance Committee consists of Margaret (Peggy) Mulligan (Chair), Bill Coley, JP Gladu, Ani Hotoyan-Joly, George Lewis and Yezdi Pavri.

Darlington Refurbishment Committee

The Darlington Refurbishment Committee is responsible for the oversight of the execution of the Darlington Refurbishment Program, including retaining external independent oversight advisors. The committee was also responsible for making a recommendation to the Board with respect to a final budget and schedule for the Darlington Refurbishment Program, which was subsequently approved by the Board of Directors in November 2015. The committee monitors and reports on the progress of the refurbishment program against the approved budget and schedule. The committee will make a recommendation to the Board with respect to the refurbishment of subsequent Darlington units, and other recommendations for approvals related to the refurbishment program as may be required from time to time.

As of the date of this AIF, the Darlington Refurbishment Committee consists of Jim Reinsch (Chair), Bill Coley, John Herron, Margaret (Peggy) Mulligan, Gerry Phillips, and James Sheppard.

Generation Oversight Committee

This committee is responsible for the oversight of safe, secure and efficient operations of OPG's generating facilities. Additionally, the committee is responsible for the development, risk management, financing, and execution of the Company's major generation projects including those related to nuclear waste management, other than the Darlington Refurbishment Program. The committee also is responsible for the oversight of OPG's environment and dam safety management systems and OPG's Indigenous relations. The committee reviews reports of internal and external advisors/assessors in respect of OPG's generation operations and management's response to the findings from such assessments. The committee provides oversight to ensure that OPG's generating facilities are in compliance with nuclear safety, industrial and occupational health and safety, and environmental laws and regulations.

As of the date of this AIF, the Generation Oversight Committee consists of John Herron (Chair), Bill Coley, Elisabeth (Lisa) DeMarco, JP Gladu, Wendy Kei, Jim Reinsch, and James Sheppard.

Special Committee of the Board

This Special Committee of the Board was established on March 10, 2017. The Special Committee was responsible for providing timely strategic and other guidance to OPG management in connection with the Province's announcement of Ontario's Fair Hydro Plan on March 2, 2017, which includes refinancing a portion of the Global Adjustment. The Committee was also responsible for making recommendations to the Board with respect to OPG's participation in the Province's implementation of the refinancing proposal. The mandate of the Special Committee concluded on November 22, 2017 and the Audit and Rick Committee will be responsible for the oversight of this process.

Assessments

The Compensation, Leadership and Governance Committee is responsible for the annual process for evaluating the performance of the Board, its committees and individual Directors. The Board and committee evaluations are based upon the completion of confidential questionnaires regarding assessment of performance and compliance with the Board and Committee Charters. The individual Director evaluations are based on self-assessment questionnaires, which are submitted in confidence to the Board Chair and the Chair of the Compensation, Leadership and Governance Committee. In addition, the process includes a follow-up one-on-one meeting between each Director and the Board Chair. The Compensation, Leadership and Governance Committee reports the results of the evaluations to the Board and the results are discussed amongst the Board. The Compensation, Leadership and Governance Committee makes recommendations to the Board for enhancing the Board's governance and effectiveness.

Further Information on OPG Governance

OPG provides additional information on the Company's governance on its website (www.opg.com) including:

- Memorandum of Agreement with the Shareholder
- Shareholder Directives
- List of Corporate Officers
- Board and Committee Charters
- Board and Committee Chair Position Descriptions
- Board of Directors Conflict of Interest Policy
- Indigenous Relations Policy
- Code of Business Conduct
- Disclosure Policy
- Environmental Policy
- Employee Health and Safety Policy
- Nuclear Safety Policy

- Safe Operations Policy
- Cyber Security Policy

Unless otherwise specifically stated, none of the information contained on, or connected to the Company's website nor any of the contents of the aforementioned additional information on OPG's governance are incorporated by reference herein.

EXECUTIVE OFFICERS

The following table sets forth the name, municipality of residence, position with the Company, and the date of commencement for each of the executive officers of the Company as of March 8, 2018:

Name and Municipality of Residence	**Current Position Held**	**Executive Officer Since**
Bernard Lord *Moncton, New Brunswick*	Board Chair	April 2014
Jeff Lyash *Toronto, Ontario*	President and Chief Executive Officer	August 2015
Carlo Crozzoli *Toronto, Ontario*	Senior Vice President, Corporate Business Development and Strategy	December 2011
Chris Ginther *Newmarket, Ontario*	Chief Administrative Officer	July 2012
Ken Hartwick *Milton, Ontario*	Chief Financial Officer & Senior Vice President – Finance	March 2016
Glenn Jager *Clarington, Ontario*	President, OPG Nuclear and Chief Nuclear Officer	November 2013
David Kaposi *Toronto, Ontario*	Vice President, Chief Investment Officer	November 2013
Barb Keenan *Toronto, Ontario*	Senior Vice President, People & Culture and Chief Ethics Officer	March 2010
Catriona King *Richmond Hill, Ontario*	Vice President, Corporate Secretary	February 2005
John Lee *Toronto, Ontario*	Vice President, Treasurer	July 2011
Mike Martelli *Etobicoke, Ontario*	President, Renewable Generation **[CONFIRM]**	July 2013
Dietmar Reiner *Clarington, Ontario*	Senior Vice President, Nuclear Projects	June 2014
Jennifer Rowe *Toronto, Ontario*	Senior Vice President, Corporate Affairs	January 2017

All of the executive officers of the Company have been engaged for more than five years in their current principal occupations, except as set out below:

- Mr. Lyash was Executive Vice President at Duke Energy from May 2008 to January 2012 and President at CB&I Power from July 2013 to July 2015.
- Mr. Crozzoli was Senior Vice President, Corporate Business Development and Chief Risk Officer at OPG from December 2011 to November 2015, Acting Senior Vice President, Finance, Strategy & Risk and Chief Financial Officer at OPG from November 2015 to March 2016 and Senior Vice-President, Corporate Business Development and Chief Risk Officer at OPG from March 2016 to August 2016.
- Mr. Ginther was Senior Vice President, Law and General Counsel and Chief Ethics Officer at OPG from July 2012 to January 2016 and Senior Vice President, Legal, Ethics and Compliance at OPG from January 2016 to February 2017.
- Mr. Hartwick was President and CEO at Just Energy Corp. from February 2008 to April 2014, Interim President and CEO at Atlantic Power Corporation from September 2014 to January 2015, Chief Financial Officer at Wellspring Financial Corporation from February 2015 to March 2016 and Senior Vice President, Finance, Strategy, Risk and Chief Financial Officer at OPG from March 2016 to February 2017.
- Mr. Jager was Senior Vice President, Pickering Nuclear Generating Station at OPG from January 2010 to November 2013 and Chief Nuclear Officer at OPG from November 2014 to March 2015.
- Mr. Kaposi was Global Head of Alternatives for Mercer (Canada) Inc. from November 2007 to June 2012 and Partner, Investor Relations at Bastion Infrastructure Group Inc. from July 2012 to September 2013.
- Ms. Keenan was Senior Vice President, People and Culture at OPG from March 2012 to January 2016 and Senior Vice President, People, Culture and Communications from January 2016 to February 2017.
- Ms. King was Vice President, Corporate Secretary at OPG from June 2005 to May 2012, Vice President, Corporate Secretary & Executive Operations from May 2012 to March 2017.
- Mr. Martelli was Plant Manager for the Niagara Plant Group at OPG from June 2010 to July 2013 and Senior Vice President, Hydro-Thermal Operations at OPG from July 2013 to January 2016.
- Mr. Reiner was Senior Vice President, Nuclear Refurbishment at OPG from March 2010 to April 2014.
- Ms. Rowe was Senior Managing Director – Marketing and Communications and VP Corporate Affairs at Manulife from January 2010 to October 2012 and Senior Vice President and Chief Marketing Officer at Meridan Credit Union from October 2012 to April 2016.

INDEBTEDNESS OF DIRECTORS AND EXECUTIVE OFFICERS

As of the date of this AIF, no director or executive officer of the Company or any of its subsidiaries had any outstanding indebtedness to the Company or any of its subsidiaries except routine indebtedness or had any indebtedness that was the subject of a guarantee, support agreement, letter of credit or other similar arrangement or understanding provided by the Company or any of its subsidiaries.

CEASE TRADE ORDERS, BANKRUPTCIES, PENALTIES OR SANCTIONS

To the knowledge of OPG, no director or executive officer is, at the date of the AIF, or was within 10 years before the date of the AIF, a director, chief executive officer, or chief financial officer of any company, that (a) was subject to an order that was issued while the director or executive officer was acting in the capacity as director, chief executive officer, or chief financial officer, or (b) was subject to an order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer, or chief financial officer, except for:

- Ani Hotoyan-Joly was the Chief Financial Officer of Coventree Inc. on November 8, 2011, when the Ontario Securities Commission issued an order that trading in any securities by Coventree cease and any exemptions contained in Ontario Securities law do not apply to Coventree until such time as Coventree completes it winding up. The order was made on the basis that Coventree had contravened Ontario Securities law by failing to issue and file certain news releases and material change reports in 2007.

- The events in question occurred before she became CFO of Coventree Inc. in May 2009. Coventree Inc. continues in the process of a court-supervised winding up and the order is still in effect.

To the knowledge of OPG, no director or executive officer of OPG, or a shareholder holding a sufficient number of securities of OPG to affect materially the control of OPG (a) is, as at the date of the AIF, or has been within the 10 years before the date of the AIF, a director or executive officer of any company (including OPG) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (b) has, within the 10 years before the date of the AIF, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager, or trustee appointed to hold the assets of the director, executive officer, or shareholder, except for:

- Bernard Lord was a director of AEA Technology from the fall of 2010 until the fall of 2012 when it became insolvent.
- Ani Hotoyan-Joly is currently the CFO and Corporate Secretary of Coventree Inc. from May 2009. On February 15, 2012 Coventree Inc. announced that the winding up of the Company will commence and that Duff & Phelpe Canada Restructuring Inc. (now known as KSV Advisory Inc.) was appointed the liquidator of the Company for the purpose of winding up its affairs.
- Peggy Mulligan was a director of MethylGene Inc. from May 2012 to June 2014. On May 9, 2013, MethylGene announced a plan of arrangement that was successfully completed on June 28, 2013.
- Bernard Lord, was a director of Clean Air Power, during September 2015 while it was subject to liquidation proceedings under the laws of Bermuda. Mr. Lord is no longer a director of Clean Air Power.
- William Coley is a director of Peabody Energy Corporation which declared voluntary Chapter 11 bankruptcy protection in April 2016 for most of its U.S. entities and is currently restructuring. As of April 13, 2017, Mr. Coley is no longer a director of the entity.

AUDIT AND RISK COMMITTEE INFORMATION

NI 52-110 has been implemented by Canadian securities regulatory authorities to encourage reporting issuers to establish and maintain strong, effective, and independent audit committees, to enhance the quality of financial disclosure, and to foster increased investor confidence in Canada's capital markets. The Audit and Risk Committee's Charter is attached to this AIF as Appendix A. Information on OPG's Audit and Risk Committee is as follows:

Composition of the Audit and Risk Committee

As at March 8, 2018, the members of the Audit and Risk Committee were George Lewis (Chair), Elisabeth (Lisa) DeMarco, Ani Hotoyan-Joly, Wendy Kei, Yezdi Pavri and Gerry Phillips. All members are independent within the meaning of NI 52-110 and have experience in business and financial matters. Each member has an understanding of internal controls and procedures for financial reporting. As part of OPG's Continuing Education Program for Directors, Audit and Risk Committee members are provided with access to both internal and external educational resources, including seminars and courses, in order to maintain or enhance their financial literacy.

Activities of the Audit and Risk Committee

The Chartered Professional Accountants of Canada (CPA Canada) and the Canadian Public Accountability Board have recommended that audit committees perform a comprehensive review of the external audit firm at least once every five years. CPA Canada issued guidelines in early 2014 to assist audit committees in implementing these recommendations. The Audit and Finance Committee of the Board conducted its first comprehensive review of the Company's external auditor, Ernst & Young LLP (EY) in 2014, for the period from 2009 to 2013, using the guidelines and format recommended by CPA Canada. EY has been OPG's external auditor since the Company's inception in 1999. EY provides audit and audit related services to OPG, including the audit of OPG's annual consolidated financial statements, reviews of OPG's quarterly financial statements, and audits of the financial statements of OPG's consolidated subsidiaries and other financial information.

In conducting the 2017 review of EY's performance, the Audit and Risk Committee considered input from management, EY, and OPG's internal audit function. The Committee performed this review taking into consideration the information submitted by these parties, as well as their individual experience. The results of the 2017 annual review were discussed at the Audit and Risk Committee meeting in August 2017. As part of the review, the Committee considered factors such as the auditor's independence, engagement team quality including the Committee's involvement in the selection of EY's lead engagement partner, and communication effectiveness between EY and OPG. Upon completion of the review, the Committee was satisfied with the performance of EY, concluded that their reappointment was in the best interests of OPG, and, in November 2017, recommended that the Board reappoint EY as the Company's auditor for the 2018 fiscal year. The Board reappointed EY as the Company's auditor for the 2018 fiscal year in November 2017.

External Auditor Service Fees [UPDATE]

The following fees were accrued by EY:

(thousands of dollars)	**2017**	**2016**
Audit fees		1,959
Audit-related fees		554
All other fees [1]		17

[1] Comprised of fees related to the subscription of an online accounting research tool and training.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Relationship with the Province and the OEFC

Relationship with the Shareholder

As a corporation created under and governed by the OBCA, OPG's management is supervised by its Board of Directors, which is obligated by law to act in the best interests of the Company. The Company's sole Shareholder, the Province, owns all of the Company's issued and outstanding common shares and thereby has the power to determine the composition of the Company's Board of Directors.

As one of several wholly-owned government business enterprises of the Province, OPG has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

Memorandum of Agreement

On August 17, 2005, OPG entered into the MOA with the Shareholder regarding OPG's role and responsibility as a power producer in Ontario. In July 2015, the MOA was revised. The MOA serves as the basis of agreement between OPG and the Shareholder regarding OPG's mandate, governance, performance, reporting and communications, and establishes the accountabilities between OPG and the Province. OPG's strategic imperatives are based on the Company's mandate as set out in the MOA. The MOA was reaffirmed for continuance by both the Ontario Minister of Energy and the OPG Board of Directors' Chair in the fourth quarter of 2016, as required by the MOA following a change in the Minister of Energy.

A copy of the MOA can be found on the Company's website at www.opg.com. ***Unless otherwise specifically stated, none of the information contained on, or connected to the Company's website nor any of the contents of the MOA are incorporated by reference herein.***

Shareholder Directives

The Shareholder may at times direct OPG to undertake special initiatives. A Shareholder directive is issued when the Shareholder finds it necessary to assume decision-making power and authority over certain aspects of the business operations of the Corporation. Under a Shareholder directive, the Shareholder assumes all the rights, powers, duties and liabilities of the Directors to manage or supervise the management of the business and the Directors are relieved of their duties and liabilities. Shareholder directives are communicated as written pursuant to section 108 of the OBCA. Copies of each Shareholder directive can be found on the Company's website at www.opg.com. ***Unless otherwise specifically stated, none of the information contained on, or connected to the Company's website nor any of the contents of the Shareholder directives are incorporated by reference herein.*** The Shareholder directives issued by the Shareholder to date are listed below in reverse chronological order:

- Sale of the Corporation's Lakeview site (June 9, 2016);
- Sale of the Corporation's Head Office (December 14, 2015);
- Bruce Power L.P. Lease Agreement and Used Fuel Agreement (November 30, 2015) – For further details, see *General Development of Business – Nuclear Business Development – Bruce Power Refurbishment and Bruce Lease Agreement*;
- Bruce Power L.P. Amended and Restated Heavy Water and Associated Services Agreement (November 30, 2015) – For further details, see *General Development of Business – Nuclear Business Development – Bruce Power Refurbishment and Bruce Lease Agreement*;
- Conversion of One Unit of Thunder Bay Generating Station to Advanced Biomass (May 1, 2014);
- Thunder Bay Generating Station Conversion (December 16, 2013);
- Early Closure of Ontario Power Generation's Lambton and Nanticoke Coal-Fired Generation Stations (March 7, 2013);
- First Nation Directive (April 1, 2011) – OPG was directed to pay a part of the Shareholder's portion of the settlement liability with a First Nation on its behalf;
- Atikokan Generating Station Conversion (March 8, 2011);
- Addressing Carbon Dioxide Emissions from the Use of Coal at Coal-Fired Generating Stations (May 20, 2010);
- Request for Indicative Prices for the Supply of Wood Pellet Fuel Declaration (Atikokan) (March 18, 2010);

- Request for Expressions of Interest for Supply and Transportation of Solid Biomass Fuel Declaration (January 13, 2009);
- Addressing Carbon Dioxide Emissions from the Use of Coal at Coal-Fired Generating Stations (May 15, 2008);
- Thunder Bay Gas Conversion Cancellation (July 12, 2006);
- Nuclear Directive (June 16, 2006) – OPG was directed to begin feasibility studies on refurbishing existing nuclear units, an environmental assessment on refurbishing Pickering B units, and federal approvals processes (including environmental assessment) for new nuclear units;
- Lower Mattagami River Agreement (May 23, 2006);
- Bruce Power Lease Agreement (October 14, 2005); and
- Thunder Bay Gas Conversion Declaration (October 6, 2005).

Ontario Nuclear Funds Agreement

The ONFA between OPG and the Province sets out the responsibility for funding the liabilities for the decommissioning of OPG's nuclear facilities and the long-term management of OPG's used nuclear fuel and other nuclear waste. Pursuant to the ONFA, the Company has established a Used Fuel Segregated Fund and a Decommissioning Segregated Fund to fund the future costs of these activities. Additional details can be found in the section, *Description of the Business* under the heading, *Regulated – Nuclear Waste Management Segment – Funding Mechanisms*.

OPG Debt Held by the OEFC

OPG's long-term debt has been financed predominantly by the OEFC. As at December 31, 2017, the OEFC held approximately $3.2 billion of OPG's long-term debt with maturities ranging from one month to 30 years. For additional details, see Note 6 to the Company's audited annual financial statements as at and for the year ended December 31, 2017.

Payments-In-Lieu of Corporate Income Taxes and Property Taxes

OPG and its wholly-owned subsidiaries are exempt from tax under the *Income Tax Act* (Canada) and *Taxation Act, 2007* (Ontario). However, under the *Electricity Act, 1998*, OPG is required to make proxy tax payments to the OEFC. These payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by the *Electricity Act, 1998* and related regulations. This results in OPG paying taxes similar to those imposed under the federal and Ontario tax acts.

OPG is subject to income tax audits by the Ontario Ministry of Finance. As of the date of this AIF, income tax audits up to and including the 2013 taxation year have been completed.

The *Electricity Act, 1998* also provides that OPG and certain of its subsidiaries are required to make payments in lieu of property tax to the OEFC on their non-hydroelectric generating station buildings and structures. These payments generally equal the difference between property taxes that would be otherwise payable if these assets were privately owned, and the amount payable to municipalities in respect of these assets as determined under the *Assessment Act, 1990* (Ontario). As with other hydroelectric generators in Ontario, OPG's hydroelectric generation operations are not subject to payments in lieu of property taxes because they are subject to the GRC regime. Additional details on the GRC regime can be found in the section, *Description of the Business* under the heading, *Generation Operations – Hydroelectric (Regulated – Hydroelectric and Contracted Generation Portfolio segments)*.

Stranded Debt

One of the OEFC's purposes under the *Electricity Act, 1998* is to manage "stranded debt," which was not transferred to any of Ontario Hydro's successor entities. The *Electricity Act, 1998* defines stranded debt as the amount of the debt and other liabilities of the OEFC that, in the opinion of the Minister of Finance, cannot reasonably be serviced and retired in a competitive electricity market. Although OPG has no obligations in connection with the stranded debt, the *Electricity Act, 1998* does provide for participants in the electricity sector, including OPG, Hydro One, and the municipal electricity utilities, to make payments to the OEFC, which the OEFC uses in managing the debt and other obligations. These payments include proxy taxes, payments in lieu of tax, including property tax, the Debt Retirement Charge levied on certain electricity consumers, and certain amounts that may be payable by municipal electricity utilities on the transfer of their electricity business.

Commented [GH3]: Not sure if we need to note that Hydro One no longer pays PILs here, given this is OPG's AIF.

Commented [JK4]: If this refers to PILs, then the next change is not needed.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Legal Proceedings

OPG is potentially the subject of various legal proceedings and claims that arise in the ordinary course of business. The outcome of these proceedings and claims is uncertain. Based on information available as of the date of this AIF, management believes that none of the proceedings and claims, individually and in the aggregate, are expected to have a material impact on OPG.

British Energy Claim

On August 9, 2006, a Notice of Action and Statement of Claim filed with the Ontario Superior Court of Justice in the amount of $500 million was served against OPG and Bruce Power by British Energy Limited and British Energy International Holdings Limited (together British Energy). The action is for contribution and indemnity of any amounts British Energy was liable for in an arbitration against it by some of the owners of Bruce Power regarding an alleged breach of British Energy's representations and warranties to the claimants when they purchased British Energy's interest in Bruce Power (the Arbitration). Both the action and the Arbitration relate to corrosion to a steam generator unit discovered after OPG leased the Bruce nuclear generating stations to Bruce Power.

In 2012, the arbitrator found that British Energy was liable to the claimants for some of the damages they claimed. The final settlement amount was valued by British Energy at $71 million. In September 2014, British Energy amended its Statement of Claim (Amended Claim) to reduce the claim amount to $100 million to reflect that the purchasers of British Energy's interest in Bruce Power did not receive the full damages they originally claimed in the Arbitration. British Energy also added an allegation to its Amended Claim that OPG breached a covenant to maintain the steam generator between the time of the initial agreement to lease and the effective date of the lease in accordance with "Good Utility Practices".

In November 2016, British Energy obtained consent to a timetable for the remaining steps in the litigation, pursuant to which the matter must be set down for trial by December 31, 2018. OPG has delivered a statement of defence in accordance with an extension of the original June 30, 2017 delivery deadline set out in the timetable.

Regulatory Actions

OPG is not aware of any penalties or sanctions imposed by a court or securities regulatory authority or other regulatory body against the Company, nor has the Company entered into any settlement agreements before a court or with a securities regulatory authority.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business (unless otherwise required by applicable securities requirements to be disclosed), there were no material contracts entered into by the Company or

its subsidiaries during the most recently completed financial year, or before the most recently completed financial year that are still in effect.

INTERESTS OF EXPERTS

The external auditor of the Company is Ernst & Young LLP, Chartered Professional Accountants, 100 Adelaide Street West, P.O. Box 1, Toronto, Ontario M5H 0B3. Ernst & Young LLP has been the Company's auditors since OPG was formed in 1999, and is independent in accordance with the Rules of Professional Conduct of the Chartered Professional Accountants of Ontario.

GLOSSARY

ancillary service	a service necessary to maintain the reliability of the IESO-controlled grid.
availability	when used in reference to a generating unit, a measure of mechanical reliability represented by the percentage of time a generating unit is capable of providing service, whether or not it is actually in-service, relative to the total time for the period.
baseload facilities	electricity generation facilities that produce a constant supply of energy. In Ontario, baseload facilities are made up of nuclear, run-of-the-river hydroelectric and variable generation facilities such as wind and solar.
bilateral contract	a contract for the purchase and sale of notional electricity usually entered into directly between a generator and an end-user, or between a generator or end-user and a market intermediary.
biomass	plant material from agricultural and forest sources that can be used to produce energy, including beneficiated biomass, which includes torrefied, carbonized, and steam exploded biomass.
CANDU	an acronym for CANada Deuterium Uranium, a family of nuclear fission reactors developed in Canada which use pressurized heavy water coolant or deuterium oxide as a moderating agent and natural uranium (uranium dioxide) as fuel.
capacity factor	the ratio (usually specified as a percentage) of the amount of energy that a generating asset actually generated over a period of time divided by the amount of energy that the generating asset would have produced over the same period of time if it had operated continuously at full capacity.
decommissioning	actions taken in the interest of health, safety, security and protection of the environment to retire a facility permanently from service and render it to a predetermined end-state condition.
detritiation	the removal of tritium from heavy water.
deuterium oxide	see heavy water.
equivalent forced outage rate	the hours of unit failure given as a percentage of the total hours of the availability of that unit.
government business enterprises	Government organizations that are separate legal entities with the power to contract in their own name, have the financial and operating authority to carry on a business, are principally focused on the selling of goods and services to individuals and non-government organizations, and are able to maintain their operations and meet their obligations through revenues generated outside the government reporting entity.
heavy water (deuterium oxide)	water containing significantly more than the natural proportion of heavy hydrogen (deuterium) atoms to ordinary hydrogen atoms, used as a moderator in CANDU reactors.
in-service capacity	the portion of installed capacity (the highest level of output which a generating unit is designed to maintain indefinitely without damage to the unit) that has not been removed from service.

interconnection	a transmission line which carries power across the service area boundary of geographically adjacent jurisdictions.
kWh	a kilowatt hour, the commercial unit of electric energy (the amount of electricity consumed by ten 100 watt light bulbs burning for one hour).
load	the quantity of electricity consumption measured as either the energy consumed over a given period of time or the rate of energy consumption at a given time by a particular customer or group of customers.
MW	a megawatt, equal to 1,000,000 watts or 1,000 kilowatts.
MWh	a megawatt hour, equal to 1,000 kWh.
OEFC	an acronym for the Ontario Electricity Financial Corporation, the legal continuation of the former Ontario Hydro. The OEFC is responsible for managing the debt and certain other obligations not transferred to other successor companies of Ontario Hydro.
ONFA	an acronym for the Ontario Nuclear Funds Agreement between OPG and the Province that sets out the responsibility for funding the liabilities for the decommissioning of OPG's nuclear stations and the long-term management of OPG's used nuclear fuel and other nuclear waste.
Ontario NFWA Trust	a trust established by OPG pursuant to the *Nuclear Fuel Waste Act* (Canada) for the purpose of funding the implementation of Canada's long-term nuclear fuel waste management plan.
operating reserve	the capacity that can be called upon on short notice by the IESO to replace scheduled energy supply that is unavailable as a result of an unexpected outage or to augment scheduled energy as a result of unexpected demand or other contingencies.
reactive support	the control and maintenance of prescribed voltages on the IESO-controlled grid.
refurbishment	the work needed to extend the life of a reactor unit by replacing the major life-limiting components (such as pressure tubes, steam generators, etc).
Shareholder	the sole shareholder of OPG, the Province of Ontario.
surplus baseload generation	a condition that occurs when electricity generation from baseload facilities is greater than the electricity market demand.
tonne	1,000 kilograms or 2,204.6 pounds.
tritium	a radioactive substance that is created within CANDU reactors as a result of heavy water in the reactor moderator and heat transport systems.
TWh	a terawatt hour, equal to 1,000,000 MWh.
unit	an electrical generator, together with its driving turbine and auxiliary equipment.
watt	a scientific unit of electric power representing the rate of work of one joule per second.

APPENDIX A

ONTARIO POWER GENERATION INC.

AUDIT AND RISK COMMITTEE CHARTER

Audit and Risk Committee Charter

Purpose

The function and purpose of the Audit and Risk Committee is to assist the Board of Directors in their responsibility for oversight of matters relating to:

1. The integrity of OPG's financial statements and reporting
2. The integrity and adequacy of internal controls and standards of Codes of Conduct and ethics
3. The performance of OPG's internal audit function
4. The performance and independence of OPG's external auditors
5. Business and financial planning
6. The performance of OPG's pension, nuclear decommissioning, and used fuel investment funds
7. OPG's Enterprise Risk Management
8. Assessment of committee performance and board policies.

Management is responsible for the preparation, presentation and integrity of OPG's interim and annual financial statements and related disclosure documents. Management is responsible for maintaining appropriate accounting and financial reporting principles and policies and systems of internal and disclosure controls and procedures to comply with accounting standards and applicable laws and regulations which

provide reasonable assurance that the assets of the Company are safeguarded and transactions are authorized, executed, recorded and properly reported.

Management is also responsible for the identification, assessment, monitoring, and management of the risks to achieving OPG's strategic and business plan objectives and the development and implementation of policies and procedures to respond to such risks.

The Committee's role is to provide oversight that ensures the Company's assets are protected and safeguarded within reasonable business limits and report such to the Board.

Committee Responsibilities and Duties

The Committee shall perform the duties set out in this Charter and shall perform such other duties as may be necessary or appropriate under applicable law or securities rules, or as may be delegated to the Committee by the Board from time to time.

1. *The integrity of OPG's financial statements and reporting*

   The Committee reviews and makes recommendations to the Board with respect to:

   a) appointment or replacement of the Chief Financial Officer.

   b) OPG's annual financial statements and external audit report, including financial statements, MD&A, related footnotes and any documentation required by the Securities Act to be prepared and filed by OPG or that OPG otherwise files with securities regulators.

   c) OPG's Annual Information Form, if required, prior to filing with securities regulators.

   The Committee reviews and approves:

   d) OPG's quarterly financial statements and interim financial information and disclosures in the Management Discussion and Analysis (MD&A) and earnings press release, prior to filing.

   In carrying out its responsibilities for oversight of the integrity of OPG's financial statements and reporting the Committee will include in its review:

   e) Adequacy of procedures in place for the review of OPG's public disclosure of financial information extracted or derived from OPG's financial statements.

   f) significant accounting principles and reporting issues and impact on the financial statements, including complex or unusual transactions, highly judgmental areas, major issues regarding or changes to OPG's selection/application of accounting principles, financial presentations, the effect of regulatory and accounting initiatives, as well as off-balance sheet arrangements on OPG's financial statements.

   g) analysis prepared by Management and/or the external auditor detailing financial reporting issues and judgments made in connection with the preparation of financial information, including analysis of the effects of alternative generally accepted accounting principles methods.

   h) whether any other matters related to conduct have come to the Committee's attention that causes it to believe that the financial statements contain an untrue statement of material fact or omit to state a necessary material fact.

2. *Integrity and adequacy of Internal Controls and standards of Codes of Conduct and ethics*

In carrying out its responsibilities for the integrity and adequacy of internal controls, including compliance with legal and regulatory requirements and standards of codes of conduct and ethics, the Committee reviews:

a) legal, tax, or regulatory matters that may have a material impact on OPG's operations and the financial statements, including, but not limited to, violations of securities law or breaches of fiduciary duty.

b) the scope of review of internal control over financial reporting, significant findings, recommendations and Management's responses for implementation of actions to correct weaknesses in internal controls.

c) disclosures made by the Chief Executive Officer and Chief Financial Officer during the certification process regarding significant deficiencies in the design or operation of internal controls or any fraud that involves Management or other employees who have a significant role in OPG's internal controls.

d) procedures for the receipt, recording and treatment of complaints received by OPG regarding accounting, internal accounting controls, or auditing matters, and procedures for the confidential and anonymous submission by OPG employees of concerns regarding accounting or auditing matters.

e) expenses of the Board Chair, Board of Directors, President/CEO and the President/CEO's direct reports on an annual basis, and of any other senior officers and employees the Committee considers appropriate.

f) reports from the Chief Ethics Officer on independent reviews and investigations of fraud allegations, matters that may involve fraud and/or Codes of Conduct violations and compliance.

3. *Performance of OPG's internal audit function*

The Committee reviews and makes recommendations to the Board with respect to:

a) Appointment or replacement of the Chief Risk and Audit Executive.

The Committee reviews and approves:

b) The annual internal audit plan and all major changes to the plan, including the organizational structure, budget and the adequacy of resources.

c) the charter of the internal audit function triennially.

In carrying out its responsibilities for the performance of OPG's internal audit function the Committee reviews:

d) results of Internal audit reports, including: significant findings, the adequacy of the control processes, Management's response and the timetable for implementation of Management actions

to correct weaknesses, any difficulties encountered in the course of their work (such as restrictions on the scope of their work or access to information).

e) Internal Audit's confirmation of organizational independence and disclosure of any conflict of interest.

f) Internal Audit performance relative to the annual internal audit plan.

4. *Performance and Independence of External Auditor*

The Committee reviews and makes recommendations to the Board with respect to:

a) the external auditor to be annually appointed on behalf of the Shareholder and related compensation, including results of a cyclical performance review, and a comprehensive review of the external audit firm at least once every five years.

The Committee reviews and approves:

b) pre-approval of additional audit services and fees to be provided by the external auditors if such services are required further to the annual compensation approved by the Board. The Committee may delegate such pre-approval authority to the Committee Chair up to a limit of $250,000. Any decisions of the Committee Chair to whom pre-approval authority is delegated must be presented to the full Audit and Risk Committee at its next scheduled meeting.

In carrying out its responsibilities for the performance and independence of OPG's external audit function the Committee reviews:

c) the work and report of the external auditor engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for OPG, including the resolution of disagreements between Management and the external auditor regarding financial reporting.

d) the independence and qualifications of the external auditor.

e) the annual report by the external auditor describing the auditing firm's internal quality control procedures, any material issues raised by the most recent internal quality-control review or peer review of the auditing firm or by any inquiry or investigation by governmental or professional authorities within the preceding five years respecting one or more independent audits carried out

by the external auditor and any steps taken to deal with any such issues and all relationships between the external auditors and OPG.

f) scope and approach of the annual audit plan with the external auditors.

g) quality and acceptability of OPG's accounting principles including all critical accounting policies and practices used, any alternative treatments that have been discussed with Management as well as any other material communications with Management.

h) external auditor's process for identifying and responding to key audit and internal control risks.

i) rotation of the lead audit partner and other audit partners every seven years, and consider regular rotation of the audit firm.

j) all related-party transactions.

k) OPG's hiring policies regarding partners, employees and former partners and employees of the present and former external auditor of OPG.

5. *Business and Financial Planning*

The Committee reviews and makes recommendations to the Board on:

a) OPG's business plan, including overall financing plan in support of the Company's capital expenditures and medium – long term forecast.

b) OPG's rate applications to the Ontario Energy Board, including proposed payment amounts and any agreement arising from a Settlement Conference with intervenors.

c) corporate financing vehicles, credit facilities, including any plans to access capital debt markets and other related financing activities. The Board may delegate to an officer of the company authority to enter into such financing activities in such a manner as the Board shall determine at the time of

such delegation. Any decisions of the officer to whom authority is delegated must be presented to the full Audit and Risk Committee at its next scheduled meeting.

6. *Pension, Nuclear Decommissioning and Used Fuel Investment Funds*

The Committee reviews and makes recommendations to the Board on:

a) the appointment or replacement of the Chief Investment Officer.

b) the appointment of the auditor for the OPG Pension Fund and the Used Fuel Segregated Fund and Decommissioning Segregated Fund.

c) the broad objectives, governance frameworks and risk posture for the OPG Pension Fund and the Used Fuel Segregated Fund and Decommissioning Segregated Fund and annual status report on these Funds.

d) the tri-ennial valuation of the Pension Fund and annual valuation of the Supplementary Employee Retirement Pension Plans. (The Committee provides advice to the Compensation, Leadership and Governance Committee on the affordability of proposed pension benefit changes.)

The Committee reviews and approves:

e) the appointment of the members of OPG's Pension Committee. In addition, the Committee may, at any time, remove or replace any member of the Pension Committee or fill a vacancy on the Pension Committee. The Pension Committee Chair may temporarily appoint a senior management

employee to fill a vacancy on the Pension Committee until the next regularly scheduled Audit and Risk Committee meeting.

f) the annual audited financial statements for the OPG Pension Fund, the Used Fuel Segregated Fund and the Decommissioning Segregated Fund.

g) the investment policies and procedures, including the design of modifications, for the OPG Pension Fund, as required by the Ontario Pension Benefits Act and its regulations, and for the Decommissioning Segregated Funds, as required by the Ontario Nuclear Funds Agreement.

h) the appointment of the Pension Plan actuary.

In carrying out its responsibilities for the oversight of financial planning and investment funds the Committee reviews:

i) reports on a quarterly, annual or by exception basis, on compliance with and appropriateness of the asset mix policy; total fund and asset class returns relative to benchmarks; material compliance with breaches of policies or procedures; and work conducted by the plan actuary.

j) periodic reports on the calculation of OPG's nuclear waste liability.

7. *OPG's Enterprise Risk Management*

The Committee reviews and makes recommendations to the Board on:

a) the appointment or replacement of the Chief Risk and Audit Executive.

b) the Company's enterprise risk policy, framework, overall risk appetite and targets.

In carrying out its responsibilities for oversight of OPG's Enterprise Risk Management the Committee reviews:

c) the processes employed by Management for identifying and assessing the Company's principal risks.

d) periodic reports on Management's assessment of the principal risks to achieving the Company's strategic and business plan objectives, and the strategies for monitoring, managing and responding to those risks.

e) periodic reports on significant emerging and evolving risks and relevant external events that could potentially impact OPG's risk profile.

f) compliance metrics related to OPG's commercial operations trading, treasury, and fuels management.

g) regular reports on OPG's cyber security position and programs.

h) periodic reports on OPG's Insurance Program.

8. *Assessment of committee performance and board policies*

In carrying out its responsibilities for assessment of committee performance and board policies the Committee shall:

a) Review and assess Committee performance, including a review of the adequacy of and its compliance with this Charter, in accordance with the evaluation process approved by the Board and taking into account all legislative and regulatory requirements applicable to the Committee as well as any best practice guidelines recommended by regulators with whom OPG has a reporting relationship.

b) Provide oversight of the implementation of the following Board of Directors' policies, and review these policies at least annually (or as otherwise noted below) to ensure their continuing adequacy:

   i. Delegation and Exercise of Authority Policy
   ii. Disclosure Policy
   iii. Code of Business Conduct and Supplier Code of Conduct, including anti-bribery and corruption
   iv. Enterprise Risk Management Policy (reviewed every three years)
   v. Cyber Security Policy

c) Provide oversight of the development of any new policies deemed necessary by the Committee.

Organization

Members

The Audit and Risk Committee shall consist of three or more Directors as determined by the Board of Directors. All members of the Committee shall be independent as defined by the Ontario Securities Commission, and not "affiliated" with OPG.

The Board shall appoint the members of the Committee and the Chair of the Committee annually. The Board may appoint a member to fill a vacancy which occurs in the Committee between annual elections of Directors. Any member of the Committee may be removed or replaced at any time by the Board.

If a member of the Committee becomes "affiliated" with OPG, the member may continue as a member of the Committee with the approval of the Board Chair, in consultation with the Corporate Secretary.

As a "venture issuer", OPG is exempt from the statutory requirements of National Instrument 52-110 requiring members of Audit Committees be independent and financially literate. However, OPG considers such independence and financial literacy to be "best practice" and therefore each of the members of the Audit and Risk Committee shall satisfy the applicable independence and financial literacy requirements of the laws and regulations governing Audit Committees.

The Board of Directors shall confirm that each member of the Audit and Risk Committee is financially literate; as such qualification is interpreted by the Board of Directors in its business judgment, and in compliance with National Instrument 52-110 and its Companion Policy.

Meetings

The Committee shall meet as frequently as it determines but not less than quarterly. During quarterly meetings, the Committee will hold separate in camera sessions with the external auditors, the Chief Internal Audit Executive, the Chief Risk Officer and Management to discuss any matters that the Committee believes should be discussed and to provide a forum for any relevant issues to be raised.

Notice of the time and place of each meeting of the Committee must be given to each member of the Committee not less than 48 hours before the time of the meeting.

A quorum of the Committee shall be a majority of its members, but not less than two. The powers of the Committee may be exercised at a meeting at which a quorum of the Committee is present in person or by

telephone or other electronic means, or by a resolution signed by all members entitled to vote on that resolution at a meeting of the Committee. Each member is entitled to one vote in Committee proceedings.

The Chair shall preside at all meetings of the Committee at which he or she is present (or if not able to be present designate another member of the Committee to chair the meeting) and shall develop the agenda for each Committee meeting. The agenda for each meeting of the committee shall be delivered to each member of the Committee at least 48 hours prior to any meeting of the Committee, together with such other materials as the chair determines necessary.

Minutes shall be kept of all meetings of the Committee and shall be maintained by OPG's Corporate Secretary. The procedure at meetings is to be determined by the Committee unless otherwise determined by the by-laws of OPG, by a resolution of the Board or by this Charter.

The Committee may meet in camera (without management present) at any time during the meeting consistent with the Board guideline on the conduct of in camera sessions and the keeping of minutes from in camera sessions.

The Committee may invite any Director, officer or employee of OPG or OPG's counsel or any other person to attend meetings of the Committee to assist in the discussion and examination of the matters under consideration by the Committee.

Reports

The Committee will report its activities and actions to the Board of Directors with recommendations, as the Committee deems appropriate.

The Committee will provide for inclusion in OPG's financial information or regulatory filings any report from the Audit and Risk Committee required by applicable laws and regulations and stating among other things whether the Committee has:

i. Reviewed and discussed the audited financial statements with Management.
ii. Discussed pertinent matters with the internal and external auditors.
iii. Received disclosures from the external auditors regarding the auditors' independence and discussed with the auditors their independence.
iv. Recommended to the Board of Directors that the audited financial statements be included in OPG's Annual Report.

Authority

The Audit and Risk Committee shall have the authority to:

a) conduct or authorize investigations into any matters within the Committee's scope of responsibilities.

b) set and pay the compensation for any advisors employed by the Committee.

c) to communicate directly with the internal and external auditors.

While the Audit and Risk Committee has the responsibilities and powers set forth in this Charter, it is not the duty of the Audit and Risk Committee to plan or conduct audits or risk assessments, or to determine that OPG's financial statements and disclosures are complete and accurate and are in accordance with

generally accepted accounting principles and applicable rules and regulations. These are the responsibility of Management and, as appropriate, the external auditor.

Delegation of Authority

The Committee may not delegate its oversight responsibilities. The Committee may delegate to a sub-committee, the Chief Executive Officer or any employee of OPG the authority to exercise any right, power or responsibility that the Committee may have on such terms and conditions and within such limits as the Committee deems appropriate provided that the sub-committee, Chief Executive Officer or employee subsequently advises the Committee of any right, power or responsibility so exercised.

Access to Management and Outside Advisors

The Audit and Risk Committee shall have unrestricted access to members of Management and relevant information.

The Audit and Risk Committee has the authority to retain legal counsel, accountants or other advisors to assist it in the conduct of any investigation, as it determines necessary to carry out its duties.

From: Bruno Amara
To: Ronald Kwan
Cc: Gavin He
Subject: FW: OPG Revenue
Date: Friday, December 22, 2017 1:48:11 PM
Attachments: OPG 2017 Budget_20171222 (003).xlsx

Hi Ron

Sorry to bother you. See below Energy has requested our OPG 2017-18 Budget outlook. You may recall that we had earlier sent them information for 2018-19 and 2019-20. The context is the OEB decision. I don't think that having the budget numbers is central to impact analysis of the decision. But let us know if any concerns or questions.

Thanks
Bruno

From: Gavin He
Sent: Friday, December 22, 2017 11:55 AM
To: Bruno Amara <Bruno.Amara@ofina.on.ca>
Subject: RE: OPG Revenue

Hi Bruno,

Here's the updated OPG revenue table for Budget 2017, as requested by Energy. Are you good with this?

I saved it under below folder:

S:\Users\CEF\Hydro 2017\OEFC\RbP\Outlook\12. December\ENERGY Request

Regards,
Gavin He

From: Gavin He
Sent: Friday, December 22, 2017 10:00 AM
To: Bruno Amara <Bruno.Amara@ofina.on.ca>
Subject: FW: OPG Revenue

Hi Bruno,

Energy is asking for the same information for 2017-18, in addition to 2018-20.

And to his last question, I think the answer is yes, right? OPG BP is the base of the plan.

Regards,
Gavin He

From: Young, Graham (ENERGY) [mailto:Graham.Young@ontario.ca]
Sent: Friday, December 22, 2017 9:58 AM
To: Gavin He <Gavin.He@ofina.on.ca>
Subject: FW: OPG Revenue

Hi Gavin

One more question for you... I previously asked about assumptions for OPG revenue in 18/19 and 19/20.

Could you provide me the same numbers for 2017/18? I'm preparing a skeleton note for whenever OEB releases the OPG payments decision. Want to include these years as the decision could impact net income and we'll likely be asked what the fiscal plan assumes.

My biggest question is if net income is the same as the most recent business plan or if there were any adjustments.

Thank you
Graham

From: Gavin He [mailto:Gavin.He@ofina.on.ca]
Sent: November-29-17 2:08 PM
To: Young, Graham (ENERGY)
Cc: Talwar, Shruti (ENERGY)
Subject: RE: OPG Revenue

Hi Graham,

Sorry for the delay in getting back to you on this. Please find attached the requested information for OPG revenues.

Please let me know if you have any questions.

Regards,
Gavin He

From: Young, Graham (ENERGY) [mailto:Graham.Young@ontario.ca]

Sent: Thursday, November 23, 2017 9:41 AM
To: Gavin He <Gavin.He@ofina.on.ca>
Cc: Talwar, Shruti (ENERGY) <Shruti.Talwar@ontario.ca>
Subject: OPG Revenue

Hi Gavin,

Can you provide me with the OPG revenue numbers used in Budget 2017 for 2018/19 and 2019/20? I'm not able to pull them out of the document because they're aggregated up with other GBE's. Please include net income, GRC, property tax payable and income tax PILS if possible.

Thank you,

Graham Young
Senior Policy Advisor
Strategic Policy and Analytics Branch
Ontario Ministry of Energy
77 Grenville Street | Toronto, ON
(416) 327-7302 | graham.young@ontario.ca

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Budget 2017 Outlook for OPG

$ Millions	2017-18	2018-19	2019-20
Ontario Power Generation Inc.[1]	480	678	726
GA - OPG Interest Revenue from OPG Trust [2]	*17*	*54*	*99*
IFRS Adjustment[3]	(400)	-	(200)
Total OPG Net Income	**97**	**732**	**625**

1. From OPG's 2017-19 Business Plan. For 2017-18, it does not include impacts of OPG head office sale as these were reflected in sales and rentals line.

2. Note: Relates only to the portion financed by sub-debt related to the Province's equity injection into OPG. Values estimated by OFA based on an assumed fiscal neutrality between the Province's interest cost on the equity injection and higher OPG interest revenue related to the sub-debt related to the equity injection.

3. Note: IFRS Provincial consolidation adjustments provided by OPG were not fully reflected in Budget 2017, as determined at a centralised level during the fiscal plannning process. IFRS was fully picked up in 2016-17 and 2017-18 reflecting the higher degree of prudence included in the near term period. The out-year impacts, 2018-19 onwards will be assessed, pending receipt of revised IFRS consolidation adjustment estimates at the time of the next Budget and it is expected that these revised estimates will be reflected in the Province's income from OPG/Hydro One.

	2017-18	2018-19	2019-20
Payments-in-lieu of tax:			
Income Taxes[1]	92	135	170
GRC: Payable to OEFC[4]	205	212	218.5
Proxy Property Tax[1]	18	19	19
Total OPG PILs	**366**	**366**	**407.5**

1. From OPG's 2017-19 Business Plan. For 2017-18, it does not include impacts of OPG head office sale as these were reflected in sales and rentals line.

4. From OPG's 2015-17 Business Plan. OPG's 2017-19 BP included the total GRC number payable to OEFC and NPC, without the details. The breakdown information of the GRC payable to OEFC from OPG's 2015-17 BP was used for Budget 2017.

From: Gadi Mayman
To: Ronald Kwan
Cc: Usman Zahid; Anna Strathy; Mike Manning; Ken Kandeepan
Subject: FW: Rating Agencies views on Fair Hydro
Date: Thursday, April 19, 2018 12:31:36 PM

Hi Ron. The deal ended up coming at 107, which is 32 back of us. We should update our interest calculation based on this.

Thanks,
Gadi

From: Caridia, Alex [mailto:alex.caridia@rbccm.com]
Sent: Thursday, April 19, 2018 9:35 AM
To: Gadi Mayman <Gadi.Mayman@ofina.on.ca>
Subject: RE: Rating Agencies views on Fair Hydro

Hi Gadi – jus called you for an update on this. As you will have seen books are open at 110 +/-3bps

See that as Ont +35 and Toronto +13bps

Happy to chat more at your convenience

Alex

From: Caridia, Alex
Sent: April 19, 18 7:59 AM
To: Gadi Mayman
Subject: Re: Rating Agencies views on Fair Hydro

Hi Gadi

In short, that's true. Moody's action on Ontario will have no immediate effect on the ratings of FHT. Moody's rates FHT in line with the Province's rating, and has stated that any move on Ontario will also move their ratings on the FH program. However, under securitization methodology, rating directions are not used, so there is no current change on FHT, but if the Province is downgraded, FHT will also be downgraded.

On: 18 April 2018 21:59,
"Gadi Mayman" <Gadi.Mayman@ofina.on.ca> wrote:

Thanks, Alex. I was told that structured finance ratings don't have negative outlooks; the rating is simply the rating, so Moody's putting us on negative outlook doesn't immediately affect their rating of the FHT. It's only if we were to

get downgraded that they would also downgrade FHT. Seems weird to me, but that's what I was told, and given that you've proceeded with the FHT transaction, I assume it's true?

From: Caridia, Alex <alex.caridia@rbccm.com>
Sent: Wednesday, April 18, 2018 5:30:32 PM
To: Gadi Mayman
Subject: Fwd: Rating Agencies views on Fair Hydro

Hi Gadi - FYI

Begin Forwarded Message:
From: "Laham, Chris" <chris.laham@rbccm.com<mailto:chris.laham@rbccm.com>>
Subject: Rating Agencies views on Fair Hydro
Date: 18 April 2018 15:51
To: "+DS-GM-Bond Sales Desk" <DS-GM-BondSalesDesk@rbc.com<mailto:DS-GM-BondSalesDesk@rbc.com>>

Here are some bullet points outlining how each agency views Fair Hydro Trust in the context of the ratings of the Province.
The key point being, Moody's assumes at some point over the horizon of the program the Province will step in, thus linking the ratings. As a reminder, if this were to happen, the Province will assume the debt.

Here is Ian's outline for those that want a deeper dive:

DBRS

* Look at the transaction through a structured finance lens
* Change of law that could invoke a Protection Event is mitigated by the risk the FHT platform would become a liability of the Province, legislation took a long time to draft and pass, adverse change of law could bring into question other Provincial guarantee arrangements
* Significant enhancement (almost 100%) supports the senior notes, as does true-up mechanism, non-bypassability of recovery charge
* Amount of recovery charge is small as a percentage of the overall electricity user bill

Moody's

* The program as structured and under current law and regulations is considered to be of similar credit quality to US utility cost recovery programs rated by Moody's
* However, the FHT program's 30-year term, combined with the pervasive role of the Province and its related entities in many aspects of this transaction, increase the risk that the Province could make future changes to the law or related regulations that could adversely affect the outstanding obligations under the FHT program
* The Provincial guarantee is a mitigant to this risk, but it is not as robust as the constitutional protection found in similar US programs. Accordingly, Moody's has linked the provisional ratings of the notes to the Aa2 rating of the Province
* Future changes to the Province's rating will result in similar changes to the ratings of the notes.

Ian Benaiah | Director, Securitization Finance | RBC Capital Markets | TEL: 416.842.3820 | FAX: 416.842.3888 | ian.benaiah@rbccm.com<mailto:ian.benaiah@rbccm.com>

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From:	Lewis, Brian (MOF)
To:	Ronald Kwan
Subject:	FW: Statement from Minister Thibeault on the Ontario Energy Board"s New Regulated Price Plan Electricity Rate Announcement
Date:	Thursday, June 22, 2017 4:55:01 PM

Hi Ron,

Does this have an impact on the OPG net income outlook?

Brian

From: Ontario News [mailto:newsroom@ontario.ca]
Sent: June 22, 2017 12:26 PM
To: Lewis, Brian (MOF)
Subject: Statement from Minister Thibeault on the Ontario Energy Board's New Regulated Price Plan Electricity Rate Announcement

Ontario Newsroom

Statement

Statement from Minister Thibeault on the Ontario Energy Board's New Regulated Price Plan Electricity Rate Announcement[news.ontario.ca]

June 22, 2017

Today, Glenn Thibeault, Minister of Energy, issued the following statement in response to the Ontario Energy Board's (OEB) announcement to lower electricity prices for residential and small business customers on the Regulated Price Plan (RPP):

“Premier Wynne committed to reducing electricity bills by 25 per cent on average for households across the province, and today represents the next stage in the implementation of Ontario’s Fair Hydro Plan.

The Ontario Energy Board Regulated Price Plan announcement means that the average 25 per cent reduction will be in place effective July 1 for all households in Ontario, providing real and significant relief on hydro costs. As many as half a million small businesses and farms will also benefit. The 25 per cent includes the eight per cent rebate, equal to the provincial portion of the HST that took effect on January 1, 2017. Our plan also holds any increases in electricity bills to the rate of inflation for four years.

Low-income Ontarians and those living in eligible rural or remote communities will receive even greater reductions, as much as 40 to 50 per cent on their bills through the already expanded Ontario Electricity Support Program and the broadening of the Rural or Remote Rate Protection program, while the delivery charge portion of residential electricity bills will be removed for on-reserve First Nations communities.

The OEB will continue to serve in its important role, which includes establishing reasonable rates and protecting energy consumers, while also ensuring proper investments are made to maintain long-term system reliability. Ontario's 2017 Long-Term Energy Plan, to be released later this summer, will focus on taking additional costs out of the system, and address long-term affordability.

Our government committed to providing significant and real relief on hydro bills for people across Ontario, and we have delivered on this pledge."

CONTACTS

Colin Nekolaichuk
Minister's Office
416-325-2690
Colin.Nekolaichuk@ontario.ca

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Ministry of Energy
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From:	Gavin He
To:	Ronald Kwan
Subject:	FW: Statement from the Minister of Energy on the Ontario Energy Board"s New Regulated Price Plan (RPP) Electricity Rate Announcement
Date:	Thursday, April 20, 2017 6:27:42 PM

Hi Ron,

FYI.

Regards,
Gavin He

From: Shajee Kathirgamanathan
Sent: Thursday, April 20, 2017 6:26 PM
To: Gavin He <Gavin.He@ofina.on.ca>; Salman Qadir <Salman.Qadir@ofina.on.ca>; Adam Prokop <Adam.Prokop@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>
Subject: FW: Statement from the Minister of Energy on the Ontario Energy Board's New Regulated Price Plan (RPP) Electricity Rate Announcement

…and the Ministers announcement on the RPP rates

Shajee Kathirgamanathan
Office: 416-325-1402 | Mobile: 647-294-3359
shajee.kathirgamanathan@ofina.on.ca

Feed: Government of Ontario News - Energy: News
Posted on: Thursday, April 20, 2017 6:44 PM
Author: newsroom@ontario.ca (Ministry of Energy)
Subject: Statement from the Minister of Energy on the Ontario Energy Board's New Regulated Price Plan (RPP) Electricity Rate Announcement

Today, Glenn Thibeault, Minister of Energy, issued the following statement in response to OEB's plan to lower electricity costs for residents and small business customers on the Regulated Price Plan:

View article...

From:	Lewis, Brian (MOF)
To:	Ronald Kwan
Subject:	FW: Statement from the Minister of Energy on the Ontario Energy Board"s New Regulated Price Plan (RPP) Electricity Rate Announcement
Date:	Thursday, April 20, 2017 6:43:31 PM

I almost hate to ask…. But… does this represent a downside risk to the OPG net income forecast we are carrying?

From: Ontario News [mailto:newsroom@ontario.ca]
Sent: April-20-17 5:46 PM
To: Lewis, Brian (MOF)
Subject: Statement from the Minister of Energy on the Ontario Energy Board's New Regulated Price Plan (RPP) Electricity Rate Announcement

Statement

Statement from the Minister of Energy on the Ontario Energy Board's New Regulated Price Plan (RPP) Electricity Rate Announcement[news.ontario.ca]

April 20, 2017

Today, Glenn Thibeault, Minister of Energy, issued the following statement in response to OEB's plan to lower electricity costs for residents and small business customers on the Regulated Price Plan:

"In March, our government committed to reducing hydro rates by 25 per cent on average for all households that pay for electricity across the province. This includes the eight per cent rebate equal to the provincial portion of the HST that took effect on January 1, 2017.

Today's Ontario Energy Board (OEB) Regulated Price Plan (RPP) announcement includes a portion of this reduction, meaning residential households and as many as half a million small businesses and farms will see real savings sooner than expected.

This is an important first step to deliver on our government's commitment to lower rates by 25 per cent on average by this summer. Rates will also be held to inflation for the next four years. This is the largest rate cut in Ontario history.

Our government intends to introduce legislation that would, if passed, provide real relief for Ontarians and greater fairness in our electricity system. With the anticipated implementation of our government's proposed legislation, the OEB would be required to lower rates again this summer to fulfill our pledge to cut electricity bills for all residential consumers by 25 per cent on average and reduce rates for families in rural or remote areas of the province up to 40 to 50 per cent.

Premier Wynne committed to providing significant and real relief on hydro bills for people across Ontario, and our government is delivering on this pledge."

CONTACTS

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From:	Usman Zahid
To:	John Kim
Cc:	Ronald Kwan
Subject:	FW: sensitive Fair Hydro Trust question
Date:	Friday, April 27, 2018 3:25:36 PM

Hi John,

Please see question from Energy below.

Regards,
Usman

From: Pichette, Marc (MOF) [mailto:Marc.Pichette@ontario.ca]
Sent: Friday, April 27, 2018 1:32 PM
To: Usman Zahid <Usman.Zahid@ofina.on.ca>
Subject: FW: sensitive Fair Hydro Trust question

Hi Usman, please see question below from the Ministry of Energy that was sent to my director.

From: Whytock, John (ENERGY) <John.Whytock@ontario.ca>
Date: Thursday, Apr 26, 2018, 4:45 PM
To: LeBlanc, Jenna (MOF) <Jenna.LeBlanc@ontario.ca>
Subject: FW: sensitive Fair Hydro Trust question

Hi Jenna. I've got a sensitive question for you. Our MO asked what the revenue implications of the Fair Hydro Trust were for OPG, and how much we estimated would return to the provincial coffers.

As you'll see below, OPG has put a number on their own expected revenues, but my policy folks were not in a position to say what it could mean for returns to government.

Is this a number that Finance can produce? More importantly, are you willing to share?

Thanks much

jw

From: ROWE Jennifer -CORPAFFAIRS [mailto:jennifer.rowe@opg.com]
Sent: April-23-18 10:19 AM
To: Whytock, John (ENERGY)
Cc: KELLY Neal -CORPCOMM
Subject: RE: EXTERNAL – Fair Hydro Trust question

John,

Here's a simplified version of what I just sent you:

The total amount of income that OPG expects to earn over the life of the Fair Hydro Plan is in the range of **$4.5 Billion to $4.9 Billion.** The actual amount will vary based on the actual debt issued and interest rates.

This is over a period of 30 years (2017 to 2047). The income will be earned gradually, and will peak around 2029/2030.

Since the Province owns OPG, and consolidates OPG into their books, the net income flows back to the Province.

Jennifer

From: LADAK Lubna -TREASURY
Sent: Monday, April 23, 2018 10:14 AM
To: ROWE Jennifer -CORPAFFAIRS <jennifer.rowe@opg.com>; KELLY Neal -CORPCOMM <neal.kelly@opg.com>; HARTWICK Ken -FINANCE <ken.hartwick@opg.com>
Cc: LEE John -TREASURY <john.s.lee@opg.com>; LIU Sheen -TREASURY <sheen.liu@opg.com>; LAURETA LAPIRA May -TREASURY <may.lapira@opg.com>
Subject: RE: EXTERNAL – Fair Hydro Trust question

The total amount of income that OPG expects to earn over the life of the Fair Hydro Plan is in the range of $4.5 Billion to $4.9 Billion.
It is comprised of about $200 M for management fees and $4.3 Billion to $4.7 Billion of interest income.

The actual amount will vary based on the actual debt issued and interest rates.

This is over a period of 30 years (2017 to 2047). The income will be earned gradually, and will peak around 2029/2030.

Since the Province owns OPG, and consolidates OPG into their books, the net income flows back to the Province.

FYI – I don't know how the Province funds the equity injections. If they borrow the funds, the overall net income impact in their books could be lower. I wouldn't get into this though.

Lubna Ladak | VP Treasury - FHP| Ontario Power Generation
700 University Avenue, Toronto, Ontario M5G 1X6 | 416-592-5984 | Cell 416-578-0219 | Fax 416-592-4189

lubna.ladak@opg.com

From:	Ronald Kwan
To:	John Kim; Francisco Chinchon; Bruno Amara
Cc:	Gavin He
Subject:	Fw: OPG BP Submission
Date:	Wednesday, April 26, 2017 4:33:49 PM
Attachments:	2017 04 25 EIGS OPG Business Plan v08.docx 2017 04 25 OPG Business Plan Review v12.pptx 2017 04 11 TBMBC - Approval Form.xls 2017 04 26 OPG concurrence letter v9.docx

Hi,

Comments?

Ron

From: Nelms, Scott (MOF) <Scott.Nelms@ontario.ca>
Sent: April 26, 2017 4:06 PM
To: Nancy Kennedy (MOHLTC); Ronald Kwan
Cc: Vivienne Skoberne (MOHLTC); Montgomery, Kaitlin (MOF)
Subject: OPG BP Submission

Hi Nancy, Ron,

Please see the attached OPG BP package and draft concurrence letter. This has been shared with ENE DMO / MO. Ron, I think you were planning to share up with MoF on our side.

Thanks,
Scott

MINISTRY OF ENERGY

TREASURY BOARD / MANAGEMENT BOARD of CABINET SUBMISSION

ONTARIO POWER GENERATION (OPG) 2017-19 BUSINESS PLAN AND SPECIAL STATUS APPLICATION

May 2017

CONFIDENTIAL

MINISTRY OF ENERGY

ONTARIO POWER GENERATION (OPG)
2017-19 BUSINESS PLAN AND SPECIAL STATUS APPLICATION

MINISTRY REQUEST

The Ministry of ENERGY is requesting that Treasury Board/Management Board of Cabinet (TB/MBC):

1. NOTE the receipt of OPG's 2017-2019 Business Plan.
2. NOTE that the Minister of Energy will provide concurrence with OPG's Business Plan.
3. APPROVE OPG's application for Special Status to Approve International Travel under Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive dated January 1, 2017.

CONTEXT

- As required by the Memorandum of Agreement (MOA) between Ontario Power Generation and the Minister of Energy, OPG provided its Business Plan for 2017-2019 to the Ministry of Energy on November 29, 2016 for concurrence
    - Note that while OPG is seeking concurrence for its three year 2017-19 business plan, the plan also includes financial projections for 2020 and 2021
- With this Business Plan OPG is also making an application for Special Status under the Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive, which allows agencies/organizations, for which international travel may be integral to their business, to seek TB/MBC approval for special status to ensure that the approval process does not have an undue negative effect on its ability to conduct business
- The Minister's concurrence requires presentation of OPG's business plan before TB/MBC
- The Ministry of Energy review and analysis of OPG's business plan is supported by the Electricity Investment and Governance Secretariat, a unit within the Ministry of Finance and the Corporate and Electricity Finance Division of the Ontario Financing Authority (OFA)
- The following provides an overview of OPG's business plan, including:
    1. Business Plan Overview
    2. Other Considerations
- Proceeding with Provincial concurrence now will demonstrate that OPG has support from its shareholder as it implements the plan and provides clarity to

the Ontario Energy Board (OEB) as it reviews OPG's current rate application covering the 2017-2021 period

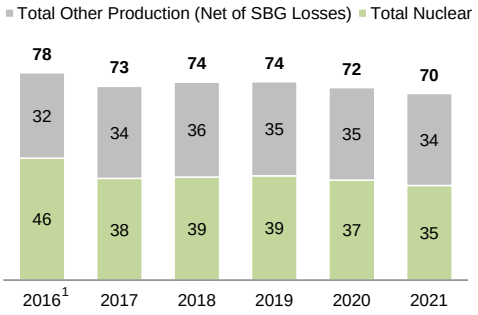
- Business plan forecasts may be affected by Ontario's Fair Hydro Plan (OFHP). Given the stage of implementation of OFHP and the timing of the receipt of the business plan in November 2016, these changes are not reflected in OPG's plan
    - The Ministry anticipates that as part of supporting the financing and administration of the global adjustment smoothing mechanism, OPG would purchase the right to future cash flows from IESO, financed partly by capital infusions from the Province, and majority by third-party lending
    - These changes are generally expected to be fiscally neutral as they would result in an increase in Provincial interest on debt, offset by increases in OPG net income
    - In addition, the Province's net debt position would remain unchanged

1. BUSINESS PLAN OVERVIEW

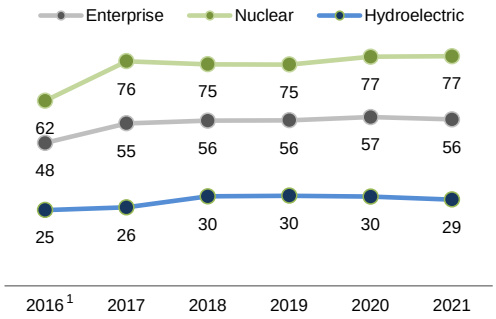
a) Production & Total Cost of Generation

- OPG's production is expected to fall to 69.8 TWh by 2021 from 77.6 TWh in 2016
    - Reflects a declining trend in the Darlington production due to refurbishment outages starting in October 2016
    - Includes a partial overlap starting in 2021 between second and third unit refurbishments, and
    - Includes the Pickering Vacuum Building Outage (VBO) in 2021 requiring the shutdown of all units for the duration of the outage
- While OM&A remains relatively stable over the planning period (see next slide), total generating cost (TGC)* shows an increasing trend over the planning period relative to 2016, reflecting:
    - Lower nuclear production due to Darlington refurbishment outages, and
    - Increased sustaining capital spending (included in TGC) on two large hydroelectric projects, the Lower Mattagami dam safety upgrade and the Sir Adam Beck I GS power canal liner rehabilitation

Production (TWh)



Total Generating Cost ($/MWh)



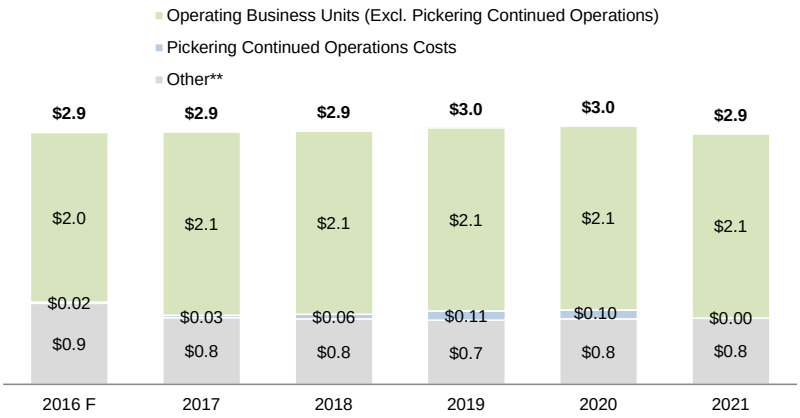
1. Actuals

*TGC = operations, maintenance and administration (OM&A) expenses from ongoing operations + fuel and Gross Revenue Charge expenses for OPG-operated stations + sustaining capital expenditures) divided by OPG generation adjusted for surplus baseload generation losses

b) Operations, Maintenance and Administration (OM&A) Expenses

- Annual OM&A expenses from ongoing operations are expected to stay consistent over the plan period, averaging $2.9B per year
- Increases over 2016 are mainly attributable to:
    - Increases in business unit expenditures, including changes in nuclear outage scope at Darlington, and planned hiring to fill staffing gaps
    - Incremental outage and other program costs to enable Pickering continued operations
- These increases are partially offset by declining pension and Other Post-Employment Benefits (OPEB) costs over the period due to projected pension asset returns, increased employee contributions, and adoption of a new method for applying discount rates to determine interest components of pension costs

OM&A from Ongoing Operations* ($B)



*Excludes Darlington refurbishment OM&A expenses and all OEB variance and deferral account offsets

** Includes centrally held pension /OPEB costs and support services

c) Financials

- OPG is forecasting net income attributable to the Shareholder to reach $1B in 2021, from $436M in 2016
    - 2017 net income is forecast to increase as a result of new regulated rates, higher capitalized interest for the Darlington Refurbishment expenditures partially offset by reduced production as a result of planned outages at Sir Adam Beck I and DeCew II hydro stations
    - Net income in 2018 and 2019 is planned to increase, primarily due to higher forecast production, and earnings from Peter Sutherland Sr. GS starting in 2017 and Nanticoke solar facility starting in 2019
- As a result, return-on-equity (ROE) is estimated to increase from 4.2% in 2016 to 7.3% by 2021
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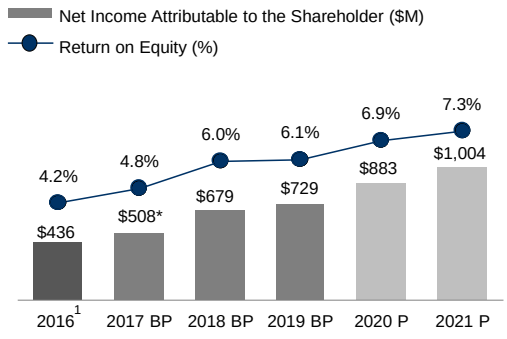
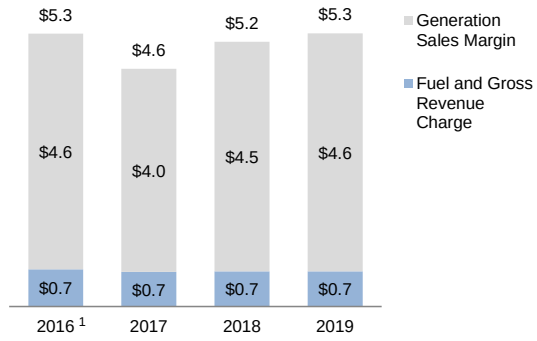
Net Income ($M) and ROE (%)



Revenue Margin ($B)



1. Actuals

*Includes extraordinary gain associated with the sale of OPG head office

d) Provincial Fiscal Impacts: Shareholder Return and Payments-in-Lieu of Taxes

- Total fiscal revenue impacts to the Province, including net income return to the shareholder and payments-in-lieu of taxes, averages ~$1B over the period
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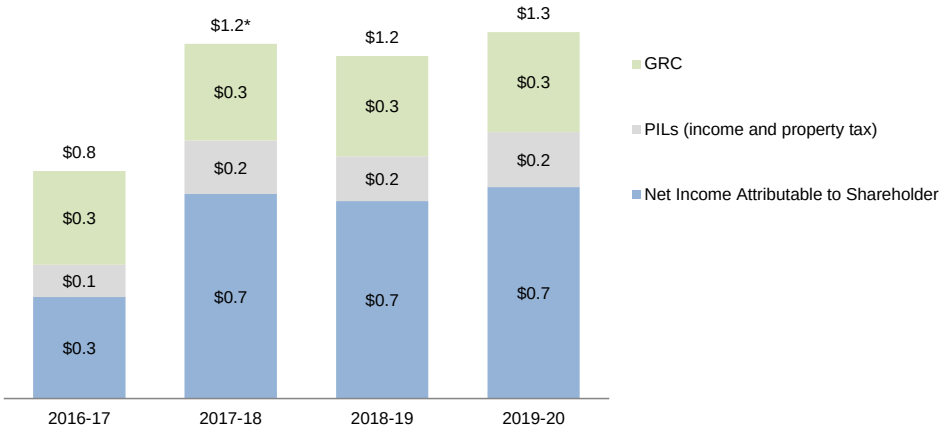
Total Fiscal Revenues ($B)



1. Aside from the water power rental portion of the GRC, paid to the CRF.

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- As part of a company-wide business transformation, OPG saved over $1B in costs from January 2011 to December 2016
    - Headcount has fallen from 11,686 in 2010 to a forecasted 9,009 in 2016 while GWh per headcount has increased from 7.6 to 9.3
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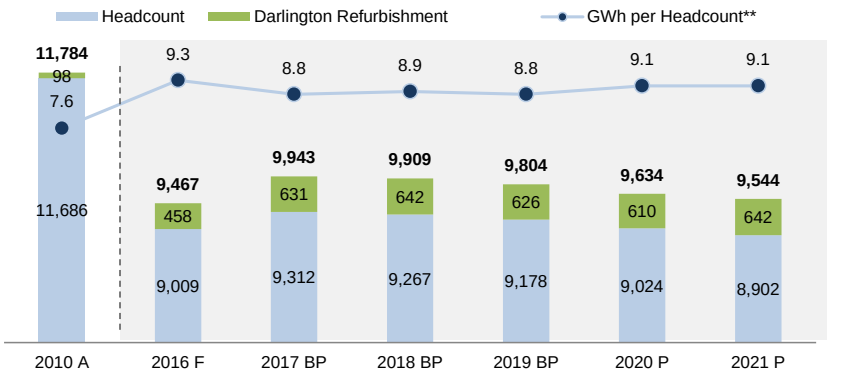
Ongoing Operations Regular Headcount and Productivity



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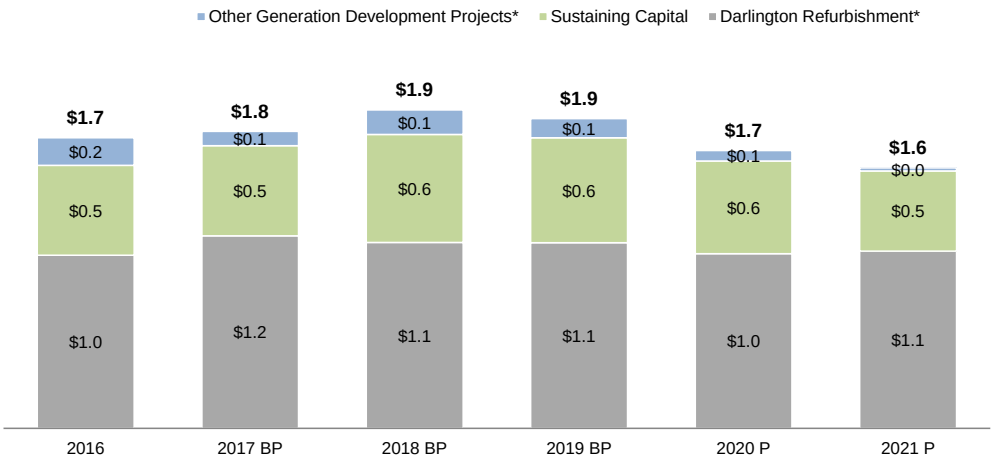
Capital Expenditure Estimates ($B)



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- OPG's 2017-19 Business Plan is dependent on the outcome of its rate filing with the OEB for the five-year period from 2017-2021
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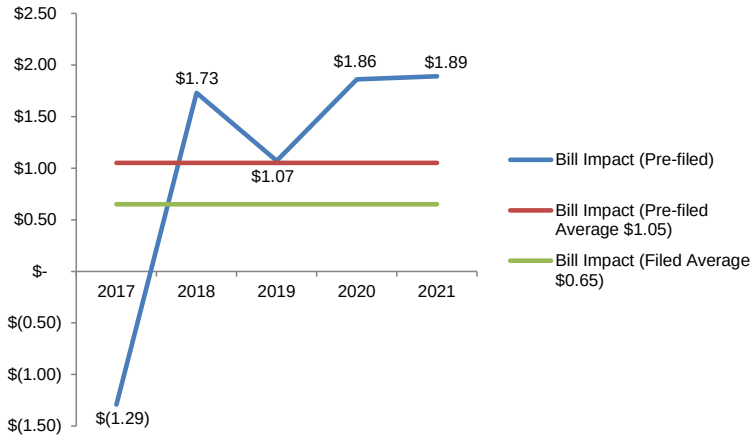
Comparison of Annual Bill Impact ($/Month per year)



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Sales

	OPG Head Office	R.L. Hearn Site	Lakeview Site
Current Status	Completed	Agreement Reached	OPG and Infrastructure Ontario are preparing for marketing
Site Description	700 University Ave. and parking garage at 40 Murray St. in Toronto	~33 acres at the R.L. Hearn site in Toronto	~67 acres to be transferred by the purchaser to the City of Mississauga (Municipal Park Lands) and ~110 acres to be developed for mixed uses (Uplands)
Buyer	KingSett Canadian Real Estate Income Fund LP	Studios of America Limited Partner	TBD
Value	Estimated up-front 2017-18 fiscal impact of ~$375M (includes after-tax gain as well as PILs to OEFC)	TBD	TBD
Other Considerations	N/A	N/A	Negotiations with the City have been lengthy and costs to remediate/prepare site may be significant due to concerns regarding site condition
Timing	The sale closed in April 2017	Anticipated to close in Q3 2017	Marketing is planned to start in April 2017, pending negotiations with the City, with an anticipated closing in 2017

Special Status for OPG to Approve International Travel

- On January 24, 2017, OPG's President and CEO wrote to the Deputy Minister to provide a business case and request authority for OPG to approve international travel for its employees. In summary:
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- OPG believes that international travel is integral to the safe and prudent operation of its business and having OPG's CEO approve international travel will enable more efficient decision-making while significantly lowering travel costs
- OPG cites the importance of enabling its engagement with the international community (in particular in regards to nuclear safety), procurement activities, and investment and due diligence processes for over $30 billion in pension fund and nuclear funds
- OPG requires a high level of international business travel at approximately 90-100 trips annually, while the Darlington Refurbishment Project accounts for 45% of OPG's international travel and is expected see increases over the 10 year life of the project
- OPG indicated that the approval process, which took 23 days on average in 2016, delays flight bookings which results in higher costs as airlines raise fares closer to the travel date
- OPG believes the inability to make timely commitments on events and meetings impacts employee engagement as well as its international relationships and reputation

- OPG is seeking Special Status as part of concurrence with its business plan. OPG has committed to providing semi-annual reports to the Ministry on international travel taken, and continue to be accountable for compliance with all applicable OPS directives, policies and procedures

RECOMMENDATION

The Ministry of ENERGY is requesting that Treasury Board/Management Board of Cabinet (TB/MBC):

1. NOTE the receipt of OPG's 2017-2019 Business Plan.
2. NOTE that the Minister of Energy will provide concurrence with OPG's Business Plan.
3. APPROVE OPG's application for Special Status to Approve International Travel under Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive dated January 1, 2017.

APPENDIX

OPG 2016 Year-End Financials

OPG Balance Sheet as at Dec 31 $B	2016
Assets	
Cash and cash equivalents	0.2
Available-for-sale securities	0.2
Receivables from related parties	0.4
Nuclear fixed asset removal and nuclear waste management funds	0.02
Other current assets	0.9
Total current assets	**$1.7**
Net property, plant and equipment	**$20.0**
Net intangible assets	**$0.1**
Nuclear fixed asset removal and nuclear waste management funds	16.0
Regulatory assets	5.9
Other long-term assets	0.7
Other assets	**$22.5**
Total assets	**$44.4**
Liabilities	
Accounts payable and accrued charges	1.2
Short-term debt and long-term debt due within one year	1.1
Income taxes payable and other current liabilities	0.1
Total current liabilities	**$2.4**
Long-term debt	4.4
Fixed asset removal and nuclear waste management liabilities	19.5
Pension liabilities	3.0
Other post-employment benefit liabilities	2.9
Other liabilities	1.7
	$31.5
Total liabilities	**$33.9**
Equity	
Equity attributable to the Shareholder	10.4
Equity attributable to non-controlling interest	0.1
Total equity	**$10.5**
Total liabilities and equity	**$44.4**

OPG Income Statement Year Ended Dec 31 $B	2016
Revenue	$5.7
Fuel expense	0.7
Gross margin	**$4.9**
Operations, maintenance and administration	2.7
Depreciation and amortization	1.3
Accretion on fixed asset removal and nuclear waste management liabilities	0.9
Earnings on nuclear fixed asset removal and nuclear waste management funds	-0.7
Other expenses	0.02
Total expenses	**$4.2**
Income before other (gains) losses, interest and income taxes	**$0.7**
Other (gains) losses	-0.02
Income before interest and income taxes	**$0.7**
Net interest expense	0.1
Income before income taxes	**$0.6**
Income tax expense	0.2
Net income	**$0.5**
Net income attributable to the Shareholder	**$0.4**
Net income attributable to non-controlling interest	**$0.02**

Ontario

MINISTRY OF
ENERGY

Ontario Power Generation (OPG) 2017-19 Business Plan and Special Status Application

May 2017

Context

- As required by the Memorandum of Agreement (MOA) between Ontario Power Generation and the Minister of Energy, OPG provided its Business Plan for 2017-2019 to the Ministry of Energy on November 29, 2016 for concurrence
  - Note that while OPG is seeking concurrence for its three year 2017-19 business plan, the plan also includes financial projections for 2020 and 2021
- With this Business Plan OPG is also making an application for Special Status under the Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive, which allows agencies/organizations, for which international travel may be integral to their business, to seek TB/MBC approval for special status to ensure that the approval process does not have an undue negative effect on its ability to conduct business
- The Minister's concurrence requires presentation of OPG's business plan before TB/MBC
- The Ministry of Energy review and analysis of OPG's business plan is supported by the Electricity Investment and Governance Secretariat, a unit within the Ministry of Finance and the Corporate and Electricity Finance Division of the Ontario Financing Authority (OFA)
- The following presentation provides an overview of OPG's business plan, including:
  1. Business Plan Overview
  2. Other Considerations

Context *(cont'd)*

- Proceeding with Provincial concurrence now will demonstrate that OPG has support from its shareholder as it implements the plan and provides clarity to the Ontario Energy Board (OEB) as it reviews OPG's current rate application covering the 2017-2021 period

- Business plan forecasts may be affected by Ontario's Fair Hydro Plan (OFHP). Given the stage of implementation of OFHP and the timing of the receipt of the business plan in November 2016, these changes are not reflected in OPG's plan

  - The Ministry anticipates that as part of supporting the financing and administration of the global adjustment smoothing mechanism, OPG would purchase the right to future cash flows from IESO, financed partly by capital infusions from the Province, and majority by third-party lending

  - These changes are generally expected to be fiscally neutral as they would result in an increase in Provincial interest on debt, offset by increases in OPG net income

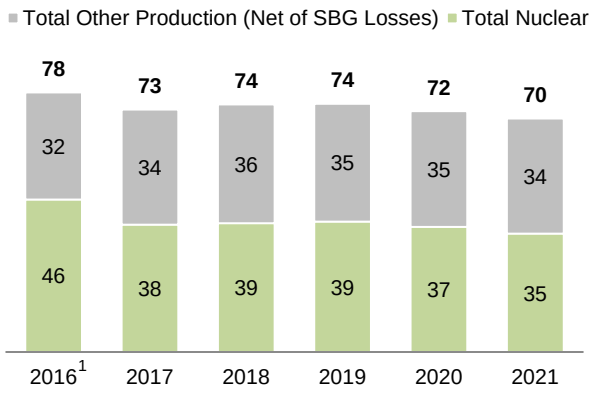
  - In addition, the Province's net debt position would remain unchanged

1. Business Plan Overview

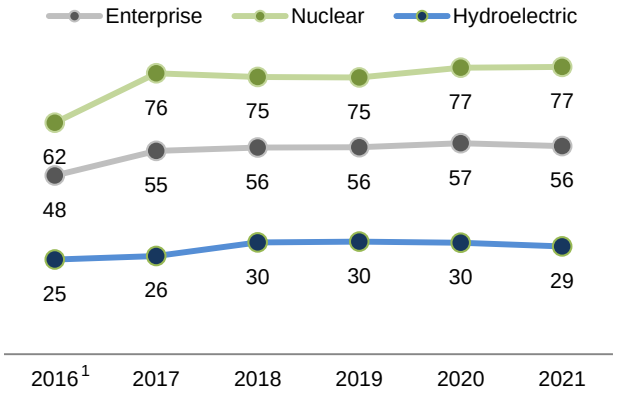
a) Production & Total Cost of Generation

- OPG's production is expected to fall to 69.8 TWh by 2021 from 77.6 TWh in 2016
  - Reflects a declining trend in the Darlington production due to refurbishment outages starting in October 2016
  - Includes a partial overlap starting in 2021 between second and third unit refurbishments, and
  - Includes the Pickering Vacuum Building Outage (VBO) in 2021 requiring the shutdown of all units for the duration of the outage
- While Operations, Maintenance and Administration (OM&A) remains relatively stable over the planning period (see next slide), total generating cost (TGC)* shows an increasing trend over the planning period relative to 2016, reflecting:
  - Lower nuclear production due to Darlington refurbishment outages, and
  - Increased sustaining capital spending (included in TGC) on two large hydroelectric projects, the Lower Mattagami dam safety upgrade and the Sir Adam Beck I GS power canal liner rehabilitation

Production (TWh)



Total Generating Cost ($/MWh)



1. Actuals

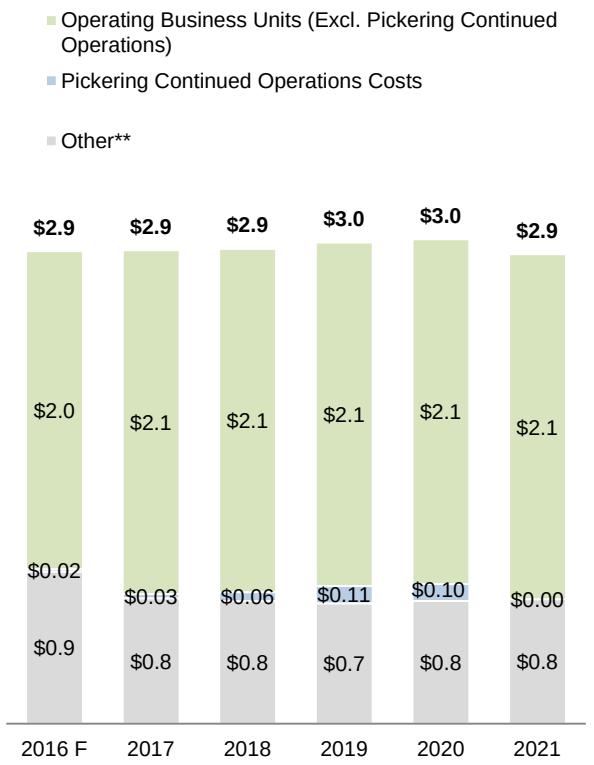
*TGC = OM&A expenses from ongoing operations + fuel and Gross Revenue Charge expenses for OPG-operated stations + sustaining capital expenditures) divided by OPG generation adjusted for surplus baseload generation losses

1. Business Plan Overview

b) Operations, Maintenance and Administration (OM&A) Expenses

- Annual OM&A expenses from ongoing operations are expected to stay consistent over the plan period, averaging $2.9B per year
- Increases over 2016 are mainly attributable to:
  - Increases in business unit expenditures, including changes in nuclear outage scope at Darlington, and planned hiring to fill staffing gaps
  - Incremental outage and other program costs to enable Pickering continued operations
- These increases are partially offset by declining pension and Other Post Employment Benefits (OPEB) costs over the period due to projected pension asset returns, increased employee contributions, and adoption of a new method for applying discount rates to determine interest components of pension costs

OM&A from Ongoing Operations* ($B)



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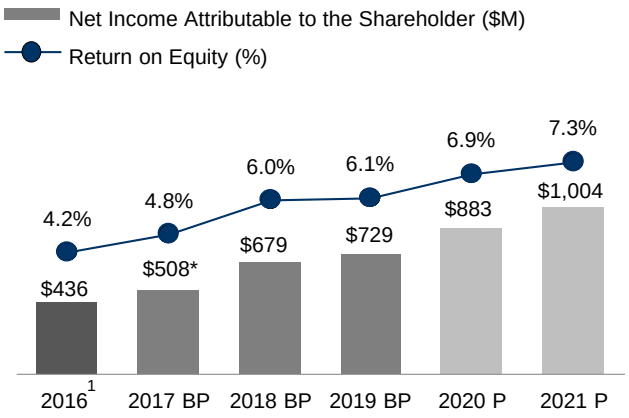

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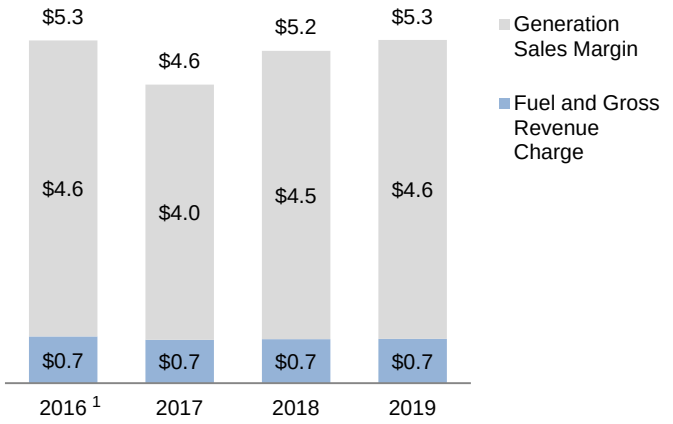

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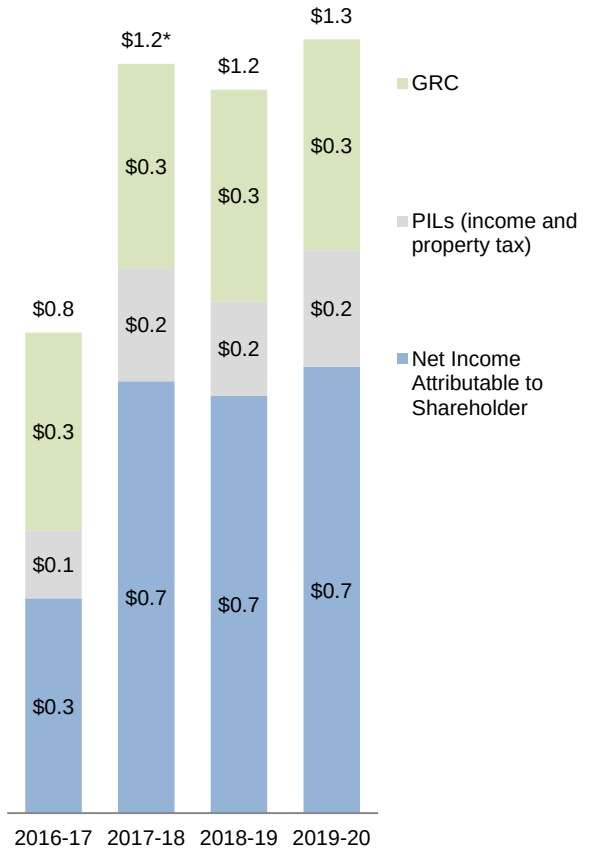

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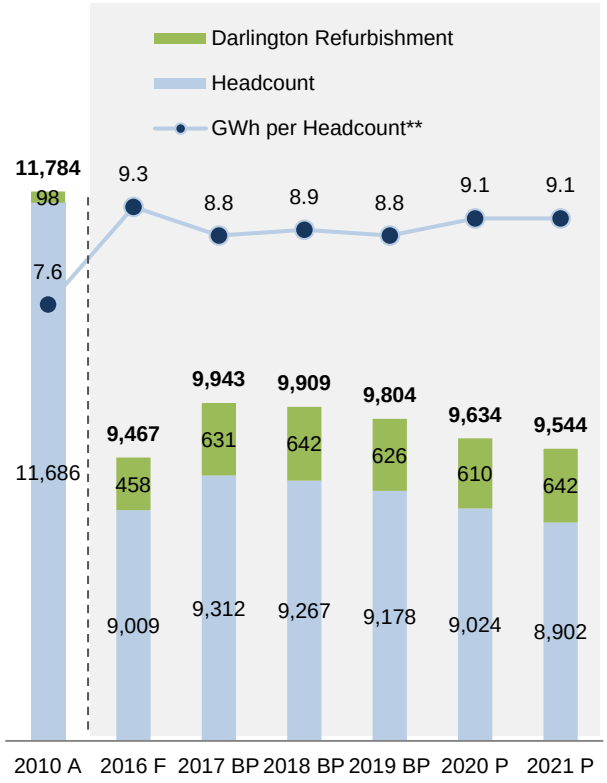

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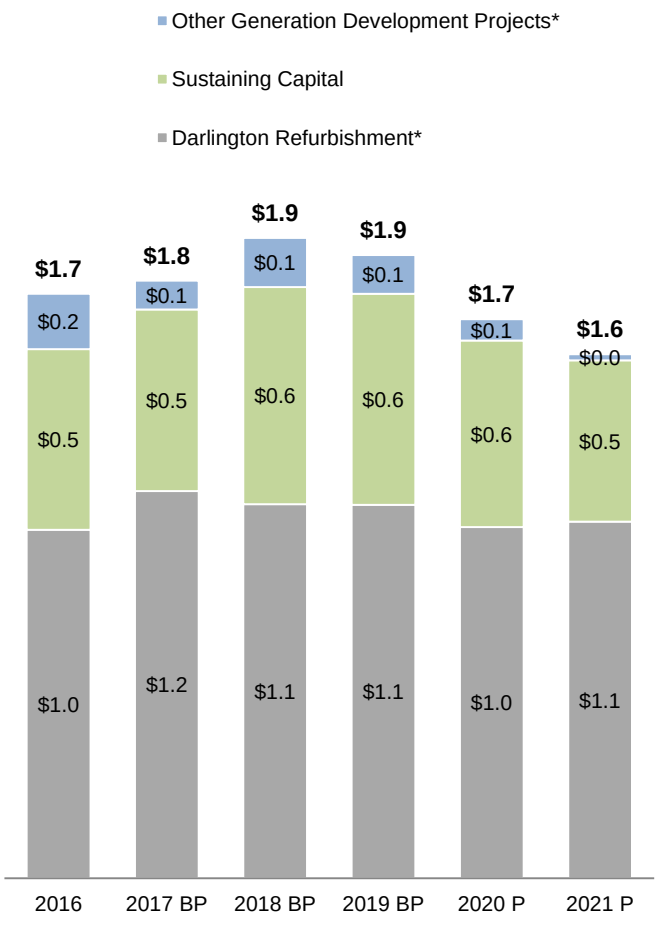

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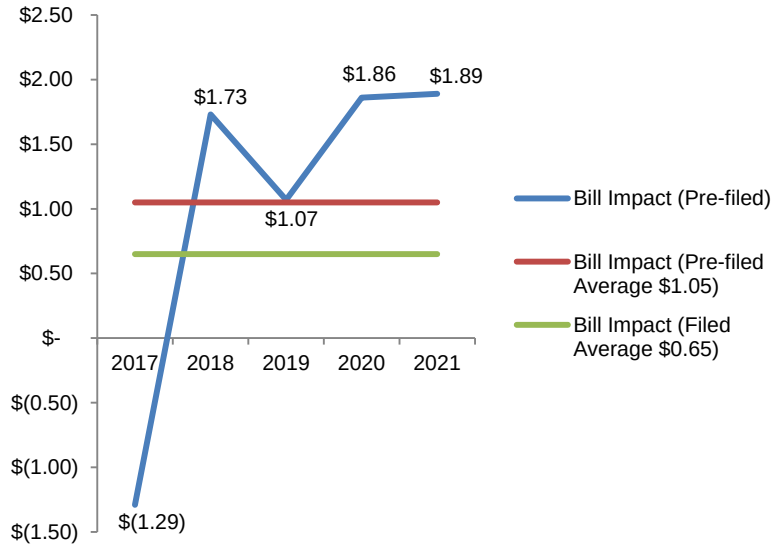

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  - Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive allows agencies/organizations, for which international travel may be integral to their business, to seek TB/MBC approval for special status to ensure that the approval process does not have an undue negative effect on its ability to conduct business
  - OPG believes that international travel is integral to the safe and prudent operation of its business and having OPG's CEO approve international travel will enable more efficient decision-making while significantly lowering travel costs
  - OPG cites the importance of enabling its engagement with the international community (in particular in regards to nuclear safety), procurement activities, and investment and due diligence processes for over $30 billion in pension fund and nuclear funds
  - OPG requires a high level of international business travel at approximately 90-100 trips annually, while the Darlington Refurbishment Project accounts for 45% of OPG's international travel and is expected see increases over the 10 year life of the project
  - OPG indicated that the approval process, which took 23 days on average in 2016, delays flight bookings which results in higher costs as airlines raise fares closer to the travel date
  - OPG believes the inability to make timely commitments on events and meetings impacts employee engagement as well as its international relationships and reputation
- OPG is seeking Special Status as part of concurrence with its business plan. OPG has committed to providing semi-annual reports to the Ministry on international travel taken, and continue to be accountable for compliance with all applicable OPS directives, policies and procedures

Appendix

2016 Year-End Financials

OPG Balance Sheet as at Dec 31 $B	2016
Assets	
Cash and cash equivalents	0.2
Available-for-sale securities	0.2
Receivables from related parties	0.4
Nuclear fixed asset removal and nuclear waste management funds	0.02
Other current assets	0.9
Total current assets	**$1.7**
Net property, plant and equipment	**$20.0**
Net intangible assets	**$0.1**
Nuclear fixed asset removal and nuclear waste management funds	16.0
Regulatory assets	5.9
Other long-term assets	0.7
Other assets	**$22.5**
Total assets	**$44.4**
Liabilities	
Accounts payable and accrued charges	1.2
Short-term debt and long-term debt due within one year	1.1
Income taxes payable and other current liabilities	0.1
Total current liabilities	**$2.4**
Long-term debt	4.4
Fixed asset removal and nuclear waste management liabilities	19.5
Pension liabilities	3.0
Other post-employment benefit liabilities	2.9
Other liabilities	1.7
	$31.5
Total liabilities	**$33.9**
Equity	
Equity attributable to the Shareholder	10.4
Equity attributable to non-controlling interest	0.1
Total equity	**$10.5**
Total liabilities and equity	**$44.4**

OPG Income Statement Year Ended Dec 31 $B	2016
Revenue	$5.7
Fuel expense	0.7
Gross margin	**$4.9**
Operations, maintenance and administration	2.7
Depreciation and amortization	1.3
Accretion on fixed asset removal and nuclear waste management liabilities	0.9
Earnings on nuclear fixed asset removal and nuclear waste management funds	-0.7
Other expenses	0.02
Total expenses	**$4.2**
Income before other (gains) losses, interest and income taxes	**$0.7**
Other (gains) losses	-0.02
Income before interest and income taxes	**$0.7**
Net interest expense	0.1
Income before income taxes	**$0.6**
Income tax expense	0.2
Net income	**$0.5**
Net income attributable to the Shareholder	**$0.4**
Net income attributable to non-controlling interest	**$0.02**

Ontario

Application and Report to Treasury Board/Management Board of Cabinet

(Refer to instructions on next page)

1. MINISTRY: Energy	2. MINISTRY LOG #	3. TB/MBC LOG #

4. TYPE OF REQUEST: Treasury Board General

5. PURPOSE OF REQUEST: The Ministry of Energy is requesting TB/MBC 1. NOTE the receipt of OPG's 2017-2019 Business Plan. 2. NOTE that the Minister of Energy will provide concurrence with OPG's Business Plan 3. APPROVE OPG's application for Special Status to Approve International Travel under Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive dated January 1, 2017.

6. FINANCIAL DETAILS ($ Millions)

		Current Year 2016/17		Year 2 2017/18		Year 3 2018/19		Matures In 2019/20	
		Operating	Capital	Operating	Capital	Operating	Capital	Operating	Capital
A. Program Current Base	Expense								
	Asset								
B. Program Request (change from existing base)	Expense								
	Asset								
C. Available for Offset	Expense								
	Asset								
D. Net Impact On Program Allocation (B-C)	Expense								
	Asset								
E. Revenue Implications									

7. IMPACT ON FTE LIMIT	Current Year 2016/2017	Year 2 2017/2018	Year 3 2018/2019	Mature in 2019/2020
A. Program Current Base FTE Limit				
B. Program FTEs Request				
C. Available FTE Offset				
D. Net Impact on FTE Limit (B-C)				
E. Change to Ministry Salaries & Wages Allocation (included in the Program Request ($ Millions)				

8. OTHER DECISION FACTORS	Y/N	EXPLANATION
A. Consistent with Government Priorities and Results (If Yes identify key Results) - include details in submission)	Y	MOA between Minister of Energy and OPG
B. Policy approval (if yes identify policy committee and date approved)	N	
C. Key Performance Risks (If yes provide details in submission)	N	
D. Impact on other Ministries (if yes - include sign-off date. Include resources impact in submission)	N	Ministries: N/A
E. Impact on the Fiscal Plan (if yes provide details in submission)	Y	Impact of OPG results

9. AUTHORIZATION /DATE

Signature of Minister	Day/Month/Year	Signature of Deputy Minister	Day/Month/Year
Glenn Thibeault	xxxx	Serge Imbrogno	xxxx

Application and Report to Treasury Board/Management Board of Cabinet

This is a general purpose form. Use it for all requests submitted to Treasury Board and Management Board of Cabinet including items delegated to the Chair of Treasury Board/Management Board of Cabinet. If the submission would result in a change in approved financial appropriations and/or full time equivalent (FTE) limits please complete Sections 6 and/or 7.

Instructions for completing the TB/MBC Submission Template

1. Ministry	State name (or names if it is a joint submissions).
2. Ministry Log #	Insert your Ministry Tracking log # for the submissions.
3. TB/MBC Log #	For use by TB/MBC Coordinaton Office only.
4. Type of Request	Choices may include any or a combination of the following: Financial Transaction, TBO, General, Procurement, legislation, Regulation, Order-in-Council.
5. Purpose of Request	In no more than two sentences, describe the objective of the request.
6. Financial Details	Provide financial details for the current year, outlook for the next 2 years and Maturity date.A32
	For each year of the following sections please provide applicable details for Expense, Asset, Operating and/or Capital:
A. Program Current Base	Provide current base associated with the request
B. Program Request	Change in costs associated with the proposal.
C. Available for Offset	Indicate the costs that can be managed from within existing appropriations (intra or inter-ministry where applicable).
D. Net Impact on Program Allocation	Net impact on the Ministry's allocations.
E. Revenue Implications	Identify new or change in revenues that would flow into the Consolidated Revenue Fund.
7. Impact on FTE Limit	Provide staff details for the current year, outlook for the next 2 years and mature FTE impact - follows the same logic as financial details (items 6 above). For Section 7E provide the change in the salaries and wages associated with the net impact of the request (i.e. 6D) if applicable.
8. Other Decision Factors	Answer Yes or No to each of the decision factors highlighted and provide key notes on template for Minister and Deputy Minister information. Provide further details in the submission.
9. Authorization /Date	To be signed by the Minister and Deputy Minister of the requesting Ministry to confirm support for the request as submitted. Joint inter-ministry submissions require the signature of all Minister and Deputy Minster affected. Signed submission due in to the TB/MBC Coordination Office no later than 2 weeks prior t the scheduled TB/MBC meeting date.

Application and Report to Treasury Board/Management Board of Cabinet

Administrative Data for Current year (relates to 6B and 6C from page 1).

TB/MBC 20

Vote & Item	Standard Account	Ministry Request ($ Millions)				
		Holdback / Release (A)	Treasury Board Order (B)	Increase (C)	(Decrease) (D)	Total (E=B+C+D)
	Salaries & Wages Employee Benefits Transportation & Communication Services Supplies and Equipment Transfer Payments _____ _____ _____ Other Transactions Recoveries Other (Specify) _____					
	ITEM TOTAL					
	Salaries & Wages Employee Benefits Transportation & Communication Services Supplies and Equipment Transfer Payments _____ _____ _____ Other Transactions Recoveries Other (Specify) _____					
	ITEM TOTAL					
	Salaries & Wages Employee Benefits Transportation & Communication Services Supplies and Equipment Transfer Payments _____ _____ _____ Other Transactions Recoveries Other (Specify) _____					
	ITEM TOTAL					
MINISTRY SUMMARY	**Salaries & Wages** **Employee Benefits** **Transportation & Communication** **Services** **Supplies and Equipment** **Transfer Payments** _____ _____ _____ **Other Transactions** **Recoveries** **Other (Specify)** _____					
	MINISTRY TOTAL					

Mr. Bernard Lord
Chair
Ontario Power Generation
1900-700 University Avenue
Toronto ON M5G 1X6

Dear Mr. Lord,

Thank you for your submission of Ontario Power Generation's (OPG) 2017-2019 Business Plan ("the Plan"). We have reviewed the Plan and find it to be consistent with our government's expectations.

I support the operational and financial targets set by OPG in its business plan. We recognize the substantial cost reductions that OPG has recently achieved and expect OPG to work closely with the Province to fully realize the additional efficiencies incorporated in the Plan in a manner that is consistent with the continued safe and environmentally responsible operation of OPG's facilities.

We commend OPG on its successful start to the Darlington Refurbishment Project, a key objective of Ontario's 2013 Long-Term Energy Plan (2013 LTEP). As a priority project for the government, I expect that OPG will continue to focus on delivering the project as per the schedule and budget contained in the Release Quality Estimate approved by the OPG Board and by the government. I also expect OPG to continue to minimize project risks consistent with the nuclear refurbishment principles set out in the 2013 LTEP, and seek concurrence prior to commencing ~~subsequent unit~~ refurbishment~~s after~~of Unit ~~2~~3 ~~is successfully returned to service~~before the end of 2017.

We continue to support the planned operation of Pickering units up to 2022/2024, subject to OPG obtaining necessary regulatory approvals, as the station's output will provide reliable, cost-effective and emission-free electricity supply during the Darlington and initial Bruce refurbishments. I expect OPG to keep the Ministry apprised throughout the regulatory processes and as we proceed to update the Long-Term Energy Plan. .

I understand that the recently approved Ontario Nuclear Funds Agreement (ONFA) Reference Plan has resulted in a reduction of the estimated liabilities for future decommissioning and long-term management of waste from Ontario's nuclear fleet. With many decades of nuclear generation in the Province's future, we expect OPG to continue managing its decommissioning and waste management obligations and related segregated funds in a prudent manner. I recognize that the ONFA is based on OPG's proposed siting of a Deep Geological Repository (DGR) for low and intermediate level waste. OPG's DGR is a key component of Ontario's plans to ensure that nuclear remains the backbone of our electricity system for years to come.

I appreciate the efforts of OPG staff, management and the Board of Directors to date as we worked to develop a plan to refinance the Global Adjustment (GA). Refinancing the GA would provide significant and immediate rate relief by spreading the cost of electricity investments over the expected lifecycle of the infrastructure that has been built. OPG will be instrumental to the success of this initiative and we plan to introduce

legislation that would, if passed, enable OPG to work with the Independent Electricity System Operator (IESO) to implement this plan. I also expect to make the necessary changes to OPG's articles of amalgamation to provide the financing flexibility to implement the refinancing of the GA to meet the Province's price objectives announced on March 2, 2017.

I expect OPG to continue to keep the government informed with regard to the company's key ongoing and emerging initiatives and progress in achieving its financial and operational performance commitments. As OPG's performance directly impacts Ontario's fiscal plan, we note the importance of achieving or exceeding OPG's financial performance commitments

Consistent with Section 7 of the Memorandum of Agreement, in advance of commencing discussions for the renewal of its collective agreements with its unions, I expect that OPG shall seek advice from the Ministry on Provincial policy direction and relevant fiscal considerations affecting labour negotiations.

This letter constitutes our concurrence with OPG's Board approved 2017-2019 Business Plan as provided for under the Memorandum of Agreement between OPG and the Shareholder dated July 17, 2015.

This letter also confirms the approval of special status for OPG to approve international travel, under Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive. OPG shall submit semi-annual reports on international travel to the Ministry of Energy, as described in the submission received from OPG's President and CEO, dated January 24, 2017.

Sincerely,

Glenn Thibeault
Minister of Energy

c: Jeff Lyash, President and Chief Executive Officer, OPG
Serge Imbrogno, Deputy Minister, Ministry of Energy
Scott Thompson, Deputy Minister, Ministry of Finance
Andrew Teliszewsky, Chief of Staff, Ministry of Energy
Ali Ghiassi, Chief of Staff, Ministry of Finance

From: Ronald Kwan
To: Gadi Mayman
Subject: Fw: sensitive Fair Hydro Trust question
Date: Friday, April 27, 2018 3:39:30 PM

Hi Gadi,

FYI. If this amount is being put forward, I think we need to put on the cost side to the Province too, not just the net income. But, for comparability, we'd need to know OPG's interest rate assumptions. I can ask John lee or Ken Hartwick.

Ron

From: Ronald Kwan
Sent: April 27, 2018 3:37 PM
To: Usman Zahid; John Kim
Subject: Re: sensitive Fair Hydro Trust question

Hi,

While Lubna may not want OPG to get into it, I think we have to cite the borrowing cost on the equity injection. It would be good to know what sub-debt rates OPG assumed on its interest revenues over the life of the Trust.

Ron

From: Usman Zahid
Sent: April 27, 2018 3:25 PM
To: John Kim
Cc: Ronald Kwan
Subject: FW: sensitive Fair Hydro Trust question

Hi John,

Please see question from Energy below.

Regards,
Usman

From: Pichette, Marc (MOF) [mailto:Marc.Pichette@ontario.ca]

Sent: Friday, April 27, 2018 1:32 PM
To: Usman Zahid <Usman.Zahid@ofina.on.ca>
Subject: FW: sensitive Fair Hydro Trust question

Hi Usman, please see question below from the Ministry of Energy that was sent to my director.

From: Whytock, John (ENERGY) <John.Whytock@ontario.ca>
Date: Thursday, Apr 26, 2018, 4:45 PM
To: LeBlanc, Jenna (MOF) <Jenna.LeBlanc@ontario.ca>
Subject: FW: sensitive Fair Hydro Trust question

Hi Jenna. I've got a sensitive question for you. Our MO asked what the revenue implications of the Fair Hydro Trust were for OPG, and how much we estimated would return to the provincial coffers.

As you'll see below, OPG has put a number on their own expected revenues, but my policy folks were not in a position to say what it could mean for returns to government.

Is this a number that Finance can produce? More importantly, are you willing to share?

Thanks much

jw

From: ROWE Jennifer -CORPAFFAIRS [mailto:jennifer.rowe@opg.com]
Sent: April-23-18 10:19 AM
To: Whytock, John (ENERGY)
Cc: KELLY Neal -CORPCOMM
Subject: RE: EXTERNAL – Fair Hydro Trust question

John,

Here's a simplified version of what I just sent you:

The total amount of income that OPG expects to earn over the life of the Fair Hydro Plan is in the range of **$4.5 Billion to $4.9 Billion.** The actual amount will vary based on the actual debt issued and interest rates.

This is over a period of 30 years (2017 to 2047). The income will be earned gradually, and will peak around 2029/2030.

Since the Province owns OPG, and consolidates OPG into their books, the net income flows back to the Province.

Jennifer

From: LADAK Lubna -TREASURY
Sent: Monday, April 23, 2018 10:14 AM
To: ROWE Jennifer -CORPAFFAIRS <jennifer.rowe@opg.com>; KELLY Neal -CORPCOMM <neal.kelly@opg.com>; HARTWICK Ken -FINANCE <ken.hartwick@opg.com>
Cc: LEE John -TREASURY <john.s.lee@opg.com>; LIU Sheen -TREASURY <sheen.liu@opg.com>; LAURETA LAPIRA May -TREASURY <may.lapira@opg.com>
Subject: RE: EXTERNAL – Fair Hydro Trust question

The total amount of income that OPG expects to earn over the life of the Fair Hydro Plan is in the range of $4.5 Billion to $4.9 Billion.
It is comprised of about $200 M for management fees and $4.3 Billion to $4.7 Billion of interest income.

The actual amount will vary based on the actual debt issued and interest rates.

This is over a period of 30 years (2017 to 2047). The income will be earned gradually, and will peak around 2029/2030.

Since the Province owns OPG, and consolidates OPG into their books, the net income flows back to the Province.

FYI – I don't know how the Province funds the equity injections. If they borrow the funds, the overall net income impact in their books could be lower. I wouldn't get into this though.

Lubna Ladak | VP Treasury - FHP| Ontario Power Generation
700 University Avenue, Toronto, Ontario M5G 1X6 | 416-592-5984 | Cell 416-578-0219 | Fax 416-592-4189
lubna.ladak@opg.com

From:	Gadi Mayman
To:	Mike Manning; Ronald Kwan; Ken Kandeepan
Cc:	Anna Strathy
Subject:	Fwd: Draft Fees Regulation
Date:	Tuesday, September 26, 2017 2:08:53 PM
Attachments:	Blackline_24180663v1 - 24180663v3.pdf ATT00001.htm

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Are all of you OK with this? If you are, I'm fine, too, but I'm having trouble reading it with all of the markups and black lines.

Gadi

Begin forwarded message:

From: "Nelms, Scott (MOF)" <Scott.Nelms@ontario.ca>
Date: September 26, 2017 at 12:18:07 PM EDT
To: "Mayman, Gadi (OFA)" <Gadi.Mayman@ofina.on.ca>
Cc: "Hume, Steen (ENERGY)" <Steen.Hume@ontario.ca>, "Manning, Mike (OFA)" <Mike.Manning@ofina.on.ca>, "Kwan, Ronald (OFA)" <Ronald.Kwan@ofina.on.ca>
Subject: Draft Fees Regulation

Hi Gadi,

I hope NYC is going well and you are finding air conditioning.

We have been working with Steen's team and Energy legal on a draft of the fees regulation for OPG Trust and OFHP. As we progress through this, there are some elements of the regulation that we were hoping you and the OFA team might be able to consider (please see attached a black line for your reference):

- The draft reg outlines a base fee as well as a variable fee.
  - The base fee is provided monthly at an annual rate of 10-basis points for the first two years (we had this initially set at one year but Torys' markup changes this to two years). After 2019, the base fee is provided at an annual rate of 8 basis points should the funding obligations exceed $10B. Does this seem reasonable?
- The variable fee structure seems consistent with previous discussions (5 basis point fee provided on the spread). Do you think this makes sense?
- It would also be helpful if the OFA could let us know if the method for calculating the monthly funding obligation is reasonable.

<!--[if !supportLists]-->• <!--[endif]-->With respect to costs, our understanding is that these sorts of costs are typically a pass through; can the OFA confirm? The Torys markup removes OEB oversight on costs but we are wondering if there should be a role for the OFA in reviewing / providing oversight in this regard?

<!--[if !supportLists]-->o <!--[endif]-->Also, do the costs they've outlined seem reasonable? In particular, LSB is wondering whether this leaves the door open for OPG to pass through any overhead costs (i.e. should we be explicit about excluding them)?

<!--[if !supportLists]-->• <!--[endif]-->On timing, the draft reg currently contemplates a fee application by OPG every two years regardless of what interest rates are in the market. Do we think this is fair or should the application occur annually? (Note that until new fees are established, the old fees are still in effect).

In terms of next steps, OPG would like to get a draft to their Board in time for the meeting on Friday. ENERGY LSB is hoping for comments by tomorrow. I don't think we need anything too detailed or formal, but a quick sniff test would be useful to ensure we are on the right track.

Thanks for your help,
Scott

CONFIDENTIAL
FOR DISCUSSION PURPOSES ONLY

ONTARIO REGULATION

made under the

ONTARIO FAIR HYDRO PLAN ACT, 2017

FEES

Definitions

1. (1) In this Regulation,

"average monthly funding obligation" means, in respect of a month, the amount determined in accordance with subsection (2);

"average annual funding obligation" means, in respect of a year, the sum of the average monthly funding obligations for the year;

"comparison fees" means ~~typical fees~~**market comparable fees, expressed as a per annum percentage rate,** charged by ~~[service providers?~~**asset** managers~~?]~~ ~~in Ontario~~ **in Canada and any other jurisdiction as may be determined by the Board** for services that are similar to the services provided by the Financial ~~Service Manger~~**Services Manager** under the Act in terms of,

(a) the type of services provided, being services in respect of funds including securitization vehicles, pension funds, other investment funds, hedge funds and other similar funds ~~in Ontario~~,

(b) the scope of the services provided, ~~and~~

(c) the level of the services provided**, and**

(d) the amount of assets under management;

"forecast interest rate" means, in respect of each tranche of funding obligations, an interest rate forecast to be applicable to such tranche of funding obligations after taking into account (i) the interest rate for debt of or guaranteed by the Province of Ontario with a corresponding term or duration, (ii) the estimated credit spread for such tranche of funding obligations with a comparable term and based on the type of instrument and risk of the issuer, and (iii) anticipated fees and commissions expected to be payable in connection with the issuance of such tranche of funding obligations.

"net annual funding obligation" means, in respect of a year, the sum of the principal amounts of funding obligations incurred by financing entities in a year~~, other than any refinancing~~;

(2) For the purposes of determining the average monthly funding obligation for a month, the following formula applies:

$$(A + B) / 2$$

Where,

A = the sum of the balances**, as** at **12:00 am on** the ~~start~~**first calendar day** of the month**,** of the principal amount of all **outstanding** funding obligations ~~incurred by~~**for all** financing entities,

2

B = the sum of the balances**, as** at **11:59 pm on** the ~~end~~**last calendar day** of the month**,** of the principal amount of all **outstanding** funding obligations ~~incurred by~~**for all** financing entities.

Fees that may be established, charged

2. (1) For the purposes of subsection 19 (3) of the Act, the fees established and charged by the Financial Services Manager may be charged to financing entities in relation to **the management and administration of financing entities and the investment asset, including in relation to** funding obligations incurred or that are planned to be incurred by the financing entities.

(2) A fee mentioned in subsection (1) shall be comprised of a base fee calculated under section [3, 4 or 5], as the case may be, and a variable fee calculated under section [6].

(3) ~~For the purposes of subsection 19 (3) of the Act, fees may be~~**Out-of-pocket costs and expenses of the financing entities incurred by the Financial Services Manager on behalf of the financing entities and for which the Financial Services Manager is entitled to reimbursement under a** management agreement with **such financing entity shall not constitute a fee** established and charged by the Financial Services Manager ~~to financing entities for the recovery of costs and expenditures, as provided for in section 7.~~**under subsection 19(3)**

of the Act.[1] The costs and expenditures of the financing entities referred to in this subsection (3) may include costs and expenditures in respect of the following:

1. Underwriters or selling agents for funding obligations**;**

2. **Banking fees, including structuring fees or work fees;**

3. Fees of issuing and paying agents for funding obligations**;**

4. **Fees of trustees;**

5. Fees incurred in the preparation of financial statements, financial reports, compliance certificates and tax returns**;**

6. Fees of legal counsel**;**

7. **Rating agency fees; and**

8. Filing or registration fees.

(4) The Financial Services Manager shall not establish or charge any fees to financing entities other than those provided for under this ~~R~~egulation.

Base fee, 2018 and 2019

3. Subject to section 5.1, the base fee for a month in the ~~year~~**calendar years** 2018 **and 2019** shall be calculated using the following formula:

$$(0.1 \times B) / 12$$

Where,

B = the average monthly funding obligation for the preceding month.

Base fee, after ~~2018,~~2019, average annual funding obligation greater than $10 billion

4. (1) This section applies for the purpose of calculating the base fee for a month in any year following ~~2018~~**2019** if the average annual funding obligation for the preceding year was greater than $10 billion.

[1] These represent third party costs and expenses of the financing entity, not part of the fees that OPG is charging the financing entity. From time to time, OPG may have to pay these upfront costs on behalf of financing entities but they will be a pass-through cost for which OPG would simply be reimbursed by the financing entity. Other than OPG's fees, the costs and expenditures of financing entities are not subject to OEB review under the Act but rather are recoverable as expenses through the CEA (and through IESO during the moratorium). Subsection (3) in this draft was added for greater certainty to ensure there was no misunderstanding.

(2) Subject to section 5.1, the base fee for the month shall be calculated using the following formula:

$$(0.08 \times B) / 12$$

Where,

B = the average monthly funding obligation for the preceding month.

Base fee, after ~~2018,~~2019, average annual funding obligation $10 billion or less

5. (1) This section applies for the purpose of calculating the base fee for a month in any year following ~~2018~~2019 if the average annual funding obligation for the preceding year was equal to or less than $10 billion.

(2) Subject to section 5.1, the base fee for the month shall be calculated using the following formula:

$$(0.1 \times B) / 12$$

Where,

4

B = the average monthly funding obligation for the preceding month.

Board review of base fee

5.1 If the Board, after reviewing a submission in respect of a proposed base fee by the Financial Services Manager under section 9, is of the view that applying the applicable formula set out in section 3, 4 or 5 results in a base fee that is inconsistent with prevailing comparison fees, the Board may refuse to approve the proposed fee. If the Board refuses to approve the proposed base fee submitted by the Financial Services Manager under section 9, the Board shall provide its reasons for such refusal and ~~may~~ make recommendations to the Financial Services Manager regarding the determination of a base fee that is consistent with comparison fees~~.~~ and based on the methodology used in the formulas set out in section 3, 4 and 5.

Variable fee

6. (1) Subject to subsection (2) and section 6.1, the variable fee for a year shall be the sum of the amounts of each tranche of net annual funding obligations for the year, calculated by using the following formula~~:~~ (which in respect of individual tranches may result in a negative number):

$$(A \times (B - C)) \times 0.05$$

Where,

A = the principal amount of the tranche,

B= the forecast interest rate for the tranche, as determined by the Financial Services Manager before the start of the year, based on the term of the tranche, and

C = the actual interest rate for the tranche.

(2) If the circumstances set out in Column 1 of the following Table apply in a year, the variable fee payable for a year is subject to the rules set out opposite the circumstances in Column 2 of the Table:

Item	Column 1 Circumstances	Column 2 Rules
1.	The average annual funding obligations are $10 billion or less.	The variable fee payable for the year shall not be more than 1 per cent of the amount that is 5 per cent of the net annual funding obligation for the year. The variable fee payable for the year shall not be less than -1per cent of the amount that is 5 per cent of the net annual funding obligation.
2.	The average annual funding obligations are greater than $10 billion.	The variable fee payable for the year shall not be more than 2 per cent of the amount that is 5 per cent of the net annual funding obligation for the year. The variable fee payable for the year shall not be less than -2 per cent of the amount that is 5 per cent of the net annual funding obligation for the year.

Board review of variable fee 5

6.1 If the Board, after reviewing a submission in respect of a proposed variable fee by the Financial Services Manager under section 9, is of the view that the forecast interest rate used for the purposes of the formula set out in subsection 6 (1) is ~~[unreasonable]~~**not consistent with market comparable forecast interest rates**, the Board may refuse to approve the proposed fee**. If the Board refuses to approve the proposed variable fee submitted by the** Financial Services Manager **under section 9, the Board shall provide its reasons for such refusal** and ~~may~~ make recommendations to the Financial Services Manager regarding the forecast interest rate that is ~~reasonable.~~**consistent with market comparable forecast interest rates.**

~~**Fees for costs and expenditures**~~

~~**7.** (1) The Financial Services Manager may establish and charge fees for the recovery from a financing entity of any costs and expenditures incurred in connection with the Financial Services Manager's duties under the Act in relation to the financing entity or under any management agreement with the financing entity.~~

~~(2) The costs and expenditures referred to in subsection (1) may include costs and expenditures in respect of the following:~~

~~1. Underwriters or selling agents for funding obligations.~~

~~2. Banking fees.~~

3. ~~Fees of issuing and paying agents for funding obligations.~~

4. ~~Fees of trustees.~~

5. ~~Fees incurred in the preparation of financial statements, financial reports, compliance certificates and tax returns.~~

6. ~~Fees of legal counsel.~~

7. ~~Filing or registration fees.~~

8. ~~Fees of any third party independent consultants required to be retained under the Act.~~

~~**Board review of fees for costs, expenditures**~~

~~**7.1** If the Board, after reviewing a submission in respect of a proposed fee for costs and expenditures by the Financial Services Manager under section 9, is of the view that the proposed fee is in respect of costs and expenses that were [not prudently incurred, or not incurred in relation to funding obligations incurred or that are planned to be incurred by financing entities], the Board may refuse to approve the proposed fee or a portion of the proposed fee and may make recommendations to the Financial Services Manager regarding the proposed fee.~~

Charging of fees

8. (1) In charging fees, the Financial Services Manager shall provide for,

(a) the base fee for a month to be payable within **[x]** days after the end of the month; and

(b) the variable fee for a year to be payable in the following calendar year in twelve equal monthly instalments that coincide with the payment of the base fee for each month.

(2) If the variable fee is a negative amount, it shall be deducted from the base fee payable in the following calendar year in twelve equal monthly instalments.

(3) Where there is more than one financing entity, the portion of the fees allocated to and payable by a financing entity shall be based on its proportionate share of the average principal amount of funding obligations for the applicable period.

Submissions to Board re fees

9. (1) The Financial Services Manager shall make submissions to the Board in respect of the fees proposed to be charged under section ~~5.1, 6.1~~**5.1** and ~~7.1~~**6.1.**

(2) The first submission **for proposed fees to be charged for a two year period commencing in 2018** shall be made no later than [October 31, 2017].

(3) ~~The submission for each calendar year starting with 2019~~**Submissions for proposed fees to be charged for a two year period commencing in 2020 and for every two year period thereafter** shall be made no later than [120 days] before the start of the **applicable two** year **period**.

(4**) Submissions to amend the proposed fees for a month in any year following approval of the proposed fees for any two year period may be made from time to time but no more frequently than once in any 12 month period and no later than 120 days before the start of the year in which such fees are proposed to be effective.**

(5) If the Board makes recommendations as described in section ~~5.1, 6.1~~**5.1** or ~~7.1,~~**6.1,** the Financial Services Manager shall submit to the Board,

(a) a revised proposed fee that takes into consideration the recommendations of the Board, and in the case of the base fee is consistent with comparison fees;

(b~~)~~ ~~a description of the methodology that the Financial Services Manager has applied to determine the revised proposed fee;~~

(~~c~~) in the case of the base fee, details concerning the comparison fees that the Financial Services Manager considered; **and**

(~~d~~**c**) in the case of the variable fee, a description of the methodology that the Financial Services Manager has applied to determine forecast interest rates in respect of tranches of the net annual funding obligations~~; and~~**.**

(~~e) in the case of a proposed fee for costs and expenditures by the Financial Services Manager, the rationale for the costs and expenditures having been [prudently incurred, and having been incurred in relation to funding obligations incurred or that are planned to be incurred by financing entities]~~ **6) Until the Board has approved the fees in respect of any two year period, the fees approved for the prior two year period shall remain in effect.**

Board approval, general

10. (1) ~~The Board may approve a proposed fee submitted by the Financial Services Manager or refuse to approve and refer the proposed fee back to the Financial Services Manager with the Board's recommendations.~~

~~[OLC Note: As noted by ENE LSB, there is some redundancy at the moment between section 10 and sections 5.1 and 6.1. This matter will be addressed in a subsequent draft when we have settled the Board approval process for each of the various scenarios (e.g. base fee; variable fee; costs/expenditures fee).]~~

~~(2) The Board may specify in its approval that a fee payable in respect of any period beginning on or after July 1, 2017.~~(3) For the purpose of determining whether to approve a proposed fee~~,~~ **described in section 5.1 or 6.1,**

(a) the Board shall consider the information provided by the Financial Service Manager in its submission relating to the proposed fee~~.~~**; and**

(~~4) For the purpose of determining whether to approve a proposed fee,~~ **b)** the Board may consider advice provided by the Ontario Financing Authority [with respect to comparison fees, annual rates and forecast interest rates].

[OLC Note re DEFERRAL ACCOUNT:
1. You included the following instruction that would require the FSM to establish a deferral account -- what is the authority for imposing this requirement? Recall that in subs. 34 (1) of the Act, the Board is given authority to require that the FSM maintain specific accounts.

2. ENE LSB note: *Necessity of this provision to be discussion with the OEB given that fees will be recovered as a financing entity expense through the Fair Hydro program and not as part of the fees to be approved by the Board.*]

[If needed, deferral provision could be along the following lines: The Financial Services Manager shall establish a deferral account in connection with subsection 19 (3) of the Act that records costs incurred by the Financial Services Manager in providing services referred to in section 1 during the period from July 1, 2017 to the day before the date of the Board's first order under subsection 19 (3) of the Act.]

[OLC Note re FINANCE AMOUNT: You included the following instruction, but I think this more properly belongs somewhere in section 5 of O. Reg. 206/17? In fact, are these fees not already covered in that section (perhaps under "financing entity expenses"?). Please confirm: *Fees established by the Financial Services Manager and approved by the Board, and any applicable taxes on such fees, shall be included in the definition of "expenses" for the purposes of determining finance amounts under the Act.*]

[Notes Re: Determining Fees:

(1) An alternative approach involves the Board approving the initial base fee and variable fee, with any changes to those fees being triggered by the FSM submitting to the Board proposed amendments to those fees (or the Board triggering a review on its own initiative (not more than once per year). However, because interest rates (and hence forecast interest rates) change over time (and can change even within a year), consider whether variable B of the variable fee should be approved annually. Similarly, because trends for "market comparable fees charged by service providers for similar services" change over time, consider whether variable A of the base fee should be approved annually.]

(2) Once every three years after the Board has approved the fees submitted by the Financial Services Manager under section 3, or more frequently if the Board requires but not more frequently than annually, the Board may require the Financial Services Manager to engage, on behalf of and at the cost of the financing entities, a third-party independent consultant to review and advise as to the appropriate benchmarks and range of values for [annual rates?] used for the purpose of determining the base fee and forecast interest rates used for the purposes of determining the variable fee and shall give due consideration to such advice.]

Commencement

x. This Regulation comes into force on the day it is filed.

Document comparison by Workshare Compare on September-23-17 6:39:45 PM

Input:	
Document 1 ID	interwovenSite://INVENTORYS1/TorysAtWork/24180663/1
Description	#24180663v1<TorysAtWork> - Fair Hydro Fee Regs (Torys Comments)
Document 2 ID	interwovenSite://INVENTORYS1/TorysAtWork/24180663/3
Description	#24180663v3<TorysAtWork> - Fair Hydro Fee Regs (Torys Comments)
Rendering set	Firm_Standard

Legend:	
Insertion	
~~Deletion~~	
~~Moved from~~	
Moved to	
Style change	
Format change	
~~Moved deletion~~	
Inserted cell	
Deleted cell	
Moved cell	
Split/Merged cell	
Padding cell	

Statistics:	
	Count
Insertions	70
Deletions	58
Moved from	8
Moved to	8
Style change	0
Format changed	0
Total changes	144

From:	Ronald Kwan
To:	Scott Nelms (ENERGY)
Cc:	Nancy Kennedy (MOHLTC)
Subject:	Fwd: OPG BP Submission
Date:	Thursday, April 27, 2017 8:11:52 AM
Attachments:	2017 04 26 OPG concurrence letter v9_markup2.docx ATT00001.htm

Hi Scott,

A few suggestions on an ONFA part.

OPG may consider it important to note the specific DGR. A DGR elsewhere, over a different timeframe to find and get approvals for would affect the liability estimates.

Ron

From: Nelms, Scott (MOF) <Scott.Nelms@ontario.ca>
Sent: April 26, 2017 4:06 PM
To: Nancy Kennedy (MOHLTC); Ronald Kwan
Cc: Vivienne Skoberne (MOHLTC); Montgomery, Kaitlin (MOF)
Subject: OPG BP Submission

Hi Nancy, Ron,

Please see the attached OPG BP package and draft concurrence letter. This has been shared with ENE DMO / MO. Ron, I think you were planning to share up with MoF on our side.

Thanks,

Scott

Mr. Bernard Lord
Chair
Ontario Power Generation
1900-700 University Avenue
Toronto ON M5G 1X6

Dear Mr. Lord,

Thank you for your submission of Ontario Power Generation's (OPG) 2017-2019 Business Plan ("the Plan"). We have reviewed the Plan and find it to be consistent with our government's expectations.

I support the operational and financial targets set by OPG in its business plan. We recognize the substantial cost reductions that OPG has recently achieved and expect OPG to work closely with the Province to fully realize the additional efficiencies incorporated in the Plan in a manner that is consistent with the continued safe and environmentally responsible operation of OPG's facilities.

We commend OPG on its successful start to the Darlington Refurbishment Project, a key objective of Ontario's 2013 Long-Term Energy Plan (2013 LTEP). As a priority project for the government, I expect that OPG will continue to focus on delivering the project as per the schedule and budget contained in the Release Quality Estimate approved by the OPG Board and by the government. I also expect OPG to continue to minimize project risks consistent with the nuclear refurbishment principles set out in the 2013 LTEP, and seek concurrence prior to commencing ~~subsequent unit~~ refurbishment~~s after~~of Unit ~~2~~3 ~~is successfully returned to service~~before the end of 2017.

We continue to support the planned operation of Pickering units up to 2022/2024, subject to OPG obtaining necessary regulatory approvals, as the station's output will provide reliable, cost-effective and emission-free electricity supply during the Darlington and initial Bruce refurbishments. I expect OPG to keep the Ministry apprised throughout the regulatory processes and as we proceed to update the Long-Term Energy Plan. .

I understand that the recently approved Ontario Nuclear Funds Agreement (ONFA) Reference Plan has resulted in a reduction of the estimated liabilities for future decommissioning and long-term management of waste from Ontario's nuclear fleet. With many decades of nuclear generation in the Province's future, we expect OPG to continue managing its decommissioning and waste management obligations and related segregated funds in a prudent manner. I recognize that the ONFA Reference Plan is based on OPG's proposed siting of a Deep Geological Repository (DGR) for low and intermediate level waste at the Bruce site. OPG's DGR is a key component of Ontario's plans to ensure that nuclear remains the backbone of our electricity system for years to come.

I appreciate the efforts of OPG staff, management and the Board of Directors to date as we worked to develop a plan to refinance the Global Adjustment (GA). Refinancing the GA would provide significant and immediate rate relief by spreading the cost of electricity investments over the expected lifecycle of the infrastructure that has been

built. OPG will be instrumental to the success of this initiative and we plan to introduce legislation that would, if passed, enable OPG to work with the Independent Electricity System Operator (IESO) to implement this plan. I also expect to make the necessary changes to OPG's articles of amalgamation to provide the financing flexibility to implement the refinancing of the GA to meet the Province's price objectives announced on March 2, 2017.

I expect OPG to continue to keep the government informed with regard to the company's key ongoing and emerging initiatives and progress in achieving its financial and operational performance commitments. As OPG's performance directly impacts Ontario's fiscal plan, we note the importance of achieving or exceeding OPG's financial performance commitments

Consistent with Section 7 of the Memorandum of Agreement, in advance of commencing discussions for the renewal of its collective agreements with its unions, I expect that OPG shall seek advice from the Ministry on Provincial policy direction and relevant fiscal considerations affecting labour negotiations.

This letter constitutes our concurrence with OPG's Board approved 2017-2019 Business Plan as provided for under the Memorandum of Agreement between OPG and the Shareholder dated July 17, 2015.

This letter also confirms the approval of special status for OPG to approve international travel, under Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive. OPG shall submit semi-annual reports on international travel to the Ministry of Energy, as described in the submission received from OPG's President and CEO, dated January 24, 2017.

Sincerely,

Glenn Thibeault
Minister of Energy

c: Jeff Lyash, President and Chief Executive Officer, OPG
Serge Imbrogno, Deputy Minister, Ministry of Energy
Scott Thompson, Deputy Minister, Ministry of Finance
Andrew Teliszewsky, Chief of Staff, Ministry of Energy
Ali Ghiassi, Chief of Staff, Ministry of Finance

From:	John Kim
To:	Ronald Kwan
Subject:	Fwd: Summary of the OFHP
Date:	Thursday, October 26, 2017 5:37:59 PM

Hi Ron,

Not sure what this is about but sharing first.

John

Sent from my iPhone

Begin forwarded message:

> **From:** Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
> **Date:** October 26, 2017 at 5:10:09 PM EDT
> **To:** John Kim <John.Kim@ofina.on.ca>
> **Cc:** Carlos Yep <Carlos.Yep@ofina.on.ca>, John Psinas <John.Psinas@ofina.on.ca>, James Devine <James.Devine@ofina.on.ca>, Anna Strathy <Anna.Strathy@ofina.on.ca>
> **Subject: Summary of the OFHP**
>
> Hi john
>
> The way I understand the operations of the OFHP at least for the first 4 years is as follows:
>
> IESO pays 100% to the generators and charges ratepayers approximately 83%, with the difference set up as a regulatory asset funded vi a credit facility of $2 billion form the Province. On a quarterly basis the regulatory asset will be purchased by the Financing Entity with debt issued to OPG (49%) and the capital markets (51%).
>
> Over the first four years the Financing Entity has no revenue sources hence interest on this debt will be paid via additional borrowings issued in the same proportion. Once the CEA kicks in, it will be used to pay interest and draw down debt as appropriate.
>
> Happy to discuss, I am relatively free in the AM tomorrow.
>
> Thanks
>
> Ken k

From: Bruno Amara
To: Ronald Kwan
Cc: Gavin He; Shajee Kathirgamanathan; Usman Zahid
Subject: Interim Electricity Outlook update
Date: Wednesday, December 13, 2017 2:20:34 PM
Attachments: Electricity Sector Outlook (2017 12 13).xlsm

Hi Ron,

Attached is a draft updated Electricity Outlook. OB/OEP have requested an Interim update to help them prepare for upcoming briefings in context of Pre-election report. This outlook is consistent with revised ESDI figures sent to CQSD. We did speak with OEP and OB and they confirmed that a revised outlook should be consistent with our PRRT submission.

Also below is the proposed cover email for when we distribute the updated electricity outlook. We are still confirming with SIFB that we are coordinated on the "unpacking" and are also trying to get other updates as we can e.g., NUGs, IOD, IFRS. Regarding the latter OPCD has indicated that they do not as of yet have IFRS adjustment updates but will let us know when they do.

S:\Users\CEF\Hydro 2017\OEFC\RbP\Outlook\12. December

Hi

Attached is our Electricity update as of December 13, 2017. **Key changes** in the electricity outlook since our previous update include the following.

- The full projected IFRS adjustments are reflected in OPG's net income outlook lowering OPG net income by $475M in 2018-19, $500M in 2019-20 and $750M in 2020-21. But we assume that a final decision on IFRS adjustments will be made centrally.

	2017-18	2018-19	2019-20	2020-21
Projected OPG IFRS adjustments (source OPCD)	(400)	(475)	(700)	(750)
Risks Built into Fiscal Plan at 2017 Budget	(400)	0	(200)	0
Additional Risks now picked up in this Electricity Outlook	0	(475)	(500)	(750)

- The revenue impact related to the asset optimization strategy are now re-categorized from sales and rental to respective electricity lines as dispositions have been completed. This includes impacts of OPG's head office sale in 2017-18 and ongoing net income impact of Hydro One share sales. These re-categorizations should be largely fiscally-neutral other than finalization/refinement of previous estimates
- The negative impact of the OEB tax decision (about $15M per year) with respect to Hydro One's transmission rate application, which was reflected in the previous electricity outlook has been reversed pending decision on Hydro One's motion to review and appeal. In addition, Hydro One clarified that if the OEB decision is upheld it would be reflected as a one-time write-down rather than an ongoing annual impact. This risk is reflected in the Risk table in the "Revenue (Risks)" tab.
- Other minor updates.

Key risks that could affect the electricity outlook include

- The final outcome of Hydro One's motion to review OEB decision, as well as the potential outcome of a legal appeal in the event of an adverse decision to the motion to review, with respect to sharing of tax savings (negative risk)
- OEB decision on OPG's rate application for the 2017 to 2021 period (one-time negative impact in 2017-18)
- ONFA adjustment (currently a positive risk in 2017-18) which will be reflected in OPG's results in the fiscal planning stage

There is still **information to come** that could change the outlook before the Document. This includes the following:

- OEB decision and order with respect to OPG's rate application for the 2017 to 2021 period (expected soon)
- OEB decision on Hydro One's distribution rate application (expected 1st half of 2018)
- Year-end results for OPG and Hydro One
- Monthly results for OPG
- ONFA adjustment result as of December 31, 2017
- Decision on PRRT submission to continue ESDI payments to OEFC beyond 2017-18

Bruno Amara
Sr. Manager, Financial and Regulatory Analysis
Electricity Finance Branch
Corporate and Electricity Finance Division
Ontario Financing Authority

Tel: 416-325-1489
Email: bruno.amara@ofina.on.ca

Electricity Sector Outlook
October 2017

Disclosure:

All information contained in this workbook is confidential and commercially sensitive

All projected numbers are estimates and subjected to change

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Please consult with OFA before sharing of information.

Commercially Sensitive and Confidential Advice to Cabinet for Consideration of Options for Discussion Purposes Only

Commercially Sensitive and Confidential Advice to Cabinet for Consideration of Options for Discussion Purposes Only

Electricity Sector Outlook
Including Line Items for Consolidation

Electricity Summary - On Deck

			MOF Expense Items (consolidated)	Current Outlook			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**38**	Power Supply Contract Costs	(292)	(325)	(301)	(273)
Expense	**MOF (OEFC)**	**40**	Demand Management Support Costs	(10)	-	-	-
Expense	**MOF (OEFC)**	**41**	Provision for Electricity Sector	306	-	-	-
Expense	**MOF**	**17**	Provision for Electricity Sector	(306)	-	-	-
Expense	**MOF (OEFC)**	**42**	Other (Finance)	(6)	(7)	(7)	(7)
			Total MOF Expense	**(308)**	**(332)**	**(308)**	**(280)**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**7**	OPG Income	430	245	108	291
Revenue	**ENE**	**8**	OPG - ONFA and other Fair Value Adjustments	-	-	-	-
Revenue	**ENE**	**10**	HOI Income	329	326	387	418
Revenue		**11**	Brampton Income	-	-	-	-
Revenue	**MOF (OEFC)**	**26**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	484	488	541	681
Revenue	**MOF (OEFC)**	**29**	Electricity Debt Retirement Charge	623	-	-	-
Revenue	**MOF (OEFC)**	**30**	Power Supply Contract Recoveries	292	325	301	273
Revenue	**MOF (OEFC)**	**31**	Net Reduction of Power Purchase Contracts	74	41	30	28
Revenue	**MOF (OEFC)**	**34**	Miscellaneous	-	-	-	-
			Total MOF Revenue	**2,232**	**1,425**	**1,368**	**1,691**
			OFA IOD Expense				
			Public Debt Interest - Electricity Sector	(454)	(454)	(454)	(454)
			Interest on Debt	(475)	(438)	(411)	(348)
			Total OFA IOD Expense	**(929)**	**(892)**	**(865)**	**(802)**
			Impact on Surplus/Deficit	**996**	**201**	**195**	**609**
			check	**-**	**-**	**-**	**-**

Electricity Summary - Budget 17

	For Discussion		MOF Expense Items (consolidated)	Plan			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**38**	Power Supply Contract Costs	(292)	(325)	(301)	(273)
Expense	**MOF (OEFC)**	**40**	Demand Management Support Costs	(10)	0	0	0
Expense	**MOF (OEFC)**	**41**	Provision for Electricity Sector	125	0	0	0
Expense	**MOF**	**17**	Provision for Electricity Sector	(125)	0	0	0
Expense	**MOF (OEFC)**	**42**	Other (Finance)	(6)	(6)	(6)	(6)
			Total MOF Expense	**(308)**	**(331)**	**(307)**	**(279)**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**7**	OPG Income	97	732	625	1,066
Revenue	**ENE**	**8**	OPG - ONFA and other Fair Value Adjustments	0	0	0	0
Revenue	**ENE**	**10**	HOI Income	520	562	603	652
			Brampton Income				
Revenue	**MOF (OEFC)**	**25**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	405	476	538	679
Revenue	**MOF (OEFC)**	**29**	Electricity Debt Retirement Charge	623	0	0	0
Revenue	**MOF (OEFC)**	**30**	Power Supply Contract Recoveries	292	325	301	273
Revenue	**MOF (OEFC)**	**31**	Net Reduction of Power Purchase Contracts	74	41	30	28
Revenue	**MOF (OEFC)**	**34**	Miscellaneous	0	0	0	0
			Total MOF Revenue	**2,011**	**2,136**	**2,098**	**2,697**
			OFA IOD Expense				
		17	Public Debt Interest - Electricity Sector	(492)	(492)	(492)	(492)
		36	Interest on Debt	(422)	(374)	(342)	(250)
			Total OFA IOD Expense	**(914)**	**(866)**	**(834)**	**(742)**
			Impact on Surplus/Deficit	**789**	**939**	**957**	**1,676**
			check	**-**	**-**	**-**	**-**

Electricity Summary - Change

			MOF Expense Items (consolidated)	Variance from Plan			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**69**	Power Supply Contract Costs	0	0	0	(0)
Expense	**MOF (OEFC)**	**71**	Demand Management Support Costs	0	0	0	0
Expense	**MOF (OEFC)**	**72**	Provision for Electricity Sector	181	0	0	0
Expense	**MOF**	**48**	Provision for Electricity Sector	(181)	0	0	0
Expense	**MOF (OEFC)**	**73**	Other (Finance)	0	(1)	(1)	(1)
			Total MOF Expense	**0**	**(1)**	**(1)**	**(1)**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**38**	OPG Income	333	(487)	(517)	(774)
Revenue	**ENE**	**39**	OPG - ONFA and other Fair Value Adjustments	0	0	0	0
Revenue	**ENE**	**41**	HOI Income	(190)	(235)	(216)	(234)
			Brampton Income	0	0	0	0
Revenue	**MOF (OEFC)**	**25**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	79	12	4	2
Revenue	**MOF (OEFC)**	**60**	Electricity Debt Retirement Charge	0	0	0	0
Revenue	**MOF (OEFC)**	**61**	Power Supply Contract Recoveries	(0)	(0)	(0)	0
Revenue	**MOF (OEFC)**	**62**	Net Reduction of Power Purchase Contracts	(0)	(0)	(0)	(0)
Revenue	**MOF (OEFC)**	**65**	Miscellaneous	0	0	0	0
			Total MOF Revenue	**221**	**(710)**	**(730)**	**(1,006)**
			OFA IOD Expense				
		17	Public Debt Interest - Electricity Sector	38	38	38	38
		36	Interest on Debt	(53)	(64)	(69)	(98)
			Total OFA IOD Expense	**(15)**	**(26)**	**(31)**	**(60)**
			Impact on Surplus/Deficit	**207**	**(737)**	**(762)**	**(1,067)**
			check	***(0)***	***-***	***-***	***-***

Track Changes in Surplus/Deficit

Date	Change ID#	Source	Tab
5/1/2017	20170501-1	Link	ONFA
5/1/2017	20170501-2	Link	Hydro One
5/1/2017	20170501-3	Link	Hydro One
5/1/2017	20170501-4	Link	Other Data
5/2/2017	20170502-1	Link	OPG
5/9/2017	20170509-1	Link	OPG
5/10/2017	20170510-1	Link	Hydro One
5/10/2017	20170510-2	Link	Other Data
5/12/2017	20170512-1	Link	Hydro One
5/15/2017	20170515-1	Link?	
5/15/2017	20170515-2	Link	OPG
5/17/2017	20170517-1	Link	Hydro One
5/17/2017	20170517-2	Link	ONFA
5/17/2017	20170517-3		
5/18/2017	20170518-1	Link	OPG
5/18/2017	20170518-2	Link	OPG
5/18/2017	20170518-3		
6/15/2017	20170615-1	Link	OPG
6/22/2017	20170622-1	Link	Hydro One
6/22/2017	20170622-2	Link	Hydro One
6/26/2017	20170626-1		
6/29/2017	20170629-1		

7/6/2017	20170706-1		
7/11/2017	20170711-1		
7/13/2017	20170713-1	Link	Provision
7/17/2017	20170717-1	Link	Revenue (Risks)
7/24/2017	20170724-1	Link	Revenue (Risks)
7/25/2017	20170725-1	Link	Revenue (Risks)
7/26/2017	20170726-1	Link	Revenue (Risks)
7/27/2017	20170727-1	Link	Revenue (Risks)
7/27/2017	20170727-2	Link	Revenue (Risks)
7/31/2017	20170731-1		
7/31/2017	20170731-2	Link	Hydro One
7/31/2017	20170731-3	Link	Other Data
8/11/2017	20170811-1	Link	OPG
8/15/2017	20170815-1		
8/15/2017	20170815-2		
8/15/2017	20170815-3		
8/15/2017	20170815-4		
8/15/2017	20170815-5		Other Data
8/15/2017	20170815-6		Other Data
8/15/2017	20170815-7		Other Data
8/15/2017	20170815-8		Other Data
8/15/2017	20170815-9		Other Data
8/15/2017	20170815-10		Other Data
8/17/2017	20170817-1	Link	Provision
8/17/2017	20170817-2	Link	Hydro One
8/18/2017	20170818-1	Link	Revenue (Risks)
8/22/2017	20170822-1	Link	OPG
8/25/2017	20170825-1		Hydro One
8/29/2017	20170829-1		Revenue (Risks)
8/31/2017	20170831-1		Revenue (Risks)
9/5/2017	20170905-1		Other Data
9/5/2017	20170905-2		Other Data
9/5/2017	20170905-3	Link	OPG

9/6/2017	20170906-1	Link	Other Data
9/6/2017	20170906-2	Link	Revenue (Risks)
9/8/2017	20170908-1	Link	Hydro One
9/8/2017	20170908-2	Link	OPG
9/11/2017			
9/12/2017			
9/13/2017			
9/21/2017			
9/22/2017			
10/2/2017			Hydro One
10/2/2017			
10/2/2017			
10/2/2017			
10/4/2017	20171004-1		OPG
10/4/2017	20171004-2		OPG
10/4/2017			
10/4/2017			
10/5/2017			
10/6/2017			
10/7/2017			
10/8/2017			
10/10/2017	20171010-1		Hydro One
10/10/2017			
10/10/2017			
10/11/2017	20171011-1		OPG
10/11/2017			
10/11/2017			
10/12/2017			OPG
10/12/2017			
10/12/2017			
10/12/2017			
10/18/2017	20171018-1		Hydro One
10/18/2017	20171018-1		Hydro One
10/18/2017	20171018-1		Hydro One
10/19/2017	20171019-1		Revenue (Risks)
10/19/2017	20171019-2		Revenue (Risks)
10/20/2017	20171020-1		Revenue (Risks)
10/20/2017	20171020-2		
10/20/2017	20171020-2		
10/20/2017	20171020-2		
10/20/2017	20171020-3		Revenue (Risks)
10/20/2017	20171020-4		OPG
10/20/2017	20171020-4		OPG
10/20/2017	20171020-4		OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017	20171114-1		Hydro One

11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017		Hydro One
11/14/2017		Hydro One
11/14/2017		Hydro One
11/30/2017	20171130-1	Revenue (Risks)
12/8/2017		Hydro One
12/11/2017	20171211-1	Other Data
12/11/2017	20171211-1	Other Data

FOR EFB USE ONLY

Budget 2017 Outlook
Current Outlook
Change Since Budget

Description of Update
ONFA Update as of March 31 2017
s. 50.3 Update for 2016-17
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Debt Interest
OPG IFRS Risk in 2019-20
Revised OPG 2016-17 Net Income
Revised OPG 2016-17 Net Income
Revised OPG 2016-17 Net Income
tech change: slight update to assumed Prov share 70.05% from 70%
tech change: slight update to assumed Prov share 70.05% from 70%
tech change: slight update to assumed Prov share 70.05% from 70%
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
Updating H1 2016-17 Net Income for ESDI
Updating H1 2016-17 Net Income for ESDI
Updating H1 2016-17 Net Income for ESDI
Power Purchase Supply
H1 Model Forecasts - No Fiscal Update Resaving Data
Update Budget 2017 Tabs to reflect fiscal plan
Update OPG forecasted PILS to reflect sources
Update H1 2016-17 CIT
Re-inputting ONFA updates
Updating H1 Net Income to include Pref Shares in 16-17
Updating OPG Income Tax Expense for 2016-17
Updating OPG non-income tax PILs
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2017
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2018
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2019
Updating with actual OPG IFRS Adjustment 2016-17
Updating with actual OPG IFRS Adjustment 2016-17
Updating with actual OPG IFRS Adjustment 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
[NOT APPLIED] Updating H1 Brampton (Interim Adjustments)
Shifted H1 Brampton 2016-17 NI to the 2017-18
Removed H1 Brampton for 2016-17 (pending finals)
Removed H1 Brampton for 2016-17 (pending finals)
Removed H1 Brampton for 2016-17 (pending finals)

add prior-year adjustment for 2016-17

add prior-year adjustment for 2016-18
Reconfigured calculation of ESDI and MOF ESDI Expense
Reconfigured calculation of OPG 2017-18 Net Income
Backup for the Provincial Interest cost
Linking source for Revenue Risks Tab
New source for Revenue Risks Tab
Revenue Risks Tab - ROE Risks
Updating OEB Risk for OPG
OEB Staff Report - H1 Tx - Revenue Risks
OPG Pensions - Cash vs Accrual Deferral Accounts
Updating Links in Electricity Summary Change and OEFC Change
Preliminary estimate for Hydro One Brampton
Preliminary estimate for Hydro One Brampton
Preliminary estimate for Hydro One Brampton

Updating DRC for Actuals 2016-17 (Based on draft FS)
Updating PILs for 2016-17 Baced on Actuals
OPG: Non-ONFA Fair Value Adjustment
Round all Hydro One ownership assumptions to two decimal places
H1 Equity Adjustment rounding.
Round all Hydro One ownership assumptions to two decimal places
Round all Hydro One ownership assumptions to two decimal places
Revising source of ESDI, Dedicated Electricity Earnings
2016-17 - Update Power Supply Recoveries to actuals
2016-17 - Update Power Supply Recoveries to actuals
2016-17 - Updating Miscellaneous OEFC Revenue to Actuals
Adj: Exclude Bramton $15m add prior year adjustment +$3M
Adj: Exclude Bramton $15m add prior year adjustment +$3M
Public Accts: Updated IESO debt interest Interest On Debt, 2016-17
Public Accts: 2016-17 - Demand Management Support Costs Update
2017-18 - Demand Management Support Costs (no change)
Public Accts: 2016-17 - Updating Operating Expense in OEFC
Sourcing Provision for Electricity Sector from Actual Public Accounts
Revised 2016-17 Brampton Amount for Public Accounts
OPG Pensions - Cash vs Accrual Deferral Accounts (Revenue Risks Tab)
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
Reclassification
Reclassification
Reverting H1 Ownership change (undoing 20170518-3)
Reverting H1 Ownership change (undoing 20170518-3)
Reverting H1 Ownership change (undoing 20170518-3)
Updating Risks based on Hydro One Q2 Results Model
Avista Acquisition Risks
NUG Amortization Liability (sourcing amortization schedule)
2016-17 Actuals - Debt Guarantee Fee
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results

Interest Revenue for IESO and "Other"
OPG Revenue Risks from OEB Filings
Net income corrected for Preferred Shares
Net income corrected for Preferred Shares
Net income corrected for Preferred Shares
Made link edits to OPG sheet so that the "Net Income Before Tax" 2017-18 number is not a h
Updated PILs to include OPCD public accounts adjustment
Provision tab fix to pick up Hydro One preferred share net income
Provision tab fix to pick up Hydro One preferred share net income
FTD Update to OEFC Outlook (Sep 19, 2017) OPG Interest
FTD Update to OEFC Outlook (Sep 19, 2017) Other Interest
Update to Hydro One PILs from information in Transmission rate application material
OEB September 28, 2017 Hydro One decision and order impact - incl. rebasing
OEB September 28, 2017 Hydro One decision and order impact - incl. rebasing
OEB September 28, 2017 Hydro One decision and order impact - incl. rebasing
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Debenture Interest Costs - Removing from Revenue (Risks) and adding it ot H1 Model
Debenture Interest Costs - Removing from Revenue (Risks) and adding it ot H1 Model
Debenture Interest Costs - Removing from Revenue (Risks) and adding it ot H1 Model
Updated OPG Net Income and PILs based on monthly report (August 2017 results)
Updated OPG Net Income and PILs based on monthly report (August 2017 results)
Updated OPG Net Income and PILs based on monthly report (August 2017 results)
Correction to PILs on OPG sheet
Correction to PILs on OPG sheet
Correction to PILs on OPG sheet
Correction to PILs on OPG sheet
Switch to Direct from Model
Switch to Direct from Model
Switch to Direct from Model
Updating ROE Risks
Updating H1 Load Risks based on model output
Updating ONFA Risks for September 2017
Adjust OEB decision/rebasing to ~50% provincial ownership
Adjust OEB decision/rebasing to ~50% provincial ownership
Adjust OEB decision/rebasing to ~50% provincial ownership
Updating OPG
OPG IOD impact from GA Financing, FHP
OPG IOD impact from GA Financing, FHP
OPG IOD impact from GA Financing, FHP
Unpacking updated OPG Gain on sale (net income)
Unpacking updated OPG Gain on sale (net income)
Unpacking updated OPG Gain on sale (net income)
Unpack PILs related to HQ gain on sale
Updating IFRS Risk
Adjustment for lower Provincial share (from 70.1% to 50.9 2017-18 & 47.4% after)
Adjustment for lower Provincial share (from 70.1% to 50.9 2017-18 & 47.4% after)
Adjustment for lower Provincial share (from 70.1% to 50.9 2017-18 & 47.4% after)
November 1 and November 7 Hydro One model updates

November 1 and November 7 Hydro One model updates	Expense
November 1 and November 7 Hydro One model updates	Expense
Revise Hydro Model to reverse OEB tax decision ongoing annual impact	Expense
Revise Hydro Model to reverse OEB tax decision ongoing annual impact	Expense
Revise Hydro Model to reverse OEB tax decision ongoing annual impact	Expense
Undo allocation adjustment in H1 tab (now that provincial shares are updated)	Revenue
Undo allocation adjustment in H1 tab (now that provincial shares are updated)	Revenue
Undo allocation adjustment in H1 tab (now that provincial shares are updated)	Revenue
Updating OPG Revenue Risks from rate application	Revenue
Update Hydro One PILs (reverses update on line 119 whuich did not account fro Dx side)	Revenue
Updating Debt Guarantee Fee	Revenue
Updating OEFC Operating Expense	Revenue
This line show net impact of latest change. READ COMMENT	

	Expense
	Expense
	Expense
	Expense
	Expense

Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue

$ Millions

		2016-17	2017-18	2018-19	2019-20
		930	789	939	957
	File	915	996	201	195
		-15	207	-737	-762
	check	*0*	*0*	*0*	*0*
		Impacts by FY →			
Outlook line affected	**Expense / Reve**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
ONFA and other Fair Value Adjustments	Revenue	41.0	0.0	0.0	0.0
N/A		0.0	0.0	0.0	0.0
?		0.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		38.1		
Provision for Electricity Sector (MOF)	Expense		(38.1)		
Public Debt Interest - Electricity Sector	Expense	0.0	38.1	38.1	38.1
Interest on Debt	Expense	0.0	(69.1)	(79.1)	(75.1)
OPG Income	Expense	0.0	0.0	0.0	
OPG Income	Revenue	(2.0)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**(2.0)**			
Provision for Electricity Sector (MOF)	Expense	2.0			
HOI Income	Revenue	0.4			
Provision for Electricity Sector (OEFC)	Expense	0.4			
Provision for Electricity Sector (MOF)	Expense	(0.4)			
Public Debt Interest - Electricity Sector	Expense	1.7			
Provision for Electricity Sector (OEFC)	Expense	(1.7)			
Provision for Electricity Sector (MOF)	Expense	1.7			
Interest on Debt	Expense	(1.7)			
HOI Income	Revenue	(39.8)	0.0	0.0	(0.0)
Provision for Electricity Sector (OEFC)	Expense	**(39.8)**			
Provision for Electricity Sector (MOF)	Expense	39.8			
	Revenue	-	-	-	-
	Revenue	-	-	-	-
	n/a	-	-	-	-
		-	-	-	-
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	4.7	0.0	0.0	0.0
	Revenue	0.0	0.0	0.0	0.0
HOI Income	Revenue	18.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	7.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	8.0	9.0	12.0	3.5
HOI Income	Revenue	0.0	(141.5)	(181.4)	(194.9)
Provision for Electricity Sector (OEFC)	Expense		(141.5)		
Provision for Electricity Sector (MOF)	Expense		141.5		
OPG Income	Revenue	(3.0)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**(3.0)**			
Provision for Electricity Sector (MOF)	Expense	3.0			
HOI Income	Revenue	7.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**7.0**			
Provision for Electricity Sector (MOF)	Expense	(7.0)			
	Revenue	-	-	-	-
	Revenue	0.0	0.0	0.0	0.0
Brampton Income	Revenue	(14.7)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**(14.7)**			
Provision for Electricity Sector (MOF)	Expense	14.7			

Provision for Electricity Sector (OEFC)	Expense		3.2			
Provision for Electricity Sector (MOF)	Expense		(3.2)			
	Revenue	-	-	-	-	
		-	-	-	-	
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
Brampton Income	Revenue		15.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		**15.0**			
Provision for Electricity Sector (MOF)	Expense		(15.0)			
Provision for Electricity Sector (OEFC)	Expense		3.2			
Provision for Electricity Sector (MOF)	Expense		(3.2)			
Electricity Debt Retirement Charge	Revenue		(4.0)	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue		(29.0)	0.0	0.0	0.0
OPG Income	Revenue		(6.0)	0.0	0.0	0.0
HOI Income	Revenue		(0.0)	(0.0)	0.0	0.0
HOI Income	Revenue		(1.7)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense			(0.0)		
Provision for Electricity Sector (MOF)	Expense			0.0		
	Revenue		0.0	0.0	0.0	0.0
Power Supply Contract Recoveries	Revenue		99.0	0.0	0.0	0.0
Power Supply Contract Costs	Expense		(99.0)			
Miscellaneous	Revenue		14.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		(12.0)			
Provision for Electricity Sector (MOF)	Expense		12.0			
Interest on Debt	Expense		(3.0)	0.0	0.0	0.0
Demand Management Support Costs	Expense		1.8	0.0	0.0	0.0
			0.0	0.0	0.0	0.0
Other (Finance)	Expense		(1.0)	0.0	0.0	0.0
	Revenue	-	-	-	-	
Brampton Income	Revenue		3.0	0.0	0.0	0.0
			0.0	0.0	0.0	0.0
OPG Income	Revenue		0.0	85.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue			(6.0)		
Provision for Electricity Sector (OEFC)	Expense			**85.0**		
Provision for Electricity Sector (MOF)	Expense			(85.0)		
OPG Income	Revenue		6.0			
ONFA and other Fair Value Adjustments	Revenue		(6.0)			
HOI Income	Revenue		0.0	141.9	181.8	195.4
Provision for Electricity Sector (OEFC)	Expense			141.9		
Provision for Electricity Sector (MOF)	Expense			(141.9)		
	n/a		0.0	0.0	0.0	0.0
			0.0	0.0	0.0	0.0
Net Reduction of Power Purchase Contracts	Revenue		0.1	(0.1)	(0.1)	(0.1)
	Revenue		0.0	0.0	0.0	0.0
OPG Income	Revenue		0.0	16.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue			(1.0)		
Provision for Electricity Sector (OEFC)	Expense			**16.0**		
Provision for Electricity Sector (MOF)	Expense			(16.0)		

		0.0	0.0	0.0	0.0
	n/a	0.0	0.0	0.0	0.0
HOI Income	Revenue	0.0	5.3	5.3	5.3
Provision for Electricity Sector (OEFC)	Expense		(12.4)		
Provision for Electricity Sector (MOF)	Expense		12.4		
ardcoded formula in the cell	n/a	0.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	(30.4)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		17.8		
Provision for Electricity Sector (MOF)	Expense		(17.8)		
Interest on Debt	Expense	(0.0)	1.0	(0.0)	1.0
Interest on Debt	Expense	0.0	15.0	15.0	5.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	0.0	(7.8)	(8.7)	(10.3)
HOI Income	Revenue	0.0	(47.4)	(54.0)	(54.0)
Provision for Electricity Sector (OEFC)	Expense	0.0	(47.4)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	47.4	0.0	0.0
OPG Income	Revenue	0.0	(61.0)	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	0.0	(21.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	(61.0)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	61.0	0.0	0.0
OPG Income	Revenue	0.0	(21.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	(21.0)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	21.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	0.0	21.0	0.0	0.0
HOI Income	Revenue	0.0	(23.6)	(27.4)	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	(23.6)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	23.6	0.0	0.0
OPG Income	Revenue	0.0	15.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	15.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	(15.0)	0.0	0.0
OPG Income	Revenue	0.0	21.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	0.0	(18.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	21.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	(21.0)	0.0	0.0
HOI Income	Revenue	0.0	(23.8)	(28.9)	(10.1)
Provision for Electricity Sector (OEFC)	Expense	0.0	(23.8)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	23.8	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
HOI Income	Revenue		16.1	26.7	20.6
Provision for Electricity Sector (OEFC)	Expense		16.1		
Provision for Electricity Sector (MOF)	Expense		(16.1)		
n/a	n/a	0.0	0.0	0.0	0.0
OPG Income	Revenue		(4.9)	(11.9)	(17.1)
Provision for Electricity Sector (OEFC)	Expense		(4.9)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		4.9	0.0	0.0
OPG Income	Revenue		283.0		
Provision for Electricity Sector (OEFC)	Expense		283.0		
Provision for Electricity Sector (MOF)	Expense		(283.0)		
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue		95.0		
OPG Income	Revenue		0.0	(475.0)	(500.0)
HOI Income	Revenue		(112.6)	(142.1)	(170.6)
Provision for Electricity Sector (OEFC)	Expense		(112.6)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		112.6	0.0	0.0
HOI Income	Revenue		(3.3)	(3.0)	(0.1)

Provision for Electricity Sector (OEFC)	Expense		(3.3)		
Provision for Electricity Sector (MOF)	Expense		3.3		
HOI Income	Revenue		14.7	14.4	12.9
Provision for Electricity Sector (OEFC)	Expense		14.7	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		(14.7)	0.0	0.0
HOI Income	Revenue		(16.1)	(26.7)	(20.6)
Provision for Electricity Sector (OEFC)	Expense		(16.1)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		16.1	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)		0.0	7.8	8.7	10.3
n/a	n/a	0.0	0.0	0.0	0.0
Other (Finance)			0.0	(1.0)	(1.0)
		0	***0***	***0***	***0***

Summary of Track Changes Above

Power Supply Contract Costs	(99.0)	0.0	0.0	0.0
Demand Management Support Costs	1.8	0.0	0.0	0.0
Provision for Electricity Sector OEFC)	(44.4)	180.9	0.0	0.0
Provision for Electricity Sector (MOF)	44.4	(180.9)	0.0	0.0
Other (Finance)	(1.0)	0.0	0.0	0.0
OPG Income	(5.0)	333.1	(486.9)	(517.1)
ONFA and other Fair Value Adjustments	35.0	0.0	0.0	0.0
HOI Income	(16.1)	(190.4)	(235.3)	(216.1)
Brampton Income	3.3	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	(39.7)	71.2	3.3	(6.8)
Electricity Debt Retirement Charge	(4.0)	0.0	0.0	0.0
Power Supply Contract Recoveries	99.0	0.0	0.0	0.0
Net Reduction of Power Purchase Contracts	0.1	(0.1)	(0.1)	(0.1)
Miscellaneous	14.0	0.0	0.0	0.0
Public Debt Interest - Electricity Sector	1.7	38.1	38.1	38.1
Interest on Debt	(4.7)	(53.1)	(64.1)	(69.1)
Impact on Surplus/Deficit	**(14.6)**	**198.9**	**(745.0)**	**(771.1)**
check	***0.0***	***(7.8)***	***(7.7)***	***(9.3)***

Check - Summary of Track Changes Above vs. Electricity Summary Change Worksheet

Power Supply Contract Costs	0.0	(0.4)	(0.1)	(0.4)
Demand Management Support Costs	(0.0)	0.0	0.0	0.0
Provision for Electricity Sector OEFC)	8.4	0.1	0.0	0.0
Provision for Electricity Sector (MOF)	(8.4)	(0.1)	0.0	0.0
Other (Finance)	0.0	0.0	1.0	1.0

OPG Income	0.0	0.0	0.0	0.0
ONFA and other Fair Value Adjustments	0.0	0.0	0.0	0.0
HOI Income	(0.0)	0.0	0.0	0.0
Brampton Income	0.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	(0.0)	(7.8)	(8.7)	(10.3)
Electricity Debt Retirement Charge	0.0	0.0	0.0	0.0
Power Supply Contract Recoveries	0.0	0.4	0.1	0.4
Net Reduction of Power Purchase Contracts	(0.0)	(0.0)	(0.0)	(0.0)
Miscellaneous	0.0	0.0	0.0	0.0
Public Debt Interest - Electricity Sector	23.4	0.1	0.1	0.1
Interest on Debt	(23.4)	(0.1)	(0.1)	(0.1)
Impact on Surplus/Deficit	**(0.0)**	**(7.8)**	**(7.7)**	**(9.3)**

2020-21
1,676
609
-1,067
0

2020-21	Further Explanation of Change and source of data
0.0	Regular quarterly ONFA Update
0.0	Benefit to OEFC under s.50.3: $411M gain, SIFB
0.0	Change to OEFC payment for interest costs of Debt for Equity Swap
38.1	Revised Provincial Debt Interest related to Hydro One Equity
(104.1)	From FTD, revised Debt Interest (net of revisions to Provincial and OPG debt interest)
0.0	Revised numbers from OEP with 2019-20 Risk
0.0	Updated numbers from OPG Q1 2017 FS
0.0	Updating H1 Net Income for actuals. Note does not update Brampton Income at this point. Will
-	No Change to numbers, just re-inputting data and saving sources
-	No Change to numbers, just re-inputting data and saving sources
-	No change to fiscal impact numbers. Deleting Budget 2016 and adding Budget 2017 fiscal imp
-	No Change to numbers, just re-inputting data and saving sources
0.0	Updated with CIT Numbers received from H1 as part of s.91.2 MB20 allocation from MOF
0.0	No Change to numbers, just re-inputting data and saving sources
0.0	Only included H1 Net Income - Common Shareholders before. Added preferred shareholder im
0.0	Updating OPG Income Tax Expense with info from OPG Monthly Presentation to Shareholder
1.8	Updating OPG GRC payable to OEFC and Proxy Property Tax from Answer back from OPG al
(210.6)	Based on H1 final offering and expected First Nations Sale by the end of 2017 (CY), with a wei
0.0	Based on EY analysis, and then applying fiscalization. Confirmation also received from OPCD.
0.0	Based on KPMG analysis, then fiscalization and other adjustments from OPCD.
-	**[NOT APPLIED, CALCULATIONS AND DATA LEFT ON THE FILE]** Used Brampton's Financ
0.0	Don't expect finalized 2016-17 data to become available in time for ESDI allocation. Will shift th
0.0	make decision on shifting when we know 2016-17 status.

-	No change to numbers. Just re-organizing spreadsheet. No backup data.
-	No change to numbers. Just re-organizing spreadsheet. No backup data.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided another scenario backup/source
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just updated the links to refer ot the delta between 2017 and On Deck
0.0	Adjustment to ESDI to include Hydro One Brampton
0.0	Finalizing 2016-17 DRC Based on Draft OEFC AR
0.0	Received actual PILs amounts from FTD with breakdown of source. Updated 2016-17 numbers
0.0	2016-17 - Non-ONFA Fair Value Adjustment
0.0	Round Hydro One ownership assumptions to 70.05% two decimal places to be consistent with
0.0	Revising Hydro One Amount for consistency with OPCD. Equity Adjustments
0.0	Updated Provision tab. Made two separate Provision amounts for ESDI in OEFC AR and Dedic
0.0	Updating Power Supply Recoveries to Public Accounts/OEFC AR actuals
0.0	Updating Miscellaneous to OEFC AR actuals
0.0	Updated 2016-17 Interest on Debt (IESO, OPG, Other (Net))
0.0	
0.0	2017-18 - Demand Management Support Costs (no change) - Linking correctly
0.0	2016-17 - Updating Operating Expense in OEFC and corresponding changes elsewhere and s
-	No change to numbers. Just re-organized spreadsheet
0.0	Revised H1 Brampton Net Income (for GBE Line only)
0.0	Revising for OPG's Q3 Finances
0.0	Revising OPG's Net Income for latest monthly report
211.1	Reverting ownership back to 70.05% from change 20170518-3. Will coordinate with other area
0.0	Updating Risks based on Hydro One Q2 Results Model
0.0	Updated two Risk components for the Avista Acquisition.
(0.0)	No significant changes, but used actual amortization liability schedule. Hence the rounding imp
0.0	Updating Debt Guarantee for actuals based on OEFC AR
0.0	Revising OPG's Net Income for latest monthly report

0.0	Linking interest revenue data for 2017-18 to 2020-21
0.0	OPG Revenue Risks from: OEB Staff Submission and OPG Updated Filings
5.3	Corrected Net income for 100% ownership in preferred shares and 70.05% in Commons Share
0.0	Updated the formula in the cell for 2017-18 Net Income Before Tax so that the numbers are no
0.0	Updated PILs to include OPCD public accounts adjustment
1.3	
5.0	
(12.2)	
(54.0)	
0.0	
0.0	
0.0	increase built into net income was $82m between NI and PILs
0.0	Remove $21m from PILs
0.0	expense impacts
0.0	expense impacts
0.0	need to also remove the $21m PILs built into OPG net incme
0.0	
0.0	
0.0	We removed $21m from PILs above, before having added it in (check is that lines 123 to 130 a
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
(13.0)	variances include: 2017-18 preferred vs common share fix, 2018-19 largely ROE change from
0.0	
0.0	
0.0	
0.0	
0.0	
21.6	
0.0	
(24.1)	
0.0	
0.0	
(750.0)	
(185.3)	
0.0	
0.0	
(2.3)	

15.2	
0.0	
0.0	
(21.6)	
0.0	
0.0	
0.0	Updating OPG Rate application Revenue Risks based on revised calculations
12.2	
0.0	
(1.0)	Received Revised FTD Forecast

0

0.0
0.0
0.0
0.0
0.0
(774.1)
0.0
(233.7)
0.0
(10.5)
0.0
0.0
(0.0)
0.0
38.1
(97.8)
(1,078)
(11.2)

t

0.2
0.0
0.0
0.0
1.0

0.0
0.0
(0.0)
0.0
(12.5)
0.0
(0.2)
0.0
0.0
0.1
0.1
(11.2)

Data Validation:

Options
Revenue (F
OPG
Hydro One
Provision

ONFA
Other Data

update once revised numbers are received.

acts

ıpact as well.

bout the BP
ghted average ownership for 2017-18. Also adjusted future net income attributed to the province.

ial Statements to produce an estimate. May require additional calculations.
ıis to 2017-18.

(from 2016 and On Deck)

s to reflect this.

OPCD.

:ated Earnings in Public Accounts.

ources.

s to ensure broadening change and reduction in net income happens concurrently in forecasts.

acts/changes.

es

t hardcoded directly

dd up to -$82m gain that we wanted to remove.

9.09% to 8.78% not previously captured.

Risks)

Electricity Sector Outlook

$ Millions

	Actual 2015-16	Interim 2016-17	Plan 2017-18	2018-19	2019-20	2020-21
On Deck Outlook as of March 2017						
Income from Investment in Government Business Enterprises						
OPG Income[1]	291	304	97	732	625	1,066
OPG - ONFA and other Fair Value Adjustments[2]	172	8	-	-	-	-
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	-
HOI Income[3]	236	516	520	562	603	652
Brampton Income	20	15	-	-	-	-
Total OPG and HOI Income	**719**	**842**	**617**	**1,294**	**1,229**	**1,717**
Other Fees and Licences	**127**	**122**	**102**	**91**	**88**	**81**
Electricity Expenses of the Province						
Provision for Electricity Sector[4]	(3)	(342)	(125)		-	-
Public Debt Interest - Electricity Sector	(520)	(492)	(492)	(492)	(492)	(492)
Subtotal	(523)	(834)	(617)	(492)	(492)	(492)
Public Debt Interest - Impact of ONFA						
Amortization of Deferred Revenue re profit on sale of H1 notes						
Total Electricity Expenses of the Province	**(523)**	**(834)**	**(617)**	**(492)**	**(492)**	**(492)**
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	3,228	373	405	476	538	679
Other Revenue						
Electricity Debt Retirement Charge[5]	859	625	623	-	-	-
Power Supply Contract Recoveries	875	739	292	325	301	273
Net Reduction of Power Purchase Contracts	172	129	74	41	30	28
Other Fees and Licences	(127)	(122)	(102)	(91)	(88)	(81)
Miscellaneous	9	-	-	-	-	-
Expenses						
Interest on Debt	(596)	(532)	(422)	(374)	(342)	(250)
Power Supply Contract Costs	(875)	(739)	(292)	(325)	(301)	(273)
Electricity Consumer Price Protection Fund	-	-	-	-	-	-
Demand Management Support Costs[6]	(8)	(10)	(10)	-	-	-
Provision for Electricity Sector	3	342	125	-	-	-
Other (Finance)	(7)	(6)	(6)	(6)	(6)	(6)
Total OEFC Income	**3,533**	**800**	**687**	**46**	**132**	**370**
Impact on Surplus/(Deficit)	**3,856**	**930**	**789**	**939**	**957**	**1,676**

Notes: The Hydro One net income outlook above (2016-17 to 2020-21) reflects the Province's 70% ownership share after the initial IPO in 2015 and the secondary offering in April 2016. At the time of 2017 Budget, net estimated fiscal impacts from future Hydro One offerings are reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

Notes:

1.OPG's 2016-17 outlook reflected its reported earnings. 2017-18 to 2019-20 reflects OPG's preliminary 2017-2019 business plan (as fiscalized by OPG). 2020-21 estimates are based on OPG's calendar year-based business plan projections. OPG net income also reflects IFRS adjustments fiscal impact decisions that were made centrally.

2. Provincial consolidation adjustments for unrealized earnings on the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds, as of the end of December 2016.

3. Hydro One 2016-17 income reflects its reported net income, adjusted for Hydro One IPO impacts. 2017-18 to 2020-21 projections are based on CEFD projections using the latest public information. The Hydro One net income outlook above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering as of 2017 Budget were reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial ONFA consolidation adjustments, less the interest on the Province's OPG/Hydro One debt payable to OEFC. The provision is currently assumed to end once the DRC ends on a legislated fixed end date of April 1, 2018.

5. Reflects April 23, 2014 announcement that DRC will be eliminated for residential users, after December 31, 2015. The end date of DRC for remaining users is legislated to be on April 1, 2018. Estimates are subject to change based on actual consumption.

6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Electricity Sector Outlook

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
On Deck Outlook as of October 2017						
Income from Investment in Government Business Enterprises						
OPG Income[1]	291	299	430	245	108	291
OPG - ONFA and other Fair Value Adjustments[2]	172	43	-	-	-	-
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	-
HOI Income[3]	236	500	329	326	387	418
Brampton Income	20	18	-	-	-	-
Total OPG and HOI Income	**719**	**860**	**760**	**572**	**496**	**710**
Other Fees and Licences (Debt Guarantee fee)	**127**	**122**	**102**	**99**	**98**	**91**
Electricity Expenses of the Province						
Provision for Electricity Sector[4]	-	(290)	(306)			
Public Debt Interest - Electricity Sector	(520)	(514)	(454)	(454)	(454)	(454)
Subtotal	(520)	(803)	(760)	(454)	(454)	(454)
Public Debt Interest - Impact of ONFA						
Amortization of Deferred Revenue re profit on sale of H1 notes						
Total Electricity Expenses of the Province	**(520)**	**(803)**	**(760)**	**(454)**	**(454)**	**(454)**
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	3,247	334	484	488	541	681
Other Revenue						
Electricity Debt Retirement Charge[5]	859	621	623	-	-	-
Power Supply Contract Recoveries	875	838	292	325	301	273
Net Reduction of Power Purchase Contracts	172	129	74	41	30	28
Other Fees and Licences	(127)	(122)	(102)	(99)	(98)	(91)
Miscellaneous	9	14	-	-	-	-
Expenses						
Interest on Debt	(596)	(513)	(475)	(438)	(411)	(348)
Power Supply Contract Costs	(875)	(838)	(292)	(325)	(301)	(273)
Electricity Consumer Price Protection Fund	-	-	-	-	-	-
Demand Management Support Costs[6]	(8)	(8)	(10)	-	-	-
Provision for Electricity Sector	-	290	306	-	-	-
Other (Finance)	(7)	(7)	(6)	(7)	(7)	(7)
Total OEFC Income	**3,549**	**737**	**894**	**(15)**	**56**	**263**
Impact on Surplus/(Deficit)	**3,876**	**915**	**996**	**201**	**195**	**609**
variance to OEFC check	*(156)*	*(454)*	*(550)*	*(0)*	*0*	*-*

Notes:

1.OPG's 2016-17 outlook reflected its reported earnings. 2017-18 reflects OPG's lates monthly update. 2018 to 2019-20 reflects OPG's preliminary 2017-2019 business plan (as fiscalized by OPG). 2020-21 estimates are based on OPG's calendar year-based business plan projections. OPG net income also reflect projected IFRS adjustments as provided by OPCD at the time of the 2017 Budget.

2. Provincial consolidation adjustments for unrealized earnings on the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds, as of the end of December 2016.

3. Hydro One 2016-17 income reflects its projected net income adjusted for the Province's ownership share in Hydro One following the final offering in May 2017 and including the planned First Nations sale in December 2017. 2017-18 to 2020-21 projections are based on CEFD projections using the latest public information.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial ONFA consolidation adjustments, minus the interest on debt payable to OEFC. The provision is currently assumed to end once the DRC ends on a legislated fixed end date of April 1, 2018. There is currently a PRRT submission to continue ESDI payments to OEFC beyond 2017-18.

5. Reflects April 23, 2014 announcement that DRC will be eliminated for residential users, after December 31, 2015. The end date of DRC for remaining users is legislated to be on April 1, 2018. Estimates are subject to change based on actual consumption.

6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Electricity Sector Change Since Budget	$ Millions					
($million)	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Changes from Budget 2017 as of October 2017						
Income from Investment in Government Business Enterprises						
OPG Income	(5)	333	(487)	(517)	(774)	2016-17 small decrease due to IFRS adjustment revision and OPG Net Income revision. 2017-18 increase mainly due to re-categorization of of OPG head office facilities from Sales and Rentals to OPG net income. Also deferral of Pickering Unit 6 planned outage to Jan 18, deferral of sale of land at Hearn site from Q1 2017 to later in 2017, partially offsdet by lower gropss margin. Decrease in 2018-19 onward is due mainly reflects taking on projeceted IFRS adjustment impacts in those years.
ONFA and other Fair Value Adjustments	35	-	-	-	-	Largely revision to ONFA fair value as of March 31, 2017
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	
HOI Income	(16)	(190)	(235)	(216)	(234)	2016-17 slight decrease from Budget 2017 Interim projection. 2017-18 onwards reflects i) recategorization of Hydro One disposition impacts as of end of 2017 from sales and Rentals to Hydro One net income, ii) impact of OEB decision on Hydro One rates, iii) interest expense on Avitsa debentures (in 2017-18 and 2018-19) and iv) update to Hydro One model update based on Hydro One Q2 results.
Brampton Income	3.3					
Total OPG and HOI Income	**17**	**142.8**	**(722)**	**(733)**	**(1,008)**	
Other Fees and Licences	**-**	**-**	**8**	**10**	**10**	
Electricity Expenses of the Province						
Provision for Electricity Sector	53	(181)	-	-	-	Changes in the Proviision (ESDI) expense in 2017-18 reflect i) an increase in OPG net income including recategorization of OPG head office sale proceeds from Sales and Rentals (exii) lower Hydro One net income including recategorization of Hydro One 2017 disposition impacts from Sales and Rentals and impact of OEB transmission rate decisions and iii) net changes in the outlook for Public Debt Interest.
Public Debt Interest - Electricity Sector	(22)	38	38	38	38	2016-17 PDI at ($514m) was slightly larger than ($492m) projected at Interim. 2017-18 change reflects revised projections for Provincial debt interest related to HydroOne's April 2016 offering. Note the impact of the final offering will be refelected in PDI during 2018.
Total Electricity Expenses of the Province	**31**	**(143)**	**38**	**38**	**38**	

Electricity Sector Change Since Budget	$ Millions					
($million)	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs)	(40)	79	12	4	2	2016-17 decrease largely due to an OPCD Public Accounts PILs adjustment related to reconciling between OPCD and OEFC net opening assets. OPG PILs also slightly lower than projected. 2017-18 increase is due mainly to recategorization of the PILs impact of the OPG head office sale from Sales and Rentals.
Other Revenue						
Electricity Debt Retirement Charge	(4)	-	-	-	-	
Power Supply Contract Recoveries	99	(0)	(0)	(0)	0	Variance is largely due to retroactive payments that the OEFC made to certain non-utility-generators (NUGs) with former Ontario Hydro power purchase agreement contracts with OEFC. OEFC was required to make these payment following the dismissal by the Supreme Court of Canada of OEFC's application for leave to appeal a judgment of the Court of Appeal of Ontario on a 2015 court decision.
Net Reduction of Power Purchase Contracts	0.1	(0)	(0)	(0)	(0)	
Other Fees and Licences	-	-	(8)	(10)	(10)	
Revenue Pool Residual	-	-	-		-	
Miscellaneous	14	-	-	-	-	
Expenses						
Interest on Debt	19	(53)	(64)	(69)	(98)	2017-18 reflects revised debt interest outlook net of revisions to OEFC interest revenue from OPG and Province.
Power Supply Contract Costs	(99)	0	0	0	(0)	Same as Power supply contract recoveries above. Power supply contract costs are fully recovered by power supply contract recoveries.
Electricity Consumer Price Protection Fund	-	-	-	-	-	
Demand Management Support Costs	1.8	-	-	-	-	
Provision for Electricity Sector	(53)	181	-	-	-	See explanation for changes in Provision expense above.
Other (Finance)	(1.0)	-	(1)	(1)	(1)	
Total OEFC Income	**(63)**	**207**	**(61)**	**(77)**	**(107)**	
Impact on Surplus/(Deficit)	**(14.6)**	**207**	**(737)**	**(762)**	**(1,067)**	
Information: Breakdown of change between revenue and expense						
Total Revenue Impact	87	221	(710)	(730)	(1,006)	
Total Expenditure impact	101	15	27	32	61	

Electricity Sector Outlook (PSAB)

Negative Revenue Risks	$ Millions			
($ millions)	**Plan**			
	2017-18	**2018-19**	**2019-20**	**2020-21**
Generic				
OPG Generation Risk: Nuclear Reliability (-1.6 TWh)[1]	(120)	(120)	(120)	(120)
1% decrease in Hydro One actual load[2]	(57)	(59)	(62)	(63)
Lower OPG's Equity weighting & Return on Equity (ROE)[3]	(12)	(20)	(26)	(45)
Lower Hydro One Return on Equity (ROE)[4]	(9)	(36)	(38)	(40)
Regulatory				
Hydro One Distribution rate application[5]	(50)	(50)	(50)	(50)
OPG Switch from accrual based to cash based accounting for pension and OPEB[6]	(600)			
Regulatory Risk - Timing of OPG Rate Decision[7]	(540)			
OEB Staff Recommendations wrt OPG rate application(May 2017)[8]	(187)	(162)	(179)	(210)
Nuclear Liabilities Cash vs. Accrual[9]	(450)	(450)	(450)	(450)
OEB decision on Hydro One tax recapture (if one-time write-down)[10]	(440)			
Accounting				
OPG IFRS Consolidation Risks[11]				
Other Risks				
Avista Acquisition - Termination fee	(51)			

Note: These risks do not reflect the impacts on electricity sector revenue and expense of reclassification of the Asset Optimiz

1. OPG's market and generation risks related to nuclear reliability similar to the scenarios OPG developed for its sales margins to capture major market risk factors (e.g., natural gas prices, coal prices, foreign exchange, nuclear reliability) in its 2012 business plan. Currently, only the nuclear reliability risk is captured at the current regulated rate for OPG's nuclear generation.

2. Estimated revenue impact if Hydro One load for Transmission and Distribution is 1% lower than projected for all years in CEFD Hydro One Forecast. Based on the assumption a 1% increase in load is directly proportional to a 1% change in revenue requirements.

3. Risk range for Hydro One transmission and distribution reflects potential risk of lower ROE by 0.5% vs assumed ROEs in business plan along with reduced deemed debt to equity weighting of 55%/45% from the current 51%/49%.

4. Risk range for Hydro One transmission and distribution reflects potential risk of lower ROE by 0.5% vs assumed ROEs in CEFD Hydro One Forecast based on the most recent rate applications and forecasted ROE rates.

5. OEB is expected to make a decision on Hydro One's Distibution rate application for 2018 during the first half of 2018.

6. The OEB directed a switch to cash-based accounting for years 2014 and 2015. However, the OEB also directed OPG to track the difference between cash based and accrual based accounting in a deferral account, while a generic proceeding is underway for all OEB-regulated electric and gas utilities. OEB September 2017 Report, recommends continuance of variance account which would mitigate this risk. However, the final decision (expected in Fall 2017) will be with the OEB Board.

7. Risk refelects OPG impact if the OEB rate rulings are applied as of the final decision date rather than retroactive to January 1, 2017. OPG's business plan assumed OEB decision would be effective as of January 1, 2017. OPG estimated an impact of -$60M for each month for which OEB decsion is not retroactive.

8. Reflects OEB staff report (May 2017) reccomendations with respect to OPG's rate application. (Inlcudes OPG rate application updates).

9. Risk refelects impact of OEB decision that OPG switch to cash-basis accounting for regulated recovery of nuclear payment anmounts. OEB staff report (May 2017) appears to mitigate this risk as it makes no decision and recommends revisiting this issue in 5 years at next OEB application.

10. The OEB's Sep. 28, 2017 ruling on Hydro One's Transmission rate application included direction on sharing, with ratepayers, tax savings related to the Hydro One IPO. Hydro One filed a Motion to Review this decision with the OEB and has also filed a court appeal. Hydro One's 2017 Q3 financial report notes that if the Motion to Review and appeal are unsuccesful teh company would record a one-time write-down of $885 million reflecting the OEB decision. The risk above reflects this risk at teh Province's 49.9% average share allocation for 2017-18.

11. OPCD provided IFRS impact estimates (largely related to OPG) at the time of Budget 2017. A portion of these were reflected in in OPG's and Hydro One's net income outlook at the time of the 2017. The current Electricity Outlook picks up this additional IFRS risk.
Table below outlines OPG IFRS Risks versus what is built into the Fiscal Plan.

	2017-18	**2018-19**	**2019-20**	**2020-21**
OPG IFRS Risk	(400)	(475)	(700)	(750)
Risks Built into Fiscal Plan at 2017 Budget	(400)	0	(200)	0
Additional Risks now picked up in this Electricity Outlook	0	(475)	(500)	(750)

Electricity Sector Outlook (PSAB)

Positive Revenue Risks				
($ millions)	**Plan**			
	2017-18	**2018-19**	**2019-20**	**2020-21**
Generic				
OPG Generation Risk: Nuclear Reliability (+1.1 TWh)[1]	85	85	85	85
1% increase in Hydro One actual load[2]	57	59	61	63
Higher OPG Return on Equity (ROE)[3]	6	22	19	33
Higher Hydro One Return on Equity (ROE)[4]	19	69	50	50
Regulatory				
Accounting				
Other Risks				
ONFA adjustment increase (as of September 2017 Q3)[5]	171			

ation strategy or updates to AO strategy.

1. OPG's market and generation risks related to nuclear reliability similar to the scenarios OPG developed for its sales margins to capture major market risk factors (e.g., natural gas prices, coal prices, foreign exchange, nuclear reliability) in its 2012 business plan. Currently, only the nuclear reliability risk is captured at the current regulated rate for OPG's nuclear generation.

2. Estimated revenue impact if Hydro One load for Transmission and Distribution is 1% higher than projected for all years in CEFD Hydro One Forecast. Based on the assumption a 1% increase in load is directly proportional to a 1% change in revenue requirements.

3. Risk range for OPG reflects potential risk of higher ROE in 2018-2021 (for nuclear base) vs assumed ROE in OPG's 2016 business plan and corresponding rate application. Assumed ROE is 9.85%, respresenting recent in 2010.

4. Risk range for Hydro One transmission and distribution reflects potential risk of higher ROE vs assumed ROEs in the Hydro One CEFD Forecast for 2018-2021. Assumed ROE is 9.85%, representing recent high in 2010.

5. Reflects consolidation adjustment to OPG net income, whereby the realized portion of gains or losses of OPG's nuclear funds are added or subtracted from OPG net income.

ONTARIO ELECTRICITY FINANCIAL CORPORATION
On Deck Outlook as of March 2017

$ Millions

	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Revenue						
Revenue Pool Residual						
Debt Retirement Charge	859	625	623	-	-	-
Payments-in-lieu of tax:						
OPG	268	302	315	366	408	537
Legacy Hydro One (Including Brampton)	2,929	7	2	2	2	2
Hydro One CIT dedicated to OEFC	3	20	20	22	23	25
MEUs	27	44	68	86	105	114
Total PILs & CIT dedicated to OEFC[1]	3,228	373	405	476	538	679
Interest :						
OPG	173	179	168	153	135	135
H1						
IESO	2	3	3	3	3	3
Province	520	492	492	492	492	492
Other	28	10	5	5	5	5
Total Interest	723	684	668	653	635	635
Power Supply Contract Recoveries	875	739	292	325	301	273
Amortization of NUG liability	172	129	74	41	30	28
Electricity sector dedicated income	3	342	525	-	-	-
Gain to OEFC under s. 50.3	172	-	-	-	-	-
Miscellaneous	9	-	-	-	-	-
	6,041	2,893	2,587	1,495	1,504	1,615
Expense						
Debt interest	1,319	1,216	1,090	1,027	977	885
Interest on nuclear risk funding						
Demand Management Support Costs	8	10	10	-	-	-
Amortization of deferred debt costs	-	-	-			
Power Supply Contract Costs	875	739	292	325	301	273
Debt Guarantee fee	127	122	102	91	88	81
Operating	7	6	6	6	6	6
	2,336	2,093	1,500	1,449	1,372	1,245
Excess (Deficiency) of Revenue over Expense	**3,705**	**800**	**1,087**	**46**	**132**	**370**
Prior period adjustment	87					
Stranded Debt - Year End	**4,393**	**3,593**	**2,506**	**2,460**	**2,328**	**1,958**

Note: All the Hydro One ownership broadening impacts, other than the ownership change from the initial IPO in 2015 and the secondary offering in April 2016, were reflected in Sales and Rentals as of the 2017 Budget.

ONTARIO ELECTRICITY FINANCIAL CORPORATION

On Deck Outlook as of October 2017 **$ Millions**

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Revenue						
Revenue Pool Residual						
Debt Retirement Charge	859	621	623	0	0	0
Payments-in-lieu of tax:						
OPG	268	224	394	378	411	539
Legacy Hydro One (Including Brampton)	2,929	4	2	2	2	2
Hydro One CIT dedicated to OEFC	3	25	20	22	23	25
MEUs	27	112	68	86	105	114
Total PILs & CIT dedicated to OEFC[1]	3,228	364	484	488	541	681
Interest :						
OPG	173	167	169	179	175	148
H1						
IESO	2	2	3	3	3	3
Province	520	514	454	454	454	454
Other	28	20	20	20	10	10
Total Interest	723	703	646	656	642	615
Power Supply Contract Recoveries	875	838	292	325	301	273
Amortization of NUG liability	172	129	74	41	30	28
Electricity sector dedicated income	3	302	306	0	0	0
Gain to OEFC under s. 50.3[2]	172	411	550	0	0	0
Miscellaneous	9	14	0	0	0	0
	6,041	3,382	2,974	1,510	1,514	1,597
Expense						
Debt interest	1,319	1,216	1,121	1,094	1,053	963
Interest on nuclear risk funding						
Demand Management Support Costs	8	8	10	0	0	0
Amortization of deferred debt costs	0	0	0			
Power Supply Contract Costs	875	838	292	325	301	273
Debt Guarantee fee	127	122	102	99	98	91
Operating	7	7	6	7	7	7
	2,336	2,191	1,531	1,525	1,459	1,334
Excess (Deficiency) of Revenue over Expense	3,705	**1,191**	**1,444**	**(15)**	**56**	**263**
Prior period adjustment	87					
Stranded Debt - Year End	4,393	**3,202**	**1,758**	**1,773**	**1,718**	**1,455**

1

Payments-in-lieu of tax:	**2015-16 Public Accounts**
OPG	290
Legacy Hydro One (Including Brampton)	2,941
Hydro One CIT dedicated to OEFC	0
MEUs	15
	3,247

2 **2017-18 value preliminary estimate, subject to change.**

ONTARIO ELECTRICITY FINANCIAL CORPORATION

Changes from Budget 2017 as of October 2017 **$ Millions**

	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Revenue						
Debt Retirement Charge	(4)	-	-	-	-	
Payments-in-lieu of tax:						
OPG	(78)	79	12	4	2	reconciling between OPCD and OEFC net opening assets. OPG PILs also slightly lower than projected. 2017-18 increase is due mainly to recategorization of the PILs impact of the OPG head office sale from Sales and Rentals.
Legacy Hydro One (Including Brampton)	(3)	-	-	-	-	
Hydro One CIT dedicated to OEFC	5	-	-	-	-	Adjustment based on updated information in Hydro One rate application
MEUs	68	-	-	-	-	Large increase in 2016-17 from $80M payment during transfer of H01 Brampton to new consolidated MEU Alectra.
Total PILs	(9)	79	12	4	2	
Interest :						
OPG	(12)	1	26	40	13	Update to OPG interest outlook (wrt interest on OEFC loan).
H1	-	-	-	-	-	
IESO	(1)	-	-	-	-	
Province	22	(38)	(38)	(38)	(38)	2016-17 PDI at ($514m) was slightly larger than ($492m) projected at Interim. 2017-18 change reflects revised projections for Provincial debt interest related to Hydro equity.
Other	10	15	15	5	5	
Total Interest	19	(22)	3	7	(20)	
Power Supply Contract Recoveries	99	(0)	(0)	(0)	0	Variance is largely due to retroactive payments that the OEFC made to certain non-utility-generators (NUGs) with former Ontario Hydro power purchase agreement contracts with OEFC. OEFC was required to make these payment following the dismissal by the Supreme Court of Canada of OEFC's application for leave to appeal a judgment of the Court of Appeal of Ontario on a 2015 court decision.
Amortization of NUG liability	0	(0)	(0)	(0)	(0)	
Electricity sector dedicated income	(41)	(219)	-	-	-	The decrease in OEFC ESDI in 2017-18 reflect i) the IFRS adjustment of $400 million in 2017-18 that was not reflected in the OEFC ESDI projection at the time of the 2017 Budget (Note the IFRS adjustment was reflected in OPG net income for the 2017 Budget fiscal plan) ii) recategorization of Hydro One 2017 disposition impacts from Sales and Rentals and impact of OEB transmission rate decisions , partially offset by iii) lower Public Debt Interest and iv) a boost to OPG net income due to recategorization of OPG head office sale proceeds from Sales and Rentals.
Gain to OEFC under s. 50.3	411	550	-	-	-	
Miscellaneous	14	-	-	-	-	
	489	387	15	10	(18)	
Expense						
Debt interest	-	31	67	76	78	Revised outlook for OEFC debt interest outlook
Interest on nuclear risk funding	-	-	-	-	-	
Demand Management Support Costs	(2)	-	-	-	-	
Amortization of deferred debt costs	-	-	-	-	-	
Power Supply Contract Costs	99	(0)	(0)	(0)	0	Same as Power supply contract recoveries above. Power supply contract costs are fully recovered by power supply contract recoveries.
Debt Guarantee fee	-	-	8	10	10	
Operating	1	-	1	1	1	
	98	31	76	87	89	
Excess (Deficiency) of Revenue over Expense	**391**	**357**	**(61)**			
Stranded Debt - Year End	**3,202**	**1,758**	**1,773**	**1,718**	**1,455**	

Provision for Electricity Sector (Dedicated Electricity Earnings/Electricity Sector Dedicated Earnings)

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Income from Investment in Government Business Enterprises						
OPG Income	291	299	430	245	108	291
Hydro One Income[1]	232	501	329	326	387	418
Hydro One Brampton (if applied separately)		15				
Total Income	**523**	**815**	**760**	**572**	**496**	**710**
Public Debt Interest - Electricity Sector						
OPG			(300)	(300)	(300)	(300)
Hydro One[1]			(154)	(154)	(154)	(154)
Public Debt Interest - Electricity Sector (OEFC Interest revenue)	**(520)**	**(514)**	**(454)**	**(454)**	**(454)**	**(454)**
MOF Provision Expense (before adjustments)	**3**	**302**	**306**	**118**	**41**	**255**
Other Adjustments						
Prior-year Adjustment[2]		3				
Exclude Brampton[3]		(15)				
MOF Provision Expense (after other adjustments)	**0**	**290**	**306**	**118**	**41**	**255**
Cumulative Shortfall Adjustment						
Opening Balance	0	0	0	0	0	0
Deduction / (Addition)	0	0	0	0	0	0
Ending Balance	0	0	0	0	0	0
Dedicated Electricity Earnings (all adjustments) (Public Accounts)	**0**	**290**	**306**	**118**	**41**	**255**
Electricity Sector Dedicated Income (OEFC Annual Report)	**3**	**302**	**306**			

Notes:

1. The Hydro One financials above currently reflects the Provincial share allocation as the May 2017 final offering.

2. 2016-17 Adjustment was due to the discrepancy between the numbers in MOF expense in PA 2015-16 and OEFC Financials in 2015-16 due to timing issues. $3M adjustment rectifies this discrepancy

3. Brampton was excluded from the Ministry of Finance's ESDI allocation.

Ontario Power Generation

OPG Income - Budget 2017

$ Millions

	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
OPG Net Income After Tax (Adjusted)	291	304	97	732	625	1,066
OPG Net Income After Tax	*291*	*379*	*480*	*678*	*726*	*913*
Extraordinary Gains	-	-	-	-	-	-
GA - OPG Trust Interest Revenue			*17*	*54*	*99*	*153*
OPG IFRS consolidation risk picked up in Fiscal Plan		(75)	(400)		(200)	
ONFA and other Fair Value Adjustments	(75)	8				
ONFA Adjustments	-	8				
Other Fair Value Adjustments	(75)					

OPG PIL - Budget 2017

$ Millions

	Actual	Interim		Pl
	2015-16	2016-17	2017-18	2018-19
Net Income Before Tax	383	396	572	867
Net Income After Tax (Adjusted)	291	304	97	732
Income Taxes	92	92	92	135
GRC: Payable to OEFC	198	196	205	212
Proxy Property Tax	16	14	18	19
Ontario Capital Tax	0	0	0	0
Total	**306**	**302**	**315**	**366**

OPG Income - December 2017

$ Millions

	Actual	Actual	Current Outlook			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
OPG Net Income	291	377	818	678	726	913
Adjustment for OPG HQ gain on sale[1]			(283)			
Unpacking updated OPG Gain on sale (net income)			283			
Extraordinary Gains	0	0	0	0	0	0
GA Financing - OPG Trust Interest Revenue[2]			12	42	82	128
OPG IFRS consolidation risk reflected in Fiscal Plan[3]		(78.00)	(400)		(200)	
Update IFRS Risk			0	(475)	(500)	(750)
OPG Net Income (Adjusted before ONFA)	**291**	**299**	**430**	**245**	**108**	**291**
ONFA Adjustments	247	49				
Other Fair Value Adjustments	(75)	(6)				
ONFA and other Fair Value Adjustments	**172**	**43**				
OPG Net Income	**463**	**342**	**430**	**245**	**108**	**291**

OPG PIL - August 2017

$ Millions

	Actual	Actual		Current
	2015-16	2016-17	2017-18	2018-19
Income Before Tax	383	308	684	380
OPG Net Income (Adjusted before ONFA)	291	299	430	245
OPG Income Tax (PILs)	92	9	162	135
Tax adjustment for OPG HQ gain on sale[1]			(95)	
Unpack PILs related to HQ gain on sale			95	
GRC: Payable to OEFC	198	201	214	224
Proxy Property Tax to OEFC	16	14	18	19
Ontario Capital Tax	0	0	0	0
Total OPG PILs	**306**	**224**	**394**	**378**

1. OPG's May 2017 head office facilities sale impacts are re-categorized from Sales and Rentals to OPG net income and PILs in the current Electricity Outlook update.
2. This reflects interest earnings on GA financing costs which are consolidated back to Province
3. See Risks tab for IFRS impacts that were not reflected in Fiscal Plan, and table below.

	2017-18	2018-19	2019-20	2020-21
OPG IFRS Risk	(400)	(475)	(700)	(750)

Hydro One Ownership Calculation:		SOURCE:
Total number of shares outstanding[1]	595,000,000	1. Hydro One Ltd Annual Report 2015, pg 94 of PDF, pg 92 of the Report.
IPO November 2015		
Initial Public Offering(2015)[2]	81,100,000	2. From news release: http://hydroone.mediaroom.com/2015-11-05-Hydro-One-Limited-Announces-Closing-of-IPO
Over allotment option (2015)[3]	8,150,000	3. From news release: http://hydroone.mediaroom.com/2015-11-12-Hydro-One-Limited-Announces-Closing-of-IPO-Over-Allotment-Option
Sales to PWU/SEP Trusts	5,646,340	
Total	94,896,340	
Province's remaining ownership, Nov 2015 (# Shares)	**500,103,660**	
Province's remaining ownership, Nov 2015 (%)	**84.05%**	
Secondary Offering April 2016		
Secondary Offering (2016)	72,434,800	4. Hydro One Ltd. Q2 Report, pg 1 http://www.hydroone.com/InvestorRelations/FinancialReporting/Documents/Hydro%20One%20Ltd%20Second%20Qu
Over allotment option (2016)	10,865,200	
Total	83,300,000	
Province's remaining ownership, Apr 2016 (# Shares)	**416,803,660**	
Province's remaining ownership, Apr 2016 (%)	**70.05%**	
Final Offering May 2017		
Final Offering (2017)	120,000,000	Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by
Over allotment option (2017)	-	Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by
Total	120,000,000	
Province's remaining ownership, May 8, 2017 (# Shares)	296,803,660	Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by
Province's remaining ownership, May 8, 2017 (%)	**49.88%**	
First Nations Sale, Assumed closing for December 31, 2017	14,875,000	
	2.5%	Source: https://news.ontario.ca/mei/en/2017/05/ontario-raises-28-billion-from-final-hydro-one-share-offering.html
Province's remaining onwership - post First Nations Sale (#Shares)	281,928,660	
Province's remaining onwership - post First Nations Sale (%)	**47.38%**	
Avista Impact (projected closing date 2nd half of 2018)		
Contingent Convertible Debenture	$1,540,000,000	
Conversion Price	$21	
Potential Dilution (# Shares)	71,962,617	
Revised Total number of shares outstanding	**666,962,617**	
Province's remaining onwership - post Avista Acquisition (#Shares)	281,928,660	
Province's remaining onwership - post Avista Aquisition (%)	**42.27%**	

Ownership Percentage in 2017-18 Fiscal Year	Number of Months	Percentage of Year
70.05%	1	8.3%
49.88%	8	66.7%
47.38%	3	25.0%
	12	
Average 2017-18 FY Ownership:	**50.9%**	

Ownership Percentage in 2018-19 Fiscal Year (assume Avista closing end of September 2018)	Number of Months	Percentage of Year
47.38%	6	50.0%
42.27%	6	50.0%
	12	
Average 2018-19 FY Ownership:	**44.8%**	

Ownership Percentage in 2019-20 Fiscal Year Onwards
42.27%

Accretive to earnings per share and cash flow for Hydro One in the first full year post closing
above is from Hydro One transaction overview. Check what this means for timing of additional shares and /or earnings.

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-the-Province-of-Ontario

-the-Province-of-Ontario

Hydro One Net Income and PILs

Hydro One Income - Budget 2017
($ millions)

	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Hydro One Net Income After Tax	685	737	742	802	862	931
Hydro One - Unrealized Gains Adjustment						

2016-17 to 2020-21 from CEFD Hydro One 2016 model.

Hydro One PIL - Budget 2017
($ millions)

	2015-16	2016-17	2017-18	2018-19
Net Income After Tax	685	737	742	802
Income Taxes PILs	132	160	181	205
Proxy Property Tax	2	2	2	2
Ontario Capital Tax	0	0	0	0
Total	**134**	**162**	**183**	**207**

Hydro One Income - December 2017
($ millions) **$ Millions**

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Hydro One Net Income After Tax			645	690	780	845
Debenture Costs Impacts (After Tax)			(34)	(39)		
Hydro One Net Income After Tax - Including Adjustments	670	680	612	651	780	845
Hydro One - Net Income Attributable to Preferred Shareholders	15	18				
Hydro One - Unrealized Gains Adjustment						

Hydro One (100% Ownership)
($ millions) **$ Millions**

	Actual 2015-16	Actual 2016-17	2017-18	Current 2018-19
Net Income After Tax - Common Shares	670	680	612	651
Net Income After Tax - Preferred Shares	15	18		
Income Taxes PILs	132	160	181	205
Proxy Property Tax	2	2	2	2
Ontario Capital Tax	0	0	0	0

Public Debt Interest and Section 50.3 payments

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Hydro One Public Debt Interest and Section 50.3 payments						
Government Annual Interest Costs - Hydro One	220	220	220	220	220	220
Reduction in Interest Costs due to Broadening[1]		(29)	(66)	(66)	(66)	(66)
Province Annual Interest Costs - Hydro One Debt	**220**	**191**	**154**	**154**	**154**	**154**
Province Annual Interest Cost - OPG Debt	300	300	300	300	300	300
Total Public Debt Interest	**520**	**514**	**454**	**454**	**454**	**454**

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Gain to OEFC under s. 50.3	172	411	550	0	0	0

1. The Hydro One reduction in interest costs above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering are currently reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

ID# (Track Cha	Fiscal Year	alue (Hardcode	Value (Linked)	Description	Source Details	Source (Link)
20170501-2	2016-17	411,152,733	411,152,733	s 50.3 Gain for	Calculation provided by SIFB	
20170501-3	2016-17	29	29	Reduction in Int	Internal Calculation	
20170501-3	2017-18	66	66	Reduction in Int	Internal Calculation	
20170501-3	n/a	220	220	Annual Interest	Internal Calculation	

ID# (Track Cha	Fiscal Year	alue (Hardcode	Value (Linked)	Description	Source Details	Source (Link)
n/a	n/a	5126		($M) Provinces	OEFC 1999-2000 FS, pg 24	
n/a	n/a	5.85%		Annual Interest	OEFC 1999-2000 FS, pg 26	
		299.871				

OPG's Annual Interest Costs: 300

20170713-1	2016-17	-513,768,361	Provincial interest cost for equity investment in OPG, H1 in 2016-17 Monthly Balances Sheet (from FTD) S:\Users\CEF\Hydro 2017\OEFC\RbP\Outlook\07. July\Backup\20170713-1\interest fr

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PROVINCIAL CONSOLIDATION ADJUSTMENTS
Ontario Nuclear Funds Agreement

Adjustment for Change in OPG Reported Net Income

Adjustment for DSF Unrealized Earnings

Unrealized Earnings as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Bruce Variance Account Adjustment
OPG Net Income Adjustment

Adjustment for UFSF Unrealized Earnings

Unrealized Earnings as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Bruce Variance Account Adjustment
OPG Net Income Adjustment

Unrealized Earnings -- Fiscal YTD

Adjustment for Change in Due to Province

Adjustment for DSF Due to Province
Due to Province (cost basis) as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Change in Due to Province -- Fiscal YTD

Adjustment for UFSF Due to Province

Due to Province (cost basis) as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Change in Due to Province -- Fiscal YTD

Provincial Consolidation Adjustment

Other Data

	Actual 2016-17	2017-18
Debt Retirement Charge	621	0

	2016-17	2017-18
Power Supply Contract Recoveries	838	292

	2016-17	2017-18
Interest		
OPG	167	169
IESO	2	3
Other (Net)	20	20
Expense		
Debt interest	1216	1121

	Actual 2016-17	2017-18
MEU - PIL Income Tax	109.8	
MEU - PIL Property Tax	0.6	
MEU - GRC	1.2	
TOTAL MEU PILs	111.6	

	Actual 2016-17	2017-18
Miscellaneous/Other (OEFC FS)	14	
Demand Management Support Costs (IEI)	8	10
Operating [Expense]	7	6
Interest on nuclear risk funding	-	-
Amortization of deferred debt costs	-	-
Amortization of NUG liability	129	74
Debt Guarantee Fee	122	102

Expense (Electrictiy Summary Tab)		
Other (Finance)	-7	-6
Demand Management Support Costs (IEI)	-8	-10
Debt Guarantee Fee	(122)	(102)

Plan		
2018-19	2019-20	2020-21
0	0	0

Plan		
2018-19	2019-20	2020-21
325	301	273

Plan		
2018-19	2019-20	2020-21
179	175	148
3	3	3
20	10	10
1094	1053	963

Plan		
2018-19	2019-20	2020-21

Plan		
2018-19	2019-20	2020-21
7	7	7
-	-	-
-	-	-
41	30	28
99	98	91
-7	-7	-7
(99)	(98)	(91)

ID# (Track Changes	Fiscal Year	Value (Hardcoded)	Value (Linked)
20170510-2	2016-17	$ 739,216,115	
20170510-2	2017-18	$ 291,629,707	
20170510-2	2018-19	$ 324,906,017	
20170510-2	2019-20	$ 300,648,570	
20170510-2	2020-21	$ 273,240,858	
20170501-4	2016-17	179	179
20170501-4	2017-18	169	169
20170501-4	2018-19	179	179
20170501-4	2019-20	175	175
20170501-4	2020-21	148	148
20170501-5	2016-17	1216	1,216
20170501-5	2017-18	1121	1,121
20170501-5	2018-19	1094	1,094
20170501-5	2019-20	1053	1,053
20170501-5	2020-21	963	963
20170731-3	2016-17	621	
20170811-1	2016-17	109.8	
20170811-1	2016-17	0.6	
20170811-1	2016-17	1.2	
20170815-5	2016-17	$ 838,000,000	
20170815-6	2016-17	$ 14,000,000	
20170815-8	2016-17	8	
20170815-9	2017-18	10	
20170815-10	2016-17	7	
20171211-2	2017-18	6	6
20171211-2	2018-19	7	7
20171211-2	2019-20	7	7
20171211-2	2020-21	7	7
20170815-7	2016-17	167	
20170815-7	2016-17	2	
20170815-7	2016-17	20	
20170815-7			

ID# (Track Changes	Fiscal Year	Value (Hardcoded)	Value (Linked)
20170905-1	2016-17	129	129
20170905-1	2017-18	74	74

20170905-1	2018-19	41	41
20170905-1	2019-20	30	30
20170905-1	2020-21	28	28
20170905-2	2016-17	122	
20170906-1	2017-18	3	3
20170906-1	2018-19	3	3
20170906-1	2019-20	3	3
20170906-1	2020-21	3	3
20170906-1	2017-18	20	5
20170906-1	2018-19	20	5
20170906-1	2019-20	10	5
20170906-1	2020-21	10	5
20171211-0	2017-18	1121	1,121
20171211-0	2018-19	1094	1,094
20171211-0	2019-20	1053	1,053
20171211-0	2020-21	963	963
20171211-1	2017-18	102	102
20171211-1	2018-19	99	99
20171211-1	2019-20	98	98
20171211-1	2020-21	91	91
20171211-1			
20171211-1			
20171211-1			
20171211-1			
20171211-1			
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Description	Source Details	Source (Link)
The table below contains an updated preliminary N	SPFB Estimates, Email	
• The tables below provides both last year's submission for NUG costs by CEFD and this year's estimates (both of which exclude HST) based on the most recent NUG model.	SPFB Estimates, BN SPFB Estimates, BN SPFB Estimates, BN SPFB Estimates, BN	
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
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Updating DRC from OEFC AR (Drafts)	2017 OEFC DRAFT FS	S:\Users\CEF\Hydro 2017\OEFC'
MEU - PIL Income Tax	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
MEU - PIL Property Tax	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
MEU - GRC	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
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OEFC Operating Expense - Updating to Actuals	2017 OEFC AR	S:\Users\CEF\Hydro 2017\OEFC'
Revised Operating Expense from FTD Forecast	FTD - October PRRT	
OPG Interest Revenue - Actuals 2016-17	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
IESO Interest Revenue - Actuals 2016-17		
Other (Net) Interest Revenue - Actuals 2016-17		

Description	Source Details	Source (Link)
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	Amortization Schedule.	S:\Users\CEF\Hydro 2017\OEFC'

Sourcing the NUG liability amortization schedule.	Tab: Summary Fiscal Impact	S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC'
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Colour Codes

Formulas are in black text

Hard coded numbers are in blue text

References elsewhere are in purple

Green bold text with or without highlights mean updates required

Policies to follow when making updates to the Outlook

*** To quickly jump to the source numbers for a link, press "**Ctrl + [**"

All new numbers must be fully sourced, and follow the colour codes above

Most numbers and text are Arial Size 10, unless it is a title

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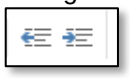
Use indents to make things more clear to read



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OEFC - (Budget17/On Deck) - Reflects OEFC Annual Reports

*Due to slight discrepancies between Public Accounts reporting and OEFC Annual Rep

Outlook Updates Frequency

Frequency	Description	Tab
Monthly	OPG Net Income in-year forecast	OPG
Monthly	OPG PILs in-year forecast	OPG
Quarterly	ONFA Consolidation Adjustment	ONFA
Quarterly	OPG Cash vs Accrual Variance Account	Revenue (Risks)

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From:	Nelms, Scott (MOF)
To:	Nancy Kennedy (MOHLTC); Ronald Kwan
Cc:	Vivienne Skoberne (MOHLTC); Montgomery, Kaitlin (MOF)
Subject:	OPG BP Submission
Date:	Wednesday, April 26, 2017 4:06:24 PM
Attachments:	2017 04 25 EIGS OPG Business Plan v08.docx 2017 04 25 OPG Business Plan Review v12.pptx 2017 04 11 TBMBC - Approval Form.xls 2017 04 26 OPG concurrence letter v9.docx

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Hi Nancy, Ron,

Please see the attached OPG BP package and draft concurrence letter. This has been shared with ENE DMO / MO. Ron, I think you were planning to share up with MoF on our side.

Thanks,
Scott

MINISTRY OF ENERGY

TREASURY BOARD / MANAGEMENT BOARD of CABINET SUBMISSION

ONTARIO POWER GENERATION (OPG) 2017-19 BUSINESS PLAN AND SPECIAL STATUS APPLICATION

May 2017

CONFIDENTIAL

MINISTRY OF ENERGY

ONTARIO POWER GENERATION (OPG)
2017-19 BUSINESS PLAN AND SPECIAL STATUS APPLICATION

MINISTRY REQUEST

The Ministry of ENERGY is requesting that Treasury Board/Management Board of Cabinet (TB/MBC):

1. NOTE the receipt of OPG's 2017-2019 Business Plan.
2. NOTE that the Minister of Energy will provide concurrence with OPG's Business Plan.
3. APPROVE OPG's application for Special Status to Approve International Travel under Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive dated January 1, 2017.

CONTEXT

- As required by the Memorandum of Agreement (MOA) between Ontario Power Generation and the Minister of Energy, OPG provided its Business Plan for 2017-2019 to the Ministry of Energy on November 29, 2016 for concurrence
    - Note that while OPG is seeking concurrence for its three year 2017-19 business plan, the plan also includes financial projections for 2020 and 2021
- With this Business Plan OPG is also making an application for Special Status under the Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive, which allows agencies/organizations, for which international travel may be integral to their business, to seek TB/MBC approval for special status to ensure that the approval process does not have an undue negative effect on its ability to conduct business
- The Minister's concurrence requires presentation of OPG's business plan before TB/MBC
- The Ministry of Energy review and analysis of OPG's business plan is supported by the Electricity Investment and Governance Secretariat, a unit within the Ministry of Finance and the Corporate and Electricity Finance Division of the Ontario Financing Authority (OFA)
- The following provides an overview of OPG's business plan, including:
    1. Business Plan Overview
    2. Other Considerations
- Proceeding with Provincial concurrence now will demonstrate that OPG has support from its shareholder as it implements the plan and provides clarity to

the Ontario Energy Board (OEB) as it reviews OPG's current rate application covering the 2017-2021 period

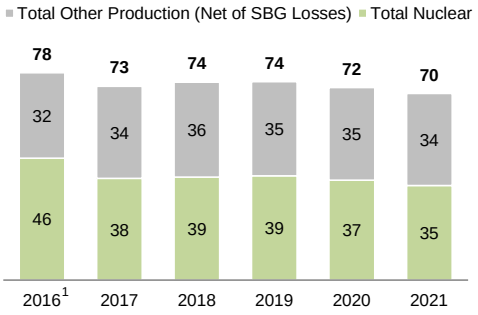
- Business plan forecasts may be affected by Ontario's Fair Hydro Plan (OFHP). Given the stage of implementation of OFHP and the timing of the receipt of the business plan in November 2016, these changes are not reflected in OPG's plan
    - The Ministry anticipates that as part of supporting the financing and administration of the global adjustment smoothing mechanism, OPG would purchase the right to future cash flows from IESO, financed partly by capital infusions from the Province, and majority by third-party lending
    - These changes are generally expected to be fiscally neutral as they would result in an increase in Provincial interest on debt, offset by increases in OPG net income
    - In addition, the Province's net debt position would remain unchanged

1. BUSINESS PLAN OVERVIEW

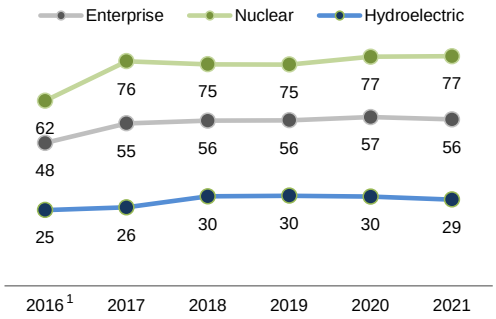
a) Production & Total Cost of Generation

- OPG's production is expected to fall to 69.8 TWh by 2021 from 77.6 TWh in 2016
    - Reflects a declining trend in the Darlington production due to refurbishment outages starting in October 2016
    - Includes a partial overlap starting in 2021 between second and third unit refurbishments, and
    - Includes the Pickering Vacuum Building Outage (VBO) in 2021 requiring the shutdown of all units for the duration of the outage
- While OM&A remains relatively stable over the planning period (see next slide), total generating cost (TGC)* shows an increasing trend over the planning period relative to 2016, reflecting:
    - Lower nuclear production due to Darlington refurbishment outages, and
    - Increased sustaining capital spending (included in TGC) on two large hydroelectric projects, the Lower Mattagami dam safety upgrade and the Sir Adam Beck I GS power canal liner rehabilitation

Production (TWh)



Total Generating Cost ($/MWh)



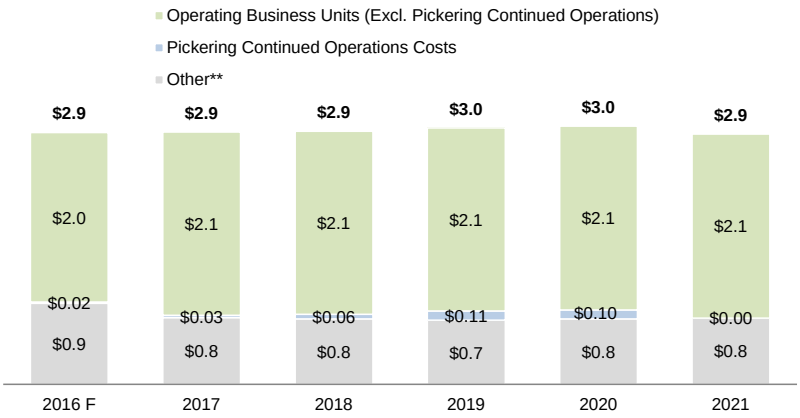
1. Actuals

*TGC = operations, maintenance and administration (OM&A) expenses from ongoing operations + fuel and Gross Revenue Charge expenses for OPG-operated stations + sustaining capital expenditures) divided by OPG generation adjusted for surplus baseload generation losses

b) Operations, Maintenance and Administration (OM&A) Expenses

- Annual OM&A expenses from ongoing operations are expected to stay consistent over the plan period, averaging $2.9B per year
- Increases over 2016 are mainly attributable to:
    - Increases in business unit expenditures, including changes in nuclear outage scope at Darlington, and planned hiring to fill staffing gaps
    - Incremental outage and other program costs to enable Pickering continued operations
- These increases are partially offset by declining pension and Other Post-Employment Benefits (OPEB) costs over the period due to projected pension asset returns, increased employee contributions, and adoption of a new method for applying discount rates to determine interest components of pension costs

OM&A from Ongoing Operations* ($B)



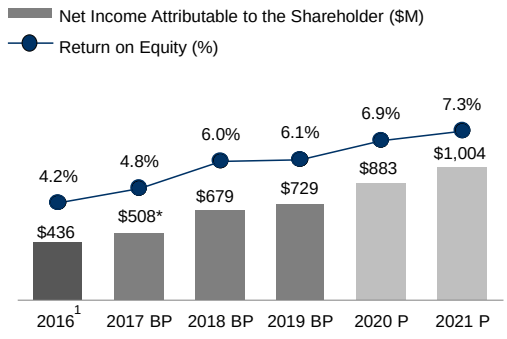
*Excludes Darlington refurbishment OM&A expenses and all OEB variance and deferral account offsets

** Includes centrally held pension /OPEB costs and support services

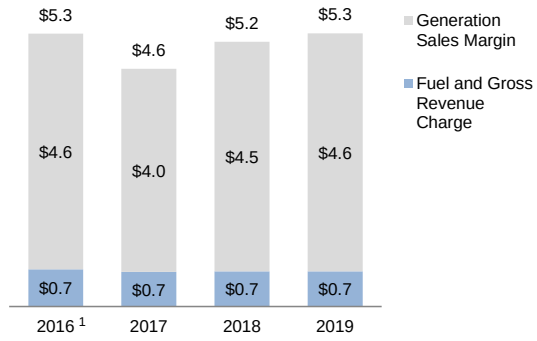
c) Financials

- OPG is forecasting net income attributable to the Shareholder to reach $1B in 2021, from $436M in 2016
    - 2017 net income is forecast to increase as a result of new regulated rates, higher capitalized interest for the Darlington Refurbishment expenditures partially offset by reduced production as a result of planned outages at Sir Adam Beck I and DeCew II hydro stations
    - Net income in 2018 and 2019 is planned to increase, primarily due to higher forecast production, and earnings from Peter Sutherland Sr. GS starting in 2017 and Nanticoke solar facility starting in 2019
- As a result, return-on-equity (ROE) is estimated to increase from 4.2% in 2016 to 7.3% by 2021
- Overall, the 2017-19 Business Plan is largely unchanged relative to last year's plan in terms of commitments for Net Income, and Total Shareholder Return
- In early January 2017, subsequent to the OPG Board's approval of the 2017-2019 Business Plan, OPG reached an agreement with KingSett Canadian Real Estate Income Fund LP for the purchase of OPG's head office property. The net gain is estimated to be $285M and will be distributed to the Trillium Trust.

Net Income ($M) and ROE (%)



Revenue Margin ($B)



1. Actuals

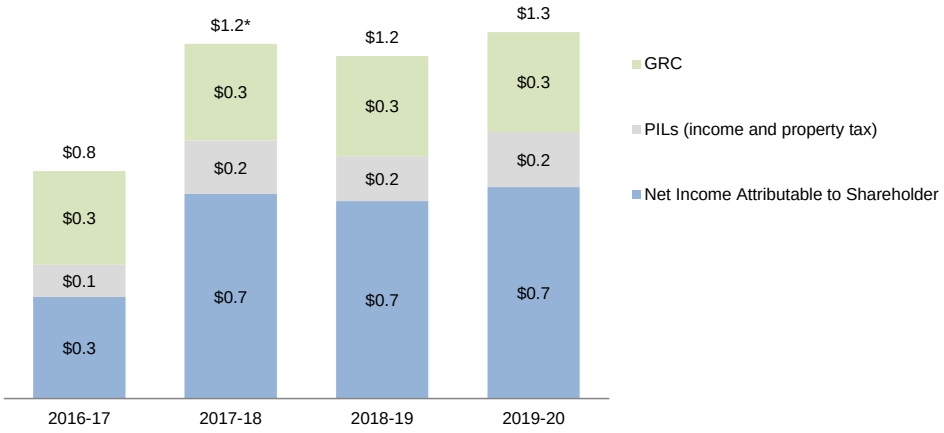
*Includes extraordinary gain associated with the sale of OPG head office

d) Provincial Fiscal Impacts: Shareholder Return and Payments-in-Lieu of Taxes

- Total fiscal revenue impacts to the Province, including net income return to the shareholder and payments-in-lieu of taxes, averages ~$1B over the period
    - Provincial revenues from OPG are dedicated to servicing and paying down stranded debt and the investment cost of the Province acquiring the equity in OPG[1]

- Return to the shareholder improves due to changes in net income, which OPG attributes to:
    - Assumed OEB rate outcomes
    - Completion of the first Darlington unit refurbishment
    - Further cost efficiencies
- Net income is consolidated by the Province as Revenue from Government Business Enterprises (GBEs)
- Income tax PILs, Gross Revenue Charges (GRC) and property tax PILs paid to the Ontario Electricity Financial Corporation (OEFC) to help service and pay down stranded debt are consolidated in Public Accounts under Taxation Revenue
- OPG also pays a portion of the GRC to the Province's Consolidated Revenue Fund (CRF)

Total Fiscal Revenues ($B)



1. Aside from the water power rental portion of the GRC, paid to the CRF.

*Includes gain associated with the sale of OPG head office

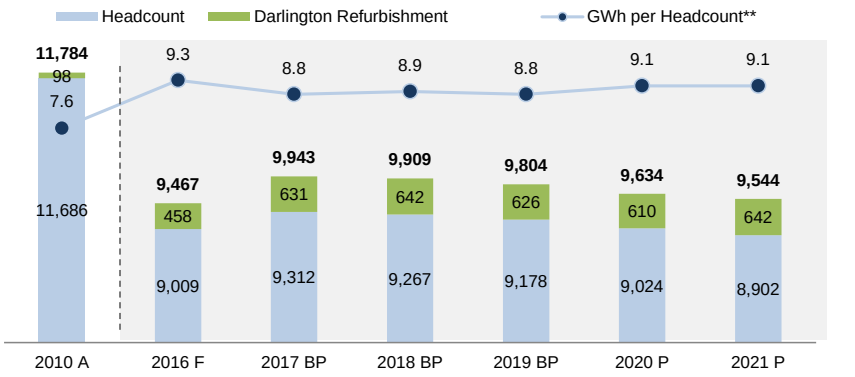
e) Business Transformation Initiative & Labour Costs

- As part of a company-wide business transformation, OPG saved over $1B in costs from January 2011 to December 2016
    - Headcount has fallen from 11,686 in 2010 to a forecasted 9,009 in 2016 while GWh per headcount has increased from 7.6 to 9.3
- However, OPG is ramping up recruitment between 2016 and 2017 to fill key vacancies in certain areas (particularly in the Nuclear business unit) due to high levels of attrition from employee demographics, as well as continued Pickering operations beyond 2020

- OPG is forecasting regular headcount to show a net increase of ~300 by the end of 2017 before gradually decreasing to 4% lower than 2017 levels in 2021

- In addition, to date OPG has hired ~95 Term employees, a new category of non-regular staff negotiated with the Power Workers' Union (PWU) through collective bargaining in 2015
  - Intention is to add fewer regular staff in circumstances where they are likely to be laid off as a result of the end of Pickering commercial operations, per the terms of the collective agreement

Ongoing Operations Regular Headcount and Productivity

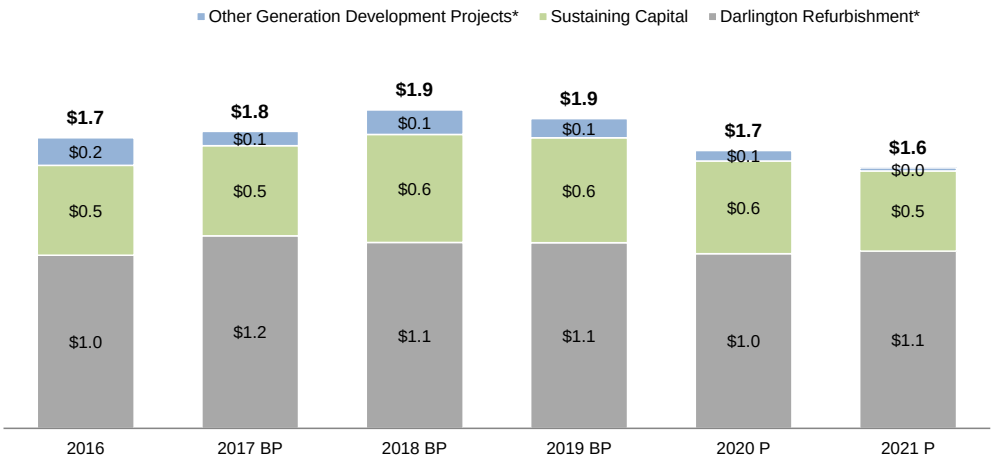


**Production is normalized by adding back hydroelectric surplus baseload generation losses and, in 2017- 2021, the lower production due to the Darlington refurbishment outages

f) Operating Highlights - Projects and Capital Expenditures

- OPG continues to focus on delivery of its major projects over the plan period, including:
  - **Darlington Refurbishment**: Unit 2 is assumed to be returned to service in February 2020 with the second unit refurbishment commencing immediately thereafter and the third unit refurbishment starting in July 2021, assuming necessary concurrence from the Province is obtained
  - **Sustaining Capital:** Expenditures average $570M, including:
    - Nuclear expenditures unrelated to refurbishment at Darlington and costs for continued operation of Pickering
    - Regulated hydro expenditures including upgrades at Sir Adam Beck and upgrades to DeCew ll
    - Lower Mattagami upgrades in 2018 and 2019
  - **Other Generation Development Projects:** Investments in current (e.g., hydroelectric) and emerging generation technologies including solar and energy storage including construction and operation of the Nanticoke solar facility by 2019

Capital Expenditure Estimates ($B)



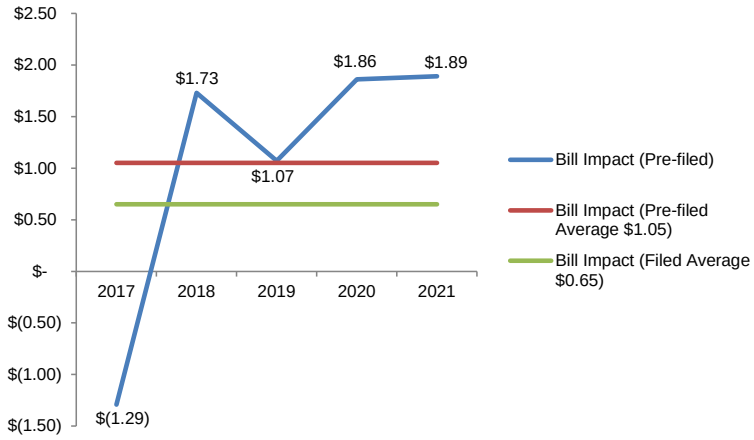
*Includes expenditures budgeted by Support Services

2. OTHER CONSIDERATIONS

Rate Application

- OPG's 2017-19 Business Plan is dependent on the outcome of its rate filing with the OEB for the five-year period from 2017-2021
- Oral hearings began February 21, 2017 with a decision expected in Q4 2017
- OPG's 2017-19 Business Plan assumes new rates are effective January 1, 2017
    - The OEB setting a later effective date would negatively impact OPG's 2017-18 fiscal year net income by ~$50-60M per month of delay*
- Rate-Smoothing Proposal:
    - On March 2, 2017 the Province filed an amendment to O.Reg.53/05, which enables OPG to smooth its rates based on OPG's weighted average hydroelectric and nuclear all-in rates (which approximates total bill impact), rather than on the basis of nuclear base rates only
        - Rate smoothing is expected to be fiscally neutral due to rate regulated accounting
    - On March 8, 2017 OPG filed a revised rate smoothing proposal with the OEB, which is expected to decrease the average year-over-year annual impact on the monthly customer bill for an average consumption of 750 KWh/month from about $1.05 to 65 cents per month per year

Comparison of Annual Bill Impact ($/Month per year)



*Forecasted in May 2016

Sales

	OPG Head Office	R.L. Hearn Site	Lakeview Site
Current Status	Completed	Agreement Reached	OPG and Infrastructure Ontario are preparing for marketing
Site Description	700 University Ave. and parking garage at 40 Murray St. in Toronto	~33 acres at the R.L. Hearn site in Toronto	~67 acres to be transferred by the purchaser to the City of Mississauga (Municipal Park Lands) and ~110 acres to be developed for mixed uses (Uplands)
Buyer	KingSett Canadian Real Estate Income Fund LP	Studios of America Limited Partner	TBD
Value	Estimated up-front 2017-18 fiscal impact of ~$375M (includes after-tax gain as well as PILs to OEFC)	TBD	TBD
Other Considerations	N/A	N/A	Negotiations with the City have been lengthy and costs to remediate/prepare site may be significant due to concerns regarding site condition
Timing	The sale closed in April 2017	Anticipated to close in Q3 2017	Marketing is planned to start in April 2017, pending negotiations with the City, with an anticipated closing in 2017

Special Status for OPG to Approve International Travel

- On January 24, 2017, OPG's President and CEO wrote to the Deputy Minister to provide a business case and request authority for OPG to approve international travel for its employees. In summary:
    - Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive allows agencies/organizations, for which international travel may be integral to their business, to seek TB/MBC approval for special status to ensure that the approval process does not have an undue negative effect on its ability to conduct business

- OPG believes that international travel is integral to the safe and prudent operation of its business and having OPG's CEO approve international travel will enable more efficient decision-making while significantly lowering travel costs
- OPG cites the importance of enabling its engagement with the international community (in particular in regards to nuclear safety), procurement activities, and investment and due diligence processes for over $30 billion in pension fund and nuclear funds
- OPG requires a high level of international business travel at approximately 90-100 trips annually, while the Darlington Refurbishment Project accounts for 45% of OPG's international travel and is expected see increases over the 10 year life of the project
- OPG indicated that the approval process, which took 23 days on average in 2016, delays flight bookings which results in higher costs as airlines raise fares closer to the travel date
- OPG believes the inability to make timely commitments on events and meetings impacts employee engagement as well as its international relationships and reputation

- OPG is seeking Special Status as part of concurrence with its business plan. OPG has committed to providing semi-annual reports to the Ministry on international travel taken, and continue to be accountable for compliance with all applicable OPS directives, policies and procedures

RECOMMENDATION

The Ministry of ENERGY is requesting that Treasury Board/Management Board of Cabinet (TB/MBC):

1. NOTE the receipt of OPG's 2017-2019 Business Plan.
2. NOTE that the Minister of Energy will provide concurrence with OPG's Business Plan.
3. APPROVE OPG's application for Special Status to Approve International Travel under Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive dated January 1, 2017.

APPENDIX

OPG 2016 Year-End Financials

OPG Balance Sheet as at Dec 31 $B	2016
Assets	
Cash and cash equivalents	0.2
Available-for-sale securities	0.2
Receivables from related parties	0.4
Nuclear fixed asset removal and nuclear waste management funds	0.02
Other current assets	0.9
Total current assets	**$1.7**
Net property, plant and equipment	**$20.0**
Net intangible assets	**$0.1**
Nuclear fixed asset removal and nuclear waste management funds	16.0
Regulatory assets	5.9
Other long-term assets	0.7
Other assets	**$22.5**
Total assets	**$44.4**
Liabilities	
Accounts payable and accrued charges	1.2
Short-term debt and long-term debt due within one year	1.1
Income taxes payable and other current liabilities	0.1
Total current liabilities	**$2.4**
Long-term debt	4.4
Fixed asset removal and nuclear waste management liabilities	19.5
Pension liabilities	3.0
Other post-employment benefit liabilities	2.9
Other liabilities	1.7
	$31.5
Total liabilities	**$33.9**
Equity	
Equity attributable to the Shareholder	10.4
Equity attributable to non-controlling interest	0.1
Total equity	**$10.5**
Total liabilities and equity	**$44.4**

OPG Income Statement Year Ended Dec 31 $B	2016
Revenue	$5.7
Fuel expense	0.7
Gross margin	**$4.9**
Operations, maintenance and administration	2.7
Depreciation and amortization	1.3
Accretion on fixed asset removal and nuclear waste management liabilities	0.9
Earnings on nuclear fixed asset removal and nuclear waste management funds	-0.7
Other expenses	0.02
Total expenses	**$4.2**
Income before other (gains) losses, interest and income taxes	**$0.7**
Other (gains) losses	-0.02
Income before interest and income taxes	**$0.7**
Net interest expense	0.1
Income before income taxes	**$0.6**
Income tax expense	0.2
Net income	**$0.5**
Net income attributable to the Shareholder	**$0.4**
Net income attributable to non-controlling interest	**$0.02**

Ontario

MINISTRY OF
ENERGY

Ontario Power Generation (OPG) 2017-19 Business Plan and Special Status Application

May 2017

Context

- As required by the Memorandum of Agreement (MOA) between Ontario Power Generation and the Minister of Energy, OPG provided its Business Plan for 2017-2019 to the Ministry of Energy on November 29, 2016 for concurrence
  - Note that while OPG is seeking concurrence for its three year 2017-19 business plan, the plan also includes financial projections for 2020 and 2021
- With this Business Plan OPG is also making an application for Special Status under the Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive, which allows agencies/organizations, for which international travel may be integral to their business, to seek TB/MBC approval for special status to ensure that the approval process does not have an undue negative effect on its ability to conduct business
- The Minister's concurrence requires presentation of OPG's business plan before TB/MBC
- The Ministry of Energy review and analysis of OPG's business plan is supported by the Electricity Investment and Governance Secretariat, a unit within the Ministry of Finance and the Corporate and Electricity Finance Division of the Ontario Financing Authority (OFA)
- The following presentation provides an overview of OPG's business plan, including:
  1. Business Plan Overview
  2. Other Considerations

Context *(cont'd)*

- Proceeding with Provincial concurrence now will demonstrate that OPG has support from its shareholder as it implements the plan and provides clarity to the Ontario Energy Board (OEB) as it reviews OPG's current rate application covering the 2017-2021 period

- Business plan forecasts may be affected by Ontario's Fair Hydro Plan (OFHP). Given the stage of implementation of OFHP and the timing of the receipt of the business plan in November 2016, these changes are not reflected in OPG's plan

  - The Ministry anticipates that as part of supporting the financing and administration of the global adjustment smoothing mechanism, OPG would purchase the right to future cash flows from IESO, financed partly by capital infusions from the Province, and majority by third-party lending

  - These changes are generally expected to be fiscally neutral as they would result in an increase in Provincial interest on debt, offset by increases in OPG net income

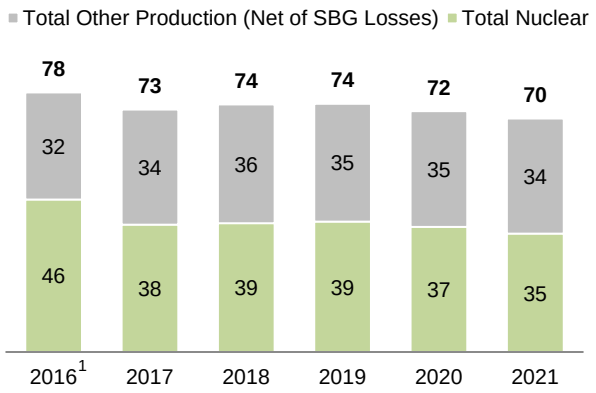
  - In addition, the Province's net debt position would remain unchanged

1. Business Plan Overview

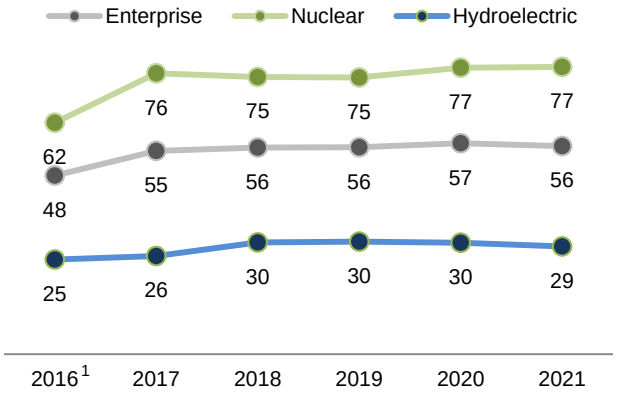
a) Production & Total Cost of Generation

- OPG's production is expected to fall to 69.8 TWh by 2021 from 77.6 TWh in 2016
  - Reflects a declining trend in the Darlington production due to refurbishment outages starting in October 2016
  - Includes a partial overlap starting in 2021 between second and third unit refurbishments, and
  - Includes the Pickering Vacuum Building Outage (VBO) in 2021 requiring the shutdown of all units for the duration of the outage
- While Operations, Maintenance and Administration (OM&A) remains relatively stable over the planning period (see next slide), total generating cost (TGC)* shows an increasing trend over the planning period relative to 2016, reflecting:
  - Lower nuclear production due to Darlington refurbishment outages, and
  - Increased sustaining capital spending (included in TGC) on two large hydroelectric projects, the Lower Mattagami dam safety upgrade and the Sir Adam Beck I GS power canal liner rehabilitation

Production (TWh)



Total Generating Cost ($/MWh)



1. Actuals

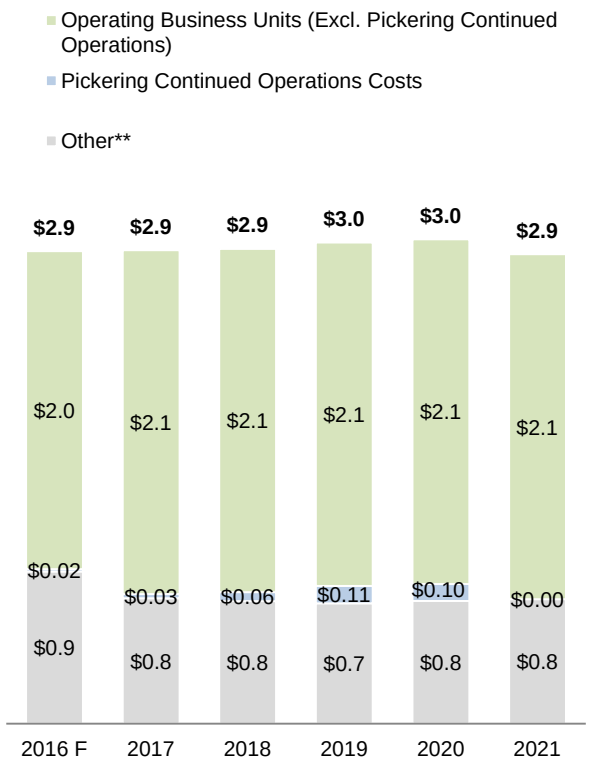
*TGC = OM&A expenses from ongoing operations + fuel and Gross Revenue Charge expenses for OPG-operated stations + sustaining capital expenditures) divided by OPG generation adjusted for surplus baseload generation losses

1. Business Plan Overview

b) Operations, Maintenance and Administration (OM&A) Expenses

- Annual OM&A expenses from ongoing operations are expected to stay consistent over the plan period, averaging $2.9B per year
- Increases over 2016 are mainly attributable to:
  - Increases in business unit expenditures, including changes in nuclear outage scope at Darlington, and planned hiring to fill staffing gaps
  - Incremental outage and other program costs to enable Pickering continued operations
- These increases are partially offset by declining pension and Other Post Employment Benefits (OPEB) costs over the period due to projected pension asset returns, increased employee contributions, and adoption of a new method for applying discount rates to determine interest components of pension costs

OM&A from Ongoing Operations* ($B)



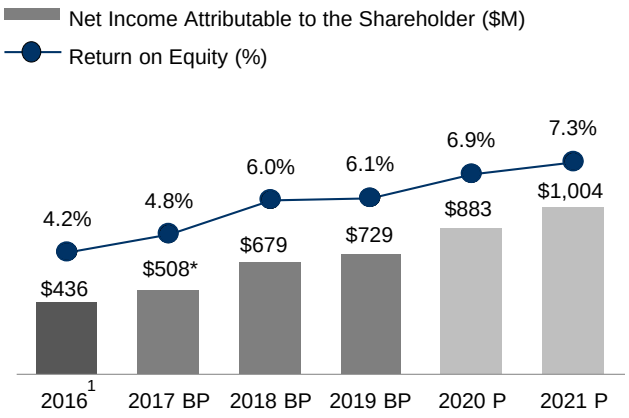
*Excludes Darlington refurbishment OM&A expenses and all OEB variance and deferral account offsets
** Includes centrally held pension /OPEB costs and support services

1. Business Plan Overview

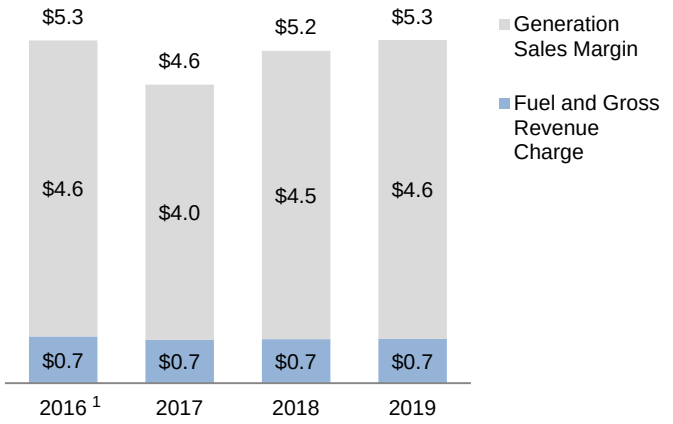
c) Financials

- OPG is forecasting net income attributable to the Shareholder to reach $1B in 2021, from $436M in 2016
  - 2017 net income is forecast to increase as a result of new regulated rates, higher capitalized interest for the Darlington Refurbishment expenditures partially offset by reduced production as a result of planned outages at Sir Adam Beck I and DeCew II hydro stations
  - Net income in 2018 and 2019 is planned to increase, primarily due to higher forecast production, and earnings from Peter Sutherland Sr. GS starting in 2017 and Nanticoke solar facility starting in 2019
- As a result, return-on-equity (ROE) is estimated to increase from 4.2% in 2016 to 7.3% by 2021
- Overall, the 2017-19 Business Plan is largely unchanged relative to last year's plan in terms of commitments for Net Income, and Total Shareholder Return
- In early January 2017, subsequent to the OPG Board's approval of the 2017-2019 Business Plan, OPG reached an agreement with KingSett Canadian Real Estate Income Fund LP for the purchase of OPG's head office property. The net gain is estimated to be $285M and will be distributed to the Trillium Trust

Net Income ($M) and ROE (%)



Revenue Margin ($B)



*Includes extraordinary gain associated with the sale of OPG head office

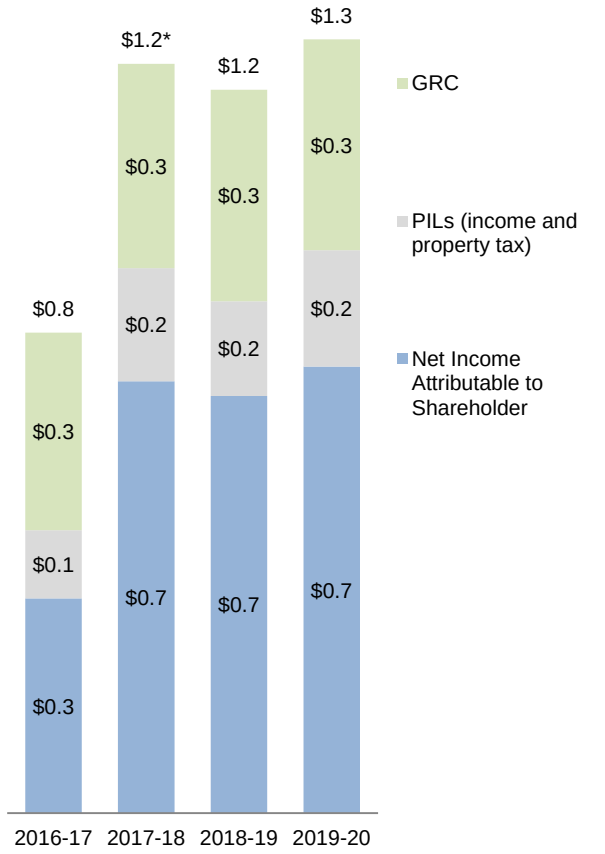
1. Actuals

1. Business Plan Overview

d) Provincial Fiscal Impacts: Shareholder Return and Payments-in-Lieu of Taxes

- Total fiscal revenue impacts to the Province, including net income return to the shareholder and payments-in-lieu of taxes, averages ~$1B over the period
  - Provincial revenues from OPG are dedicated to servicing and paying down stranded debt and the investment cost of the Province acquiring the equity in OPG[1]
- Return to the shareholder improves due to changes in net income, which OPG attributes to:
  - Assumed OEB rate outcomes
  - Completion of the first Darlington unit refurbishment
  - Further cost efficiencies
- Net income is consolidated by the Province as Revenue from Government Business Enterprises (GBEs)
- Income tax PILs, Gross Revenue Charges (GRC) and property tax PILs paid to the Ontario Electricity Financial Corporation (OEFC) to help service and pay down stranded debt are consolidated in Public Accounts under Taxation Revenue
- OPG also pays a portion of the GRC to the Province's Consolidated Revenue Fund (CRF)

Total Fiscal Revenues ($B)



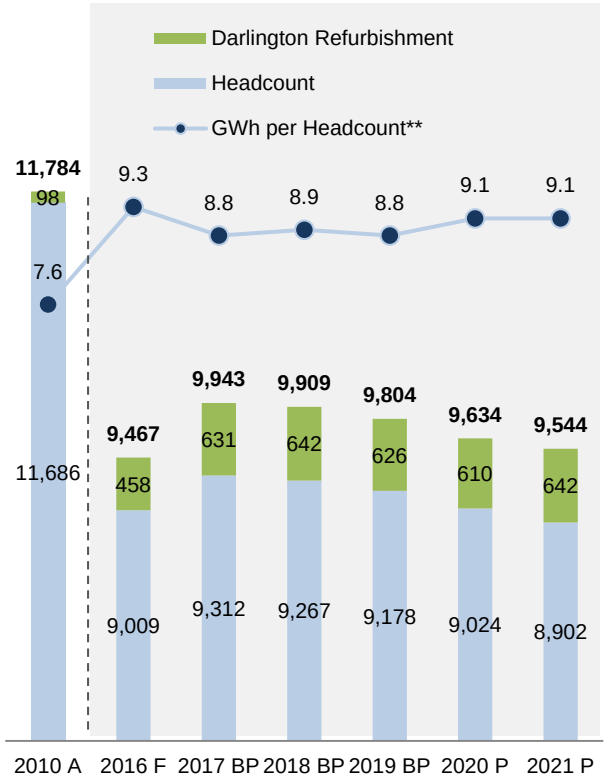
1. Aside from the water power rental portion of the GRC, paid to the CRF.
*Includes gain associated with the sale of OPG head office

1. Business Plan Overview

e) Business Transformation Initiative & Labour Costs

- As part of a company-wide business transformation, OPG saved over $1B in costs from January 2011 to December 2016
  - Headcount has fallen from 11,686 in 2010 to a forecasted 9,009 in 2016 while GWh per headcount has increased from 7.6 to 9.3
- However, OPG is ramping up recruitment between 2016 and 2017 to fill key vacancies in certain areas (particularly in the Nuclear business unit) due to high levels of attrition from employee demographics, as well as continued Pickering operations beyond 2020
  - OPG is forecasting regular headcount to show a net increase of ~300 by the end of 2017 before gradually decreasing to 4% lower than 2017 levels in 2021
- In addition, to date OPG has hired ~95 Term employees, a new category of non-regular staff negotiated with the Power Workers' Union (PWU) through collective bargaining in 2015
  - Intention is to add fewer regular staff in circumstances where they are likely to be laid off as a result of the end of Pickering commercial operations, per the terms of the collective agreement

Ongoing Operations Regular Headcount and Productivity



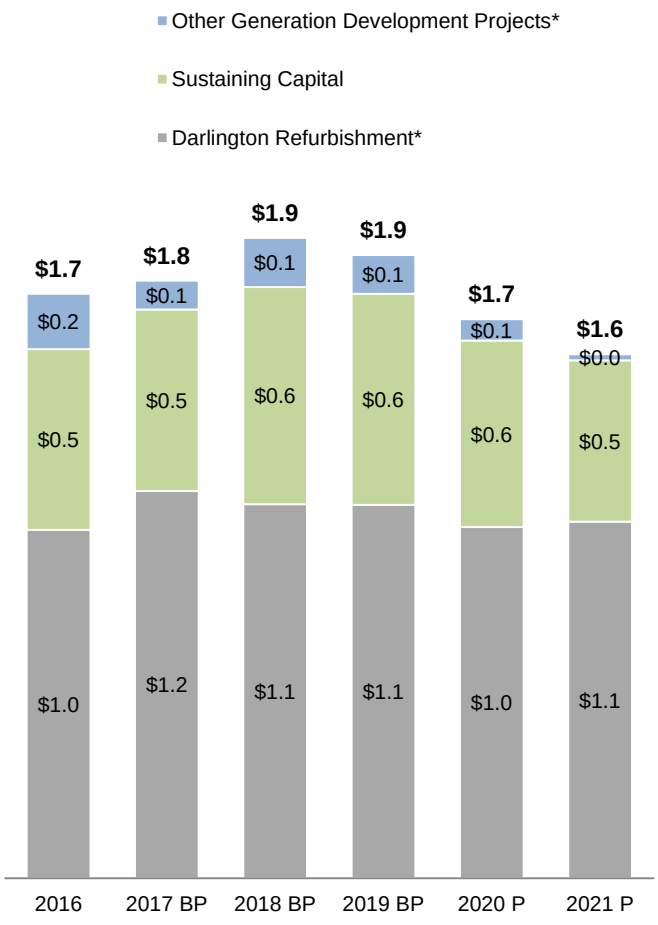
**Production is normalized by adding back hydroelectric surplus baseload generation losses and, in 2017- 2021, the lower production due to the Darlington refurbishment outages

1. Business Plan Overview

f) Operating Highlights - Projects and Capital Expenditures

- OPG continues to focus on delivery of its major projects over the plan period, including:
  - **Darlington Refurbishment**: Unit 2 is assumed to be returned to service in February 2020 with the second unit refurbishment commencing immediately thereafter and the third unit refurbishment starting in July 2021, assuming necessary concurrence from the Province is obtained
  - **Sustaining Capital:** Expenditures average $570M, including:
    - Nuclear expenditures unrelated to refurbishment at Darlington and costs for continued operation of Pickering
    - Regulated hydro expenditures including upgrades at Sir Adam Beck and upgrades to DeCew ll
    - Lower Mattagami upgrades in 2018 and 2019
  - **Other Generation Development Projects:** Investments in current (e.g., hydroelectric) and emerging generation technologies including solar and energy storage including construction and operation of the Nanticoke solar facility by 2019

Capital Expenditure Estimates ($B)



*Includes expenditures budgeted by Support Services

2. Other Considerations

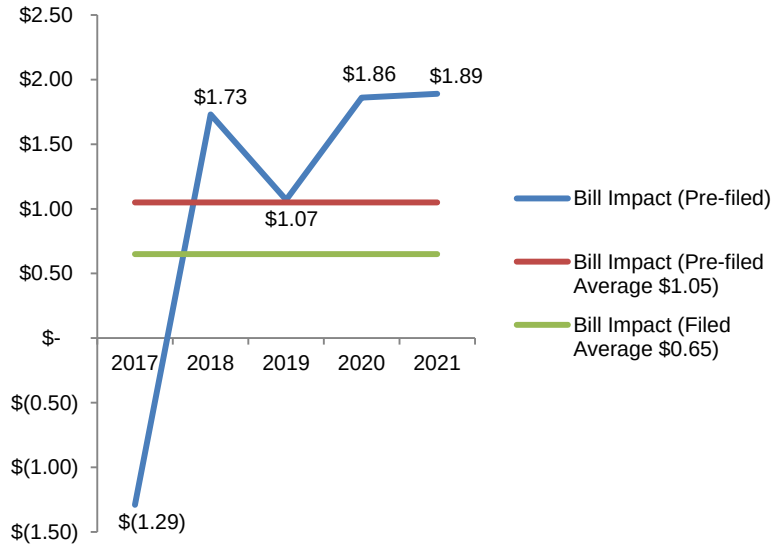
Rate Application

- OPG's 2017-19 Business Plan is dependent on the outcome of its rate filing with the OEB for the five-year period from 2017-2021
- Oral hearings began February 21, 2017 with a decision expected in Q4 2017
- OPG's 2017-19 Business Plan assumes new rates are effective January 1, 2017
  - The OEB setting a later effective date would negatively impact OPG's 2017-18 fiscal year net income by ~$50-60M per month of delay*

Rate-Smoothing Proposal:

- On March 2, 2017 the Province filed an amendment to O.Reg.53/05, which enables OPG to smooth its rates based on OPG's weighted average hydroelectric and nuclear all-in rates (which approximates total bill impact), rather than on the basis of nuclear base rates only
  - Rate smoothing is expected to be fiscally neutral due to rate regulated accounting
- On March 8, 2017 OPG filed a revised rate smoothing proposal with the OEB, which is expected to decrease the average year-over-year annual impact on the monthly customer bill for an average consumption of 750 KWh/month from about $1.05 to 65 cents per month per year

Comparison of Annual Bill Impact ($/Month per year)



*Forecasted in May 2016

2. Other Considerations

Sales

	OPG Head Office	R.L. Hearn Site	Lakeview Site
Current Status	Completed	Agreement Reached	OPG and Infrastructure Ontario are preparing for marketing
Site Description	700 University Ave. and parking garage at 40 Murray St. in Toronto	~33 acres at the R.L. Hearn site in Toronto	~67 acres to be transferred by the purchaser to the City of Mississauga (Municipal Park Lands) and ~110 acres to be developed for mixed uses (Uplands)
Buyer	KingSett Canadian Real Estate Income Fund LP	Studios of America Limited Partner	TBD
Value	Estimated up-front 2017-18 fiscal impact of ~$375M (includes after-tax gain as well as PILs to OEFC)	TBD	TBD
Other Considerations	N/A	N/A	Negotiations with the City have been lengthy and costs to remediate/prepare site may be significant due to concerns regarding site condition
Timing	The sale closed in April 2017	Anticipated to close in Q3 2017	Marketing is planned to start in April 2017, pending negotiations with the City, with an anticipated closing in 2017

2. Other Considerations

Special Status for OPG to Approve International Travel

- On January 24, 2017, OPG's President and CEO wrote to the Deputy Minister to provide a business case and request authority for OPG to approve international travel for its employees. In summary:
  - Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive allows agencies/organizations, for which international travel may be integral to their business, to seek TB/MBC approval for special status to ensure that the approval process does not have an undue negative effect on its ability to conduct business
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Appendix

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OPG Balance Sheet as at Dec 31 $B	2016
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Other current assets	0.9
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Regulatory assets	5.9
Other long-term assets	0.7
Other assets	**$22.5**
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Short-term debt and long-term debt due within one year	1.1
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Depreciation and amortization	1.3
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Earnings on nuclear fixed asset removal and nuclear waste management funds	-0.7
Other expenses	0.02
Total expenses	**$4.2**
Income before other (gains) losses, interest and income taxes	**$0.7**
Other (gains) losses	-0.02
Income before interest and income taxes	**$0.7**
Net interest expense	0.1
Income before income taxes	**$0.6**
Income tax expense	0.2
Net income	**$0.5**
Net income attributable to the Shareholder	**$0.4**
Net income attributable to non-controlling interest	**$0.02**

Ontario

Application and Report to Treasury Board/Management Board of Cabinet

(Refer to instructions on next page)

1. MINISTRY: Energy	2. MINISTRY LOG #	3. TB/MBC LOG #

4. TYPE OF REQUEST: Treasury Board General

5. PURPOSE OF REQUEST: The Ministry of Energy is requesting TB/MBC 1. NOTE the receipt of OPG's 2017-2019 Business Plan. 2. NOTE that the Minister of Energy will provide concurrence with OPG's Business Plan 3. APPROVE OPG's application for Special Status to Approve International Travel under Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive dated January 1, 2017.

6. FINANCIAL DETAILS ($ Millions)

		Current Year 2016/17		Year 2 2017/18		Year 3 2018/19		Matures In 2019/20	
		Operating	Capital	Operating	Capital	Operating	Capital	Operating	Capital
A. Program Current Base	Expense								
	Asset								
B. Program Request (change from existing base)	Expense								
	Asset								
C. Available for Offset	Expense								
	Asset								
D. Net Impact On Program Allocation (B-C)	Expense								
	Asset								
E. Revenue Implications									

7. IMPACT ON FTE LIMIT	Current Year 2016/2017	Year 2 2017/2018	Year 3 2018/2019	Mature in 2019/2020
A. Program Current Base FTE Limit				
B. Program FTEs Request				
C. Available FTE Offset				
D. Net Impact on FTE Limit (B-C)				
E. Change to Ministry Salaries & Wages Allocation (included in the Program Request ($ Millions)				

8. OTHER DECISION FACTORS	Y/N	EXPLANATION
A. Consistent with Government Priorities and Results (If Yes identify key Results) - include details in submission)	Y	MOA between Minister of Energy and OPG
B. Policy approval (if yes identify policy committee and date approved)	N	
C. Key Performance Risks (If yes provide details in submission)	N	
D. Impact on other Ministries (if yes - include sign-off date. Include resources impact in submission)	N	Ministries: N/A
E. Impact on the Fiscal Plan (if yes provide details in submission)	Y	Impact of OPG results

9. AUTHORIZATION /DATE

Signature of Minister	Day/Month/Year	Signature of Deputy Minister	Day/Month/Year
Glenn Thibeault	xxxx	Serge Imbrogno	xxxx

Application and Report to Treasury Board/Management Board of Cabinet

This is a general purpose form. Use it for all requests submitted to Treasury Board and Management Board of Cabinet including items delegated to the Chair of Treasury Board/Management Board of Cabinet. If the submission would result in a change in approved financial appropriations and/or full time equivalent (FTE) limits please complete Sections 6 and/or 7.

Instructions for completing the TB/MBC Submission Template

1. Ministry	State name (or names if it is a joint submissions).
2. Ministry Log #	Insert your Ministry Tracking log # for the submissions.
3. TB/MBC Log #	For use by TB/MBC Coordinaton Office only.
4. Type of Request	Choices may include any or a combination of the following: Financial Transaction, TBO, General, Procurement, legislation, Regulation, Order-in-Council.
5. Purpose of Request	In no more than two sentences, describe the objective of the request.
6. Financial Details	Provide financial details for the current year, outlook for the next 2 years and Maturity date.A32
	For each year of the following sections please provide applicable details for Expense, Asset, Operating and/or Capital:
A. Program Current Base	Provide current base associated with the request
B. Program Request	Change in costs associated with the proposal.
C. Available for Offset	Indicate the costs that can be managed from within existing appropriations (intra or inter-ministry where applicable).
D. Net Impact on Program Allocation	Net impact on the Ministry's allocations.
E. Revenue Implications	Identify new or change in revenues that would flow into the Consolidated Revenue Fund.
7. Impact on FTE Limit	Provide staff details for the current year, outlook for the next 2 years and mature FTE impact - follows the same logic as financial details (items 6 above). For Section 7E provide the change in the salaries and wages associated with the net impact of the request (i.e. 6D) if applicable.
8. Other Decision Factors	Answer Yes or No to each of the decision factors highlighted and provide key notes on template for Minister and Deputy Minister information. Provide further details in the submission.
9. Authorization /Date	To be signed by the Minister and Deputy Minister of the requesting Ministry to confirm support for the request as submitted. Joint inter-ministry submissions require the signature of all Minister and Deputy Minster affected. Signed submission due in to the TB/MBC Coordination Office no later than 2 weeks prior t the scheduled TB/MBC meeting date.

Application and Report to Treasury Board/Management Board of Cabinet

Administrative Data for Current year (relates to 6B and 6C from page 1).

TB/MBC 20

Vote & Item	Standard Account	Ministry Request ($ Millions)				
		Holdback / Release (A)	Treasury Board Order (B)	Increase (C)	(Decrease) (D)	Total (E=B+C+D)
	Salaries & Wages Employee Benefits Transportation & Communication Services Supplies and Equipment Transfer Payments _____ _____ _____ Other Transactions Recoveries Other (Specify) _____					
	ITEM TOTAL					
	Salaries & Wages Employee Benefits Transportation & Communication Services Supplies and Equipment Transfer Payments _____ _____ _____ Other Transactions Recoveries Other (Specify) _____					
	ITEM TOTAL					
	Salaries & Wages Employee Benefits Transportation & Communication Services Supplies and Equipment Transfer Payments _____ _____ _____ Other Transactions Recoveries Other (Specify) _____					
	ITEM TOTAL					
MINISTRY SUMMARY	**Salaries & Wages** **Employee Benefits** **Transportation & Communication** **Services** **Supplies and Equipment** **Transfer Payments** _____ _____ _____ **Other Transactions** **Recoveries** **Other (Specify)** _____					
	MINISTRY TOTAL					

Mr. Bernard Lord
Chair
Ontario Power Generation
1900-700 University Avenue
Toronto ON M5G 1X6

Dear Mr. Lord,

Thank you for your submission of Ontario Power Generation's (OPG) 2017-2019 Business Plan ("the Plan"). We have reviewed the Plan and find it to be consistent with our government's expectations.

I support the operational and financial targets set by OPG in its business plan. We recognize the substantial cost reductions that OPG has recently achieved and expect OPG to work closely with the Province to fully realize the additional efficiencies incorporated in the Plan in a manner that is consistent with the continued safe and environmentally responsible operation of OPG's facilities.

We commend OPG on its successful start to the Darlington Refurbishment Project, a key objective of Ontario's 2013 Long-Term Energy Plan (2013 LTEP). As a priority project for the government, I expect that OPG will continue to focus on delivering the project as per the schedule and budget contained in the Release Quality Estimate approved by the OPG Board and by the government. I also expect OPG to continue to minimize project risks consistent with the nuclear refurbishment principles set out in the 2013 LTEP, and seek concurrence prior to commencing ~~subsequent unit~~ refurbishment~~s after~~of Unit ~~2~~3 ~~is successfully returned to service~~before the end of 2017.

We continue to support the planned operation of Pickering units up to 2022/2024, subject to OPG obtaining necessary regulatory approvals, as the station's output will provide reliable, cost-effective and emission-free electricity supply during the Darlington and initial Bruce refurbishments. I expect OPG to keep the Ministry apprised throughout the regulatory processes and as we proceed to update the Long-Term Energy Plan. .

I understand that the recently approved Ontario Nuclear Funds Agreement (ONFA) Reference Plan has resulted in a reduction of the estimated liabilities for future decommissioning and long-term management of waste from Ontario's nuclear fleet. With many decades of nuclear generation in the Province's future, we expect OPG to continue managing its decommissioning and waste management obligations and related segregated funds in a prudent manner. I recognize that the ONFA is based on OPG's proposed siting of a Deep Geological Repository (DGR) for low and intermediate level waste. OPG's DGR is a key component of Ontario's plans to ensure that nuclear remains the backbone of our electricity system for years to come.

I appreciate the efforts of OPG staff, management and the Board of Directors to date as we worked to develop a plan to refinance the Global Adjustment (GA). Refinancing the GA would provide significant and immediate rate relief by spreading the cost of electricity investments over the expected lifecycle of the infrastructure that has been built. OPG will be instrumental to the success of this initiative and we plan to introduce

legislation that would, if passed, enable OPG to work with the Independent Electricity System Operator (IESO) to implement this plan. I also expect to make the necessary changes to OPG's articles of amalgamation to provide the financing flexibility to implement the refinancing of the GA to meet the Province's price objectives announced on March 2, 2017.

I expect OPG to continue to keep the government informed with regard to the company's key ongoing and emerging initiatives and progress in achieving its financial and operational performance commitments. As OPG's performance directly impacts Ontario's fiscal plan, we note the importance of achieving or exceeding OPG's financial performance commitments

Consistent with Section 7 of the Memorandum of Agreement, in advance of commencing discussions for the renewal of its collective agreements with its unions, I expect that OPG shall seek advice from the Ministry on Provincial policy direction and relevant fiscal considerations affecting labour negotiations.

This letter constitutes our concurrence with OPG's Board approved 2017-2019 Business Plan as provided for under the Memorandum of Agreement between OPG and the Shareholder dated July 17, 2015.

This letter also confirms the approval of special status for OPG to approve international travel, under Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive. OPG shall submit semi-annual reports on international travel to the Ministry of Energy, as described in the submission received from OPG's President and CEO, dated January 24, 2017.

Sincerely,

Glenn Thibeault
Minister of Energy

c: Jeff Lyash, President and Chief Executive Officer, OPG
Serge Imbrogno, Deputy Minister, Ministry of Energy
Scott Thompson, Deputy Minister, Ministry of Finance
Andrew Teliszewsky, Chief of Staff, Ministry of Energy
Ali Ghiassi, Chief of Staff, Ministry of Finance

From:	Ronald Kwan
To:	Marianne Nguyen (MCYS)
Cc:	Lesau, Victoria (MOF); Scott Nelms (ENERGY)
Subject:	OPG BP and Submission to TB
Date:	Friday, April 28, 2017 5:04:08 PM
Attachments:	2017 04 25 EIGS OPG Business Plan v08.docx 2017 04 25 OPG Business Plan Review v12.pptx 2017 04 11 TBMBC - Approval Form.xls 2017 04 26 OPG concurrence letter v9.docx

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Hi Marianne,

FYI. Not sure if you've seen these yet, with respect to the Energy TB submission on OPG's business plan. I got them late on Wednesday, but forgot to send them to you before Lock-up.

Ron

MINISTRY OF ENERGY

TREASURY BOARD / MANAGEMENT BOARD of CABINET SUBMISSION

ONTARIO POWER GENERATION (OPG) 2017-19 BUSINESS PLAN AND SPECIAL STATUS APPLICATION

May 2017

CONFIDENTIAL

MINISTRY OF ENERGY

ONTARIO POWER GENERATION (OPG)
2017-19 BUSINESS PLAN AND SPECIAL STATUS APPLICATION

MINISTRY REQUEST

The Ministry of ENERGY is requesting that Treasury Board/Management Board of Cabinet (TB/MBC):

1. NOTE the receipt of OPG's 2017-2019 Business Plan.
2. NOTE that the Minister of Energy will provide concurrence with OPG's Business Plan.
3. APPROVE OPG's application for Special Status to Approve International Travel under Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive dated January 1, 2017.

CONTEXT

- As required by the Memorandum of Agreement (MOA) between Ontario Power Generation and the Minister of Energy, OPG provided its Business Plan for 2017-2019 to the Ministry of Energy on November 29, 2016 for concurrence
    - Note that while OPG is seeking concurrence for its three year 2017-19 business plan, the plan also includes financial projections for 2020 and 2021
- With this Business Plan OPG is also making an application for Special Status under the Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive, which allows agencies/organizations, for which international travel may be integral to their business, to seek TB/MBC approval for special status to ensure that the approval process does not have an undue negative effect on its ability to conduct business
- The Minister's concurrence requires presentation of OPG's business plan before TB/MBC
- The Ministry of Energy review and analysis of OPG's business plan is supported by the Electricity Investment and Governance Secretariat, a unit within the Ministry of Finance and the Corporate and Electricity Finance Division of the Ontario Financing Authority (OFA)
- The following provides an overview of OPG's business plan, including:
    1. Business Plan Overview
    2. Other Considerations
- Proceeding with Provincial concurrence now will demonstrate that OPG has support from its shareholder as it implements the plan and provides clarity to

the Ontario Energy Board (OEB) as it reviews OPG's current rate application covering the 2017-2021 period

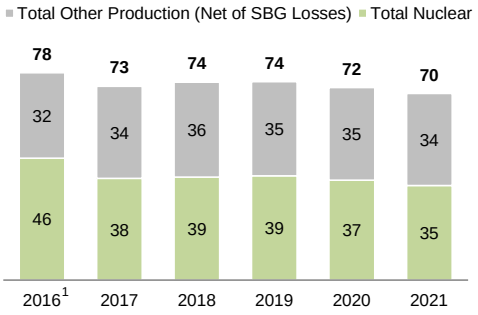
- Business plan forecasts may be affected by Ontario's Fair Hydro Plan (OFHP). Given the stage of implementation of OFHP and the timing of the receipt of the business plan in November 2016, these changes are not reflected in OPG's plan
    - The Ministry anticipates that as part of supporting the financing and administration of the global adjustment smoothing mechanism, OPG would purchase the right to future cash flows from IESO, financed partly by capital infusions from the Province, and majority by third-party lending
    - These changes are generally expected to be fiscally neutral as they would result in an increase in Provincial interest on debt, offset by increases in OPG net income
    - In addition, the Province's net debt position would remain unchanged

1. BUSINESS PLAN OVERVIEW

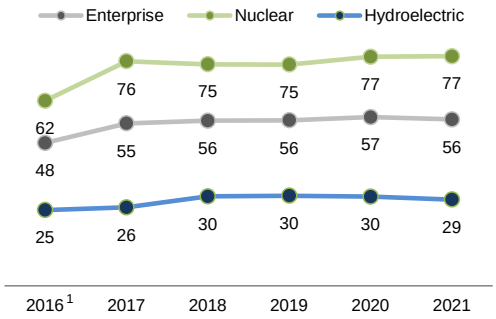
a) Production & Total Cost of Generation

- OPG's production is expected to fall to 69.8 TWh by 2021 from 77.6 TWh in 2016
    - Reflects a declining trend in the Darlington production due to refurbishment outages starting in October 2016
    - Includes a partial overlap starting in 2021 between second and third unit refurbishments, and
    - Includes the Pickering Vacuum Building Outage (VBO) in 2021 requiring the shutdown of all units for the duration of the outage
- While OM&A remains relatively stable over the planning period (see next slide), total generating cost (TGC)* shows an increasing trend over the planning period relative to 2016, reflecting:
    - Lower nuclear production due to Darlington refurbishment outages, and
    - Increased sustaining capital spending (included in TGC) on two large hydroelectric projects, the Lower Mattagami dam safety upgrade and the Sir Adam Beck I GS power canal liner rehabilitation

Production (TWh)



Total Generating Cost ($/MWh)



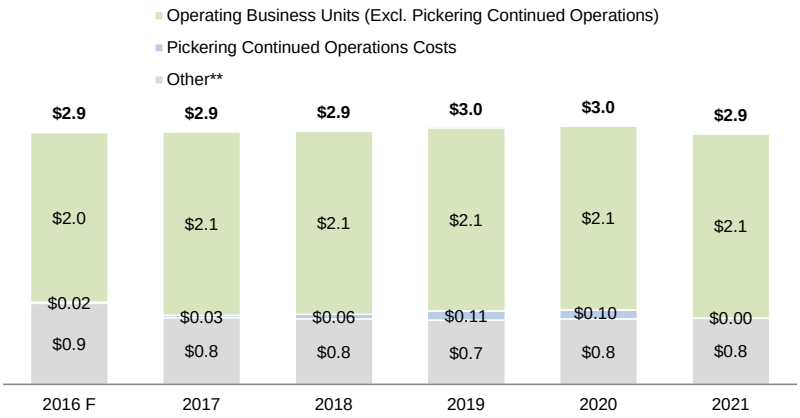
1. Actuals

*TGC = operations, maintenance and administration (OM&A) expenses from ongoing operations + fuel and Gross Revenue Charge expenses for OPG-operated stations + sustaining capital expenditures) divided by OPG generation adjusted for surplus baseload generation losses

b) Operations, Maintenance and Administration (OM&A) Expenses

- Annual OM&A expenses from ongoing operations are expected to stay consistent over the plan period, averaging $2.9B per year
- Increases over 2016 are mainly attributable to:
    - Increases in business unit expenditures, including changes in nuclear outage scope at Darlington, and planned hiring to fill staffing gaps
    - Incremental outage and other program costs to enable Pickering continued operations
- These increases are partially offset by declining pension and Other Post-Employment Benefits (OPEB) costs over the period due to projected pension asset returns, increased employee contributions, and adoption of a new method for applying discount rates to determine interest components of pension costs

OM&A from Ongoing Operations* ($B)



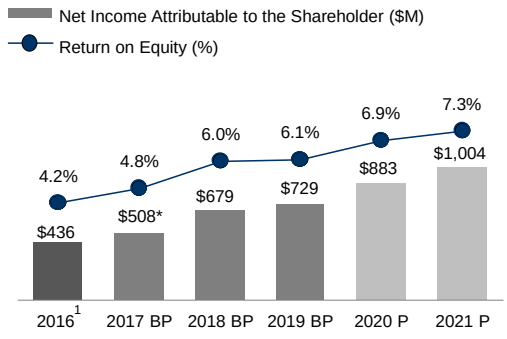
*Excludes Darlington refurbishment OM&A expenses and all OEB variance and deferral account offsets

** Includes centrally held pension /OPEB costs and support services

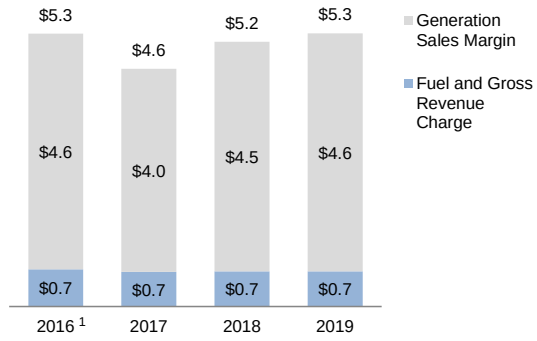
c) Financials

- OPG is forecasting net income attributable to the Shareholder to reach $1B in 2021, from $436M in 2016
    - 2017 net income is forecast to increase as a result of new regulated rates, higher capitalized interest for the Darlington Refurbishment expenditures partially offset by reduced production as a result of planned outages at Sir Adam Beck I and DeCew II hydro stations
    - Net income in 2018 and 2019 is planned to increase, primarily due to higher forecast production, and earnings from Peter Sutherland Sr. GS starting in 2017 and Nanticoke solar facility starting in 2019
- As a result, return-on-equity (ROE) is estimated to increase from 4.2% in 2016 to 7.3% by 2021
- Overall, the 2017-19 Business Plan is largely unchanged relative to last year's plan in terms of commitments for Net Income, and Total Shareholder Return
- In early January 2017, subsequent to the OPG Board's approval of the 2017-2019 Business Plan, OPG reached an agreement with KingSett Canadian Real Estate Income Fund LP for the purchase of OPG's head office property. The net gain is estimated to be $285M and will be distributed to the Trillium Trust.

Net Income ($M) and ROE (%)



Revenue Margin ($B)



1. Actuals

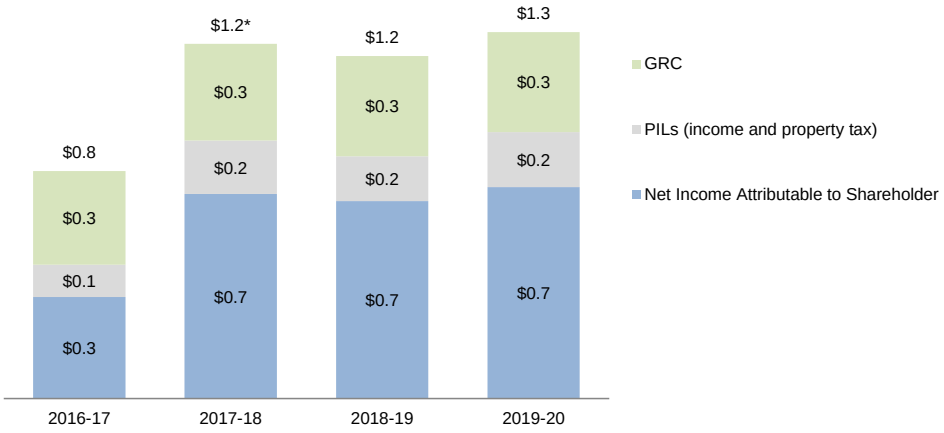
*Includes extraordinary gain associated with the sale of OPG head office

d) Provincial Fiscal Impacts: Shareholder Return and Payments-in-Lieu of Taxes

- Total fiscal revenue impacts to the Province, including net income return to the shareholder and payments-in-lieu of taxes, averages ~$1B over the period
    - Provincial revenues from OPG are dedicated to servicing and paying down stranded debt and the investment cost of the Province acquiring the equity in OPG[1]

- Return to the shareholder improves due to changes in net income, which OPG attributes to:
    - Assumed OEB rate outcomes
    - Completion of the first Darlington unit refurbishment
    - Further cost efficiencies
- Net income is consolidated by the Province as Revenue from Government Business Enterprises (GBEs)
- Income tax PILs, Gross Revenue Charges (GRC) and property tax PILs paid to the Ontario Electricity Financial Corporation (OEFC) to help service and pay down stranded debt are consolidated in Public Accounts under Taxation Revenue
- OPG also pays a portion of the GRC to the Province's Consolidated Revenue Fund (CRF)

Total Fiscal Revenues ($B)



1. Aside from the water power rental portion of the GRC, paid to the CRF.

*Includes gain associated with the sale of OPG head office

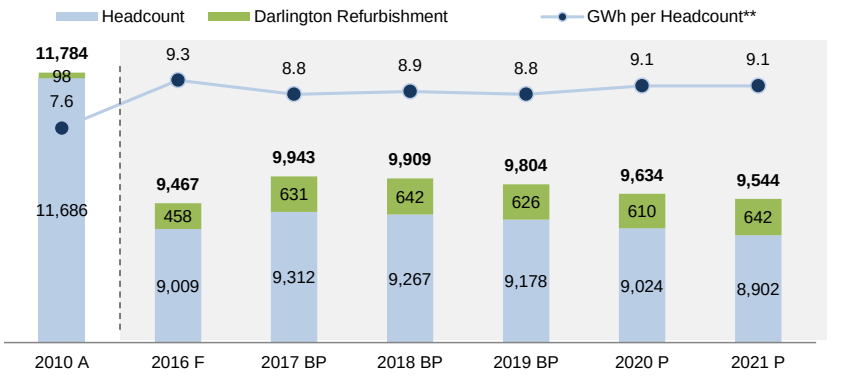
e) Business Transformation Initiative & Labour Costs

- As part of a company-wide business transformation, OPG saved over $1B in costs from January 2011 to December 2016
    - Headcount has fallen from 11,686 in 2010 to a forecasted 9,009 in 2016 while GWh per headcount has increased from 7.6 to 9.3
- However, OPG is ramping up recruitment between 2016 and 2017 to fill key vacancies in certain areas (particularly in the Nuclear business unit) due to high levels of attrition from employee demographics, as well as continued Pickering operations beyond 2020

- OPG is forecasting regular headcount to show a net increase of ~300 by the end of 2017 before gradually decreasing to 4% lower than 2017 levels in 2021

- In addition, to date OPG has hired ~95 Term employees, a new category of non-regular staff negotiated with the Power Workers' Union (PWU) through collective bargaining in 2015
  - Intention is to add fewer regular staff in circumstances where they are likely to be laid off as a result of the end of Pickering commercial operations, per the terms of the collective agreement

Ongoing Operations Regular Headcount and Productivity

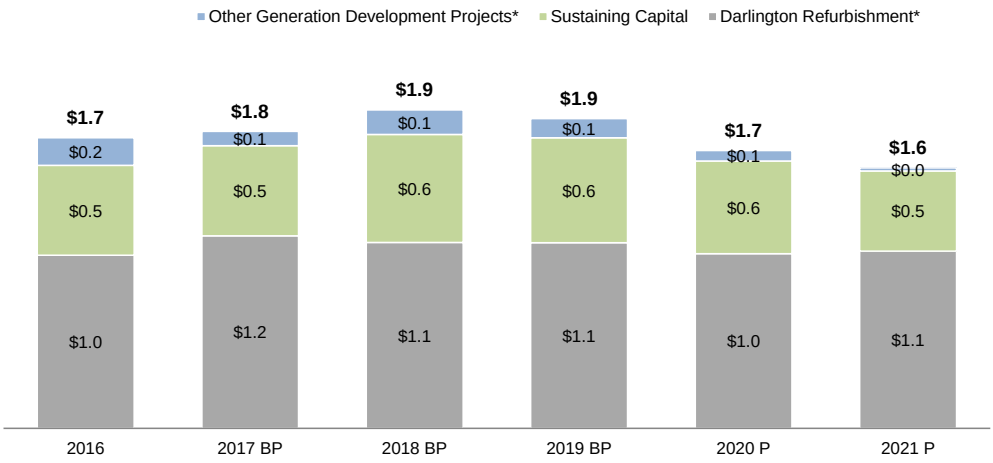


**Production is normalized by adding back hydroelectric surplus baseload generation losses and, in 2017- 2021, the lower production due to the Darlington refurbishment outages

f) Operating Highlights - Projects and Capital Expenditures

- OPG continues to focus on delivery of its major projects over the plan period, including:
  - **Darlington Refurbishment**: Unit 2 is assumed to be returned to service in February 2020 with the second unit refurbishment commencing immediately thereafter and the third unit refurbishment starting in July 2021, assuming necessary concurrence from the Province is obtained
  - **Sustaining Capital:** Expenditures average $570M, including:
    - Nuclear expenditures unrelated to refurbishment at Darlington and costs for continued operation of Pickering
    - Regulated hydro expenditures including upgrades at Sir Adam Beck and upgrades to DeCew ll
    - Lower Mattagami upgrades in 2018 and 2019
  - **Other Generation Development Projects:** Investments in current (e.g., hydroelectric) and emerging generation technologies including solar and energy storage including construction and operation of the Nanticoke solar facility by 2019

Capital Expenditure Estimates ($B)



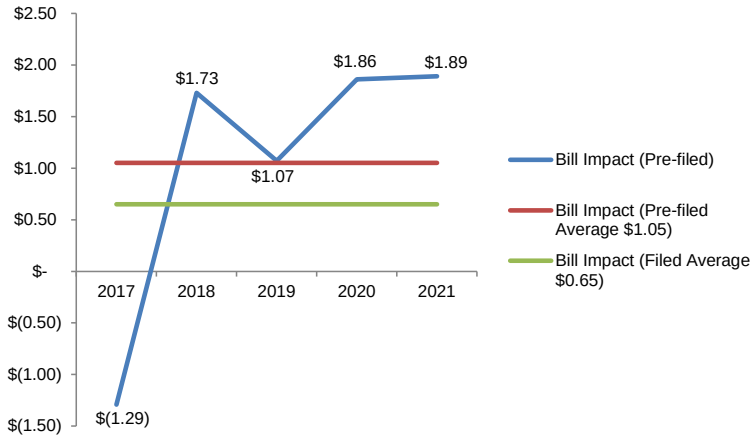
*Includes expenditures budgeted by Support Services

2. OTHER CONSIDERATIONS

Rate Application

- OPG's 2017-19 Business Plan is dependent on the outcome of its rate filing with the OEB for the five-year period from 2017-2021
- Oral hearings began February 21, 2017 with a decision expected in Q4 2017
- OPG's 2017-19 Business Plan assumes new rates are effective January 1, 2017
    - The OEB setting a later effective date would negatively impact OPG's 2017-18 fiscal year net income by ~$50-60M per month of delay*
- Rate-Smoothing Proposal:
    - On March 2, 2017 the Province filed an amendment to O.Reg.53/05, which enables OPG to smooth its rates based on OPG's weighted average hydroelectric and nuclear all-in rates (which approximates total bill impact), rather than on the basis of nuclear base rates only
        - Rate smoothing is expected to be fiscally neutral due to rate regulated accounting
    - On March 8, 2017 OPG filed a revised rate smoothing proposal with the OEB, which is expected to decrease the average year-over-year annual impact on the monthly customer bill for an average consumption of 750 KWh/month from about $1.05 to 65 cents per month per year

Comparison of Annual Bill Impact ($/Month per year)



*Forecasted in May 2016

Sales

	OPG Head Office	R.L. Hearn Site	Lakeview Site
Current Status	Completed	Agreement Reached	OPG and Infrastructure Ontario are preparing for marketing
Site Description	700 University Ave. and parking garage at 40 Murray St. in Toronto	~33 acres at the R.L. Hearn site in Toronto	~67 acres to be transferred by the purchaser to the City of Mississauga (Municipal Park Lands) and ~110 acres to be developed for mixed uses (Uplands)
Buyer	KingSett Canadian Real Estate Income Fund LP	Studios of America Limited Partner	TBD
Value	Estimated up-front 2017-18 fiscal impact of ~$375M (includes after-tax gain as well as PILs to OEFC)	TBD	TBD
Other Considerations	N/A	N/A	Negotiations with the City have been lengthy and costs to remediate/prepare site may be significant due to concerns regarding site condition
Timing	The sale closed in April 2017	Anticipated to close in Q3 2017	Marketing is planned to start in April 2017, pending negotiations with the City, with an anticipated closing in 2017

Special Status for OPG to Approve International Travel

- On January 24, 2017, OPG's President and CEO wrote to the Deputy Minister to provide a business case and request authority for OPG to approve international travel for its employees. In summary:
    - Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive allows agencies/organizations, for which international travel may be integral to their business, to seek TB/MBC approval for special status to ensure that the approval process does not have an undue negative effect on its ability to conduct business

- OPG believes that international travel is integral to the safe and prudent operation of its business and having OPG's CEO approve international travel will enable more efficient decision-making while significantly lowering travel costs
- OPG cites the importance of enabling its engagement with the international community (in particular in regards to nuclear safety), procurement activities, and investment and due diligence processes for over $30 billion in pension fund and nuclear funds
- OPG requires a high level of international business travel at approximately 90-100 trips annually, while the Darlington Refurbishment Project accounts for 45% of OPG's international travel and is expected see increases over the 10 year life of the project
- OPG indicated that the approval process, which took 23 days on average in 2016, delays flight bookings which results in higher costs as airlines raise fares closer to the travel date
- OPG believes the inability to make timely commitments on events and meetings impacts employee engagement as well as its international relationships and reputation

- OPG is seeking Special Status as part of concurrence with its business plan. OPG has committed to providing semi-annual reports to the Ministry on international travel taken, and continue to be accountable for compliance with all applicable OPS directives, policies and procedures

RECOMMENDATION

The Ministry of ENERGY is requesting that Treasury Board/Management Board of Cabinet (TB/MBC):

1. NOTE the receipt of OPG's 2017-2019 Business Plan.
2. NOTE that the Minister of Energy will provide concurrence with OPG's Business Plan.
3. APPROVE OPG's application for Special Status to Approve International Travel under Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive dated January 1, 2017.

APPENDIX

OPG 2016 Year-End Financials

OPG Balance Sheet as at Dec 31 $B	2016
Assets	
Cash and cash equivalents	0.2
Available-for-sale securities	0.2
Receivables from related parties	0.4
Nuclear fixed asset removal and nuclear waste management funds	0.02
Other current assets	0.9
Total current assets	**$1.7**
Net property, plant and equipment	**$20.0**
Net intangible assets	**$0.1**
Nuclear fixed asset removal and nuclear waste management funds	16.0
Regulatory assets	5.9
Other long-term assets	0.7
Other assets	**$22.5**
Total assets	**$44.4**
Liabilities	
Accounts payable and accrued charges	1.2
Short-term debt and long-term debt due within one year	1.1
Income taxes payable and other current liabilities	0.1
Total current liabilities	**$2.4**
Long-term debt	4.4
Fixed asset removal and nuclear waste management liabilities	19.5
Pension liabilities	3.0
Other post-employment benefit liabilities	2.9
Other liabilities	1.7
	$31.5
Total liabilities	**$33.9**
Equity	
Equity attributable to the Shareholder	10.4
Equity attributable to non-controlling interest	0.1
Total equity	**$10.5**
Total liabilities and equity	**$44.4**

OPG Income Statement Year Ended Dec 31 $B	2016
Revenue	$5.7
Fuel expense	0.7
Gross margin	**$4.9**
Operations, maintenance and administration	2.7
Depreciation and amortization	1.3
Accretion on fixed asset removal and nuclear waste management liabilities	0.9
Earnings on nuclear fixed asset removal and nuclear waste management funds	-0.7
Other expenses	0.02
Total expenses	**$4.2**
Income before other (gains) losses, interest and income taxes	**$0.7**
Other (gains) losses	-0.02
Income before interest and income taxes	**$0.7**
Net interest expense	0.1
Income before income taxes	**$0.6**
Income tax expense	0.2
Net income	**$0.5**
Net income attributable to the Shareholder	**$0.4**
Net income attributable to non-controlling interest	**$0.02**

Ontario

MINISTRY OF
ENERGY

Ontario Power Generation (OPG) 2017-19 Business Plan and Special Status Application

May 2017

Context

- As required by the Memorandum of Agreement (MOA) between Ontario Power Generation and the Minister of Energy, OPG provided its Business Plan for 2017-2019 to the Ministry of Energy on November 29, 2016 for concurrence
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- The following presentation provides an overview of OPG's business plan, including:
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  2. Other Considerations

Context *(cont'd)*

- Proceeding with Provincial concurrence now will demonstrate that OPG has support from its shareholder as it implements the plan and provides clarity to the Ontario Energy Board (OEB) as it reviews OPG's current rate application covering the 2017-2021 period

- Business plan forecasts may be affected by Ontario's Fair Hydro Plan (OFHP). Given the stage of implementation of OFHP and the timing of the receipt of the business plan in November 2016, these changes are not reflected in OPG's plan

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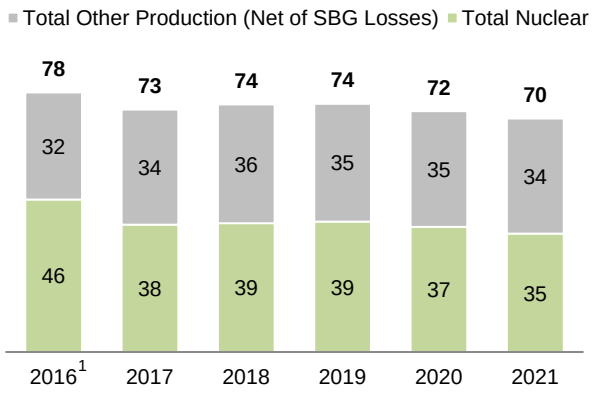
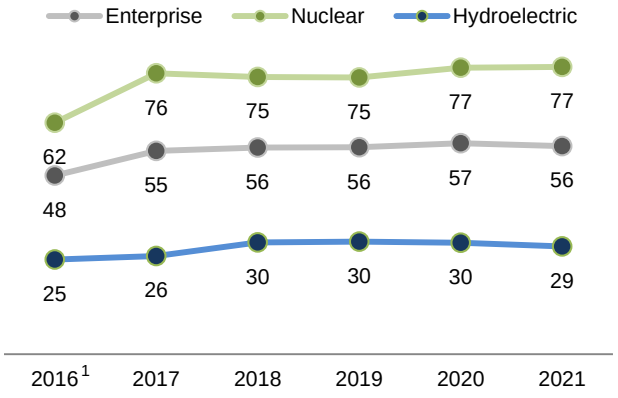
Production (TWh)



Total Generating Cost ($/MWh)



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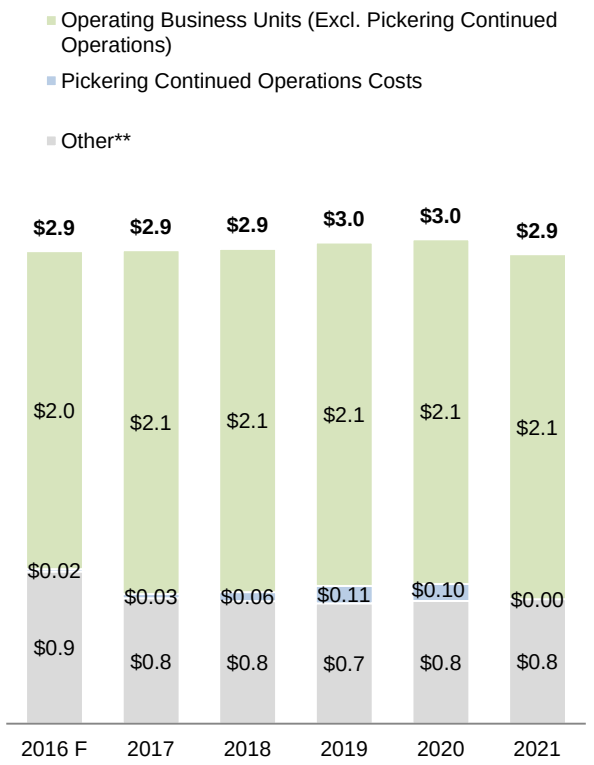
OM&A from Ongoing Operations* ($B)



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1. Business Plan Overview

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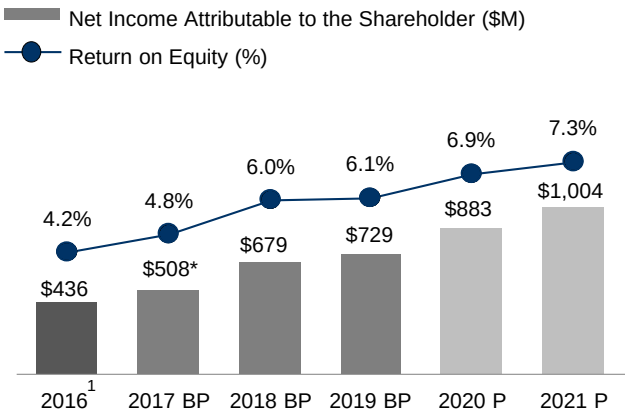
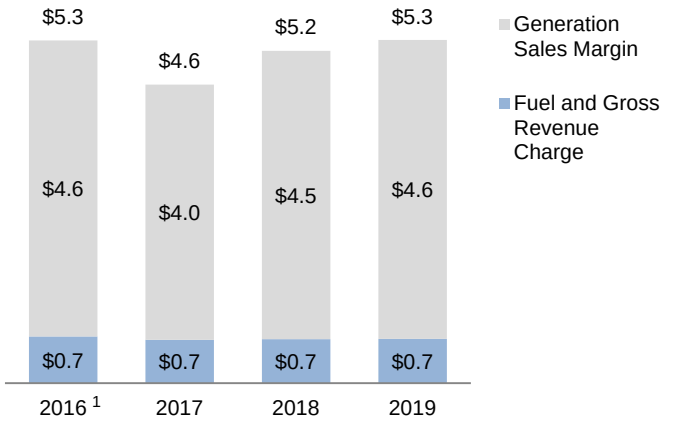
- In early January 2017, subsequent to the OPG Board's approval of the 2017-2019 Business Plan, OPG reached an agreement with KingSett Canadian Real Estate Income Fund LP for the purchase of OPG's head office property. The net gain is estimated to be $285M and will be distributed to the Trillium Trust

Net Income ($M) and ROE (%)



Revenue Margin ($B)



*Includes extraordinary gain associated with the sale of OPG head office

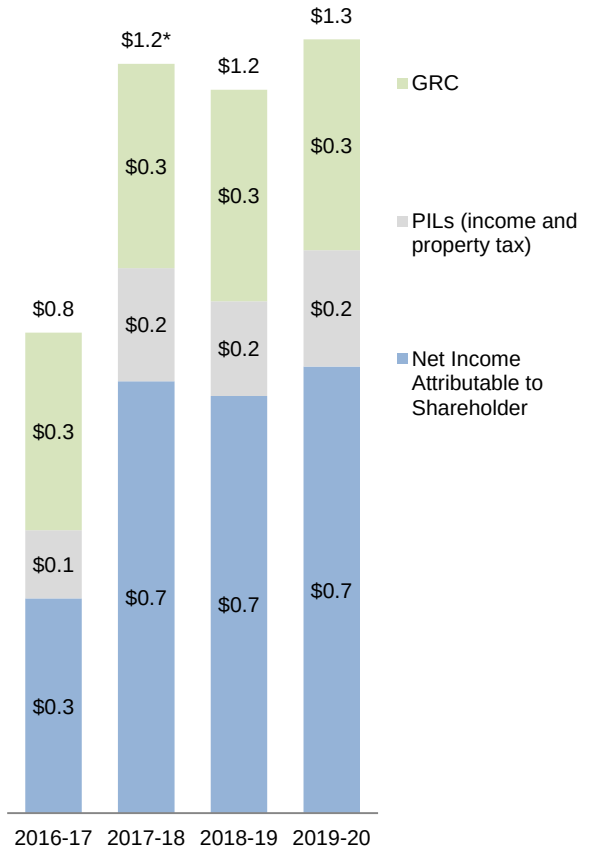
1. Actuals

1. Business Plan Overview

d) Provincial Fiscal Impacts: Shareholder Return and Payments-in-Lieu of Taxes

- Total fiscal revenue impacts to the Province, including net income return to the shareholder and payments-in-lieu of taxes, averages ~$1B over the period
  - Provincial revenues from OPG are dedicated to servicing and paying down stranded debt and the investment cost of the Province acquiring the equity in OPG[1]
- Return to the shareholder improves due to changes in net income, which OPG attributes to:
  - Assumed OEB rate outcomes
  - Completion of the first Darlington unit refurbishment
  - Further cost efficiencies
- Net income is consolidated by the Province as Revenue from Government Business Enterprises (GBEs)
- Income tax PILs, Gross Revenue Charges (GRC) and property tax PILs paid to the Ontario Electricity Financial Corporation (OEFC) to help service and pay down stranded debt are consolidated in Public Accounts under Taxation Revenue
- OPG also pays a portion of the GRC to the Province's Consolidated Revenue Fund (CRF)

Total Fiscal Revenues ($B)



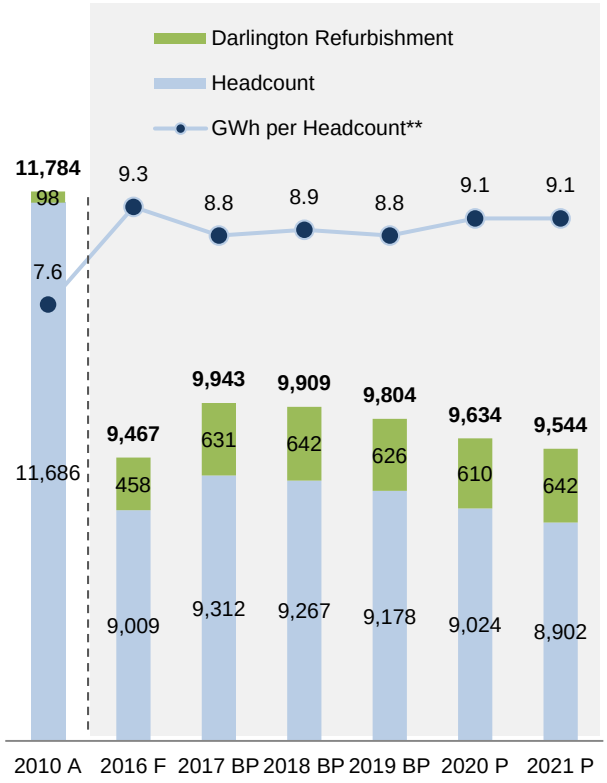
1. Aside from the water power rental portion of the GRC, paid to the CRF.
*Includes gain associated with the sale of OPG head office

1. Business Plan Overview

e) Business Transformation Initiative & Labour Costs

- As part of a company-wide business transformation, OPG saved over $1B in costs from January 2011 to December 2016
  - Headcount has fallen from 11,686 in 2010 to a forecasted 9,009 in 2016 while GWh per headcount has increased from 7.6 to 9.3
- However, OPG is ramping up recruitment between 2016 and 2017 to fill key vacancies in certain areas (particularly in the Nuclear business unit) due to high levels of attrition from employee demographics, as well as continued Pickering operations beyond 2020
  - OPG is forecasting regular headcount to show a net increase of ~300 by the end of 2017 before gradually decreasing to 4% lower than 2017 levels in 2021
- In addition, to date OPG has hired ~95 Term employees, a new category of non-regular staff negotiated with the Power Workers' Union (PWU) through collective bargaining in 2015
  - Intention is to add fewer regular staff in circumstances where they are likely to be laid off as a result of the end of Pickering commercial operations, per the terms of the collective agreement

Ongoing Operations Regular Headcount and Productivity



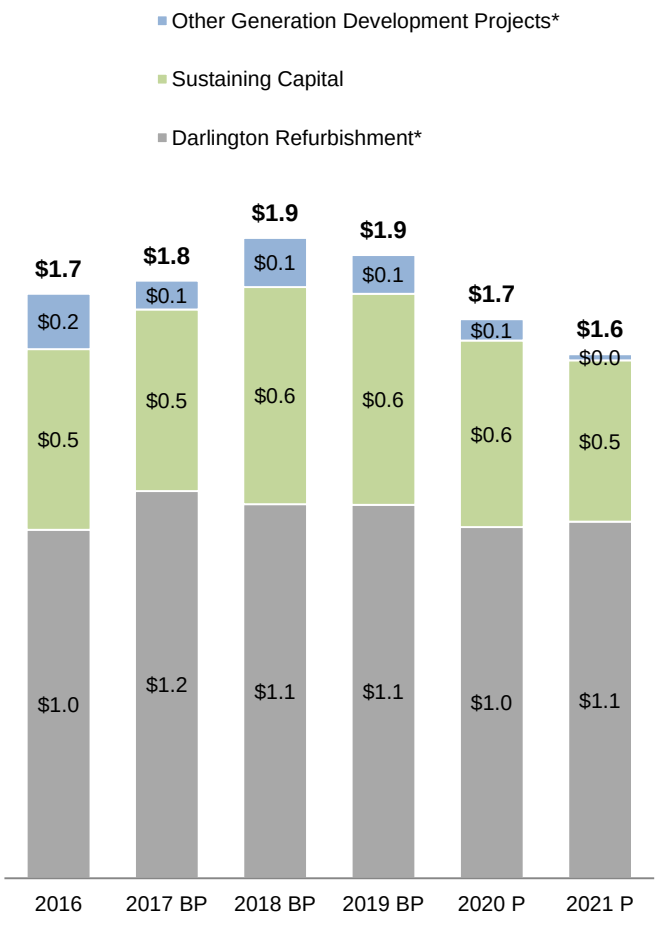
**Production is normalized by adding back hydroelectric surplus baseload generation losses and, in 2017- 2021, the lower production due to the Darlington refurbishment outages

1. Business Plan Overview

f) Operating Highlights - Projects and Capital Expenditures

- OPG continues to focus on delivery of its major projects over the plan period, including:
  - **Darlington Refurbishment**: Unit 2 is assumed to be returned to service in February 2020 with the second unit refurbishment commencing immediately thereafter and the third unit refurbishment starting in July 2021, assuming necessary concurrence from the Province is obtained
  - **Sustaining Capital:** Expenditures average $570M, including:
    - Nuclear expenditures unrelated to refurbishment at Darlington and costs for continued operation of Pickering
    - Regulated hydro expenditures including upgrades at Sir Adam Beck and upgrades to DeCew ll
    - Lower Mattagami upgrades in 2018 and 2019
  - **Other Generation Development Projects:** Investments in current (e.g., hydroelectric) and emerging generation technologies including solar and energy storage including construction and operation of the Nanticoke solar facility by 2019

Capital Expenditure Estimates ($B)



*Includes expenditures budgeted by Support Services

2. Other Considerations

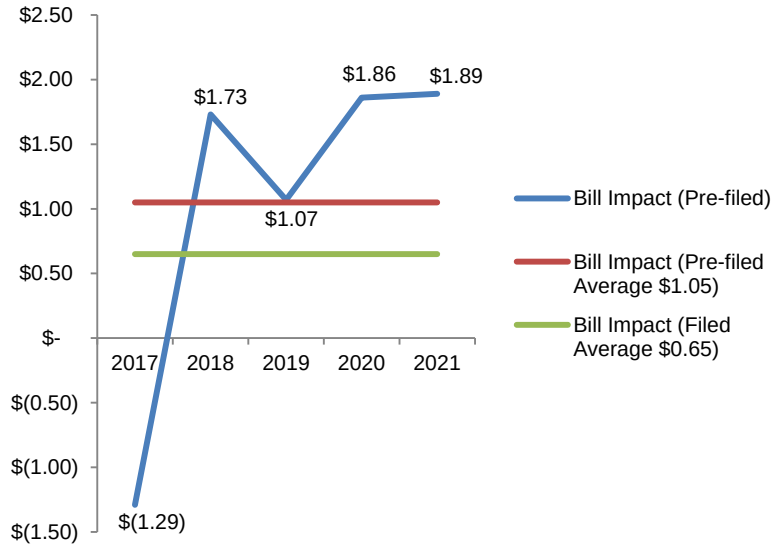
Rate Application

- OPG's 2017-19 Business Plan is dependent on the outcome of its rate filing with the OEB for the five-year period from 2017-2021
- Oral hearings began February 21, 2017 with a decision expected in Q4 2017
- OPG's 2017-19 Business Plan assumes new rates are effective January 1, 2017
  - The OEB setting a later effective date would negatively impact OPG's 2017-18 fiscal year net income by ~$50-60M per month of delay*

Rate-Smoothing Proposal:

- On March 2, 2017 the Province filed an amendment to O.Reg.53/05, which enables OPG to smooth its rates based on OPG's weighted average hydroelectric and nuclear all-in rates (which approximates total bill impact), rather than on the basis of nuclear base rates only
  - Rate smoothing is expected to be fiscally neutral due to rate regulated accounting
- On March 8, 2017 OPG filed a revised rate smoothing proposal with the OEB, which is expected to decrease the average year-over-year annual impact on the monthly customer bill for an average consumption of 750 KWh/month from about $1.05 to 65 cents per month per year

Comparison of Annual Bill Impact ($/Month per year)



*Forecasted in May 2016

2. Other Considerations

Sales

	OPG Head Office	R.L. Hearn Site	Lakeview Site
Current Status	Completed	Agreement Reached	OPG and Infrastructure Ontario are preparing for marketing
Site Description	700 University Ave. and parking garage at 40 Murray St. in Toronto	~33 acres at the R.L. Hearn site in Toronto	~67 acres to be transferred by the purchaser to the City of Mississauga (Municipal Park Lands) and ~110 acres to be developed for mixed uses (Uplands)
Buyer	KingSett Canadian Real Estate Income Fund LP	Studios of America Limited Partner	TBD
Value	Estimated up-front 2017-18 fiscal impact of ~$375M (includes after-tax gain as well as PILs to OEFC)	TBD	TBD
Other Considerations	N/A	N/A	Negotiations with the City have been lengthy and costs to remediate/prepare site may be significant due to concerns regarding site condition
Timing	The sale closed in April 2017	Anticipated to close in Q3 2017	Marketing is planned to start in April 2017, pending negotiations with the City, with an anticipated closing in 2017

2. Other Considerations

Special Status for OPG to Approve International Travel

- On January 24, 2017, OPG's President and CEO wrote to the Deputy Minister to provide a business case and request authority for OPG to approve international travel for its employees. In summary:
  - Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive allows agencies/organizations, for which international travel may be integral to their business, to seek TB/MBC approval for special status to ensure that the approval process does not have an undue negative effect on its ability to conduct business
  - OPG believes that international travel is integral to the safe and prudent operation of its business and having OPG's CEO approve international travel will enable more efficient decision-making while significantly lowering travel costs
  - OPG cites the importance of enabling its engagement with the international community (in particular in regards to nuclear safety), procurement activities, and investment and due diligence processes for over $30 billion in pension fund and nuclear funds
  - OPG requires a high level of international business travel at approximately 90-100 trips annually, while the Darlington Refurbishment Project accounts for 45% of OPG's international travel and is expected see increases over the 10 year life of the project
  - OPG indicated that the approval process, which took 23 days on average in 2016, delays flight bookings which results in higher costs as airlines raise fares closer to the travel date
  - OPG believes the inability to make timely commitments on events and meetings impacts employee engagement as well as its international relationships and reputation
- OPG is seeking Special Status as part of concurrence with its business plan. OPG has committed to providing semi-annual reports to the Ministry on international travel taken, and continue to be accountable for compliance with all applicable OPS directives, policies and procedures

Appendix

2016 Year-End Financials

OPG Balance Sheet as at Dec 31 $B	2016
Assets	
Cash and cash equivalents	0.2
Available-for-sale securities	0.2
Receivables from related parties	0.4
Nuclear fixed asset removal and nuclear waste management funds	0.02
Other current assets	0.9
Total current assets	**$1.7**
Net property, plant and equipment	**$20.0**
Net intangible assets	**$0.1**
Nuclear fixed asset removal and nuclear waste management funds	16.0
Regulatory assets	5.9
Other long-term assets	0.7
Other assets	**$22.5**
Total assets	**$44.4**
Liabilities	
Accounts payable and accrued charges	1.2
Short-term debt and long-term debt due within one year	1.1
Income taxes payable and other current liabilities	0.1
Total current liabilities	**$2.4**
Long-term debt	4.4
Fixed asset removal and nuclear waste management liabilities	19.5
Pension liabilities	3.0
Other post-employment benefit liabilities	2.9
Other liabilities	1.7
	$31.5
Total liabilities	**$33.9**
Equity	
Equity attributable to the Shareholder	10.4
Equity attributable to non-controlling interest	0.1
Total equity	**$10.5**
Total liabilities and equity	**$44.4**

OPG Income Statement Year Ended Dec 31 $B	2016
Revenue	$5.7
Fuel expense	0.7
Gross margin	**$4.9**
Operations, maintenance and administration	2.7
Depreciation and amortization	1.3
Accretion on fixed asset removal and nuclear waste management liabilities	0.9
Earnings on nuclear fixed asset removal and nuclear waste management funds	-0.7
Other expenses	0.02
Total expenses	**$4.2**
Income before other (gains) losses, interest and income taxes	**$0.7**
Other (gains) losses	-0.02
Income before interest and income taxes	**$0.7**
Net interest expense	0.1
Income before income taxes	**$0.6**
Income tax expense	0.2
Net income	**$0.5**
Net income attributable to the Shareholder	**$0.4**
Net income attributable to non-controlling interest	**$0.02**

Ontario

Application and Report to Treasury Board/Management Board of Cabinet

(Refer to instructions on next page)

1. MINISTRY: Energy	2. MINISTRY LOG #	3. TB/MBC LOG #

4. TYPE OF REQUEST: Treasury Board General

5. PURPOSE OF REQUEST: The Ministry of Energy is requesting TB/MBC 1. NOTE the receipt of OPG's 2017-2019 Business Plan. 2. NOTE that the Minister of Energy will provide concurrence with OPG's Business Plan 3. APPROVE OPG's application for Special Status to Approve International Travel under Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive dated January 1, 2017.

6. FINANCIAL DETAILS ($ Millions)

		Current Year 2016/17		Year 2 2017/18		Year 3 2018/19		Matures In 2019/20	
		Operating	Capital	Operating	Capital	Operating	Capital	Operating	Capital
A. Program Current Base	Expense								
	Asset								
B. Program Request (change from existing base)	Expense								
	Asset								
C. Available for Offset	Expense								
	Asset								
D. Net Impact On Program Allocation (B-C)	Expense								
	Asset								
E. Revenue Implications									

7. IMPACT ON FTE LIMIT	Current Year 2016/2017	Year 2 2017/2018	Year 3 2018/2019	Mature in 2019/2020
A. Program Current Base FTE Limit				
B. Program FTEs Request				
C. Available FTE Offset				
D. Net Impact on FTE Limit (B-C)				
E. Change to Ministry Salaries & Wages Allocation (included in the Program Request ($ Millions)				

8. OTHER DECISION FACTORS	Y/N	EXPLANATION
A. Consistent with Government Priorities and Results (If Yes identify key Results) - include details in submission)	Y	MOA between Minister of Energy and OPG
B. Policy approval (if yes identify policy committee and date approved)	N	
C. Key Performance Risks (If yes provide details in submission)	N	
D. Impact on other Ministries (if yes - include sign-off date. Include resources impact in submission)	N	Ministries: N/A
E. Impact on the Fiscal Plan (if yes provide details in submission)	Y	Impact of OPG results

9. AUTHORIZATION /DATE

Signature of Minister	Day/Month/Year	Signature of Deputy Minister	Day/Month/Year
Glenn Thibeault	xxxx	Serge Imbrogno	xxxx

Application and Report to Treasury Board/Management Board of Cabinet

This is a general purpose form. Use it for all requests submitted to Treasury Board and Management Board of Cabinet including items delegated to the Chair of Treasury Board/Management Board of Cabinet. If the submission would result in a change in approved financial appropriations and/or full time equivalent (FTE) limits please complete Sections 6 and/or 7.

Instructions for completing the TB/MBC Submission Template

1. Ministry	State name (or names if it is a joint submissions).
2. Ministry Log #	Insert your Ministry Tracking log # for the submissions.
3. TB/MBC Log #	For use by TB/MBC Coordinaton Office only.
4. Type of Request	Choices may include any or a combination of the following: Financial Transaction, TBO, General, Procurement, legislation, Regulation, Order-in-Council.
5. Purpose of Request	In no more than two sentences, describe the objective of the request.
6. Financial Details	Provide financial details for the current year, outlook for the next 2 years and Maturity date.A32
	For each year of the following sections please provide applicable details for Expense, Asset, Operating and/or Capital:
A. Program Current Base	Provide current base associated with the request
B. Program Request	Change in costs associated with the proposal.
C. Available for Offset	Indicate the costs that can be managed from within existing appropriations (intra or inter-ministry where applicable).
D. Net Impact on Program Allocation	Net impact on the Ministry's allocations.
E. Revenue Implications	Identify new or change in revenues that would flow into the Consolidated Revenue Fund.
7. Impact on FTE Limit	Provide staff details for the current year, outlook for the next 2 years and mature FTE impact - follows the same logic as financial details (items 6 above). For Section 7E provide the change in the salaries and wages associated with the net impact of the request (i.e. 6D) if applicable.
8. Other Decision Factors	Answer Yes or No to each of the decision factors highlighted and provide key notes on template for Minister and Deputy Minister information. Provide further details in the submission.
9. Authorization /Date	To be signed by the Minister and Deputy Minister of the requesting Ministry to confirm support for the request as submitted. Joint inter-ministry submissions require the signature of all Minister and Deputy Minster affected. Signed submission due in to the TB/MBC Coordination Office no later than 2 weeks prior t the scheduled TB/MBC meeting date.

Application and Report to Treasury Board/Management Board of Cabinet

Administrative Data for Current year (relates to 6B and 6C from page 1).

TB/MBC 20

Vote & Item	Standard Account	Ministry Request ($ Millions)				
		Holdback / Release (A)	Treasury Board Order (B)	Increase (C)	(Decrease) (D)	Total (E=B+C+D)
	Salaries & Wages Employee Benefits Transportation & Communication Services Supplies and Equipment Transfer Payments _____ _____ _____ Other Transactions Recoveries Other (Specify) _____					
	ITEM TOTAL					
	Salaries & Wages Employee Benefits Transportation & Communication Services Supplies and Equipment Transfer Payments _____ _____ _____ Other Transactions Recoveries Other (Specify) _____					
	ITEM TOTAL					
	Salaries & Wages Employee Benefits Transportation & Communication Services Supplies and Equipment Transfer Payments _____ _____ _____ Other Transactions Recoveries Other (Specify) _____					
	ITEM TOTAL					
MINISTRY SUMMARY	**Salaries & Wages** **Employee Benefits** **Transportation & Communication** **Services** **Supplies and Equipment** **Transfer Payments** _____ _____ _____ **Other Transactions** **Recoveries** **Other (Specify)** _____					
	MINISTRY TOTAL					

Mr. Bernard Lord
Chair
Ontario Power Generation
1900-700 University Avenue
Toronto ON M5G 1X6

Dear Mr. Lord,

Thank you for your submission of Ontario Power Generation's (OPG) 2017-2019 Business Plan ("the Plan"). We have reviewed the Plan and find it to be consistent with our government's expectations.

I support the operational and financial targets set by OPG in its business plan. We recognize the substantial cost reductions that OPG has recently achieved and expect OPG to work closely with the Province to fully realize the additional efficiencies incorporated in the Plan in a manner that is consistent with the continued safe and environmentally responsible operation of OPG's facilities.

We commend OPG on its successful start to the Darlington Refurbishment Project, a key objective of Ontario's 2013 Long-Term Energy Plan (2013 LTEP). As a priority project for the government, I expect that OPG will continue to focus on delivering the project as per the schedule and budget contained in the Release Quality Estimate approved by the OPG Board and by the government. I also expect OPG to continue to minimize project risks consistent with the nuclear refurbishment principles set out in the 2013 LTEP, and seek concurrence prior to commencing ~~subsequent unit~~ refurbishment~~s after~~of Unit ~~2~~3 ~~is successfully returned to service~~before the end of 2017.

We continue to support the planned operation of Pickering units up to 2022/2024, subject to OPG obtaining necessary regulatory approvals, as the station's output will provide reliable, cost-effective and emission-free electricity supply during the Darlington and initial Bruce refurbishments. I expect OPG to keep the Ministry apprised throughout the regulatory processes and as we proceed to update the Long-Term Energy Plan. .

I understand that the recently approved Ontario Nuclear Funds Agreement (ONFA) Reference Plan has resulted in a reduction of the estimated liabilities for future decommissioning and long-term management of waste from Ontario's nuclear fleet. With many decades of nuclear generation in the Province's future, we expect OPG to continue managing its decommissioning and waste management obligations and related segregated funds in a prudent manner. I recognize that the ONFA is based on OPG's proposed siting of a Deep Geological Repository (DGR) for low and intermediate level waste. OPG's DGR is a key component of Ontario's plans to ensure that nuclear remains the backbone of our electricity system for years to come.

I appreciate the efforts of OPG staff, management and the Board of Directors to date as we worked to develop a plan to refinance the Global Adjustment (GA). Refinancing the GA would provide significant and immediate rate relief by spreading the cost of electricity investments over the expected lifecycle of the infrastructure that has been built. OPG will be instrumental to the success of this initiative and we plan to introduce

legislation that would, if passed, enable OPG to work with the Independent Electricity System Operator (IESO) to implement this plan. I also expect to make the necessary changes to OPG's articles of amalgamation to provide the financing flexibility to implement the refinancing of the GA to meet the Province's price objectives announced on March 2, 2017.

I expect OPG to continue to keep the government informed with regard to the company's key ongoing and emerging initiatives and progress in achieving its financial and operational performance commitments. As OPG's performance directly impacts Ontario's fiscal plan, we note the importance of achieving or exceeding OPG's financial performance commitments

Consistent with Section 7 of the Memorandum of Agreement, in advance of commencing discussions for the renewal of its collective agreements with its unions, I expect that OPG shall seek advice from the Ministry on Provincial policy direction and relevant fiscal considerations affecting labour negotiations.

This letter constitutes our concurrence with OPG's Board approved 2017-2019 Business Plan as provided for under the Memorandum of Agreement between OPG and the Shareholder dated July 17, 2015.

This letter also confirms the approval of special status for OPG to approve international travel, under Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive. OPG shall submit semi-annual reports on international travel to the Ministry of Energy, as described in the submission received from OPG's President and CEO, dated January 24, 2017.

Sincerely,

Glenn Thibeault
Minister of Energy

c: Jeff Lyash, President and Chief Executive Officer, OPG
Serge Imbrogno, Deputy Minister, Ministry of Energy
Scott Thompson, Deputy Minister, Ministry of Finance
Andrew Teliszewsky, Chief of Staff, Ministry of Energy
Ali Ghiassi, Chief of Staff, Ministry of Finance

From:	John Kim
To:	Ronald Kwan
Cc:	Deena Padamadan; Bruno Amara; Shajee Kathirgamanathan
Subject:	OPG Business Plan Meeting (2017 05 01 v2)_Markup.pptx
Date:	Wednesday, May 03, 2017 6:10:17 PM
Attachments:	OPG Business Plan Meeting (2017 05 01 v2)_Markup.pptx

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Hi Ron,

Pls. see attached back pocket for tomorrow's meeting.

John

DRAFT

OPG Fiscal Impacts

Corporate and Electricity Finance Division
2017-05-01

DRAFT

OPG Fiscal Impact

- The table below illustrates OPG's fiscal impacts in the 2017 Budget forecast.

	2016-17	2017-18	2018-19	2019-20	2020-21
OPG Net Income - 2017 Ontario Budget / Fiscal Plan					
OPG 2017-19 Business Plan[1]	349	702	678	726	913[1]
OPG Monthly Shareholder Update (February 2017)	30				
OPG IFRS Consolidation Risk[2]	(75)	(400)	-	(200)	-
OPG Head Office Sales (Reported under Sales and Rentals)[3]		(222)			
GA Refinancing – OPG Trust Interest Revenue		17	54	99	153
OPG Net Income (After Tax, Adjusted)	**304**	**97**	**732**	**625**	**1,066**
ONFA Adjustments[4]	8	-	-	-	-
OPG Income Tax PILs - 2017 Ontario Budget / Fiscal Plan					
OPG 2017-19 Business Plan	96	166	135	170	298[1]
OPG Monthly Shareholder Update (February 2017)	(4)				
OPG Head Office Sales (Reported under Sales and Rentals)[3]		(74)			
OPG Income Tax PILs (Adjusted)	92	92	135	170	298

1 Fiscalized projection from OPG Business Plan

2 IFRS risk is related to Province's reporting of nuclear asset retirement obligations. The Ontario Auditor General recommended (2016 AG Report) that the Province include Hydro One and OPG financial information in the consolidated financial statements using the IFRS reporting framework as required by PSAB standards, versus the companies U.S. GAAP basis of reporting.

3 For public Budget reporting, projected net impacts of Province asset optimization strategy including, OPG Head Office sale, are reported under Sales and Rentals for commercial confidentiality. OPG proceeds estimate updated per 2017 Budget.

4 Provincial consolidation adjustments for unrealized earnings on decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds.

Updated OPG Fiscal Impacts

- The table below illustrates updated OPG's net income, income tax PILs and ONFA adjustment figures from the 2017 Budget forecast.

	2016-17	2017-18	2018-19	2019-20	2020-21
Other updates since Budget 2017					
March 2017 Shareholder Update: OPG Net Income	385	-	-	-	-
March 2017 Shareholder Update: Income Tax Expense	94	-	-	-	-
ONFA Adjustments (as at Mar 31, 2017)	49	-	-	-	-

Risks

- **OEB Risks:** OPG's multi-year rate application to the Ontario Energy Board for the period starting January 1, 2017, is currently in process. Potential OEB decisions providing for lower rates, including disallowance of recovery of OPG's operating costs, current or future deferral and variance account balances (including for the proposed nuclear rate smoothing) and unfavourable future treatment of pension costs would adversely affect OPG's results, resulting in negative fiscal impacts.
- **IFRS Risks:** A change in the basis of accounting used for consolidation of OPG results from U.S. GAAP to International Financial Reporting Standards (IFRS) on the Province's financial statements is expected to result in potentially significant fiscal impacts.

	2016-17	2017-18	2018-19	2019-20	2020-21
Net additional OPG IFRS Consolidation Risks	-	(25)	(525)	(475)	N/A

- **Financing Costs:** Higher cost public capital market borrowing (vs the Province's borrowing cost for OEFC to lend to OPG) would have a negative fiscal impact.

Risks – Darlington Refurbishment

- **Darlington Refurbishment Risk:** Darlington Refurbishment is executed consistent with the approved project budget and schedule. Failure to maintain cost and schedule commitments for the project could potentially result in significant write-offs against net income as well as reputational damage. In addition, inability to carry out the refurbishment of the first unit as planned may result in the Province of Ontario (Province) not proceeding with OPG's refurbishment of the remaining units.

- Darlington Refurbishment Update from March 2017 OPG Monthly Update:
  - Vault Preparations commenced on January 11th. Since that time, the project has lost 28 days of critical path and, is two days behind the working schedule. Key contributors to these delays are unanticipated work, vendor performance, and vendor and OPG integration.
  - In order to mitigate the impacts, the Joint Venture and OPG have implemented four Logistic Coordinators, an hour-by-hour schedule of critical path activities, assigned dedicated staff to vault and rubber area activities and OPG's construction oversight organization is taking a move active and intrusive role on execution activities.

Electricity Sector Rules of Thumb

- **OPG Rule of Thumb**: For every $50M change in OPG revenues due to changes in regulated prices, all-in rate impact of about 0.04 ¢/kWh (less than 0.25% of total bill)

OPG Risks	Fiscal Impact
Realised gains in ONFA funds v plan -/+ 1%	-/+ $100 million
Change in Regulated Prices -/+ 1%	-/+ $40 million
Regulated ROE -/+ 1%	-/+ $45 million
Nuclear regulated price -/+ 0.1 ¢/kWh	-/+ $40 million
Hydro regulated price -/+ 0.1 ¢/kWh	-/+ $20 million
Nuclear output -/+ 1 TWh	-/+ $70 million
Hydro output -/+ 1 TWh	-/+ $45 million

From: Ken Kandeepan
To: Scott Nelms (ENERGY)
Cc: Ronald Kwan; Mike Manning; Carlos Yep
Subject: OPG Performance fees
Date: Friday, May 12, 2017 11:24:04 AM

Hi Scott

This issue has come up a couple of times and after discussing with Gadi we felt that you may be able to raise it either directly with OPG or via Energy. As the Financial Services Manager, OPG is proposing a performance fee for itself based beating a benchmark for borrowing costs the Trust incurs in presumably the 51% it seeks to borrow from the capital markets.

OPG argues that the latter of the two fundamental principles, "Power" and "Profit" allowing the Trust to be consolidated with OPG requires the implementation of a performance fee structure. The counter argument is that OPG already has access to profit, by virtue of its position as the funding entity for 44% of the debt incurred by the Trust. OPG uses the funds it receives from the Province's equity injection, for which it pays no interest, for this purpose.

Upon consolidation with the Trust, OPG's interest income will therefore increase by the amount of the interest the Trust receives on 44% of its overall debt, a relatively risk free profit source, at least over the duration of the Fair Hydro Plan. While the use of a benchmark is appropriate and contributes to an efficient borrowing program, any performance fees arising from beating the benchmark will effectively be funded by the ratepayers, by increasing the investment asset and the associated debt to be repaid by ratepayers.

Mike and I will be happy to provide any further technical assistance that you may require as you raise this issue.

Thanks

Ken k

From:	HO Philip -FIN & C CTRL
To:	Shruti.Talwar@ontario.ca; Manu.Sud@ontario.ca; John Kim; Ronald Kwan
Cc:	GORE Michael -FIN & C CTRL; PAN Rebecca -FIN & C CTRL; DYKXHOORN Sandra -STAKEREL; CHANG Stephanie -ASSRNCE&ERM
Subject:	OPG Q1 2018 Submission to Province
Date:	Wednesday, May 02, 2018 11:42:24 PM
Attachments:	Q1 2018 Press Release - DRAFT - PROVINCE MAILING.docx Q1 2018 MD&A - DRAFT PROVINCE MAILING.docx Q1 2018 OPG FS PROVINCE MAILING.docx

Hi All,

Please find attached OPG's draft Q1 2018 Interim Financial Results Press Release, Management's Discussion and Analysis (MD&A), and Financial Statements for the Province's review.

We would greatly appreciate comments on the above **no later than Friday, May 4th**.

These documents will be filed with the Ontario Securities Commission on **Tuesday, May 15th**.

Kindly forward all comments directly to Philip Ho – philip.ho@opg.com.

To assist the review process, the following are the key items in the Q1 2018 MD&A:

Highlights	
Recent Developments	MD&A pgs.5-8
OEB's Payment Amounts Order on OPG's Application for New Regulated Prices	MD&A pgs.5-7
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ONTARIO POWER GENERATION

News
from Ontario Power Generation

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[DRAFT]

May 15, 2018

OPG REPORTS 2018 FIRST QUARTER FINANCIAL RESULTS

Strong results attributable to former Lakeview generating station land sale and continued strong nuclear generation performance

[Toronto]: – Ontario Power Generation Inc. (OPG or Company) today reported net income attributable to the Shareholder of $535 million for the first quarter of 2018, compared to $64 million for the same period in 2017, inclusive of a one-time gain of $205 million related to the sale of the former Lakeview generating station (GS) property. The net proceeds of the Lakeview property sale will be transferred to the Government of Ontario.

"As Ontario's publically-owned electricity generator, we are pleased to report our strong first quarter results that have resulted in significant net income to our shareholder, the Province of Ontario. We remain focused on continuing to supply Ontario with safe, clean, reliable, and low cost power to help moderate customer's electricity bills, and are investing in our assets to the benefit of Ontarians for years to come," said Jeff Lyash, OPG President and CEO. "Canada's single largest investment in low-cost, clean energy, the refurbishment of the Darlington Nuclear Station, remains on time and on budget due to the hard work and dedication of our employees and partners. Refurbishing this public asset will ensure OPG remains Ontario's largest provider of low cost electricity for another 30 years while providing clean power that is over 99 per cent free of carbon emissions."

Lyash continued, "In addition to investing in the Darlington Nuclear Station, OPG has begun the relicensing process to keep the Pickering Nuclear Station operating until 2024. Running Pickering until 2024 will save electricity customers up to $600 million and benefit Ontario by contributing over $12 billion to the economy. Pickering remains a safe, efficient and reliable public asset that can continue to supply low-cost electricity for up to 1.5 million homes each day, with almost no carbon emissions."

"Major contributors to the strong financial results for the quarter include the one-time gain on the sale of OPG's former Lakeview generating station lands in Mississauga, Ontario in March, the net proceeds of which will be transferred to our shareholder, and the continued strong nuclear generation performance," added Lyash. "In the same month as the Lakeview sale, a special dividend of $283 million from the last year's sale of our head office premises was transferred to the Province."

The increase in net income in the first quarter of 2018 is also attributable to the impact

of new regulated prices for OPG's nuclear and most of its hydroelectric generation, resulting from the Ontario Energy Board's (OEB) decision on OPG's application for new regulated prices for the 2017-2021 period issued in December 2017.

The OEB issued the final payment amounts order on the application in March 2018, allowing OPG to begin collecting revenues based on the new regulated prices. Taking into account the impact of the OEB's decision, OPG continues to provide electricity at a price that is 40 per cent less than the average of other generators. OPG is the only electricity generator in Ontario that has its prices set through a public hearing process by the OEB.

Generating and Operating Performance

Electricity generated during the three months ended March 31, 2018 increased to 18.8 terawatt hours (TWh) from 18.6 TWh for the same quarter in 2017.

Regulated – Nuclear Generation Segment

Higher nuclear generation of 0.4 TWh during three months ended March 31, 2018 was primarily due to fewer planned outage days at the Darlington GS.

For the three months ended March 31, 2018, the unit capability factor for the operating units at the Darlington GS was 96.5 per cent, compared to 85.3 per cent for the same quarter in 2017. The increase was primarily due to a lower number of planned outage days at the station.

At the Pickering GS, the unit capability factor decreased to 74.5 per cent for 2018, compared to 78.5 per cent for the same quarter in 2017, primarily due to a higher number of planned outage days in the cyclical maintenance schedule at the station in the first quarter of 2018.

Regulated – Hydroelectric Segment

Lower generation from the regulated hydroelectric stations of 0.3 TWh during three months ended March 31, 2018 compared to the same quarter in 2017, was primarily due to lower water flows on the northwestern and eastern Ontario river systems.

The availability of 87.3 per cent at these stations in 2018 was lower than 89.5 per cent for the same quarter in 2017. The decrease in the availability was primarily due to a higher number of unplanned outage days at the eastern and northeastern Ontario regions' regulated hydroelectric stations.

Contracted Generation Portfolio Segment

Generation from the Contracted Generation Portfolio during three months ended March 31, 2018 was comparable to the same quarter in 2017.

The availability of these hydroelectric stations for three months ended March 31, 2018 was 80.1 per cent, compared to 83.6 per cent for the same quarter in 2017. The decrease in the availability was primarily due to a higher number of planned outage days at the Little Long GS on the Lower Mattagami River.

Total Generating Cost

The Enterprise Total Generating Cost per megawatt hour (MWh) was $49.84 for the three months ended March 31, 2018, compared to $47.86 for the same quarter in 2017. The increase was mainly a result of higher OM&A expenses and higher sustaining capital expenditures, partially offset by higher nuclear electricity generation.

Generation Development

OPG is undertaking a number of generation development and life extension projects in support of Ontario's electricity planning initiatives. Significant developments during the first quarter of 2018 were as follows:

Darlington Refurbishment

The Darlington Refurbishment project is expected to extend the operating life of the four-unit Darlington GS by approximately 30 years. In early May 2018, OPG completed the removal of the existing reactor components, which included end fittings, pressure tubes, and calandria tubes, signifying the completion of the second major segment of the project. The refurbishment of Unit 2 has transitioned into the third major segment, the installation and reassembly of reactor components. The Darlington Refurbishment project continues to track on schedule and to the $12.8 billion budget.

In addition to the execution of refurbishment activities on Unit 2, OPG is progressing with planning activities on the refurbishment of Unit 3 and ensuring that lessons learned from the Unit 2 refurbishment are being incorporated. OPG is also entering into commitments to procure major components that require long lead times. Execution of the prerequisite activities for Unit 3 refurbishment have commenced. Unit 3 refurbishment is expected to commence upon the return to service of Unit 2. As of March 31, 2018, $137 million has been invested in planning and prerequisite activities related to the refurbishment of Unit 3. In February 2018, the Government of Ontario confirmed its commitment to proceed with the refurbishment of Unit 3.

Total life-to-date capital expenditures on the project were approximately $4.7 billion as at March 31, 2018.

Ranney Falls Hydroelectric GS

In 2017, OPG began construction work on a 10 MW single-unit powerhouse on the existing Ranney Falls GS site. The new unit will replace an existing unit that reached its end of life in 2014. Construction continues in the expanded forebay, powerhouse and spillway area. Fabrication of the sectional gates and two head gates has been completed, with assembly and site delivery in progress. Turbine and generator unit fabrication is also in progress. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget. The Ranney Falls GS is included in the Regulated – Hydroelectric segment.

Nanticoke Solar Facility

The project encompasses the construction of a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands under a contract with the IESO, through

Nanticoke Solar LP, a partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation. Significant contracts for equipment and engineering construction services were executed and site preparation commenced in the first quarter of 2018. The facility is expected to be completed in the first quarter of 2019 **[MONITOR]**, with a budget of $107 million. The project is included in the Contracted Generation Portfolio segment.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

(millions of dollars – except where noted)	Three Months Ended March 31 2018	2017
Revenue	**1,407**	1,176
Fuel expense	**155**	155
Operations, maintenance and administration	**722**	708
Depreciation and amortization	**186**	167
Other (gains) expenses, net [1]	**(227)**	47
Income before interest and income taxes	**571**	99
Net interest expense	**19**	19
Income tax expense	**13**	12
Net Income	**539**	68
Net income attributable to the Shareholder	**535**	64
Net income attributable to non-controlling interest [2]	**4**	4
Income before interest and income taxes		
Electricity generation business segments	**324**	139
Regulated – Nuclear Waste Management	**(33)**	(47)
Fair Hydro Trust	**4**	-
Other	**276**	7
Total income before interest and income taxes	**571**	99
Cash flow		
Cash flow provided by operating activities	**226**	168
Electricity generation (TWh)		
Regulated – Nuclear Generation	**10.4**	10.0
Regulated – Hydroelectric	**7.7**	8.0
Contracted Generation Portfolio [3]	**0.7**	0.6
Total electricity generation	**18.8**	18.6
Nuclear unit capability factor (per cent) [4]		
Darlington Nuclear GS	**96.5**	85.3
Pickering Nuclear GS	**74.5**	78.5
Availability (per cent)		
Regulated – Hydroelectric	**87.3**	89.5
Contracted Generation Portfolio – hydroelectric stations	**80.1**	83.6
Equivalent forced outage rate		
Contracted Generation Portfolio – thermal stations	**0.3**	1.6
Enterprise Total Generating Cost (TGC) per MWh for the three months ended March 31, 2018 and March 31, 2017 ($/MWh) [5]	**49.84**	47.86
Return on Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI) for the twelve months ended March 31, 2018 and December 31, 2017 (%) [5]	**11.5**	7.6

[1] For the three months ended March 31, 2018, includes the pre-tax gain on sale of the former Lakeview GS site.

[2] Relates to the 25 per cent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation in the Lower Mattagami Limited Partnership, the 33 per cent interest of Coral Rapids Power Corporation (CRP), a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership, and the 10 per cent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP. CRP increased its partnership interest in PSS to 33 per cent in April 2017.

[3] Includes OPG's share of generation volume from its 50 per cent ownership interests in the Portlands Energy Centre and Brighton Beach GS.

[4] Nuclear unit capability factor excludes unit(s) during the period in which they are undergoing refurbishment. Unit 2 of the Darlington GS is excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

[5] Enterprise TGC per MWh and ROE Excluding AOCI are non-GAAP financial measures and do not have any standardized meaning prescribed by US GAAP. Additional information about the non-GAAP measures is provided in OPG's Management's Discussion and Analysis for the three months ended March 31, 2018, in the sections *Highlights – Return on Equity Excluding Accumulated Other Comprehensive Income*, *Highlights – Enterprise Total Generating Cost per MWh*, and *Supplementary Non-GAAP Financial Measures.*

Ontario Power Generation Inc. is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. Our mission is providing low cost power in a safe, clean, reliable and sustainable manner for the benefit of our customers and shareholder.

Ontario Power Generation Inc.'s unaudited interim financial statements and Management's Discussion and Analysis as at and for the three months ended March 31, 2018 can be accessed on OPG's web site (www.opg.com), the Canadian Securities Administrators' web site (www.sedar.com), or can be requested from the Company.

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ONTARIO POWER GENERATION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

2018 FIRST QUARTER REPORT

[DRAFT]

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ONTARIO POWER GENERATION

ONTARIO POWER GENERATION INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) should be read in conjunction with the unaudited interim consolidated financial statements and accompanying notes of Ontario Power Generation Inc. (OPG or Company) as at and for the three months ended March 31, 2018. OPG's unaudited interim consolidated financial statements are prepared in accordance with United States generally accepted accounting principles (US GAAP) and are presented in Canadian dollars.

For a complete description of OPG's corporate strategies, risk management, corporate governance, and the effect of critical accounting policies and estimates on OPG's results of operations and financial condition, this MD&A should also be read in conjunction with OPG's audited consolidated financial statements, accompanying notes, Annual Information Form, and MD&A as at and for the year ended December 31, 2017.

As required by *Ontario Regulation 395/11*, as amended, a regulation under the *Financial Administration Act* (Ontario) (FAA), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. Since January 1, 2012, OPG also has received exemptive relief from the Ontario Securities Commission (OSC) that allows OPG to apply US GAAP. In April 2018, the OSC approved an exemption which allows the Company to continue to apply US GAAP up to January 1, 2024. The term of the exemption is subject to certain conditions, which may result in the expiry of the exemption prior to January 1, 2024. For details, refer to the section, *Change in Accounting Policies and Estimates* under the heading, *Exemptive Relief for Reporting under US GAAP.* This MD&A is dated May 15, 2018.

FORWARD-LOOKING STATEMENTS

The MD&A contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could", and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

All forward-looking statements involve inherent assumptions, risks, and uncertainties, including those set out in the section, *Risk Management,* and forecasts discussed in the section, *Core Business, Strategy, and Outlook.* All forward-looking statements could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's generating station performance and availability, fuel costs, surplus baseload generation (SBG), cost of fixed asset removal and nuclear waste management, performance and earnings of investment funds, refurbishment of existing facilities, development and construction of new facilities, pension and other post-employment benefit (OPEB) obligations and funds, income taxes, proposed new legislation, the ongoing evolution of Ontario's electricity industry, environmental and other regulatory requirements, operating licence applications to the Canadian Nuclear Safety Commission (CNSC), health, safety and environmental developments, business continuity events, the weather, financing and liquidity, applications to the Ontario Energy Board (OEB) for regulatory prices, the impact of regulatory decisions by the OEB, Ontario's Fair Hydro Plan and forecasts of earnings, cash flows, Return on Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI), Total Generating Cost (TGC), Operations, Maintenance and Administration (OM&A) expenditures, retention of critical talent, supplier and third party performance, and project expenditures. Accordingly, undue reliance should not be placed on any forward-looking statement. The forward-looking statements included in this

MD&A are made only as of the date of this MD&A. Except as required by applicable securities laws, OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events, or otherwise.

THE COMPANY

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG was established under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (Province or Shareholder).

As at March 31, 2018, OPG's electricity generation portfolio had an in-service capacity of 16,218 megawatts (MW). OPG operates two nuclear generating stations, 66 hydroelectric generating stations, three thermal generating stations, and one wind power turbine. In addition, OPG and TransCanada Energy Ltd. co-own the 550 MW Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS), and OPG and ATCO Power Canada Ltd. co-own the 560 MW Brighton Beach gas-fired combined cycle GS (Brighton Beach). OPG's 50 percent share of the in-service capacity and generation volume of these co-owned facilities is included in the generation portfolio statistics set out in this report. The income from the co-owned facilities is accounted for using the equity method of accounting, and OPG's share of income is presented as income from investments subject to significant influence in the Contracted Generation Portfolio segment.

OPG also owns two other nuclear generating stations, the Bruce A GS and the Bruce B GS, which are leased on a long-term basis to Bruce Power LP. Income from these leased stations is included as leasing revenue under the Regulated – Nuclear Generation segment. The leased stations are not included in the generation portfolio statistics set out in this report. A description of OPG's segments is provided in OPG's 2017 annual MD&A in the section, *Business Segments*.

All of OPG's owned and co-owned generating facilities are located in Ontario. OPG does not operate PEC, Brighton Beach, the Bruce A GS and the Bruce B GS.

In-Service Generating Capacity

OPG's in-service generating capacity by business segment as of March 31, 2018 and December 31, 2017 was as follows:

	As at	
(MW)	**March 31 2018**	**December 31 2017**
Regulated – Nuclear Generation [1]	**5,728**	5,728
Regulated – Hydroelectric	**6,426**	6,426
Contracted Generation Portfolio [2]	**4,064**	4,056
Total	**16,218**	16,210

[1] The in-service generating capacity as of March 31, 2018 and December 31, 2017 excludes Unit 2 of the Darlington Nuclear GS (Darlington GS). The unit, which has a generating capacity of 878 MW, was taken offline in mid-October 2016 and is currently undergoing refurbishment.

[2] Includes OPG's share of in-service generating capacity of 275 MW for PEC and 280 MW for Brighton Beach.

During the three months ended March 31, 2018, total in-service capacity increased by 8 MW. The increase was due to the completion of the overhaul and upgrade of Unit 1 of the Harmon hydroelectric GS, which was returned to service in February 2018 as part of the Contracted Generation Portfolio segment.

HIGHLIGHTS

Overview of Results

This section provides an overview of OPG's unaudited interim consolidated operating results and summarizes OPG's income before interest and income taxes by business segment. Significant factors which contributed to OPG's results during the three months ended March 31, 2018, compared to the same period in 2017, are discussed below. A detailed discussion of OPG's performance by reportable segment is included in the section, *Discussion of Operating Results by Business Segment*.

(millions of dollars – except where noted) (unaudited)	Three Months Ended March 31 2018	2017
Revenue	**1,407**	1,176
Fuel expense	**155**	155
Operations, maintenance and administration	**722**	708
Depreciation and amortization	**186**	167
Other (gains) expenses, net [3]	**(227)**	47
Income before interest and income taxes	**571**	99
Net interest expense	**19**	19
Income tax expense	**13**	12
Net income	**539**	68
Net income attributable to the Shareholder	**535**	64
Net income attributable to non-controlling interest [1]	**4**	4
Electricity production (TWh) [2]	**18.8**	18.6
Cash flow		
Cash flow provided by operating activities	**226**	168
Segment Results		
Regulated – Nuclear Generation	**75**	(118)
Regulated – Hydroelectric	**171**	180
Contracted Generation Portfolio	**78**	77
Total electricity generation business segments	**324**	139
Regulated – Nuclear Waste Management	**(33)**	(47)
Fair Hydro Trust	**4**	-
Other [3]	**276**	7
Income before interest and income taxes	**571**	99

[1] Relates to the 25 percent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in the Lower Mattagami Limited Partnership, the 33 percent interest of Coral Rapids Power Corporation (CRP), a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership (PSS), and the 10 percent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP. CRP increased its partnership interest in PSS to 33 percent in April 2017.

[2] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

[3] For the three months ended March 31, 2018, includes the pre-tax gain on sale of the former Lakeview GS site.

Net income attributable to the Shareholder was $535 million for the first quarter of 2018, representing an increase of $471 million compared to the same quarter in 2017. Income before interest and income taxes was $571 million for the first quarter of 2018, representing an increase of $472 million compared to the same quarter in 2017. The following summarizes the significant factors which contributed to the variance:

Significant factors that increased income before interest and income taxes:

- Higher revenue from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments of approximately $210 million, reflecting the impact of new regulated prices approved by the OEB in its December 2017 decision and March 2018 payment amounts order on OPG's application for new regulated prices. Further details can be found under the heading, *Recent Developments – OEB's Payment Amounts Order on OPG's Application for New Regulated Prices*.
- Higher revenue of approximately $25 million, partially offset by an increase in fuel expense of $5 million, reflecting higher electricity generation of 0.4 terawatt hours (TWh) from the Regulated – Nuclear Generation segment.
- A pre-tax gain on the sale of the former Lakeview GS site of $273 million was recognized in net income upon completion of the transaction in the first quarter of 2018. The sale was undertaken pursuant to a Shareholder Declaration and a Shareholder Resolution. Further details can be found under the heading, *Recent Developments – Sale of Lakeview Site*.
- Higher earnings of $14 million from the Regulated – Nuclear Waste Management segment, primarily due to higher earnings from the nuclear fixed asset removal and nuclear waste management funds (Nuclear Segregated Funds), partially offset by an increase in accretion expense on the nuclear fixed asset removal and nuclear waste management liabilities (Nuclear Liabilities).

Significant factors that reduced income before interest and income taxes:

- Higher depreciation and amortization expenses of $19 million, mainly due to a higher amount of depreciation expense deferred in regulatory variance and deferral accounts in the first quarter of 2017. The higher deferrals in 2017 were due to costs not included in the regulated prices in effect prior to the OEB's December 2017 decision.
- Higher OM&A expenses of $14 million, mainly in the Regulated – Nuclear Generation segment, reflecting higher services and materials costs associated with planned outages at the nuclear stations.
- Lower hydroelectric incentive mechanism payments of $7 million in the Regulated – Hydroelectric segment.

Net interest expense for the first quarter of 2018 was comparable with the same quarter in 2017.

Income tax expense increased by $1 million in the first quarter of 2018, compared to the same quarter in 2017, primarily due to higher income before income taxes, largely offset by a higher amount of deferred income tax expense recorded as a regulatory asset and a reduction in income taxes resulting from a dividend distribution.

Recent Developments

OEB's Payment Amounts Order on OPG's Application for New Regulated Prices

The OEB's decision on OPG's May 2016 five-year application for new regulated prices for nuclear and regulated hydroelectric generation was issued on December 28, 2017, following a public hearing process, with an effective date for the new regulated prices of June 1, 2017. The decision included the OEB's findings with respect to ratemaking methodologies for OPG's regulated facilities, the basis for inputs into the hydroelectric incentive mechanism formula, and the elements of the nuclear revenue requirement. Pursuant to the OEB's decision, the new base regulated prices for the regulated hydroelectric facilities for each of the years 2017 to 2021 are to be determined by annually escalating the base regulated prices in effect prior to June 1, 2017, with some adjustments, using an approved formula equal to an industry-specific weighted inflation factor based on indices published annually by the OEB, less a stretch factor adjustment. For the nuclear facilities, a revenue requirement is determined for each of the years 2017

to 2021 based on the OEB-allowed level of operating costs and a return of and on invested capital, reduced by a stretch factor amount. Consistent with the requirement of *Ontario Regulation 53/05*, OPG's overall production-weighted regulated price is smoothed, with a portion of the approved nuclear revenue requirements for the 2017-2021 period deferred for future collection in the Rate Smoothing Deferral Account. The difference between the non-deferred portion of the annual nuclear revenue requirement, calculated by multiplying the approved nuclear base regulated price determined under rate smoothing and the approved forecast of OPG's nuclear electricity production, and the total approved nuclear revenue requirement determines the amount deferred for future collection. Further details on OPG's December 2017 decision can be found in OPG's 2017 annual MD&A in the section, *Highlights* under the heading, *Recent Developments – OEB's Decision on OPG's Application for New Regulated Prices*.

To reflect management's best estimate of the impact of the OEB's decision, in the fourth quarter of 2017, OPG recorded incremental net revenue for the June 1, 2017 to December 31, 2017 interim period based on the draft payment amounts order. The revenue was recorded as an increase in regulatory assets for the June 1, 2017 to December 31, 2017 interim period revenue shortfall based on proposed new regulated prices, net of a regulatory liability for the Rate Smoothing Deferral Account.

On March 29, 2018, the OEB issued the final payment amounts order establishing new regulated prices for OPG's regulated facilities, with an implementation date of March 1, 2018. For the regulated hydroelectric facilities, the OEB approved the base regulated prices as calculated by OPG in the draft payment amounts order it submitted to the OEB on January 17, 2018. The final payment amounts order set base regulated prices for the regulated hydroelectric facilities for the June 1, 2017 to December 31, 2017 period and for the January 1, 2018 to December 31, 2018 period, based on the approved incentive regulation formula and inflation indices published by the OEB. For the 2019-2021 period, the base regulated prices for the regulated hydroelectric facilities will be determined annually before the beginning of each year using the approved formula and published indices.

For the nuclear facilities, the OEB approved the 2017-2021 revenue requirements as submitted by OPG in the draft payment amounts order, with minor adjustments. The OEB also made certain adjustments to OPG's rate smoothing proposal and resulting nuclear base regulated prices for the June 1, 2017 to December 31, 2017 period and each of the years 2018 to 2021 submitted in the draft payment amounts order. Pursuant to the final payment amounts order, no amounts will be deferred in the Rate Smoothing Deferral Account until 2019 with approximately $500 million to be deferred over the 2019-2021 period. Parties to OPG's application were given an opportunity to review and comment on OPG's draft payment amounts order prior to the OEB's issuance of the final payment amounts order.

The OEB's adjustments to OPG's rate smoothing proposal and resulting nuclear base regulated prices in the final payment amounts order resulted in a partial reversal of the regulatory asset for the June 1, 2017 to December 31, 2017 interim period revenue shortfall recorded in the fourth quarter of 2017, largely offset by the reversal of the regulatory liability for the Rate Smoothing Deferral Account recorded in the fourth quarter of 2017. Taken together, these reversals did not have a material impact on the results of operations for the first quarter of 2018.

In addition, for the period from March 1, 2018 to December 31, 2020, the final payment amounts order authorized interim period shortfall riders to collect the revenue shortfall for the June 1, 2017 to February 28, 2018 period based on the newly approved base regulated prices. The order established separate rate riders for the March 1, 2018 to December 31, 2020 period to recover variance and deferral account balances approved in the application. As the interim period shortfall riders and the variance and deferral account riders will collect amounts previously recorded as regulatory assets, they will contribute to improved cash flow from operations but are not expected to have a material impact on net income.

The OEB's final payment amounts order authorized the following regulated prices for electricity generated from OPG's nuclear and regulated hydroelectric facilities for the 2017-2021 period, effective June 1, 2017:

($/MWh)	**2017 June 1 to December 31**	**2018**	**2019**	**2020**	**2021**
Regulated – Nuclear Generation					
Base regulated price [1]	77.96	78.64	77.00	85.00	89.70
Variance and deferral account rate rider [2]	-	1.05	2.79	2.04	-
	77.96	79.69	79.79	87.04	89.70
Regulated – Hydroelectric					
Base regulated price [1, 3]	41.67	42.05	-	See Note 3	-
Variance and deferral account rate rider [2]	-	0.52	-	-	-
	41.67	42.57	-	-	-

[1] As part of the payment amounts order process, the OEB authorized separate rate riders to allow for the recovery of the revenue shortfall between the new base regulated prices and the previously approved base regulated prices that OPG continued to receive during the interim period between June 1, 2017 and February 28, 2018, over the March 1, 2018 to December 31, 2020 period. The revenue shortfall was recorded as a regulatory asset in the fourth quarter of 2017 and the first quarter of 2018. The nuclear interim period shortfall rider is $2.89/MWh during the March 1, 2018 to December 31, 2018 period, $7.71/MWh in 2019 and $5.64/MWh in 2020. The regulated hydroelectric interim period shortfall rider is $0.13/MWh during the March 1, 2018 to December 31, 2018 period, $0.35/MWh in 2019 and $0.24/MWh in 2020.

[2] Consistent with the OEB's December 2017 decision, in 2018, OPG plans to file an application with the OEB requesting disposition of the next set of variance and deferral account balances, which may result in additional variance and deferral account riders prospectively over the period, depending on the outcome of the application.

[3] Base regulated prices for the regulated hydroelectric facilities for the 2019-2021 period will be determined annually before the beginning of each year using the OEB-approved incentive regulation formula and OEB-published inflation indices.

Darlington Refurbishment

In early May 2018, OPG completed the second major segment of the Unit 2 refurbishment of the Darlington GS, the removal of reactor components, and has transitioned into the third major segment, the installation and reassembly of new reactor components.

Planning activities for the refurbishment of Unit 3 of the Darlington GS continue. In February 2018, the Government of Ontario confirmed its commitment to proceed with the Unit 3 refurbishment. The Darlington Refurbishment project continues to track on schedule and to the $12.8 billion budget.

The Darlington Refurbishment project is discussed further in the section, *Core Business, Strategy, and Outlook* under the heading, *Project Excellence*.

Payment of Dividend to Shareholder

In April 2017, OPG completed the sale of its head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street in Toronto, Ontario. The sale was undertaken pursuant to a Shareholder Declaration and a Shareholder Resolution received by OPG in December 2015. Pursuant to the Shareholder Declaration and the Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014* (Trillium Trust Act), OPG was required to transfer the proceeds from this disposition, net of prescribed deductions under the Trillium Trust Act, into the Province's Consolidated Revenue Fund. In accordance with these requirements, a special dividend of $283 million was authorized by OPG's Board of Directors and transferred into the Consolidated Revenue Fund in March 2018.

Sale of Lakeview Site

In March 2018, OPG completed the sale of its former Lakeview GS site property located in Mississauga, Ontario, with an after-tax gain on sale of $205 million recognized in net income in the first quarter of 2018. The sale was undertaken pursuant to a Shareholder Declaration and a Shareholder Resolution received by OPG in June 2016. Pursuant to the Shareholder Declaration and the Shareholder Resolution, and as prescribed in the Trillium Trust Act, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Trillium Trust Act, into the Province's Consolidated Revenue Fund. OPG expects that the amount of designated proceeds to be transferred into the Consolidated Revenue Fund will be largely consistent with the after-tax gain on sale, and is working with the Ontario Ministry of Finance to finalize the amount. **[MONITOR]** In accordance with the Shareholder Resolution, approximately 67 acres of the site will be transferred to the City of Mississauga by the purchaser, for parkland, institutional, and cultural uses.

Electricity Generation

Electricity generation for the three months ended March 31, 2018 and 2017 was as follows:

	Three Months Ended March 31	
(TWh)	**2018**	**2017**
Regulated – Nuclear Generation	**10.4**	10.0
Regulated – Hydroelectric	**7.7**	8.0
Contracted Generation Portfolio [1]	**0.7**	0.6
Total OPG electricity generation	**18.8**	18.6
Total electricity generation by other generators in Ontario [2]	**19.1**	18.6

[1] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

[2] Non-OPG generation is calculated as the Ontario electricity demand plus net exports, as published by the Independent Electricity System Operator (IESO), minus OPG electricity generation.

Total OPG electricity generation increased by 0.2 TWh during the first quarter of 2018, compared to the same quarter in 2017. This was mainly due to higher electricity generation of 0.4 TWh from the Regulated – Nuclear Generation segment, partially offset by lower electricity generation of 0.3 TWh from the Regulated – Hydroelectric segment.

The increase in electricity generation from the Regulated – Nuclear segment was primarily due to fewer planned outage days at the Darlington GS. The lower electricity generation from the Regulated – Hydroelectric segment was primarily due to lower water flows on the northwestern and eastern Ontario river systems.

OPG's operating results are affected by changes in grid-supplied electricity demand resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. For the first quarter of 2018, Ontario's electricity demand as reported by the IESO was 35.0 TWh compared to 34.3 TWh for the same quarter in 2017, excluding electricity exports out of the province.

Power that is surplus to the Ontario market is managed by the IESO, mainly through generation reductions at hydroelectric and certain nuclear stations, and other grid-connected renewable resources. Baseload generation supply surplus in Ontario continued to be prevalent during first quarter of 2018, resulting in total forgone hydroelectric generation for OPG of 0.8 TWh, which was comparable to the same quarter in 2017. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions during these periods was offset by the impact of a regulatory variance account authorized by the OEB. Production forgone at OPG's regulated hydroelectric stations due to SBG conditions was 0.8 TWh in the first quarter of 2018, which was comparable to the same quarter in 2017. OPG did not forgo any electricity production at its nuclear stations due to SBG conditions.

Average Sales Prices

The majority of OPG's generation is from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments. The regulated prices authorized by the OEB for electricity generated from OPG's nuclear and regulated hydroelectric generating stations are discussed further in the section, *Highlights* under the heading, *Recent Developments – OEB's Payment Amounts Order on OPG's Application for New Regulated Prices* and OPG's 2017 annual MD&A in the section, *Revenue Mechanisms for Regulated and Non-Regulated Generation*.

The average sales price for the Regulated – Nuclear Generation segment was 7.2 cents per kilowatt hour (¢/kWh) during the first quarter of 2018, compared to 5.8 ¢/kWh during the same quarter in 2017. The increase in the average sales price primarily reflected the impact of the new base regulated prices approved by the OEB in its December 2017 decision and March 2018 payment amounts order, partially offset by a partial reversal of the regulatory asset for the June 1, 2017 to December 31, 2017 interim period revenue shortfall to reflect the March 2018 payment amounts order. While the reversal of the regulatory liability for the Rate Smoothing Deferral Account that also resulted from the issuance of the March 2018 payment amounts order largely offset the revenue and income impact of the partial reversal of the June 1, 2017 to December 31, 2017 revenue shortfall regulatory asset, it did not impact the average sales price for the first quarter of 2018 as amounts deferred under rate smoothing are not included in the calculation of the average sales price until the period they are settled with ratepayers.

The average sales price for the Regulated – Hydroelectric segment was 4.2 ¢/kWh during each of the first quarters of 2018 and 2017. The average sales price was comparable in these periods as the impact of the new base regulated prices approved by the OEB in its December 2017 decision and March 2018 payment amounts order was offset by lower revenue under the hydroelectric incentive mechanism in the first quarter of 2018.

Cash Flow from Operations

Cash flow provided by operating activities for the three months ended March 31, 2018 was $226 million, compared to $168 million for the same period in 2017. The increase was due to higher generation revenue receipts as a result of higher electricity generation from the Regulated – Nuclear Generation segment, higher cash receipts from non-generation revenues, and lower payments of income tax installments compared to the same period in 2017. The increase in cash flow provided by operating activities was partly offset by higher OM&A expenditures as a result of increased outage expenditures.

Return on Equity Excluding Accumulated Other Comprehensive Income

ROE Excluding AOCI is an indicator of OPG's performance consistent with the Company's strategy to provide value to the Shareholder. ROE Excluding AOCI is measured over a 12-month period. ROE Excluding AOCI for the twelve months ended March 31, 2018 was 11.5 percent, compared to 7.6 percent for the twelve months ended December 31, 2017. The increase in ROE Excluding AOCI was primarily due to higher net income attributable to the Shareholder as a result of increased revenue reflecting the impact of the new base regulated prices approved by the OEB in its December 2017 decision and March 2018 payment amounts order, and the gain on the sale of the former Lakeview GS site recorded in the first quarter of 2018. ROE Excluding AOCI for these periods also reflected the after-tax gain of $283 million on the sale of the Company's head office premises and associated parking facility recorded in the second quarter of 2017. The gains on the sale of the former Lakeview GS site and the head office premises and associated parking facility, including the effect of the associated special dividend authorized in March 2018, together with the associated tax effects of these transactions, contributed approximately 4.9 percent to ROE Excluding AOCI for the twelve months ended March 31, 2018 (twelve months ended December 31, 2017 – contribution of approximately 2.5 percent).

Enterprise Total Generating Cost per Megawatt-Hour

The Enterprise TGC per megawatt hour (MWh) was $49.84 for the three months ended March 31, 2018, compared to $47.86 for the same period in 2017. The increase was mainly a result of higher OM&A expenses before the impact of

regulatory variance and deferral accounts and higher sustaining capital expenditures, partially offset by higher nuclear electricity generation.

Nuclear Total Generating Cost per Megawatt-Hour

The Nuclear TGC per MWh was $70.90 for the three months ended March 31, 2018, compared to $69.87 for the same period in 2017. The increase in Nuclear TGC per MWh was primarily due to higher OM&A expenses before the impact of regulatory variance and deferral account and higher sustaining capital expenditures, partially offset by higher nuclear electricity generation.

Hydroelectric Total Generating Cost per Megawatt-Hour

The Hydroelectric TGC per MWh was $20.42 for the three months ended March 31, 2018, compared to $19.79 for the same period in 2017. The increase in the Hydroelectric TGC per MWh was primarily due to the decrease in hydroelectric electricity generation as a result of lower water flows on the northwestern and eastern Ontario river systems.

ROE Excluding AOCI, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are not measurements in accordance with US GAAP, and should not be considered alternative measures to net income or any other performance measure under US GAAP. OPG believes that these non-GAAP financial measures are effective indicators of its performance and are consistent with the Company's strategic imperatives and related objectives. The definition and calculation of ROE Excluding AOCI, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are found in the section, *Supplementary Non-GAAP Financial Measures*.

CORE BUSINESS, STRATEGY, AND OUTLOOK

The discussion in this section is qualified in its entirety by the cautionary statements included in the section, *Forward-Looking Statements,* at the beginning of the MD&A.

OPG's mission is to provide low cost power in a safe, clean, reliable and sustainable manner for the benefit of its customers and its Shareholder. OPG also seeks to pursue, on a commercial basis, generation development projects and other business growth opportunities to the benefit of the Shareholder.

The following sections provide an update to OPG's disclosures in the 2017 annual MD&A related to its four key strategic imperatives – operational excellence, project excellence, financial strength, and social licence. A detailed discussion of these strategic imperatives is included in the 2017 annual MD&A in the section, *Core Business, Strategy, and Outlook*.

Operational Excellence

Operational excellence at OPG is accomplished by the safe and environmentally responsible generation of reliable and cost-effective electricity from the Company's generating assets through a highly trained and engaged workforce.

Public Safety

To ensure continued public safety, radiation exposure to members of the public resulting from the operation of OPG's nuclear generating stations is estimated on an annual basis for individuals living or working near the stations. The annual dose to the public resulting from operations of each nuclear facility is expressed in microsieverts (µSv), which is an international unit of radiation dose measurement. For 2017, the annual public doses resulting from the Darlington GS operations and the Pickering Nuclear GS (Pickering GS) operations were 0.7 µSv and 1.8 µSv, respectively, which is approximately 0.1 percent and 0.2 percent of the annual legal limit of 1,000 µSv, respectively.

Electricity Generation Production and Reliability

The status updates for OPG's electricity generation portfolio as of March 31, 2018 are summarized below:

- OPG's current five-year operating licence for the Pickering GS was approved by the CNSC in 2013 and expires on August 31, 2018. This current licence was issued assuming that the station would shut down in 2020. As previously announced, OPG is continuing to execute on a plan to extend safe and reliable operation of the Pickering GS to 2024. In June 2017, OPG confirmed to the CNSC that it intends to cease commercial operation of all Pickering units on December 31, 2024. In August 2017, OPG submitted a ten-year licence renewal application to the CNSC in order to extend commercial operation to December 31, 2024 and place the station in a safe storage state in 2028. The first public hearing for the Pickering GS licence renewal application took place on April 4, 2018 and provided an opportunity for OPG to present its submission to the CNSC that outlined how the Pickering GS meets technical requirements and is qualified to continue operations. The final set of public hearings will take place between June 26 and June 28, 2018. Based on the evidence and documentation submitted to the CNSC, OPG continues to believe it is well positioned to obtain a licence renewal that would support its extended operations plan for the Pickering GS to 2024.

- In 2016, OPG submitted applications with the CNSC seeking a ten-year licence renewal for the Pickering Waste Management Facility (PWMF) to August 31, 2028. On February 7, 2018, following public hearings in April 2017, the CNSC announced that the PWMF licence was renewed for a ten-year period and will be valid until August 31, 2028.

- During the first quarter of 2018, OPG completed the overhaul and rehabilitation of Unit 1 of the Sir Adam Beck Pump GS to ensure reliable unit operation for approximately the next 20 years, as well as the overhaul and upgrade of Unit 1 of the Harmon GS, which increased the station's generating capacity by 8 MW.

- Work is continuing on the overhauls and upgrade of Unit 2 of the DeCew Falls GS and Unit 2 of the Little Long GS and the overhauls and rehabilitation of Unit 2 of the Lower Notch GS and Unit 6 of the Sir Adam Beck Pump GS.

- The definition phase work continues for the Water Conveyance System project to rehabilitate the Sir Adam Beck 1 GS canal and associated structures to ensure their continued safe and reliable operations for approximately the next 50 years.

- Commencement of definition phase work for the frequency conversion of Units 1 and 2 of the Sir Adam Beck 1 GS and the overhaul and upgrade of the R.H. Saunders GS units.

- As part of the process to decommission the Nanticoke GS, OPG safely demolished the station's stacks in February 2018. The removal of the powerhouse and associated structures is in progress. A competitive bidding process for the demolition of the Lambton GS is continuing, with a contract for the removal of the powerhouse and associated structures expected to be issued during 2018. The costs of the decommissioning activities are charged to a previously established decommissioning provision.

Environmental Performance

In February 2018, the CNSC released sampling results from its 2017 independent environmental monitoring program, which confirmed that the public and environment around the Pickering GS are protected and that there are no expected health impacts. Samples were collected in publicly accessible areas outside the Pickering GS site perimeter and included air, lake water, soil, and wild vegetation. Samples of food were also taken from a local farm near the Pickering GS.

In the first quarter of 2018, the Government of Canada introduced legislation to amend the *Fisheries Act* (Bill C-68) and to replace the *Canadian Environmental Assessment Act, 2012* with a more comprehensive *Impact Assessment*

Act (Bill C-69). If passed by Parliament, this legislation could introduce new regulatory requirements to further protect fish and fish habitat, and for assessing designated projects. OPG is reviewing the proposed changes and exploring opportunities to mitigate any associated risks.

Disclosures related to the Company's environmental policy and environmental risks can be found in OPG's 2017 annual MD&A.

People and Culture

A well trained and engaged workforce is fundamental to the achievement of OPG's strategic imperatives. To succeed in a demanding business environment, OPG is focused on building a diverse, healthy, engaged workforce and fostering a culture of collaboration, accountability and innovation. OPG also continues to communicate and implement the values and behaviours expected from its employees in order to maintain a strong focus on safety, performance excellence, continuous improvement, and corporate citizenship.

In March 2018, the Employee Assistance Society of North America awarded OPG the annual Corporate Award of Excellence. These awards are given to organizations that showcase the excellence, innovation and impact of employee assistance programs in the workplace with a view to enhance employee well-being and support a healthy and productive working environment. OPG was recognized for its commitment to an organizational culture that values safety and good mental health as critical components of the organization's success.

Project Excellence

OPG is pursuing a number of generation development and other major projects in support of Ontario's electricity planning initiatives. The status updates for OPG's major projects as of March 31, 2018 are outlined below.

Project	Capital expenditures		Approved budget	Expected in-service date	Current status
(millions of dollars)	Year-to-date	Life-to-date			
Darlington Refurbishment	241	4,675	12,800 [1]	First unit - 2020 Last unit - 2026	The removal of existing Unit 2 reactor components was completed in early May 2018, with the installation of new components commencing thereafter. Planning activities for the refurbishment of Unit 3 are continuing. The overall project is tracking on schedule and on budget.
Ranney Falls Hydroelectric GS	8	36	77	2019	Construction is continuing in the expanded forebay, powerhouse and spillway area. Fabrication of the sectional gates and two head gates has been completed. Turbine and generator unit fabrication is in progress. The project is tracking on schedule and on budget.
Nanticoke Solar Facility	5	8	107	2019	Significant contracts for equipment and engineering construction services were executed and site preparation commenced in the first quarter of 2018. The facility is expected to be completed in the first quarter of 2019. **[MONITOR]**
Deep Geologic Repository (DGR) for Low and Intermediate Level Radioactive Waste (L&ILW)	- [2]	208 [2]			In August 2017, the federal Minister of Environment and Climate Change requested further information related to the project's environmental assessment (EA). OPG is continuing to work on a response to this information request.

[1] The total project budget of $12.8 billion is for the refurbishment of all four units at the Darlington GS. Project costs that do not meet capitalization criteria are charged to OM&A expenses in the period incurred.

[2] Expenditures are charged against the Nuclear Liabilities.

Darlington Refurbishment

The Darlington generating units are approaching their originally designed end-of-life. Refurbishment of the four generating units is expected to extend the operating life of the station by approximately 30 years. The approved budget for the four-unit refurbishment is $12.8 billion, which includes the costs of the prerequisite projects in support of the execution phase of the refurbishment. The first refurbished unit is scheduled to be returned to service in the first quarter of 2020 and the last unit is scheduled to be completed by 2026.

OPG commenced the refurbishment of the first unit, Unit 2, in October 2016. The de-fuelling of the reactor and islanding of Unit 2, the physical separation of the unit under refurbishment from the three operating units, was completed in the first half of 2017, signifying the completion of the first major segment of the project.

The second major segment included the disassembly and removal of the existing reactor components. In early May 2018, OPG completed the removal of the reactor components, which included end fittings, pressure tubes, and calandria tubes, signifying the completion of the second major segment of the project.

The Unit 2 refurbishment has transitioned into the third major segment, the installation and reassembly of reactor components, including new feeder tubes and fuel channel assemblies. Construction activities on the Heavy Water Storage and Drum Handling Facility are also continuing.

In February 2018, the Government of Ontario confirmed its commitment to proceed with the refurbishment of the second unit at the Darlington GS, Unit 3. In March 2018, OPG's Board of Directors approved the funding to complete planning and prerequisite activities for the Unit 3 refurbishment. Planning activities for the Unit 3 refurbishment are progressing in accordance with the overall project schedule. OPG is ensuring that lessons learned from the Unit 2 refurbishment are appropriately incorporated into the Unit 3 refurbishment, and is entering into commitments to procure major components that require long lead times. Prerequisite activities for Unit 3 refurbishment have commenced, with the Unit 3 refurbishment execution expected to commence upon the return to service of Unit 2. As of March 31, 2018, $137 million has been invested in planning and prerequisite activities related to the Unit 3 refurbishment.

The Darlington Refurbishment project continues to track on schedule and to the $12.8 billion budget.

Ranney Falls Hydroelectric GS

In 2017, OPG began construction work on a 10 MW single-unit powerhouse on the existing Ranney Falls GS site. The new unit will replace an existing unit that reached its end of life in 2014. Construction continues in the expanded forebay, powerhouse and spillway area. Fabrication of the sectional gates and two head gates has been completed, with assembly and site delivery in progress. Turbine and generator unit fabrication is also in progress. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget. The Ranney Falls GS is included in the Regulated – Hydroelectric segment.

Nanticoke Solar Facility

The project encompasses the construction of a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands under a contract with the IESO, through Nanticoke Solar LP, a partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation. Significant contracts for equipment and engineering construction services were executed and site preparation commenced in the first quarter of 2018. The facility is expected to be completed in the first quarter of 2019 **[MONITOR]**, with a budget of $107 million. The project is included in the Contracted Generation Portfolio segment.

Deep Geologic Repository for Low and Intermediate Level Waste

OPG has proposed a deep geologic repository as the preferred solution for the safe long-term management of the L&ILW produced from the continued operation of OPG-owned nuclear generating stations. Agreement has been

reached with local municipalities for OPG to develop the L&ILW DGR on lands adjacent to OPG's Western Waste Management Facility (WWMF) in Kincardine, Ontario.

Before the CNSC can make licensing decisions for the proposal, an EA must be conducted. The environmental effects of the proposed L&ILW DGR were examined by the CNSC and Canadian Environmental Assessment Agency (CEAA)-appointed Joint Review Panel (JRP) to meet the requirements of the *Canadian Environmental Assessment Act* as well as the project specific Environmental Impact Statement Guidelines. The JRP submitted its report on the EA to the federal Minister of Environment in May 2015, concluding that, given mitigation, there is unlikely to be significant environmental impact from the project and recommending that the Minister approve the EA. In December 2016, at the request of the federal Minister of Environment and Climate Change, OPG submitted additional information on certain aspects of the EA, with further information provided in May 2017 at the request of the CEAA. In June 2017, the CEAA notified OPG that it had sufficient and adequate information to proceed with the next step of the EA process and advised that a draft report and updated terms and conditions would be prepared for public review.

In August 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of potential cumulative effects of the project on the Saugeen Ojibway Nation's (SON) physical and cultural heritage, including a description of the potential effects of the project on the SON's spiritual and cultural connection to the land, taking into account the results of the SON Community Process. OPG continues its engagement with the SON towards securing support for the project and to formulate a response to the information request.

The L&ILW DGR at the WWMF site remains OPG's preferred solution for the safe long-term management of the L&ILW. The in-service date of the L&ILW DGR is expected to be approximately six to seven years from the start of construction.

Financial Strength

As a commercial enterprise, OPG's financial priority is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future expansion.

Increasing Revenue, Reducing Costs and Achieving Appropriate Return

In line with its commercial mandate, OPG is focused on increasing revenue and net income and achieving an appropriate rate of return on the Shareholder's investment, while taking into account the impact on Ontario electricity customers by seeking further efficiencies in the Company's cost structure.

For the regulated operations, achievement of the above objectives is largely dependent on outcomes of applications for regulated prices to the OEB and growth of the asset base earning a return as part of the regulated prices. The OEB's December 2017 decision and March 2018 payment amounts order establishing new regulated prices effective June 1, 2017 provide substantial price certainty for the regulated business up to 2021.

While the OEB set costs for determining the new regulated prices below OPG's forecasted levels, including through the use of stretch factors under incentive ratemaking, the new regulated prices will result in a substantial increase in revenue and net income compared to the previously approved prices.

To further improve the financial strength of the regulated operations, OPG continues to focus on optimizing operational performance and outage plans across the generating fleet and pursue further efficiency improvements in the Company's cost structure and operating model. This includes continuing to progress the multi-year OPG25 initiative, which involves identifying and implementing a coordinated set of plans and targets to ensure the optimization of the Company's longer-term operating model, business strategies and organizational design between now and the planned end of Pickering commercial operation in 2024.

OPG's capital structure currently reflects lower levels of debt than the deemed capital structure of 45 percent equity and 55 percent debt maintained by the OEB's December 2017 decision on new regulated prices. OPG continues to evaluate strategies to enhance Shareholder returns by optimizing the Company's capital structure through better alignment with the deemed capital structure, taking into account the overall financial strength of the Company and the potential impact on the Company's investment grade credit rating.

Consistent with the OEB's December 2017 decision, later in 2018, OPG plans to file an application with the OEB requesting disposition of the Pension & OPEB Cash Versus Accrual Differential Deferral Account balance as at December 31, 2017 and the balances accumulated between December 31, 2015 and December 31, 2017 in other variance and deferral account balances. If approved by the OEB, recovery of these balances would contribute to improved cash flow from operations.

Ensuring Availability of Cost Effective Funding

In April 2018, DBRS Limited (DBRS) re-affirmed the long-term credit rating on OPG's debt at 'A (low)' and OPG's commercial paper rating at 'R-1 (low)'. All ratings from DBRS have a stable outlook.

Social Licence

As the largest electricity generator in Ontario with diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust. OPG is committed to maintaining high standards of public safety and corporate citizenship, including environmental stewardship, transparency, community engagement, and Indigenous relations.

OPG is focused on building long-term, mutually beneficial working relationships with Indigenous communities, businesses and organizations across Ontario, and continues to support procurement, employment and educational opportunities with Indigenous communities. OPG seeks to establish these relationships based on a foundation of respect for the languages, customs, and political, social and cultural organizations of Indigenous communities. In the first quarter of 2018, the Dictionary of Moose Cree, an OPG-supported project that preserves the unique language and culture of the Moose Cree First Nation, was recognized by the Lieutenant Governor of Ontario. The language initiative was funded by OPG as a cultural project under the 2010 Amisk-oo-skow Agreement between OPG and the Moose Cree First Nation.

OPG's commitment in the area of Indigenous relations includes pursuing generation-related development partnerships on the basis of long-term commercial arrangements and other joint projects. In addition to the development of the Nanticoke solar facility in partnership with the Six Nations of the Grand River, OPG is currently working with the Kiashke Zaaging Anishinaabek (KZA), also known as the Gull Bay First Nation, to construct a new renewable micro grid that will utilize solar generation, battery storage, and micro grid control technology to reduce the community's reliance on diesel generation. As the lead developer of the project, OPG will work with several collaborators to construct the micro grid on KZA reserve land. Upon completion, the micro grid will be transferred to KZA for ownership and operation. The micro grid project is OPG's fifth development project in partnership with an Indigenous community.

OPG is committed to improving Indigenous access to procurement and employment opportunities, including increasing the profile of the nuclear generation industry in Indigenous communities. In 2018, this includes continuing to track the implementation of the Indigenous Business Engagement Initiative launched in 2017 to increase access to procurement opportunities for Indigenous businesses interested in supplying materials and services to OPG, and continuing to identify ways to increase the Indigenous representation in OPG's workforce. Recruitment initiatives include the launch of the Indigenous Opportunities in Nuclear program in the first quarter of 2018 using the Darlington Refurbishment project as a catalyst, and the continuing development of a dedicated Indigenous recruitment and retention strategy.

Outlook

The financial performance of OPG's regulated operations is driven, in large part, by the outcome of applications for regulated prices to the OEB.

In 2018, the full-year effect of the new regulated prices established by the OEB's December 2017 decision and March 2018 payment amounts order effective June 1, 2017 will contribute to an improvement in net income and ROE Excluding AOCI over the 2017 results. An improvement in cash flow from operating activities during the remainder of 2018, compared to 2017, is also expected, as OPG begins to receive revenue from the IESO based on new regulated prices as of March 1, 2018, the implementation date for the regulated prices. The Fair Hydro Trust segment will also modestly improve cash flow from operating activities in 2018. OPG expects to continue to have the necessary financial capacity and sufficient access to cost effective financing sources to continue to fund its capital requirements and other disbursements, including purchases of subordinated debt issued by the Fair Hydro Trust (the Trust) to fund a portion of the Trust's acquisition of Investment Interest from the IESO, being the irrevocable right to recover Global Adjustment costs deferred by the IESO under the *Ontario Fair Hydro Plan Act, 2017* (Fair Hydro Act or the Act) and associated financing and other costs.

Several OEB-authorized regulatory variance and deferral accounts will continue to contribute to reducing the relative variability of the Company's net income and ROE Excluding AOCI. Among others, these accounts include those related to the revenue impact of variability in water flows and forgone production due to SBG conditions at the regulated hydroelectric stations. As there are no variance or deferral accounts in place related to the impact of generation performance of the nuclear stations on revenue from base regulated prices, the Regulated – Hydroelectric segment generally is expected to produce overall more predictable earnings. OPG continues to operate and maintain its nuclear facilities with a view to optimize their performance and availability, while focusing on improving the overall reliability and predictability of the fleet.

Electricity generated from most of OPG's non-regulated assets is subject to ESAs with the IESO or other long-term contracts. Based on these agreements, OPG expects the Contracted Generation Portfolio segment to continue to contribute a generally stable level of earnings and cash flow from operating activities going forward.

Lower nuclear generation due to the Darlington Refurbishment outages will continue, as planned, to negatively impact the Enterprise TGC and Nuclear TGC measures for the duration of the refurbishment project. Lower hydroelectric generation due to outages related to various refurbishment and operational projects may negatively impact Enterprise TGC and Hydroelectric TGC for the duration of these projects. Variability in sustaining capital investment expenditures and nuclear outage profile may also impact TGC measures in future periods.

OPG's total forecast capital expenditures for the 2018 year are approximately $2.1 billion. This includes amounts for the Darlington Refurbishment project, hydroelectric and other development projects including the Ranney Falls GS redevelopment and construction of the Nanticoke solar facility, and sustaining capital investments across the generating fleet. OPG's major projects are discussed in the section, *Project Excellence*.

In addition to the operating and financial performance of the electricity generation business, OPG's results are affected by earnings on the Nuclear Segregated Funds established under the Ontario Nuclear Funds Agreement (ONFA) between OPG and the Province, which are reported in the Regulated – Nuclear Waste Management segment. Variations in rates of return for the funds based on financial market conditions, including changes in the Ontario consumer price index (CPI) that affect earnings on the portion of the Used Fuel Segregated Fund guaranteed by the Province, can be volatile and cause fluctuations in the Company's income in the near term. This volatility is reduced by the impact of the OEB-authorized Bruce Lease Net Revenues Variance Account and during periods when the funds are in a fully funded or overfunded position. As at March 31, 2018, the Decommissioning Segregated Fund was overfunded by approximately 26 percent, and the Used Fuel Segregated Fund was marginally overfunded, by less than one percent, based on the current ONFA reference plan. Variability in asset performance due to volatility

inherent in financial markets and changes in Ontario CPI, or changes in funding liability estimates, may result in either or both funds becoming underfunded in the future.

OPG's results include the earnings from the Fair Hydro Trust segment, primarily related to interest income from the Trust. Management expects that these earnings will increase in 2018 as additional Investment Interest is acquired. OPG's involvement as the Financial Services Manager under the Fair Hydro Act is expected to put downward pressure on ROE Excluding AOCI as a result of increases in shareholder's equity through future issuances of Class A shares to partially fund OPG's purchases of the Trust's subordinated debt, partially offset by the impact of incremental earnings from the Trust.

ENVIRONMENT, SOCIAL GOVERNANCE, AND SUSTAINABILITY

OPG's Darlington and Pickering nuclear generating stations and renewable fleet of hydroelectric generating stations produce clean, reliable electricity with virtually no greenhouse gas emissions. However, OPG recognizes that efforts are required to plan for the impacts of climate change and has identified climate change adaptation as a strategic priority for the company. OPG monitors developments in climate science, adaptation activities, and potential changes to policy and regulatory requirements, and is continuing to work with stakeholders to better define adaptation requirements.

OPG has established an Environment, Social Governance and Sustainability (ESG) steering committee consisting of a diverse group of representatives from various disciplines within the Company. The mandate of the committee is to evaluate the potential impact of environmental issues on the Company, oversee the development of a formal climate change strategy, assess and monitor the evolution of the climate-related risks, and develop associated financial reporting disclosures.

OPG is in the process of developing its ESG framework to best reflect and disclose information that is meaningful to stakeholders. OPG plans to structure its ESG framework around four core themes:

- **Metrics and targets** to assess and manage relevant climate-related risks and opportunities;
- **Risk management** processes to identify, assess and manage climate-related risks;
- **Strategy** for incorporating climate change impacts into business planning and decision-making; and
- **Governance** for integrating the climate change strategy in the business.

In developing its ESG framework, OPG expects to leverage industry-specific and other emerging guidance on best practices related to ESG reporting. OPG also continues to monitor the Canadian Securities Administrators' project to review the disclosures of risks and financial impacts associated with climate change.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

Regulated – Nuclear Generation Segment

(millions of dollars) (unaudited)	Three Months Ended March 31 2018	2017
Revenue from contracts with customers	**871**	643
Leasing revenue	**9**	9
Revenue	**880**	652
Fuel expense	**73**	68
Gross margin	**807**	584
Operations, maintenance and administration	**604**	589
Depreciation and amortization	**121**	107
Property taxes	**7**	6
Income (loss) before interest and income taxes	**75**	(118)

Income before income interest and income taxes from the segment increased by $193 million during the first quarter of 2018, compared to the same quarter in 2017. The increase in earnings was primarily due to an increase in revenue of $228 million, reflecting the impact of new regulated prices approved by the OEB in its December 2017 decision and March 2018 payment amounts order on OPG's application for new regulated prices, effective June 1, 2017. The higher earnings were also partially due to an increase in electricity generation of 0.4 TWh during the first quarter of 2018, compared to the same quarter in 2017, which contributed approximately $25 million to the year-over-year increase in revenue.

The increase in OM&A expenses of $15 million in the first quarter of 2018, compared to the same quarter in 2017, partially offset the increase in segment earnings. The increase in OM&A expenses was primarily due to higher services and materials costs associated with major planned outages.

Higher depreciation and amortization expenses of $14 million in the first quarter of 2018 were mainly due to a higher amount of depreciation expense deferred in regulatory variance and deferral accounts in the first quarter of 2017. The higher deferrals in 2017 were due to costs not included in the regulated prices in effect prior to the OEB's December 2017 decision. In addition, new assets in service for the Pickering GS contributed to the increase in depreciation and amortization expenses.

At the end of 2017, OPG revised the accounting end-of-life assumptions for the Pickering GS from December 31, 2020 to December 31, 2022 for Units 1 and 4 and to December 31, 2024 for Units 5 to 8, and recorded a corresponding change in the nuclear asset retirement obligation and associated asset retirement costs capitalized as part of the carrying value of property, plant and equipment, effective December 31, 2017. The change in these end-of-life assumptions took into account technical assessments completed to date as part of OPG's plan to extend the commercial operation of the Pickering GS to 2024 and the safety case reflected in the Pickering GS licence renewal application submitted to the CNSC in 2017. The resulting decrease in depreciation expense associated with the change in these end-of-life assumptions in the first quarter of 2018, compared to the same quarter in 2017, was offset by the impact of regulatory variance and deferral accounts, including a new deferral account proposed by OPG in its December 2017 accounting order application to the OEB and subsequently authorized by the OEB on an interim basis pending a final decision on the application. **[MONITOR]**

The Unit Capability Factors for the Darlington GS and Pickering GS were as follows:

	Three Months Ended March 31	
	2018	**2017**
Unit Capability Factor *(%)* [1]		
Darlington GS	**96.5**	85.3
Pickering GS	**74.5**	78.5

[1] The nuclear Unit Capability Factor excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS was excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

The Unit Capability Factor at the Darlington GS increased in the first quarter of 2018, compared to the same quarter in 2017, primarily due to a lower number of planned outage days at the station in the first quarter of 2018.

The decrease in the Unit Capability Factor at the Pickering GS in the first quarter of 2018, compared to the same quarter in 2017, was primarily due to a higher number of planned outage days in the cyclical maintenance schedule at the station in the first quarter of 2018.

Regulated – Nuclear Waste Management Segment

	Three Months Ended March 31	
(millions of dollars) (unaudited)	**2018**	**2017**
Other revenue	**33**	27
Operations, maintenance and administration	**33**	29
Accretion on nuclear fixed asset removal and nuclear waste management liabilities	**243**	234
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(210)**	(189)
Loss before interest and income taxes	**(33)**	(47)

Earnings from the segment improved by $14 million in the first quarter of 2018, compared to the same quarter in 2017. The improvement was primarily due to higher earnings from the Nuclear Segregated Funds, partially offset by an increase in accretion expense on the Nuclear Liabilities.

The year-over-year increase in earnings from the Nuclear Segregated Funds was primarily due to the growth rate in the present value of the underlying funding liabilities per the current ONFA reference plan in effect since January 1, 2017, as both the Decommissioning Segregated Fund and the Used Fuel Fund were in an overfunded position since the beginning of 2017 and were not impacted by market returns and the rate of return guaranteed by the Province for a portion of the Used Fuel Segregated Fund. When both funds are in an overfunded position, OPG limits the amount of Nuclear Segregated Funds assets reported on the balance sheet to the present value of the underlying life cycle funding liabilities per the most recently approved ONFA reference plan. Further details on the accounting for the Nuclear Segregated Funds can be found in OPG's 2017 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

Regulated – Hydroelectric Segment

(millions of dollars) (unaudited)	Three Months Ended March 31 2018	2017
Revenue from contracts with customers [1]	**356**	363
Fuel expense	**65**	73
Gross margin	**291**	290
Operations, maintenance and administration	**80**	76
Depreciation and amortization	**36**	34
Other losses	**4**	-
Income before interest and income taxes	**171**	180

[1] During the three months ended March 31, 2018 and 2017, the Regulated – Hydroelectric segment revenue reflected incentive payments of $1 million and $8 million, respectively, related to the OEB-approved hydroelectric incentive mechanism. The mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers. The incentive payments are reduced to remove incentive revenues arising in connection with SBG conditions.

Income before interest and income taxes from the segment decreased by $9 million during the first quarter of 2018, compared to the same quarter in 2017. The decrease in earnings was primarily due to lower hydroelectric incentive mechanism payments, higher OM&A expenses as a result of increased maintenance work programs, and retirement of replaced equipment.

The above factors were partially offset by the increase in revenue of approximately $5 million in the first quarter of 2018 to reflect the impact of new regulated prices approved by the OEB in its December 2017 decision and March 2018 payment amounts order, effective June 1, 2017.

The Hydroelectric Availability for the stations included in the Regulated – Hydroelectric segment was as follows:

	Three Months Ended March 31 2018	2017
Hydroelectric Availability *(%)*	**87.3**	89.5

The Hydroelectric Availability decreased in the first quarter of 2018, compared to the same period in 2017, primarily due to a higher number of unplanned outage days at the eastern and northeastern Ontario regions' regulated hydroelectric stations.

Contracted Generation Portfolio Segment

(millions of dollars) (unaudited)	Three Months Ended March 31 2018	2017
Revenue from contract with customers	**149**	143
Fuel expense	**17**	14
Gross margin	**132**	129
Operations, maintenance and administration	**41**	39
Depreciation and amortization	**20**	19
Accretion on fixed asset removal liabilities	**2**	2
Property taxes	**1**	2
Income from investments subject to significant influence	**(10)**	(10)
Income before interest and income taxes	**78**	77

Income before interest and income taxes from the segment in the first quarter of 2018 was comparable to the same quarter in 2017.

The increase in gross margin of $3 million was primarily due to revenue from the Peter Sutherland Sr. GS that was placed in-service at the end of the first quarter of 2017. The increase in OM&A expenses of $2 million reflected higher station expenditures at the Lennox GS.

The Hydroelectric Availability and the Thermal Equivalent Forced Outage Rate (EFOR) for the Contracted Generation Portfolio segment were as follows:

	Three Months Ended March 31 2018	2017
Hydroelectric Availability *(%)*	**80.1**	83.6
Thermal EFOR *(%)*	**0.3**	12.6

The Hydroelectric Availability decreased in the first quarter of 2018, compared to the same quarter in 2017, primarily due to a higher number of planned outage days as a result of the overhaul and upgrade of Unit 2 of the Little Long GS.

The lower Thermal EFOR in the first quarter of 2018, compared to the same quarter in 2017, was primarily due to a higher number of unplanned outage days at a Lennox GS unit as a result of a transmission outage in the first quarter of 2017.

Fair Hydro Trust Segment

(millions of dollars) (unaudited)	Three Months Ended March 31 2018	2017
Earnings from Fair Hydro Trust	**4**	-
Income before interest and income taxes	**4**	-

The Fair Hydro Trust was established in December 2017 as the financing entity contemplated by the Fair Hydro Act, for the purpose of acquiring Investment Interest from the IESO. In order for the Trust to finance such acquisitions, it incurs senior debt from capital markets and subordinated debt from OPG. The Company consolidates the financial results of the Trust in accordance with US GAAP.

In March 2018 and April 2018, the Trust purchased Investment Interests from the IESO in the amount of $460 million and $149 million, respectively. Fifty-one percent of the funding requirements for each acquisition totalling approximately $311 million was financed by the Trust through a revolving warehouse facility ranked as senior notes, and the remaining 49 percent totalling approximately $298 million was funded through the following sources:

- the Province provided 44 percent of the funding requirements for each acquisition, or a total of $268 million, through an equity injection in OPG in exchange for approximately 6.1 million non-voting Class A shares at a price of $43.74 per share; and
- OPG provided five percent of the funding requirements, or $30 million.

Earnings from Fair Hydro Trust were $4 million during the first quarter of 2018, primarily due to net interest income for the period.

Refer to the section, *Liquidity and Capital Resources* under the heading, *Financing Activities* for further details on the Trust's financing arrangements.

LIQUIDITY AND CAPITAL RESOURCES

OPG's primary sources of liquidity and capital are funds generated from operations, bank financing, credit facilities provided by the Ontario Electricity Financial Corporation (OEFC), long-term corporate debt, including public debt offerings and notes payable to the OEFC, private placement project financing, and equity issuances. These sources are used for multiple purposes including: to invest in plants and technologies, to undertake major projects, to fund long-term obligations such as contributions to the pension fund and the Nuclear Segregated Funds, to make payments under the OPEB plans, to fund expenditures on Nuclear Liabilities not eligible for reimbursement from the Nuclear Segregated Funds, to service and repay long-term debt, to provide general working capital, and to fund a portion of OPG's purchases of subordinated debt issued by the Fair Hydro Trust.

Changes in cash and cash equivalents for the three months ended March 31, 2018 and 2017 were as follows:

	Three Months Ended March 31	
(millions of dollars) (unaudited)	**2018**	**2017**
Cash and cash equivalents, beginning of period [1]	**234**	186
Cash flow provided by operating activities	**226**	168
Cash flow used in investing activities	**(604)**	(413)
Cash flow provided by financing activities	**472**	279
Net increase in cash and cash equivalents	**94**	34
Cash and cash equivalents, end of period [1]	**328**	220

[1] Includes restricted cash.

For a discussion of cash flow provided by operating activities, refer to the details in the section, *Highlights* under the heading, *Overview of Results*.

Investing Activities

Electricity generation is a capital-intensive business. It requires continued investment in plants and technologies to maintain and improve operating performance including asset reliability, safety and environmental performance, to increase the generating capacity of existing stations, and to invest in the development of new generating stations, emerging technologies and other business growth opportunities.

Cash flow used in investing activities during the first quarter of 2018 increased by $191 million compared to the same quarter in 2017. The increase in net cash flow used in investing activities was primarily due to the Trust's acquisition of Investment Interest from the IESO of $460 million in March 2018, partially offset by the receipt of proceeds from the sale of the former Lakeview GS site in March 2018.

Financing Activities

As at March 31, 2018, long-term debt outstanding was $6,896 million, including $263 million due within one year and including the Fair Hydro Trust's senior debt reported on OPG's interim consolidated balance sheets. This included $1,400 million outstanding under OPG's $2,350 million general corporate credit facility agreement with the OEFC that expires on December 31, 2018. The Fair Hydro Trust's senior debt outstanding was $836 million as at March 31, 2018.

During the first quarter of 2018, OPG issued a total of $600 million senior notes payable to OEFC maturing in 2048. The effective and coupon interest rates on these notes ranged from 3.87 percent to 4.00 percent.

In December 2017, the Fair Hydro Trust entered into an $800 million two-year revolving warehouse facility agreement expiring in December 2019. As at March 31, 2018, there were outstanding senior notes of $336 million under this credit facility, $235 million of which was used to finance 51 percent of the Trust's funding requirement for the acquisition of the Investment Interest from the IESO in March 2018 in the amount of $460 million. An additional $76 million was issued under the credit facility in April 2018 to finance fifty-one percent of the Trust's funding requirement for the acquisition of the Investment Interest from the IESO in April 2018 in the amount of $149 million.

In February 2018, the Fair Hydro Trust issued $500 million of senior notes payable with a coupon interest rate of 3.36 percent and an effective interest rate of 3.44 percent, payable semi-annually until maturity in May 2033. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility issued by the Trust in December 2017 to provide a portion of the funding requirement for the Trust's purchase of the first tranche of Investment Interest from the IESO in December 2017.

In April 2018, the Trust issued $400 million of senior notes payable with a coupon interest rate of 3.52 percent and an effective interest rate of 3.60 percent, payable semi-annually until maturity in May 2038. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility after the Investment Interest acquisition in April 2018. Following this repayment, the facility had $12 million outstanding.

BALANCE SHEET HIGHLIGHTS

The following section provides highlights of OPG's unaudited interim consolidated financial position using selected balance sheet data:

(millions of dollars) (unaudited)	As At March 31 2018	As At December 31 2017
Property, plant and equipment – net	**21,515**	21,322
The increase was primarily due to capital expenditures on the Darlington Refurbishment and other projects, partially offset by depreciation expense.		
Nuclear fixed asset removal and nuclear waste management funds *(current and non-current portions)*	**16,909**	16,724
The increase was primarily due to earnings on the Nuclear Segregated Funds, partially offset by reimbursement of eligible expenditures on nuclear fixed asset removal and nuclear waste management activities.		
Regulatory assets and liabilities – net *(current and non-current portions)*	**6,773**	6,637
The increase was primarily due to the continued recognition of net revenue in January and February 2018 in the revenue shortfall account resulting from the OEB's December 2017 decision on new regulated prices and an increase in future income taxes.		
Long-term debt *(current and non-current portions)*	**6,876**	6,319
The increase was primarily due to the issuance of senior notes payable to the OEFC of $600 million and the net issuance of senior notes payable by the Fair Hydro Trust of $232 million. The increase was offset by debt repayments totalling $275 million.		
Fixed asset removal and nuclear waste management liabilities	**20,639**	20,421
The increase was primarily a result of accretion expense representing the increase in the present value liabilities due to the passage of time, partially offset by expenditures on nuclear fixed asset removal and waste management activities		

Off-Balance Sheet Arrangements

In the normal course of operations, OPG engages in a variety of transactions that, under US GAAP, are either not recorded in the Company's interim consolidated financial statements or are recorded in the Company's interim consolidated financial statements using amounts that differ from the full contract amounts. Principal off-balance sheet activities for OPG include guarantees and long-term contracts.

CHANGES IN ACCOUNTING POLICIES AND ESTIMATES

OPG's significant accounting policies are outlined in Note 3 to the audited consolidated financial statements as at and for the year ended December 31, 2017. A discussion of new accounting policies resulting from the adoption of new accounting standards effective January 1, 2018, recent accounting pronouncements, and change in accounting estimates are included in Note 2 to OPG's unaudited interim consolidated financial statements as at and for the three months ended March 31, 2018 under the heading, *Significant Accounting Policies and Estimates*. Disclosure regarding OPG's critical accounting policies is included in OPG's 2017 annual MD&A.

Exemptive Relief for Reporting under US GAAP

In April 2018, OPG received an extension to its exemptive relief from the OSC requirements of section 3.2 of National Instrument 52-107 *Acceptable Accounting Policies and Auditing Standards*. The exemption allows OPG to file consolidated financial statements based on US GAAP, rather than International Financial Reporting Standards (IFRS), without becoming a Securities and Exchange Commission registrant. This exemption replaces the exemptive relief received by OPG from the OSC in February 2014. The exemption will terminate on the earliest of the following:

- January 1, 2024;
- the financial year that commences after OPG ceases to have activities subject to rate regulation; and
- the effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within IFRS specific to entities with rate-regulated activities.

As a result of adopting US GAAP in 2011 as required by the FAA regulation, OPG's plan to convert to IFRS, effective January 1, 2012, was discontinued. OPG had substantively completed the IFRS conversion project when it suspended the project. If a future transition to IFRS for the purposes of OPG's consolidated financial statements is required, conversion work can be effectively restarted with sufficient lead time to evaluate and conclude on changes that occurred subsequent to the decision to suspend the project. OPG continues to monitor the IASB's current standard-setting project related to entities with rate-regulated activities and is evaluating alternatives with respect to the Company's future financial reporting.

RISK MANAGEMENT

The following provides an update to the discussion of the Company's risks and risk management activities included in OPG's 2017 annual MD&A. As such, the disclosure in this section should be read in conjunction with the *Risk Management* section included in the annual MD&A.

Risks to Achieving Operational Excellence

Proposed Asbestos Regulations

The Government of Canada is in the final stages of developing new regulations to prohibit the use of asbestos and products containing asbestos. The new *Prohibition of Asbestos and Asbestos Products Regulations* (the proposed Regulations) are expected to come into effect in 2018. The proposed Regulations would prohibit the import, sale and use of asbestos and the manufacture, import, sale and use of products containing asbestos, with a limited number of exclusions. In addition, the proposed Regulations would not prohibit the use of asbestos and products containing asbestos that were installed prior to the proposed Regulations coming into force.

OPG is assessing the risk and impact of the proposed Regulations, particularly affecting the use of spare parts and the existing inventory which may contain asbestos. A key concern is the application of this regulation within OPG's nuclear fleet, where a significant number of spare parts are known to contain asbestos and may be required to address an emergent condition or to complete a maintenance outage to return the unit to operation. OPG has

provided submissions to Environment and Climate Change Canada and to the CNSC to ensure the issues and potential impacts are understood by the respective regulatory bodies.

Risks to Maintaining Financial Strength

Commodity Markets

Changes in the market price of fuels used to produce electricity can adversely impact OPG's earnings and cash flow from operations.

To manage the risk of unpredictable increases in the price of fuels, the Company has fuel hedging programs, which include using fixed price and indexed contracts.

The percentages hedged of OPG's fuel requirements are shown in the following table. These amounts are based on yearly forecasts of generation and supply mix and, as such, are subject to change as these forecasts are updated.

	2018 [1]	2019	2020
Estimated fuel requirements hedged [2]	79%	75%	77%

[1] Based on actual fuel requirements hedged for the three months ended March 31, 2018 and forecast for the remainder of the year.

[2] Represents the approximate portion of megawatt-hours of expected generation production (and year-end inventory targets) from each type of OPG-operated facility (nuclear, hydroelectric and thermal) for which the Company has entered into contractual arrangements or obligations in order to secure the price of fuel, or which is subject to rate regulation. In the case of hydroelectric generation, this represents the gross revenue charge and water rental charges. Excess fuel inventories (nuclear and thermal) in a given year are attributed to the next year for the purpose of measuring hedge ratios.

Foreign Exchange

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are primarily denominated in or tied to US dollars. To manage this risk, OPG periodically employs various financial instruments such as forwards and other derivative contracts, in accordance with approved risk management policies. As at March 31, 2018, OPG had no foreign exchange contracts outstanding.

Trading

OPG's financial performance can be affected by its trading activities. OPG's electricity trading operations are closely monitored, with total exposures measured and reported to senior management on a daily basis. The main metric used to measure the financial risk of trading activity is Value at Risk (VaR). VaR is defined as a probabilistic maximum potential future loss expressed in monetary terms for a portfolio based on normal market conditions over a set period of time. For the first quarter of 2018, the VaR utilization ranged between nil and $1 million.

Credit

The Company's credit risk exposure is a function of its electricity sales, trading and hedging activities, treasury activities including investing and commercial transactions with various suppliers of goods and services. OPG's credit exposure relating to energy markets transactions as at March 31, 2018 was $449 million, including $436 million to the IESO. OPG's credit risk exposure relating to electricity sales is considered low as the majority of sales are through the IESO-administered spot market. The IESO oversees the credit worthiness of all market participants. In accordance with the IESO's prudential support requirements, market participants are required to provide collateral to cover funds that they might owe to the market. Of the $13 million remaining exposure as at March 31, 2018, over 95 percent was with investment grade counterparties. Other major components of OPG's credit risk exposure include those associated with vendors that are contracted to provide services or products. OPG manages its exposure to various suppliers or counterparties by evaluating their financial condition and ensuring that the Company holds appropriate collateral or other forms of security.

RELATED PARTY TRANSACTIONS

Given that the Province owns all of the outstanding common shares and Class A shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One Limited, the IESO, and the OEFC. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As a wholly owned government business enterprise of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions are summarized below:

	Three Months Ended March 31			
	2018		2017	
(millions of dollars) (unaudited)	**Income**	**Expense**	**Income**	**Expense**
Hydro One				
Electricity sales	**4**	**-**	4	-
Services	**-**	**5**	1	5
Dividends	**2**	**-**	2	-
Province of Ontario				
Change in Decommissioning Segregated Fund amount due to Province [1]	**-**	**(2)**	-	163
Change in Used Fuel Segregated Fund amount due to Province [1]	**-**	**(21)**	-	217
Hydroelectric gross revenue charge	**-**	**28**	-	28
ONFA guarantee fee	**-**	**-**	-	2
OEFC				
Hydroelectric gross revenue charge	**-**	**38**	-	38
Interest expense on long-term notes	**-**	**37**	-	41
Income taxes, net of investment tax credits	**-**	**53**	-	12
IESO				
Electricity related revenue	**1,232**	**-**	1,067	-
Earnings from Fair Hydro Trust	**4**	**-**	-	-
	1,242	**138**	1,074	506

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at March 31, 2018 and December 31, 2017, the Nuclear Segregated Funds were reported net of amounts due to the Province of $4,439 million and $4,462 million, respectively.

The receivables, financing receivables, equity securities, payable and long-term debt balances between OPG and its related parties are summarized below:

(millions of dollars) (unaudited)	**March 31 2018**	**December 31 2017**
Receivables from related parties		
Hydro One	**1**	1
IESO – Electricity related receivables	**436**	354
IESO – Fair Hydro Trust [1]	**7**	7
OEFC	**2**	-
PEC	**4**	4
Province of Ontario	**2**	3
Financing receivables		
IESO – Fair Hydro Trust	**1,639**	1,179
Equity securities		
Hydro One shares	**170**	188
Accounts payable and accrued charges		
Hydro One	**-**	1
OEFC	**35**	52
Province of Ontario	**11**	9
IESO – Electricity related payables	**1**	5
IESO – Fair Hydro Trust	**1**	3
Long-term debt (including current portion)		
Notes payable to OEFC	**3,520**	3,195

[1] Balance consists of unbilled cost recovery revenue.

OPG may hold Province of Ontario bonds and treasury bills in the Nuclear Segregated Funds and the OPG registered pension fund. As at March 31, 2018, the Nuclear Segregated Funds held $1,319 million of Province of Ontario bonds (December 31, 2017 – $1,502 million) and $1 million of Province of Ontario treasury bills (December 31, 2017 – $9 million). As at March 31, 2018, the registered pension fund did not hold Province of Ontario treasury bills (December 31, 2017 – $1 million). These Province of Ontario bonds and treasury bills are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

In March and April 2018, the Fair Hydro Trust purchased Investment Interests from the IESO for an exchange amount of $460 million and $149 million, respectively, which have been classified as financing receivables on OPG's unaudited interim consolidated balance sheets. The transactions were settled in cash using proceeds from the Trust's issuance of senior debt to third parties and subordinated debt to OPG. Pursuant to the general regulation of the Fair Hydro Act, the IESO is required to pay and remit carrying costs of the Trust, excluding repayment of principal on any debt obligations, up to July 31, 2021. Commencing May 1, 2021, residential, farm, small businesses and other eligible customers will be invoiced by their local distribution company for the Clean Energy Adjustment to pay the carrying costs of the Trust and principal on debt. These funds will be remitted to the Trust through the IESO and will be used to settle all funding and other related expenses of the Trust that underlie the financing receivables.

As at March 31, 2018, OPG's unaudited interim consolidated balance sheets included approximately $7 million of unbilled cost recovery revenue from the IESO (December 31, 2017 – $7 million), primarily for OPG's general fee for 2017 as the Financial Services Manager under the Act relating to incurred third-party and certain direct labour costs.

The Province has provided a limited guarantee to specified creditors of the Fair Hydro Trust. The limited guarantee would be triggered in the event that the Trust's ability to receive amounts in respect of its Investment Interest to pay for certain funding obligations is adversely affected due to one or more of the following: the Province changes the Fair Hydro Act or any other legislation or regulation; a significant change in Ontario's electricity market undertaken by the Province; or a court declares that the Act is invalid or unconstitutional.

INTERNAL CONTROLS OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

The Company maintains a comprehensive system of policies, procedures, and processes that represents its framework for internal controls over financial reporting and for its disclosure controls and procedures (together, ICOFR). There were no changes in the Company's internal control system during the current interim period that has or is reasonably likely to have a material impact to the ICOFR.

QUARTERLY FINANCIAL HIGHLIGHTS

The following tables set out selected annual financial from OPG's unaudited interim consolidated financial statements for each of the eight most recently completed quarters.

(millions of dollars – except where noted) (unaudited)	**March 31 2018**	**December 31 2017**	**September 30 2017**	**June 30 2017**
Revenue	**1,407**	**1,619**	**1,217**	**1,146**
Net income	**539**	**366**	**140**	**307**
Less: Net income attributable to non-controlling interest	**4**	**4**	**9**	**4**
Net income attributable to the Shareholder	**535**	**362**	**131**	**303**
Earnings per share, attributable to the Shareholder *(dollars)*	**$1.99**	**$1.41**	**$0.51**	**$1.18**

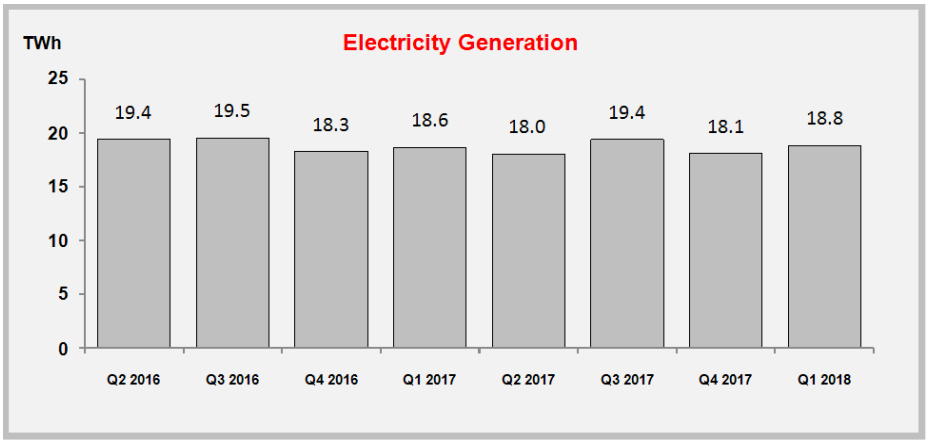
(millions of dollars – except where noted) (unaudited)	**March 31 2017**	**December 31 2016**	**September 30 2016**	**June 30 2016**
Revenue	1,176	1,388	1,400	1,387
Net income (loss)	68	(8)	198	135
Less: Net income attributable to non-controlling interest	4	5	4	3
Net income (loss) attributable to the Shareholder	64	(13)	194	132
Earnings per share, attributable to the Shareholder *(dollars)*	$0.25	($0.05)	$0.76	$0.51

Trends

OPG's quarterly results are affected by changes in grid-supplied electricity demand, primarily resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. Weather conditions affect water flows, electricity demand, and prevalence of SBG conditions. Historically, OPG's revenues have been higher in the first quarter of a fiscal year as a result of winter heating demands and in the third quarter due to air conditioning and cooling demands. The financial impact of forgone production due to SBG conditions at the regulated hydroelectric stations and the financial impact of differences between forecast water flows reflected in OEB-approved regulated prices and the actual water flows are mitigated by regulatory accounts authorized by the OEB.

The outage cycle at each of OPG's nuclear generating stations determines the number and frequency of planned outages in a particular year. The outage cycle is designed to ensure the continued safe and reliable long-term operations of the plant and its compliance with CNSC regulatory requirements. The frequency of planned outages under the outage cycle may result in year-over-year variability in OPG's operating results, including the impact on revenue and OM&A expenses. In addition, the timing of planned outages at a nuclear generating station during the year can cause variability in year-over-year operating results for partial periods of a fiscal year but is not a significant driver of variability for full fiscal year results.

OPG's financial results are also affected by earnings on the Nuclear Segregated Funds, net of the impact of the Bruce Lease Net Revenues Variance Account. The volatility of earnings on the Nuclear Segregated Funds is mitigated by their funded status.



SUPPLEMENTARY NON-GAAP FINANCIAL MEASURES

In addition to providing net income and other financial information in accordance with US GAAP, certain non-GAAP financial measures are also presented in OPG's MD&A. These non-GAAP measures do not have any standardized meaning prescribed by US GAAP, and therefore, may not be comparable to similar measures presented by other issuers. OPG utilizes these measures to make operating decisions and assess performance. Readers of the MD&A would utilize these measures in assessing the Company's financial performance from ongoing operations. The Company believes that these indicators are important since they provide additional information about OPG's performance, facilitate comparison of results over different periods, and present measures consistent with the Company's strategies to provide value to the Shareholder, improve cost performance, and ensure availability of cost effective funding. These non-GAAP financial measures have not been presented as an alternative to net income or any other measure in accordance with US GAAP, but as indicators of operating performance.

The definitions of the non-GAAP financial measures are as follows:

(1) ROE Excluding AOCI is defined as net income attributable to the Shareholder divided by average equity attributable to the Shareholder excluding AOCI, for the period.

ROE Excluding AOCI is measured over a 12-month period and is calculated as follows:

(millions of dollars – except where noted) (unaudited)	**Twelve Months Ended March 31 2018**	**December 31 2017**
ROE Excluding AOCI		
Net income attributable to the Shareholder	**1,331**	860
Divided by: Average equity attributable to the Shareholder, excluding AOCI	**11,602**	11,351
ROE Excluding AOCI *(percent)*	**11.5**	7.6

(2) Enterprise Total Generating Cost per MWh is used to measure OPG's overall organizational cost performance. Enterprise TGC per MWh is defined as OM&A expenses (excluding the Darlington Refurbishment project and other generation development project costs, the impact of regulatory accounts, and expenses ancillary to OPG's electricity generation business), fuel expense for OPG-operated stations including hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory accounts), and capital expenditures (excluding the Darlington Refurbishment project and other generation development projects) incurred during the period, divided by total electricity generation from OPG-operated generating stations plus electricity generation forgone due to SBG conditions during the period.

	Three Months Ended March 31	
(millions of dollars – except where noted) (unaudited)	**2018**	**2017**
Enterprise TGC		
Total OM&A expenses	**722**	708
Total fuel expense	**155**	155
Total capital expenditures	**359**	408
Less: Darlington Refurbishment capital and OM&A costs	**(259)**	(309)
Less: Other generation development project capital and OM&A costs	**(17)**	(17)
Add (Less): OM&A and fuel expenses deferred in (refundable through) regulatory accounts	**26**	(11)
Less: Nuclear fuel expense for non OPG-operated stations	**(15)**	(13)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**6**	11
Less: OM&A expenses ancillary to electricity generation business	**(4)**	(5)
Other adjustments	**-**	(2)
	973	925
Adjusted electricity generation *(TWh)*		
Total OPG electricity generation	**18.8**	18.6
Adjust for electricity generation forgone due to SBG conditions and OPG's share of electricity generation from co-owned facilities	**0.7**	0.7
	19.5	19.3
Enterprise TGC per MWh *($/MWh)* [1]	**49.84**	**47.86**

[1] Amounts may not calculate due to rounding.

(3) Nuclear Total Generating Cost per MWh is used to measure the cost performance of OPG's nuclear generating assets. Nuclear TGC per MWh is defined as OM&A expenses of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs, the impact of regulatory accounts, and expenses ancillary to the nuclear electricity generation business), nuclear fuel expense for OPG-operated stations (excluding the impact of regulatory accounts), and capital expenditures of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs) incurred during the period, divided by nuclear electricity generation for the period.

	Three Months Ended March 31	
(millions of dollars – except where noted) (unaudited)	**2018**	**2017**
Nuclear TGC		
Regulated – Nuclear Generation OM&A expenses	**604**	589
Regulated – Nuclear Generation fuel expense	**73**	68
Regulated – Nuclear Generation capital expenditures	**313**	366
Less: Darlington Refurbishment capital and OM&A costs	**(259)**	(309)
Add (Less): Regulated – Nuclear Generation OM&A and fuel expenses deferred in (refundable through) regulatory accounts	**24**	(2)
Less: Nuclear fuel expense for non OPG-operated stations	**(15)**	(13)
Less: Regulated – Nuclear Generation OM&A expenses ancillary to electricity generation business	**(2)**	(1)
Other adjustments	**(1)**	-
	737	698
Nuclear electricity generation *(TWh)*	**10.4**	10.0
Nuclear TGC per MWh *($/MWh)* [1]	**70.90**	69.87

[1] Amounts may not calculate due to rounding.

(4) Hydroelectric Total Generating Cost per MWh is used to measure the cost performance of OPG's hydroelectric generating assets. Hydroelectric TGC per MWh is defined as OM&A expenses of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding generation development project costs, the impact of regulatory accounts, and expenses ancillary to the hydroelectric electricity generation business), hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory accounts), and capital expenditures of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding expenditures related to the Peter Sutherland Sr. GS, Ranney Falls GS, and other hydroelectric generation development projects) incurred during the period, divided by total hydroelectric electricity generation plus hydroelectric electricity generation forgone due to SBG conditions during the period. OPG reports hydroelectric gross revenue charge and water rental payments as fuel expense.

(millions of dollars – except where noted) (unaudited)	Three Months Ended March 31 2018	2017
Hydroelectric TGC		
Regulated – Hydroelectric OM&A expenses	**80**	76
Regulated – Hydroelectric fuel expense	**65**	73
Contracted Generation Portfolio OM&A expenses	**41**	39
Contracted Generation Portfolio fuel expense	**17**	14
Regulated – Hydroelectric and Contracted Generation Portfolio capital expenditures	**36**	37
Less: Regulated – Hydroelectric and Contracted Generation Portfolio generation development project capital and OM&A costs	**(18)**	(16)
Less: Thermal OM&A and fuel expenses and capital expenditures in the Contracted Generation Portfolio	**(44)**	(39)
Add (Less): Regulated – Hydroelectric OM&A and fuel expenses deferred in (refundable through) regulatory accounts	**2**	(9)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**6**	11
Other adjustments	**-**	(1)
	185	185
Adjusted hydroelectric electricity generation *(TWh)*		
Regulated – Hydroelectric electricity generation	**7.7**	8.0
Contracted Generation Portfolio electricity generation	**0.7**	0.6
Adjust for hydroelectric electricity generation forgone due to SBG conditions and non-hydroelectric electricity generation of the Contracted Generation Portfolio, including OPG's share of electricity generation from co-owned facilities	**0.7**	0.7
	9.1	9.3
Hydroelectric TGC per MWh *($/MWh)* [1]	**20.42**	19.79

[1] Amounts may not calculate due to rounding.

(5) Gross margin is defined as revenue less fuel expense**.**

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ONTARIO POWER GENERATION INC.

INTERIM CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

MARCH 31, 2018

[DRAFT]

INTERIM CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

Three Months Ended March 31 *(millions of dollars except where noted)*	**2018**	**2017**
Revenue	**1,407**	1,176
Fuel expense	**155**	155
Gross margin	**1,252**	1,021
Operations, maintenance and administration	**722**	708
Depreciation and amortization	**186**	167
Accretion on fixed asset removal and nuclear waste management liabilities	**247**	238
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(210)**	(189)
Earnings from Fair Hydro Trust *(Note 15)*	**(4)**	-
Income from investments subject to significant influence	**(10)**	(10)
Property taxes	**9**	11
	940	925
Income before other gains, interest and income taxes	**312**	96
Other gains *(Note 18)*	**259**	3
Income before interest and income taxes	**571**	99
Net interest expense *(Note 5)*	**19**	19
Income before income taxes	**552**	80
Income tax expense *(Note 19)*	**13**	12
Net income	**539**	68
Net income attributable to the Shareholder	**535**	64
Net income attributable to non-controlling interest	**4**	4
Basic and diluted earnings per share *(dollars) (Note 13)*	**1.99**	0.25

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

Three Months Ended March 31 *(millions of dollars)*	**2018**	**2017**
Net income	**539**	68
Other comprehensive income, net of income taxes *(Note 8)*		
Reclassification to income of amounts related to pension and other post-employment benefits [1]	**3**	3
Reclassification to income of losses on derivatives designated as cash flow hedges [2]	**4**	4
Unrealized gain on available-for-sale securities [3]	**-**	5
Other comprehensive income for the period	**7**	12
Comprehensive income	**546**	80
Comprehensive income attributable to the Shareholder	**542**	76
Comprehensive income attributable to non-controlling interest	**4**	4

[1] Net of income tax expenses of $1 million for each of March 31, 2018 and 2017.

[2] Net of income tax expenses of $1 million for each of March 31, 2018 and 2017.

[3] Net of income tax expense of nil and $1 million for March 31, 2018 and 2017, respectively.

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

Three Months Ended March 31 *(millions of dollars)*	2018	2017
Operating activities		
Net income	**539**	68
Adjust for non-cash items:		
Depreciation and amortization	**186**	167
Accretion on fixed asset removal and nuclear waste management liabilities	**247**	238
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(210)**	(189)
Pension and other post-employment benefit costs *(Note 9)*	**99**	113
Deferred income taxes	**(6)**	11
Regulatory assets and liabilities	**(141)**	(28)
Other gains	**(257)**	(1)
Other	**(13)**	(4)
Reimbursement of eligible expenditures on nuclear fixed asset removal and nuclear waste management	**23**	22
Contributions to pension funds and expenditures on other post-employment benefits and supplementary pension plans	**(79)**	(88)
Distributions received from investments subject to significant influence	**12**	14
Net changes to other long-term assets and liabilities	**(20)**	(38)
Net changes to non-cash working capital balances *(Note 16)*	**(154)**	(117)
Cash flow provided by operating activities	**226**	168
Investing activities		
Acquisition of Fair Hydro Trust financing receivables	**(460)**	-
Proceeds from deposit note	**-**	45
Net proceeds from sale of property, plant and equipment	**273**	-
Investment in property, plant and equipment and intangible assets	**(417)**	(458)
Cash flow used in investing activities	**(604)**	(413)
Financing activities		
Issuance of Class A shares *(Note 12)*	**202**	-
Issuance of OPG long-term debt *(Note 5)*	**600**	200
Repayment of OPG long-term debt	**(275)**	(50)
Issuance of Fair Hydro Trust long-term debt *(Note 5)*	**732**	-
Repayment of Fair Hydro Trust long-term debt	**(500)**	
Distribution to non-controlling interest	**(4)**	(4)
Dividend to the Province's Consolidated Revenue Fund *(Note 17)*	**(283)**	-
Issuance of short-term debt	**1,295**	589
Repayment of short-term debt	**(1,295)**	(456)
Cash flow provided by financing activities	**472**	279
Net increase in cash, cash equivalents and restricted cash	**94**	34
Cash, cash equivalents and restricted cash, beginning of period	**234**	186
Cash, cash equivalents and restricted cash, end of period	**328**	220

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

(millions of dollars)	March 31 2018	December 31 2017
Assets		
Current assets		
Cash, cash equivalents and restricted cash *(Note 3)*	**328**	234
Equity securities	**170**	188
Receivables from related parties	**452**	369
Nuclear fixed asset removal and nuclear waste management funds	**23**	23
Fuel inventory	**299**	309
Materials and supplies	**96**	103
Regulatory assets *(Note 4)*	**259**	-
Prepaid expenses	**196**	192
Income tax recoverable	**10**	-
Other current assets	**98**	146
	1,931	1,564
Property, plant and equipment	**30,292**	29,950
Less: accumulated depreciation	**8,777**	8,628
	21,515	21,322
Intangible assets	**576**	565
Less: accumulated amortization	**440**	432
	136	133
Other assets		
Nuclear fixed asset removal and nuclear waste management funds	**16,886**	16,701
Financing receivables	**1,639**	1,179
Long-term materials and supplies	**352**	355
Regulatory assets *(Note 4)*	**7,107**	7,231
Investments subject to significant influence	**307**	309
Other long-term assets	**32**	28
	26,323	25,803
	49,905	48,822

INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

(millions of dollars)	March 31 2018	December 31 2017
Liabilities		
Current liabilities		
Accounts payable and accrued charges	**1,119**	1,228
Short-term debt *(Note 6)*	**260**	260
Deferred revenue due within one year	**9**	12
Long-term debt due within one year *(Note 5)*	**263**	398
Income taxes payable	**-**	80
Regulatory liabilities *(Note 4)*	**19**	-
	1,670	1,978
Long-term debt *(Note 5)*	**6,613**	5,921
Other liabilities		
Fixed asset removal and nuclear waste management liabilities *(Note 7)*	**20,639**	20,421
Pension liabilities	**3,389**	3,423
Other post-employment benefit liabilities	**3,118**	3,092
Long-term accounts payable and accrued charges	**252**	252
Deferred revenue	**368**	351
Deferred income taxes	**917**	879
Regulatory liabilities *(Note 4)*	**574**	594
	29,257	29,012
Equity		
Common shares *(Note 12)*	**5,126**	5,126
Class A shares *(Note 12)*	**721**	519
Retained earnings	**6,632**	6,396
Accumulated other comprehensive loss *(Note 8)*	**(279)**	(295)
Equity attributable to the Shareholder	**12,200**	11,746
Equity attributable to non-controlling interest	**165**	165
Total equity	**12,365**	11,911
	49,905	48,822

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY

Three Months Ended March 31 *(millions of dollars)*	**2018**	**2017**
Common shares *(Note 12)*	**5,126**	5,126
Class A shares *(Note 12)*		
Balance at beginning of period	**519**	-
Issuance of Class A shares	**202**	-
Balance at end of period	**721**	-
Retained earnings		
Balance at beginning of period	**6,396**	5,534
Reclassification of cumulative unrealized losses on available-for-sale securities to opening retained earnings *(Note 2)*	**(9)**	-
Adjustment to recognize income tax effects of intercompany transfer of assets to opening retained earnings *(Note 2)*	**(7)**	-
	6,380	5,534
Net income attributable to the Shareholder	**535**	64
Dividend to the Province's Consolidated Revenue Fund *(Note 17)*	**(283)**	-
Balance at end of period	**6,632**	5,598
Accumulated other comprehensive loss, net of income taxes		
Balance at beginning of period	**(295)**	(295)
Other comprehensive income	**7**	12
Reclassification of cumulative unrealized losses on available-for-sale securities *(Note 2)*	**9**	-
Balance at end of period	**(279)**	(283)
Equity attributable to the Shareholder	**12,200**	10,441
Equity attributable to non-controlling interest		
Balance at beginning of period	**165**	143
Distribution to non-controlling interest	**(4)**	(4)
Income attributable to non-controlling interest	**4**	4
Balance at end of period	**165**	143
Total equity	**12,365**	10,584

See accompanying notes to the interim consolidated financial statements

NOTES TO THE INTERIM CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

For the three months ended March 31, 2018 and 2017

1. BASIS OF PRESENTATION

These interim consolidated financial statements for the three months ended March 31, 2018 and 2017 include the accounts of Ontario Power Generation Inc. (OPG or the Company) and its subsidiaries. The Company consolidates its interest in entities over which it is able to exercise control and attributes the results to its sole shareholder, the Province of Ontario (Province). Interests owned by other parties are reflected as non-controlling interest. These interim consolidated financial statements have been prepared and presented in accordance with United States generally accepted accounting principles (US GAAP). These interim consolidated financial statements do not contain all of the disclosures required by US GAAP for annual financial statements. Accordingly, they should be read in conjunction with the annual consolidated financial statements of the Company as at and for the year ended December 31, 2017. All dollar amounts are presented in Canadian dollars.

As required by *Ontario Regulation 395/11,* as amended, under the *Financial Administration Act* (Ontario), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. Since January 1, 2012, OPG also has received exemptive relief from the Ontario Securities Commission (OSC) from the requirements of section 3.2 of National Instrument 52-107, *Acceptable Accounting Policies and Auditing Standards*. The exemption allows OPG to file consolidated financial statements based on US GAAP, rather than International Financial Reporting Standards (IFRS), without becoming a US Securities and Exchange Commission registrant.

In April 2018, OPG received an extension to its previous exemptive relief from the OSC. The exemptive relief will now terminate on the earliest of the following:

- January 1, 2024
- The financial year that commences after OPG ceases to have activities subject to rate regulation
- The effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within IFRS specific to entities with rate regulated activities.

All dollar amounts are presented in Canadian dollars, unless otherwise noted. Certain 2017 comparative amounts have been reclassified from financial statements previously presented to conform to the 2018 consolidated financial statement presentation.

Use of Management Estimates

The preparation of consolidated financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the interim consolidated financial statements, and the reported amounts of revenues and expenses for the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in the period incurred. Significant estimates are included in the determination of pension and other post-employment benefit (OPEB) balances, asset retirement obligations and associated asset retirement costs capitalized as part of property, plant and equipment, income taxes (including deferred income taxes), contingencies, regulatory assets and liabilities, valuation of derivative instruments and investments in segregated funds, depreciation and amortization expenses, and inventories. Actual results may differ significantly from these estimates.

2. SIGNIFICANT ACCOUNTING POLICIES AND ESTIMATES

New Accounting Standards Effective in 2018

Revenue from Contracts with Customers

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09, *Revenue from Contracts with Customers (Topic 606)*, which supersedes nearly all existing revenue recognition guidance, including industry-specific guidance, under US GAAP. The core principle of Topic 606 is to recognize revenues when promised goods or services are transferred to customers in an amount that reflects the consideration to which an entity expects to be entitled for those goods or services.

Effective January 1, 2018, OPG adopted Topic 606, including relevant practical expedients, to recognize its revenue, utilizing the modified retrospective approach to complete the transition and identified no material differences in timing or amount of revenue recognition. The adoption of Topic 606 has required OPG to amend its accounting policy with respect to revenue recognition, as described below:

Revenue from Contracts with Customers – Regulated Generation

Energy revenue generated from OPG's regulated facilities is based on regulated prices determined by the OEB that include base regulated prices and, as applicable, rate riders for the recovery or repayment of approved variance and deferral account balances. The revenues from the regulated hydroelectric facilities are also subject to the OEB-approved hydroelectric incentive mechanism. This mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers.

All of OPG's electricity generation is offered into the real-time energy spot market administered by the IESO. For electricity generated from its regulated nuclear and regulated hydroelectric facilities, OPG receives payment from the IESO on a monthly basis. OPG has determined that its performance obligation to supply electricity generated from its regulated nuclear and regulated hydroelectric facilities is satisfied over time. The Company utilizes the output method under Topic 606 to recognize revenue by applying the relevant base regulated price and rate riders as applicable to each MWh of electricity generated and metered to the IESO. This methodology appropriately reflects the real-time nature of electricity generation and the underlying performance obligation, of which no portion remains unsatisfied at the end of the applicable reporting period. OPG's receivables in connection with electricity generated from its regulated nuclear and regulated hydroelectric facilities are part of the Company's electricity related receivables from the IESO. For further discussion, refer to Note 10.

Base regulated prices in effect during the period January 1, 2016 to May 31, 2017 were established by the OEB's November 2014 decision and December 2014 order, using a forecast cost-of-service rate-setting methodology based on the OEB-approved revenue requirements, taking into account the OEB-approved forecasts of production and operating costs for the regulated facilities for 2014 and 2015 and a return on rate base. Rate base is a regulatory construct that, for OPG, represents the average net level of investment in regulated fixed and intangible assets in-service and an allowance for working capital.

On December 28, 2017, the OEB issued its decision on OPG's May 2016 application for new regulated prices for the 2017−2021 period. The OEB set an effective date for the new regulated prices of June 1, 2017. The decision included the OEB's findings with respect to ratemaking methodologies for the prescribed facilities, the basis for inputs into the hydroelectric incentive ratemaking formula, and the elements of the nuclear revenue requirement.

Pursuant to the decision, the new base regulated prices will be determined on an incentive ratemaking methodology for the hydroelectric facilities and under a custom incentive regulation framework for the nuclear facilities. For the hydroelectric facilities, the new base regulated prices for each of the years 2017 to 2021 will be determined using a formula that annually escalates the previously approved regulated prices, subject to some adjustments, based on an

industry-specific weighted inflation factor less a stretch factor adjustment. For the nuclear facilities, the new base regulated prices will be determined under a rate smoothing approach that defers a portion of the approved nuclear revenue requirement for future collection in the Rate Smoothing Deferral Account authorized by the OEB pursuant to Ontario Regulation 53/05, with the objective of making changes in OPG's production-weighted average nuclear and hydroelectric regulated price more stable year over year. The nuclear revenue requirement for each of the years 2017 to 2021 is based on the OEB-approved forecast of operating costs as reduced by a stretch factor amount, and a return on rate base. The difference between the non-deferred portion of the nuclear revenue requirement calculated by multiplying the nuclear base regulated price determined under rate smoothing and the OEB-approved forecast of OPG's nuclear electricity production for the year, and the total approved nuclear revenue requirement for that year determines the portion of the revenue requirement deferred for future collection in the Rate Smoothing Deferral Account. Amounts recorded in the Rate Smoothing Deferral Account are recognized as adjustments to revenue.

In March 2018, the OEB issued the final payment amounts order in connection with the decision. The payment amounts order requires OPG to implement a payment amount smoothing approach whereby no additions are made to the Rate Smoothing Deferral Account in 2017 or 2018. See Note 4 for further information on the OEB's decision on OPG's May 2016 application for new regulated prices and the Rate Smoothing Deferral Account.

Revenue from Contracts with Customers – Non-regulated Generation

The electricity generation from OPG's non-regulated assets receives the Ontario electricity spot market price, except where an energy supply agreement (ESA) with the IESO or another contractual agreement is in place. The IESO is the counterparty to all ESAs that are currently entered into. As at December 31, 2017, most of OPG's operating non-regulated generating assets are subject to an ESA. As permitted by the practical expedient within Topic 606, revenue from the generating stations subject to an ESA is recognized in the amount that OPG has a right to invoice on a monthly basis to the IESO as the Company satisfies its performance obligation in accordance with the terms of the agreement to supply energy and capacity via the applicable facilities. No portion of OPG's performance obligation remains unsatisfied at the end of any applicable reporting period. OPG estimates revenues for variable or conditional amounts within each ESA using a most likely amount approach on a contract-by-contract basis. Variable consideration within each ESA is included in revenue only to the extent that it is highly probable that the amount will not be subject to significant reversal when the uncertainty is resolved. OPG's receivables in connection with electricity generated from its non-regulated assets are part of the Company's electricity related receivables from the IESO. For further discussion, refer to Note 10.

Revenue from Contracts with Customers – Non-Generation

OPG also sells into, and purchases from, interconnected markets of other provinces and the northeast and mid-west regions of the US. All contracts that are not designated as hedges are recorded on the consolidated balance sheets at market value, with gains or losses recorded in the consolidated statements of income. Gains and losses on energy trading contracts (including those to be physically settled) are recorded on a net basis in the consolidated statements of income.

OPG also derives non-energy revenue under the terms it associated, non-lease agreements with Bruce Power L.P. (Bruce Power) related to the Bruce nuclear generating stations. The associated agreements include revenue from heavy water sales, detritiation services and waste management services.

In addition, non-energy revenue includes isotope sales and other service revenues. Revenues from these activities are recognized as the respective performance obligations are satisfied, in accordance with the terms stipulated in the respective contracts.

Revenue Recognition – Lease revenue

The minimum lease payments stemming from OPG's lease arrangement with Bruce Power are recognized in revenue on a straight-line basis over the term of the lease. Similarly, revenue from real estate rentals are recognized over the term of the lease as the Company renders the requisite services outlined in the respective contracts.

Recognition and Measurement of Financial Assets and Financial Liabilities

In January 2016, the FASB issued ASU No. 2016-01, *Financial Instruments – Overall: Recognition and Measurement of Financial Assets and Financial Liabilities*. Under the updated guidance, entities are required to measure equity investments at fair value and recognize any changes in fair value in net income. Effective January 1, 2018, the available-for-sale (AFS) classification for securities is no longer available. Any unrealized gains and losses related to equity securities is now recognized in net income instead of OCI. Any unrealized gains and losses for AFS securities reported by OPG in AOCI as at December 31, 2017 was reclassified to retained earnings as of January 1, 2018.

The adoption of ASU No. 2016-01 resulted in an adjustment to transfer cumulative losses of $9 million on OPG's equity securities from AOCI to opening retained earnings on January 1, 2018. There are no other significant differences to OPG's consolidated financial statements upon adoption of the new standard, other than to replace the accounting policy for available-for-sale securities with a new policy for holdings of equity securities as described below.

Equity securities

Equity securities held by OPG are measured at fair value, with gains and losses due to changes in fair value recognized within other gains and losses in the consolidated statement of income. Related transaction costs are expensed as incurred, and dividend income is included in net income in the period in which dividends are declared. Equity securities are initially measured at the transaction price.

Restricted Cash

In November 2016, the FASB issued ASU No. 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash (a consensus of the FASB Emerging Issues Task Force)*, which clarifies how entities should present restricted cash and restricted cash equivalents in the statement of cash flows. The guidance is applied retrospectively and is effective for OPG's 2018 fiscal year, including interim periods. The changes in disclosures required under this update are reflected in the interim consolidated statements of cash flows and Note 3.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost

In March 2017, the FASB issued ASU No. 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. Under the new guidance, employers that sponsor defined benefit plans for pensions and/or other postretirement benefits are required to present the service cost component of net periodic benefit cost in the same statement of income line item as other employee compensation costs arising from services rendered during the period. The other components of the net periodic benefit cost are to be presented separately from the line item that includes the service cost and outside of any subtotal of income from operations, if such a subtotal is presented. In addition, the new guidance requires that only the service cost component of net benefit cost be eligible for capitalization.

Effective January 1, 2018, OPG adopted the provisions of Topic 715. Adoption of Topic 715 does not have a material impact on OPG's consolidated financial statements, as OPG already capitalized only the service cost component of postretirement benefits costs prior to the adoption of the new guidance. Additionally, OPG previously included the service cost component of postretirement benefit costs with other compensation costs within OM&A expenses in the consolidated statements of income, and did not show a subtotal of income from operations prior to the adoption of the new guidance. As such, the new guidance does not affect the presentation of OPG's consolidated financial

statements nor result in any significant changes in OPG's accounting policies.

Intra-Entity Transfers of Assets Other than Inventory

The FASB issued ASU 2016-16, Income Taxes (Topic 740): *Intra-Entity Transfers of Assets Other than Inventory*, in October 2016 to amend existing guidance with respect to accounting for the income tax effects of intra-entity asset transfers. Effective January 1, 2018, entities are required to recognize the income tax effects of all intra-entity asset transfers, with the exception of inventory, as soon as the transfer occurs. Previously, entities were required to defer recognition of such income tax effects until the asset was sold to a third party.

The update is effective for OPG beginning January 1, 2018 and is required to be applied on a modified retrospective basis. On adoption of the update, the Company recorded an adjustment to opening retained earnings of $7 million to reflect the associated deferred income tax liability resulting from the cumulative effect of OPG's transfer of assets, other than inventory, to the UMH Energy Limited Partnership and the Lower Mattagami Energy Limited Partnership in prior years. Adoption of this update resulted in no other material impacts to the Company's consolidated financial statements, other than an addition to OPG's accounting policy for income taxes as described below.

Income taxes – Intra-entity transfers of non-inventory assets

The income tax impact of any intra-entity transfers of non-inventory assets is recognized upon the occurrence of the transfer.

Recent Accounting Pronouncements Not Yet Adopted

Lease Accounting

In February 2016, the FASB issued ASU No. 2016-02, *Leases* (Topic 842) to replace existing lease accounting guidance under Topic 840. The update includes comprehensive changes to existing guidance, particularly for lessees, and aims to increase transparency and comparability among organizations by requiring the recognition of lease assets and lease liabilities on the balance sheet. The standard is effective for annual periods beginning after December 15, 2018, including interim periods within that year.

Under the current guidance related to the new leasing standard, entities are required to use a modified retrospective approach for leases that exist, or are entered into, after the beginning of the earliest comparative period presented in the financial statements of the period of adoption. Under this method, Topic 842 would effectively be implemented by recognizing any adjustments stemming from the transition as of the beginning of the earliest comparative period presented in the entity's financial statements. Full retrospective application is prohibited. In January 2018, the FASB issued a proposed ASU (ASU 2018-200) wherein entities would be able to utilize an additional optional transition method of recording the cumulative impact of adopting the new lease standard as an adjustment to opening balances in the initial period of adoption, with comparative periods continuing to be presented in accordance with Topic 840, including disclosures. The Company will continue to monitor the status of this proposed ASU.

The FASB also issued ASU No. 2018-01, *Land Easement Practical Expedient for Transition to Topic 842* in January 2018. The amendments therein allow an entity to choose not to evaluate under Topic 842 land easements that exist or expired before the entity's adoption of the new leasing standard and that were not previously accounted for as leases under Topic 840.

The Company has implemented a comprehensive project governance framework to oversee the transition to the new leasing guidance, comprised of a Steering Committee, Implementation & Stakeholder Committee, Project Management Office, and various working groups in order to evaluate and implement the new standard. The working groups are represented by cross functional finance and non-finance stakeholders and will support the financial and operational implementation of the standard. Management has commenced procedures to provide assurance over the completeness of the population of leasing arrangements to be assessed for impact upon adoption of the new

guidance. The Company continues to evaluate the impact of the new leasing standard on its consolidated financial statements.

3. CASH, CASH EQUIVALENTS AND RESTRICTED CASH

Cash, cash equivalents, and restricted cash include cash on deposit and money market securities with a maturity of less than 90 days on the date of purchase. All other money market securities with a maturity on the date of purchase that is greater than 90 days, but less than one year, are recorded as short-term investments and classified as current assets. These securities are valued at the lower of cost and market.

Cash, cash equivalents, and restricted cash consist of the following:

(millions of dollars)	**March 31 2018**	**December 31 2017**
Cash and cash equivalents	**315**	230
Restricted cash	**13**	4
Total cash, cash equivalents and restricted cash	**328**	234

Restricted cash represents Fair Hydro Trust's (the Trust) cash on deposit that is subject to contractual restrictions of the Trust's Master Trust Indenture. All of the Fair Hydro Trust's bank accounts are under the name of and exclusive control of its indenture trustee. Amounts on deposit are restricted in purpose and the distribution of use is subject to the order of payment priority outlined in the Fair Hydro Trust's Master Trust Indenture.

4. REGULATORY ASSETS AND LIABILITIES

Through its March 2017 approval of a partial settlement agreement reached by OPG and intervenors on a limited set of issues in OPG's May 2016 application for new regulated prices for the 2017−2021 period (Settlement Agreement) and its December 2017 decision on the application, the OEB approved OPG's request to recover amounts totalling $305 million related to previously recorded variance and deferral account balances, without adjustments. These approved amounts relate to the December 31, 2015 balances in all of the Company's OEB-authorized regulatory accounts, with the exception of the Pension & OPEB Cash Versus Accrual Differential Deferral Account, less amounts previously approved for recovery or repayment for these accounts in 2016.

The OEB issued its decision on the Draft Payment Amounts Order and Procedural Order No. 10 in EB-2016-0152 on March 12, 2018. In its decision, the OEB ordered that OPG recover the approved regulatory account balances over the period March 1, 2018 to December 31, 2020, with 15 percent of the balance to be recovered between March 1, 2018 and December 31, 2018, 50 percent of the balance to be recovered between January 1, 2019 and December 31, 2019, and 35 percent of the balance to be recovered between January 1, 2020 and December 31, 2020. This amortization was confirmed in the final Payment Amounts Order, issued by the OEB on March 29, 2018.

The final payment amount order also ordered OPG to implement a payment amount smoothing approach whereby no additions are made to the Rate Smoothing Deferral Account in 2017 and 2018. The change in smoothing approach resulted in the reversal of amounts previously recorded in the Rate Smoothing Deferral Account as at December 31, 2017, with a corresponding change in the interim Period Revenue Shortfall Account. The direction provided by the final payment amount order resulted in an immaterial financial impact.

The regulatory assets and liabilities recorded as at March 31, 2018 and December 31, 2017 are as follows:

(millions of dollars)	**March 31 2018**	**December 31 2017**
Regulatory assets		
Variance and deferral accounts authorized by the OEB		
Pension and OPEB Cost Variance Account	**712**	716
Pension & OPEB Cash Versus Accrual Differential Deferral Account	**655**	614
Hydroelectric Surplus Baseload Generation Variance Account	**387**	360
Bruce Lease Net Revenues Variance Account	**127**	121
Other variance and deferral accounts	**124**	124
	2,005	1,935
Interim Period Revenue Shortfall	**612**	544
Pension and OPEB Regulatory Asset *(Note 9)*	**3,806**	3,855
Deferred Income Taxes	**943**	897
Total regulatory assets	**7,366**	7,231
Less: current portion	**259**	-
Non current regulatory assets	**7,107**	7,231
Regulatory liabilities		
Variance and deferral accounts authorized by the OEB		
Hydroelectric Water Conditions Variance Account	**167**	150
Pension & OPEB Cash Payment Variance Account	**157**	140
Changes in Station End-of-Life Dates Deferral Account	**103**	103
Other variance and deferral accounts	**166**	201
Total regulatory liabilities	**593**	594
Less: current portion	**19**	-
Non-current regulatory liabilities	**574**	594

As at March 31, 2018 and December 31, 2017, regulatory assets for other variance and deferral accounts included amounts for the Nuclear Deferral and Variance Over/Under Recovery Variance Account, the Nuclear Liability Deferral Account, the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account, the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account, and the Nuclear Development Variance Account. As at March 31, 2018 and December 31, 2017, regulatory liabilities for other variance and deferral accounts included the amounts for the Capacity Refurbishment Variance Account, the Ancillary Services Net Revenue Variance Account, the Income and Other Taxes Variance Account and the SR&ED ITC Variance Account.

As at December 31, 2017, regulatory assets for other variance and deferral accounts included amounts for the Rate Smoothing Deferral Account. This account is no longer included in the other variance and deferral accounts as of March 31, 2018.

In January 2018, the OEB approved the establishment of a new Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account, effective January 1, 2018 on an interim basis. The purpose of the account is to record the revenue requirement impact of changes to nuclear liabilities and depreciation and amortization expense resulting from changes to station end-of-life dates for OPG's Pickering prescribed nuclear facilities effective December 31, 2017. As of March 31, 2018, OPG recognized a regulatory liability of $31 million related to the balance in the deferral account.

As at March 31, 2018, regulatory liabilities for other variance and deferral accounts also included amounts for the Impact Resulting from Changes to Pickering End-of-Life Dates (December 31, 2017) Deferral Account.

5. LONG-TERM DEBT AND NET INTEREST EXPENSE

Long-term debt consists of the following:

(millions of dollars)	**March 31 2018**	**December 31 2017**
Senior notes payable to the Ontario Electricity Financial Corporation	**3,520**	3,195
Medium Term Note	**500**	500
UMH Energy Partnership project debt	**181**	181
PSS Generating Station Limited Partnership project debt	**245**	245
Lower Mattagami Energy Limited Partnership project debt	**1,595**	1,595
Fair Hydro Trust senior debt	**836**	601
Other	**19**	19
	6,896	6,336
Less: unamortized bond issuance fees	**(20)**	(17)
Less: amounts due within one year	**(263)**	(398)
Long-term debt	**6,613**	5,921

In the first quarter of 2018, OPG issued a total of $600 million senior notes payable to the OEFC maturing in 2048. The effective and coupon interest rates on these notes ranged from 3.87 percent to 4.00 percent.

In December 2017, the Fair Hydro Trust entered into an $800 million two-year revolving warehouse facility agreement with an expiry date of December 2019. In February 2018, the Fair Hydro Trust issued $500 million of senior notes payable with a coupon interest rate of 3.36 percent and an effective interest rate of 3.44 percent, payable semi-annually until maturity in May 2033. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility.

In March 2018, the Trust purchased an Investment Interest from the IESO in the amount of $460 million. Fifty-one percent of the funding requirement or approximately $235 million was financed by the Trust through the revolving warehouse facility ranked as senior notes, and the remaining 49 percent was funded through the issuance of short-term subordinated debt to OPG. The outstanding balance of the revolving warehouse credit facility of $336 million has been classified as long-term debt as at March 31, 2018 reflecting the contractual terms of the facility agreement.

In April 2018, the Trust issued $400 million of senior notes payable with a coupon interest rate of 3.52 percent and an effective interest rate of 3.60 percent, payable semi-annually until maturity in May 2038. The proceeds were used to repay the majority of the balance of the revolving warehouse facility outstanding after the April 2018 Investment Interest acquisition from the IESO of the $149 million, of which $76 million was funded through this facility.

The following table summarizes the net interest expense for the three months period ended March 31 :

(millions of dollars)	**2018**	**2017**
Interest on long-term debt [1]	**70**	70
Interest income	**(1)**	-
Interest capitalized to property, plant and equipment and intangible assets	**(44)**	(42)
Interest related to regulatory assets and liabilities [2]	**(6)**	(9)
Net interest expense	**19**	19

[1] Excludes interest on Fair Hydro Trust senior debt and interest costs on debt issued by OPG to fund its purchase of the Trust's subordinated debt, which have been included in the Earnings from Fair Hydro Trust line in the interim consolidated statements of income. Refer to Note 15 for interest expense incurred on the Trust's senior debt and on debt issued by OPG to fund its purchase of the Trust's subordinated debt. .

[2] Includes interest to recognize the cost of financing related to regulatory accounts, as authorized by the OEB, and interest deferred in the Bruce Lease Net Revenues Variance Account, the Capacity Refurbishment Variance Account, and the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account.

6. SHORT-TERM DEBT

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. During 2017, OPG renewed and extended the expiry date of both tranches to May 2022. There were no amounts outstanding under the bank credit facility. There was $100 million of commercial paper outstanding under OPG's commercial paper program as at March 31, 2018 (December 31, 2017 – $100 million). The commercial paper program is used to provide short-term funding for the Company, at interest rates of approximately one percent and for less than one year in duration.

As at March 31, 2018, Lower Mattagami Energy Limited Partnership (LME) maintained a $400 million bank credit facility to support the funding requirements for the Lower Mattagami River project including support for LME's commercial paper program. The facility consists of a $300 million tranche maturing in August 2022 and a $100 million tranche maturing in August 2018. As at March 31, 2018, there was $160 million of commercial paper outstanding under LME's commercial paper program (December 31, 2017 − $160 million). A letter of credit of $55 million was issued in July 2017 and remains outstanding as at March 31, 2018 under the first tranche of LME's credit facility.

As at March 31, 2018, OPG maintained $25 million of short-term, uncommitted overdraft facilities and $464 million of short-term, uncommitted credit facilities, which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other general corporate purposes. As at March 31, 2018, a total of $390 million of Letters of Credit had been issued under these facilities. This included $353 million for the supplementary pension plans, $36 million for general corporate purposes, and $1 million related to the operation of the Portland Energy Centre (PEC).

The Company's short-term, uncommitted credit facilities include an agreement to sell an undivided co-ownership interest in its current and future accounts receivable to an independent trust. The maximum amount of co-ownership interest that can be sold under this agreement is $150 million, expiring on November 30, 2018. As at March 31, 2018, there were Letters of Credit outstanding under this agreement of $150 million, which were issued in support of OPG's supplementary pension plans.

UMH Energy Partnership has entered into an $8 million short-term, uncommitted overdraft facility and $16 million of irrevocable, standby Letters of Credit facilities in support of its operations. As at March 31, 2018, total Letters of Credit of $15 million had been issued under these facilities.

7. FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT LIABILITIES

The liabilities for fixed asset removal and nuclear waste management on a present value basis as at March 31, 2018 and December 31, 2017 consist of the following:

(millions of dollars)	**March 31 2018**	**December 31 2017**
Liability for nuclear used fuel management	**12,112**	11,970
Liability for nuclear decommissioning and nuclear low and intermediate level waste management	**8,185**	8,107
Liability for non-nuclear fixed asset removal	**342**	344
Fixed asset removal and nuclear waste management liabilities	**20,639**	20,421

8. ACCUMULATED OTHER COMPREHENSIVE LOSS

The changes in the balance of each component of accumulated other comprehensive loss (AOCL), net of income taxes, are as follows:

	Three Months Ended March 31, 2018			
(millions of dollars)	**Unrealized Gains and Losses on Cash Flow Hedges**	**Pension and OPEB**	**Available-for-sale securities**	**Total**
AOCL, beginning of period	**(66)**	**(220)**	**(9)**	**(295)**
Reclassification of cumulative unrealized losses on available-for-sale securities to opening retained earnings *(Note 2)*	**-**	**-**	**9**	**9**
	(66)	**(220)**	**-**	**(286)**
Amounts reclassified from AOCL	**4**	**3**	**-**	**7**
Other comprehensive income for the period	**4**	**3**	**-**	**7**
AOCL, end of period	**(62)**	**(217)**	**-**	**(279)**

	Three Months Ended March 31, 2017			
(millions of dollars)	**Unrealized Gains and Losses on Cash Flow Hedges**	**Pension and OPEB**	**Available-for-sale securities**	**Total**
AOCL, beginning of period	(87)	(207)	(1)	(295)
Unrealized loss on available-for-sale securities	-	-	5	5
Amounts reclassified from AOCL	4	3	-	7
Other comprehensive income for the period	4	3	5	12
AOCL, end of period	(83)	(204)	4	(283)

The significant amounts reclassified out of each component of AOCL, net of income taxes, during the three months ended March 31, 2018 and 2017 are as follows:

	Amount Reclassified from AOCL		
(millions of dollars)	**2018**	**2017**	**Statement of Income Line Item**
Amortization of losses from cash flow hedges			
Losses	**5**	5	Net interest expense
Income tax recovery	**(1)**	(1)	Income tax expense
	4	4	
Amortization of amounts related to pension and OPEB			
Actuarial losses	**4**	4	See (1) below
Income tax recovery	**(1)**	(1)	Income tax expense
	3	3	
Total reclassifications for the period	**7**	7	

[1] These AOCL components are included in the computation of pension and OPEB costs (see Note 9 for additional details).

9. PENSION AND OTHER POST-EMPLOYMENT BENEFITS

OPG's pension and OPEB costs for the three months ended March 31, 2018 and 2017 are as follows:

(millions of dollars)	Registered Pension Plans 2018	Registered Pension Plans 2017	Supplementary Pension Plans 2018	Supplementary Pension Plans 2017	Other Post-Employment Benefits 2018	Other Post-Employment Benefits 2017
Components of Cost Recognized for the period						
Current service costs	**83**	68	**2**	1	**20**	17
Interest on projected benefit obligation	**142**	137	**3**	3	**26**	27
Expected return on plan assets, net of expenses	**(205)**	(191)	**-**	-	**-**	-
Amortization of net actuarial loss [1]	**49**	46	**2**	2	**2**	-
Costs recognized [2]	**69**	60	**7**	6	**48**	44

[1] The amortization of net actuarial loss is recognized as an increase to other comprehensive income. This increase for the three months ended March 31, 2018 was partially offset by a decrease in the Pension and OPEB Regulatory Asset of $49 million (three months ended March 31, 2017 − $44 million).

[2] These pension and OPEB costs for the three months ended March 31, 2018 exclude the net reduction of costs of $25 million from the recognition of changes in the regulatory assets for the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB Cash Payment Variance Account (three months ended March 31, 2017 − net addition of costs of $3 million).

10. RISK MANAGEMENT AND DERIVATIVES

OPG is exposed to risks related to changes in market interest rates on debt expected to be issued in the future and movements in foreign currency that affect the Company's assets, liabilities, and forecasted transactions. Select derivative instruments are used to manage such risks. Derivatives are used as hedging instruments, as well as for trading purposes.

Interest rate risk is the risk that the value of assets and liabilities can change due to movements in related interest rates. Interest rate risk for OPG arises with the need to refinance existing debt and/or undertake new financing. The management of these risks includes using derivatives to hedge the exposure in accordance with corporate risk management policies. OPG periodically uses interest rate swap agreements to mitigate elements of interest rate risk exposure associated with anticipated financing.

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are denominated in, or tied to, US dollars. OPG enters into foreign exchange derivatives and agreements with major financial institutions, when appropriate, in order to manage the Company's exposure to foreign currency movements.

The majority of OPG's revenues are derived from sales through the IESO administered spot market. Market participants in the IESO spot market provide collateral in accordance with the IESO prudential support requirements to cover funds that they might owe to the market. Although the credit exposure to the IESO represents a significant portion of OPG's accounts receivable, the Company's management accepts this risk due to the IESO's primary role in the Ontario electricity market. OPG's electricity related accounts receivable from the IESO constituted of $436 million as at March 31, 2018 (December 31, 2017 − $354 million). The remaining receivables exposure is to a diverse group of generally high quality counterparties. OPG's allowance for doubtful accounts as at March 31, 2018 was less than $1 million.

The fair value of the outstanding derivatives totalled a net liability of $14 million as at March 31, 2018 (December 31, 2017 − $20 million).

Existing pre-tax net losses of $19 million deferred in AOCL as at March 31, 2018 are expected to be reclassified to net income within the next 12 months.

11. FAIR VALUE MEASUREMENTS

The fair value of financial instruments traded in active markets is based on quoted market prices as at the interim consolidated balance sheet dates. A market is regarded as active if quoted prices are readily and regularly available from an exchange, dealer, broker, industry group, pricing service, or regulatory agency, and those prices represent actual and regularly occurring market transactions on an arm's-length basis. The quoted market price used for financial assets held by OPG is the current bid price. These instruments are included in Level 1 and are comprised primarily of equity investments and fund investments. The fair value hierarchy groups financial instruments into three levels, based on the significance of inputs used in measuring the fair value of the assets and liabilities.

For financial instruments for which quoted market prices are not directly available, fair values are estimated using forward price curves developed from observable market prices or rates. The estimation of fair value may include the use of valuation techniques or models, based wherever possible on assumptions supported by observable market prices or rates prevailing as at the interim consolidated balance sheet dates. This is the case for over-the-counter derivatives and securities, which include energy commodity derivatives, foreign exchange derivatives, interest rate swap derivatives, and fund investments. Pooled fund investments are valued at the unit values supplied by the pooled fund administrators. The unit values represent the underlying net assets at fair values, determined using closing market prices. Valuation models use general assumptions and market data and therefore do not reflect the specific risks and other factors that would affect a particular instrument's fair value. The methodologies used for calculating the fair value adjustments are reviewed on an ongoing basis to ensure that they remain appropriate. If all significant inputs required to fair value an instrument are observable, the instrument is included in Level 2.

The following is a summary of OPG's financial instruments and their fair value as at March 31, 2018 and December 31, 2017:

	Fair Value		Carrying Value [1]		
(millions of dollars)	**2018**	**2017**	**2018**	**2017**	**Balance Sheet Line Item**
Nuclear Segregated Funds (includes current portion) [2]	**16,909**	16,724	**16,909**	16,724	Nuclear fixed asset removal and nuclear waste management funds
Financing receivables	**1,655**	1,179	**1,639**	1,179	Financing receivables
Investment in Hydro One shares	**170**	188	**170**	188	Equity securities
Payable related to cash flow hedges	**(38)**	(40)	**(38)**	(40)	Long-term accounts payable and accrued charges
Long-term debt – OPG (includes current portion)	**(6,539)**	(6,234)	**(6,060)**	(5,735)	Long-term debt
Long-term debt – Fair Hydro Trust	**(847)**	(601)	**(836)**	(601)	Long-term debt
Other financial instruments	**(5)**	(16)	**(5)**	(16)	Various

[1] The carrying values of other financial instruments included in cash, cash equivalents and restricted cash, receivables from related parties, other current assets, short-term debt, and accounts payable and accrued charges approximate their fair values due to the immediate or short-term maturity of these financial instruments.

[2] The Nuclear Segregated Funds are comprised of the Decommissioning Segregated Fund and the Used Fuel Segregated Fund. OPG's fair value of the Nuclear Segregated Funds is set not to exceed an amount equal to the funding liability pursuant to the ONFA when the Nuclear Segregated Funds are in a surplus position.

The fair value of the Fair Hydro Trust senior warehouse facility debt, long-term senior debt, and OPG's long-term debt issued under the Medium Term Note Program are based on indicative pricing from the market. The fair value of these debt instruments would be considered Level 3 in the fair value hierarchy. All other long-term debt instruments are determined based on a conventional pricing model, which is a function of future cash flows, the current market yield curve and term to maturity. These inputs are considered Level 2 inputs.

For the financing receivables related to the Investment Interest acquired from the IESO, fair value is estimated to equal the fair value of the underlying long-term debt due to the direct relationship between the asset and the debt instruments that financed the acquisition. The financing receivables are funded by both long-term senior debt issued by the Fair Hydro Trust to third parties and subordinated debt issued by the Trust to OPG, which is eliminated on consolidation. Both sources of funding are considered Level 3 inputs. Therefore, the fair value of the financing receivables would be considered Level 3 in the fair value hierarchy.

If one or more of the significant inputs is not based on observable market data, the instrument is included in Level 3. Specific valuation techniques are used to value these instruments. Significant Level 3 inputs include: recent comparable transactions, comparable benchmark information, bid/ask spread of similar transactions, and other relevant factors.

Certain alternative investments are measured at fair value by their investment managers using net asset value (NAV). Investments measured at NAV as a practical expedient for determining their fair value are excluded from the fair value hierarchy.

Transfers into, out of, or between levels are deemed to have occurred on the date of the event or change in circumstances that caused the transfer to occur.

The following tables present financial assets and financial liabilities measured at fair value in accordance with the fair value hierarchy as at March 31, 2018 and December 31, 2017:

	March 31, 2018			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Used Fuel Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	**6,096**	**4,693**	**-**	**10,789**
Investments measured at NAV [1]				**1,378**
				12,167
Due to Province				**(2,508)**
Used Fuel Segregated Fund, net				**9,659**
Decommissioning Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	**4,567**	**3,482**	**-**	**8,049**
Investments measured at NAV [1]				**1,132**
				9,181
Due to Province				**(1,931)**
Decommissioning Segregated Fund, net				**7,250**
Investment in equity securities	**170**	**-**	**-**	**170**
Other financial assets	**5**	**-**	**10**	**15**
Liabilities				
Other financial liabilities	**(20)**	**-**	**-**	**(20)**

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to amounts presented on the interim consolidated balance sheets.

(millions of dollars)	December 31, 2017 Level 1	Level 2	Level 3	Total
Assets				
Used Fuel Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	6,090	4,705	-	10,795
Investments measured at NAV [1]				1,292
				12,087
Due to Province				(2,529)
Used Fuel Segregated Fund, net				9,558
Decommissioning Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	4,547	3,487	-	8,034
Investments measured at NAV [1]				1,065
				9,099
Due to Province				(1,933)
Decommissioning Segregated Fund, net				7,166
Investments in available-for-sale securities	188	-	-	188
Other financial assets	5	3	6	14
Liabilities				
Other financial liabilities	(28)	(2)	-	(30)

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to amounts presented on the interim consolidated balance sheets.

During the period ended March 31, 2018, there were no transfers between Level 1 and Level 2. In addition, there were no transfers into or out of Level 3.

The following table presents the changes in OPG's net assets measured at fair value that are classified as Level 3 financial instruments.

(millions of dollars)	Other financial instruments
Opening balance, January 1, 2018	**6**
Realized losses included in revenue	**(5)**
Purchases	**9**
Closing balance, March 31, 2018	**10**

Nuclear Segregated Funds

The fair value of the investments within the Nuclear Segregated Funds' real assets portfolio is determined using appropriate valuation techniques, such as recent arm's-length market transactions, references to current fair values of other instruments that are substantially the same, discounted cash flow analyses, third-party independent appraisals, valuation multiples, or other valuation methods. Any control, size, liquidity or other discount premiums on the investments are considered in the determination of fair value.

The process of valuing investments for which no published market price exists is based on inherent uncertainties and the resulting values may differ from values that would have been used had a ready market existed for these investments. The values may also differ from the prices at which the investments may be sold.

The following are the classes of investments within the Nuclear Segregated Funds that are reported on the basis of NAV as at March 31, 2018:

(millions of dollars except where noted)	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice
Real Assets				
Infrastructure	**1,412**	**805**	**n/a**	**n/a**
Real Estate	**994**	**487**	**n/a**	**n/a**
Agriculture	**104**	**91**	**n/a**	**n/a**
Pooled Funds				
Short-term Investments	**33**	**n/a**	**Daily**	**1-5 days**
Fixed Income	**461**	**n/a**	**Daily**	**1-5 days**
Equity	**972**	**n/a**	**Daily**	**1-5 days**
Total	**3,976**	**1,383**		

The fair value of the pooled funds is classified as Level 2. Infrastructure, real estate and agriculture investments are measured using NAV as a practical expedient for determining their fair value.

Infrastructure

This asset class includes investments in funds and assets with an objective to generate a combination of long-term capital appreciation and current income, generally through private investments in sectors such as energy, transportation, communication and utilities. The fair values of investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in these investments. The investments in the respective funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests/shares to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Distributions from each infrastructure fund will be received based on the operations of the underlying investments and/or as the underlying investments are liquidated. It is not possible to estimate when the underlying assets in this asset class will be liquidated.

Real Estate

This asset class includes investments in funds and assets with an objective to generate a combination of long-term capital appreciation and current income, generally through investments in institutional-grade real estate property. The fair values of the investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in these investments. The investments in the respective funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Distributions from each real estate fund will be received based on the operations of the underlying investments and/or as the underlying investments are liquidated. For investments in private real estate corporations, shares may be redeemed through a pre-established redemption process. It is not possible to estimate when the underlying assets in this asset class will be liquidated.

Agriculture

This asset class includes investments in funds and assets with an objective to provide a differentiated return source, income yield, and inflation protection, generally through private investments in global farmland and timberland. The fair values of the investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in these investments. The investments in the respective funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests/shares to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Distributions from each agriculture fund will be received based on the operations of the underlying investments and/or as the underlying investments are liquidated. It is not possible to estimate when the underlying assets in this asset class will be liquidated.

Pooled Funds

This asset class represents investments in pooled funds, which primarily include a diversified portfolio of fixed income securities, issued mainly by Canadian corporations, and diversified portfolios of Emerging Market listed equity. The investment objective of the pooled funds is to achieve capital appreciation and income through professionally managed portfolios. The fair value of the investments in this class has been estimated using NAV per share of the investments. There are no significant restrictions on the ability to sell the investments in this class.

12. SHARE CAPITAL

Common Shares

As at March 31, 2018 and December 31, 2017, OPG had 256,300,010 common shares issued and outstanding at a stated value of $5,126 million. OPG is authorized to issue an unlimited number of common shares without nominal or par value. Any issue of new shares is subject to the consent of OPG's shareholder, the Province.

Class A Shares

The Company's Articles of Amalgamation were amended effective December 1, 2017 to allow for the creation and issuance of non-voting Class A shares to the Province in exchange for equity injections in OPG. All of the outstanding shares are owned directly by the Province and OPG is authorized to issue an unlimited number of Class A shares without nominal or par value. The Class A and common shares rank equally as to entitlement to dividends, and all dividends declared by OPG must be declared in equal amounts per share on all outstanding shares without preference or distinction. Upon the liquidation, dissolution or wind-up of OPG, whether voluntary or involuntary, the holders of Class A shares and common shares are entitled to share equally, on a share for share basis, in all distributions of property and assets without preference or distinction. Any issue of new class of shares is subject to the consent of the Province. OPG is entitled to redeem outstanding Class A shares as may be approved by OPG's Board of Directors.

In March 2018 and December 2017, OPG issued 4,627,343 Class A shares at a price of $43.74 per share and 12,217,616 Class A shares at a price of $42.46 per share to the Province for its equity injections in OPG, generating proceeds of $202 million and $519 million, respectively. The proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt representing 44 percent of the total funding requirements for the Trust's acquisitions of Investment Interests from the IESO in March 2018 and December 2017 of $460 million and $1.18 billion, respectively.

As at March 31, 2018, OPG had 16,844,959 Class A shares issued and outstanding at a stated value of $721 million. (December 31, 2017 − 12,217,616 Class A shares issued and outstanding at a stated value of $519 million).

In April 2018, OPG issued 1,498,856 Class A shares at a price of $43.74 per share to the Province for its equity injection in OPG, generating proceeds of $66 million. The proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt representing 44 percent of the total funding requirements for the Trust's acquisition of Investment Interest from the IESO in April 2018 of $149 million.

13. EARNINGS PER SHARE

Basic and diluted earnings per share are calculated by dividing net income attributable to the Shareholder by the weighted average number of shares outstanding.

Class A shares are included in the weighted average number of shares outstanding. The weighted average number of shares outstanding as at March 31, 2018 was 269 million (year ended December 31, 2017 – 256.7 million). There were no dilutive securities as at March 31, 2018 and December 31, 2017.

14. COMMITMENTS AND CONTINGENCIES

Litigation

On August 9, 2006, a Notice of Action and Statement of Claim filed with the Ontario Superior Court of Justice in the amount of $500 million was served against OPG and Bruce Power L.P. (Bruce Power) by British Energy Limited and British Energy International Holdings Limited (together British Energy). The action is for contribution and indemnity of any amounts British Energy was liable for in an arbitration against it by some of the owners of Bruce Power regarding an alleged breach of British Energy's representations and warranties to the claimants when they purchased British Energy's interest in Bruce Power (the Arbitration). Both the action and the Arbitration relate to corrosion to a steam generator unit discovered after OPG leased the Bruce nuclear generating stations to Bruce Power.

In 2012, the arbitrator found that British Energy was liable to the claimants for some of the damages they claimed. The final settlement amount was valued by British Energy at $71 million. In September 2014, British Energy amended its Statement of Claim (Amended Claim) to reduce the claim amount to $100 million to reflect that the purchasers of British Energy's interest in Bruce Power did not receive the full damages they originally claimed in the Arbitration. British Energy also added an allegation to its Amended Claim that OPG breached a covenant to maintain the steam generator between the time of the initial agreement to lease and the effective date of the lease in accordance with "Good Utility Practices".

In November 2016, British Energy obtained consent from the Ontario Superior Court of Justice to a timetable for the remaining steps in the litigation, pursuant to which the matter must be set down for trial by December 31, 2018. OPG has delivered a statement of defence in accordance with an extension of the original June 30, 2017 delivery deadline set up in the timetable. [**MONITOR**]

Various other legal proceedings are pending against OPG or its subsidiaries covering a wide range of matters that arise in the ordinary course of business activities.

Each of these matters is subject to various uncertainties. Some of these matters may be resolved unfavourably. While it is not possible to determine the ultimate outcome of the various pending actions, it is the Company's belief that their resolution is not likely to have a material adverse impact on its financial position.

Guarantees

The Company and its joint venture partners have jointly guaranteed the financial performance of jointly owned entities related primarily to the payment of liabilities. As at March 31, 2018, the total amount of guarantees OPG provided to these entities was $83 million (December 31, 2017 − $82 million). OPG may terminate some of these guarantees within a short time frame by providing written notice to the counterparties at any time. Other guarantees have terms ending between 2019 and 2029. As at March 31, 2018, the potential impact of the fair value of these guarantees to income has been estimated to be negligible and OPG does not expect to make any payments associated with these guarantees.

Contractual Obligations

OPG's contractual obligations as at March 31, 2018 are as follows:

(millions of dollars)	**2018** [1]	**2019**	**2020**	**2021**	**2022**	**Thereafter**	**Total**
Fuel supply agreements	141	125	115	88	68	67	604
Contributions to the OPG registered pension plan [2]	161	219	-	-	-	-	380
OPG long-term debt repayment	123	368	663	413	172	4,321	6,060
Interest on OPG long-term debt	189	249	227	199	185	3,612	4,661
Fair Hydro Trust senior debt repayment [3]	-	336	-	-	-	500	836
Interest on Fair Hydro Trust senior debt	6	25	17	17	17	177	259
Commitments related to Darlington Refurbishment project [4]	450	-	-	-	-	-	450
Commitments related to Ranney Falls GS project	22	4	-	-	-	-	26
Operating licences	30	41	24	28	28	87	238
Operating lease obligations	21	25	24	22	22	79	193
Unconditional purchase obligations	41	54	52	4	-	-	151
Accounts payable and accrued charges	859	8	-	-	-	260	1,127
Other	69	33	7	1	1	63	174
Total	2,112	1,487	1,129	772	493	9,166	15,159

[1] Represents amounts for the remainder of the year.

[2] The pension contributions include ongoing funding requirements and additional funding requirements towards the deficit, in accordance with the actuarial valuation of the OPG registered pension plan as at January 1, 2017. The next actuarial valuation of the OPG registered pension plan must have an effective date no later than January 1, 2020. The pension contributions are affected by various factors including market performance, changes in actuarial assumptions, plan experience, changes in the pension regulatory environment, and the timing of funding valuations. Funding requirements after 2019 are excluded due to significant variability in the assumptions required to project the timing of future cash flows. The amount of OPG's additional voluntary contribution, if any, is revisited from time to time.

[3] The repayment of Fair Hydro Trust senior notes includes an outstanding balance of $336 million issued under an $800 million revolving warehouse facility expiring in December 2019 and $500 million of 15-year senior notes due in May 2033.

[4] Represents estimated currently committed costs to close the project, including accruals for completed work, demobilization of project staff and cancellation of existing contracts and material orders.

Contractual and commercial commitments as noted exclude certain purchase orders, as they represent purchase authorizations rather than legally binding contracts, and are subject to change without significant penalties.

15. BUSINESS SEGMENTS

Segment Income (Loss) for the Three Months Ended March 31, 2018 *(millions of dollars)*	Regulated		Unregulated					
	Nuclear Generation	Nuclear Waste Management	Hydro-Electric	Contracted Generation Portfolio	Fair Hydro Trust	Other	Elimination	Total
Revenue from contracts with customers	871	-	356	149	-	10	-	1,386
Leasing revenue	9	-	-	-	-	4	-	13
Other revenue	-	33	-	-	-	7	(32)	8
Total revenue	880	33	356	149	-	21	(32)	1,407
Fuel expense	73	-	65	17	-	-	-	155
Gross margin	807	33	291	132	-	21	(32)	1,252
Operations, maintenance and administration	604	33	80	41	-	(4)	(32)	722
Depreciation and amortization	121	-	36	20	-	9	-	186
Accretion on fixed asset removal and nuclear waste management liabilities	-	243	-	2	-	2	-	247
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(210)	-	-	-	-	-	(210)
Earnings from Fair Hydro Trust	-	-	-	-	(4)	-	-	(4)
Income from investments subject to significant influence	-	-	-	(10)	-	-	-	(10)
Property taxes	7	-	-	1	-	1	-	9
Other losses (gains)	-	-	4	-	-	(263)	-	(259)
Income (loss) before interest and income taxes	75	(33)	171	78	4	276	-	571
Net interest expense								19
Income before income taxes								552
Income tax expense								13
Net income								539

Segment (Loss) Income for the Three Months Ended March 31, 2017 *(millions of dollars)*	Nuclear Generation	Regulated Nuclear Waste Management	Hydroelectric	Unregulated Contracted Generation Portfolio	Other	Elimination	Total
Revenue from contracts with customers	643	-	363	143	2	-	1,151
Leasing revenue	9	-	-	-	14	-	23
Other revenue	-	27	-	-	1	(26)	2
Total revenue	652	27	363	143	17	(26)	1,176
Fuel expense	68	-	73	14	-	-	155
Gross margin	584	27	290	129	17	(26)	1,021
Operations, maintenance and administration	589	29	76	39	1	(26)	708
Depreciation and amortization	107	-	34	19	7	-	167
Accretion on fixed asset removal and nuclear waste management liabilities	-	234	-	2	2	-	238
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(189)	-	-	-	-	(189)
Income from investments subject to significant influence	-	-	-	(10)	-	-	(10)
Property taxes	6	-	-	2	3	-	11
Other gains	-	-	-	-	(3)	-	(3)
(Loss) income before interest and income taxes	(118)	(47)	180	77	7	-	99
Net interest expense							19
Income before income taxes							80
Income tax expense							12
Net income							68

The earnings from Fair Hydro Trust are comprised of the following for the three months period ended March 31:

(millions of dollars)	2018	2017
Revenue	**(1)**	-
Operating expenses	**1**	-
Interest income	**(10)**	-
Interest expense	**6**	-
Earnings from Fair Hydro Trust	**(4)**	-

In December 2017, the Fair Hydro Trust was established as a separate entity to be the financing entity contemplated by the Fair Hydro Act. The majority unitholder and beneficiary of the Trust is a wholly owned subsidiary of OPG, and the Trust's financial position and results are consolidated into OPG's financial results. As a legal matter, the assets and liabilities of the Trust do not form part of the assets and liabilities of OPG, and vice versa, pursuant to section 53.1(1.4) of the *Electricity Act, 1998 (Ontario).*

16. NET CHANGES IN NON-CASH WORKING CAPITAL BALANCES

	Three Months Ended March 31	
(millions of dollars)	**2018**	**2017**
Receivables from related parties	**(83)**	67
Fuel inventory	**10**	13
Materials and supplies	**12**	9
Prepaid expenses	**(2)**	(10)
Other current assets [1]	**44**	34
Income taxes payable	**(90)**	(117)
Accounts payable and accrued charges	**(45)**	(113)
	(154)	(117)

[1] Represents other accounts receivable.

17. PAYMENT OF DIVIDEND TO SHAREHOLDER

In April 2017, OPG completed the sale of its head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street in Toronto, Ontario. The sale was undertaken pursuant to a Shareholder Declaration and a Shareholder Resolution received by OPG in December 2015. Pursuant to the Shareholder Declaration and the Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014* (Trillium Trust Act), OPG was required to transfer the proceeds from this disposition, net of prescribed deductions under the Trillium Trust Act, into the Province's Consolidated Revenue Fund. In accordance with these requirements, a special dividend of $283 million was authorized by OPG's Board of Directors and transferred into the Consolidated Revenue Fund in March 2018.

18. SALE OF LAKEVIEW SITE

In March 2018, OPG completed the sale of its former Lakeview GS site property located in Mississauga, Ontario, with an after-tax gain on sale of $205 million recognized in net income in the first quarter of 2018. The sale was undertaken pursuant to a Shareholder Declaration and a Shareholder Resolution received by OPG in June 2016. Pursuant to the Shareholder Declaration and the Shareholder Resolution, and as prescribed in the Trillium Trust Act, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Trillium Trust Act, into the Province's Consolidated Revenue Fund. OPG expects that the amount of designated proceeds to be transferred into the Consolidated Revenue Fund will be largely consistent with the after-tax gain on sale, and is working with the Ontario Ministry of Finance to finalize the amount. **[MONITOR]** In accordance with the Shareholder Resolution, approximately 67 acres of the site will be transferred to the City of Mississauga by the purchaser, for parkland, institutional, and cultural uses.

19. INCOME TAXES

Income tax expense increased by $1 million in the first quarter of 2018 as compared to the same quarter in 2017, primarily due to higher income before income taxes, largely offset by a higher amount of deferred income tax expense recorded as a regulatory asset and a reduction of tax resulting from dividend distributions.

From:	HO Philip -FIN & C CTRL
To:	Ronald Kwan; John Kim; "Montgomery, Kaitlin (MOF)"
Cc:	MAK Ricky -FIN & C CTRL; DYKXHOORN Sandra -STAKEREL; GORE Michael -FIN & C CTRL
Subject:	OPG Q3 2017 Submission to Province
Date:	Wednesday, October 25, 2017 12:21:46 PM
Attachments:	Q3 2017 OPG Press Release_PROVINCE MAILING.docx Q3 2017 OPG MD&A - DRAFT - PROVINCE MAILING.docx Q3 2017 OPG FS Province MAILING.docx

Hi All,

Please find attached OPG's draft Q3 2017 Financial Results Press Release, Management's Discussion and Analysis (MD&A), and Financial Statements for the Province's review.

We would greatly appreciate comments on the above **no later than Monday, Oct 30th**.

These documents will be filed with the Ontario Securities Commission on **Thursday, November 9th** following OPG's Board of Directors meeting.

Kindly forward all comments directly to Philip Ho – philip.ho@opg.com.

To assist the review process, the following are the key items in the Q3 2017 MD&A:

Highlights	
Recent Developments	MD&A p.10-11
Darlington Refurbishment	MD&A p.13-15
Ontario's Fair Hydro Plan	MD&A p.10-11

Philip Ho, CPA, CA | Senior Manager, External Reporting & Accounting Policy | Ontario Power Generation
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ONTARIO POWER GENERATION

News
from Ontario Power Generation

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[DRAFT]

Nov. 9, 2017

OPG REPORTS 2017 THIRD QUARTER FINANCIAL RESULTS

Darlington Refurbishment Project Remains on Time and on Budget at One-Year Mark

Toronto: – Ontario Power Generation Inc. (OPG or Company) today reported net income attributable to the Shareholder of $131 million for the third quarter of 2017, compared to $194 million for the same period in 2016.

“The Company’s focus continues to be on ensuring the success of the Darlington Refurbishment Project. Just after the one year mark of work on Darlington’s Unit 2, Canada’s largest clean energy project remains on time and on budget,” said Jeff Lyash, OPG President and CEO. “This is a ten year mega-project that will extend the life of the Darlington nuclear plant by 30 years, boosting Ontario’s GDP by $90 billion and creating more than 14,000 new jobs per year over the station’s life.”

Lyash went on to say, “I am also pleased with the performance of our Pickering Nuclear plant, which has so far generated 2.1 terawatt hours of electricity more than last year. We are applying for a licence to extend the operation of the station until 2024. This will ensure a reliable, clean source of low cost power during the Darlington Refurbishment project and avoid 17 million tonnes of carbon emissions.”

“The successful performance of our assets is built around a strong safety culture. This quarter, the Canadian Nuclear Safety Commission has once again given Pickering and Darlington the highest possible safety ratings,” Lyash added. “Darlington has now achieved this rating for eight consecutive years and Pickering has achieved the highest possible safety rating for the second year in a row.”

“Additionally, OPG successfully completed its first public debt issuance in October, raising $500 million for our general corporate needs and to fund OPG's investment in Ontario’s Fair Hydro Plan,” said Lyash. “This will provide OPG with financial flexibility and further our ability to invest in our projects to the benefit of customers and stakeholders.”

The results for the third quarter continued to be impacted by the expected year-over-year decline in generation revenue, reflecting lower nuclear electricity generation due to the refurbishment outage for Unit 2 at the Darlington Generating Station (GS) without the resetting of base regulated prices, largely offset by higher generation from the Pickering GS and the regulated hydroelectric generating stations. The lower generation revenue was partially offset by lower operations, maintenance and administration (OM&A) expenses across all business segments.

OPG provides electricity at a price that is 40 per cent less than other generators and is the only electricity generator in Ontario that has its prices set through a public hearing process by the Ontario Energy Board (OEB). Earlier in 2017, OPG completed the public hearing process for its current application with the OEB that will set prices for the Company's nuclear and most of its hydroelectric generation for the next five years, with a proposed effective date of January 1, 2017. The OEB is expected to make a decision on the rate application prior to the end of the year. In the meantime, OPG is operating under base regulated prices that were set in 2014 and do not reflect this year's reduced nuclear electricity generation, which is primarily due to the Darlington Refurbishment. As in earlier quarters this year, the continuation of these prices has negatively affected revenue and net income in the third quarter of 2017. The outcome of the current rate application and the effective date of the new regulated prices are expected to affect OPG's revenue and net income for the fourth quarter of 2017.

Net income attributable to the Shareholder was $498 million for the nine months ended September 30, 2017, compared to $449 million for the same period in 2016. The sale of OPG's head office building and parking facility, and the associated one-time gain recorded in the second quarter of 2017, offset the year-to-date reduction in generation revenue and was the main driver of the increase in net income for the nine months ended September 30, 2017, compared to the same period in 2016.

Lower earnings on the nuclear fixed asset removal and nuclear waste management segregated funds of $52 million during the third quarter of 2017 and $41 million during the nine months ended September 30, 2017, compared to the corresponding periods in 2016, also contributed to the year-over-year change in net income.

Generation and Operating Performance

Electricity generated during the three months ended September 30, 2017 was 19.4 terawatt hours (TWh), compared to 19.5 TWh for the same quarter in 2016. Total electricity generated during the nine months ended September 30, 2017 decreased to 56.0 TWh from 59.9 TWh for the same period in 2016. The decrease in electricity generation reflected the expected lower generation from the Darlington GS and lower generation from the contracted plants. The quarter-over-quarter decrease was largely offset by higher generation from the Pickering GS, primarily due to fewer outage days, and higher hydroelectric generation from the regulated stations.

Regulated – Nuclear Generation Segment

Lower nuclear generation of 0.4 TWh and 4.0 TWh during the three and nine month periods ended September 30, 2017, was primarily due to the removal from service of Unit 2 at the Darlington GS for the duration of the unit's refurbishment that began in October 2016 and is expected to continue until early 2020. Offsetting the reduction in generation from the Darlington GS was an increase in generation of 0.9 TWh and 2.1 TWh from the strong performance of the Pickering GS during the three and nine month periods ended September 30, 2017, respectively.

For the three months ended September 30, 2017, the unit capability factor at the Darlington GS for operating units was 96.2 per cent, compared to 89.6 per cent for the same quarter in 2016. The increase is primarily due to a lower number of planned outage days during the third quarter of 2017. For the nine months ended September 30, 2017, the unit capability factor at the Darlington GS was 82.1 per cent,

compared to 87.6 per cent for the same period in 2016. The decrease was primarily a result of a higher number of planned outage days at the station in the first half of 2017, largely driven by constraints related to the transition of the station toward refurbishment.

At the Pickering GS, the unit capability factor increased to 88.7 per cent and 83.8 per cent for the three and nine month periods ended September 30, 2017, respectively, compared to 77.3 and 73.8 per cent for the same periods in 2016, primarily due to outage optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station in 2017.

Regulated – Hydroelectric Segment

Higher generation from the regulated hydroelectric stations of 0.4 TWh and 0.7 TWh during the three and nine month periods ended September 30, 2017, was due to higher water flows, primarily on the eastern Ontario river systems.

The availability of 87.6 per cent at these stations in the third quarter of 2017 was higher than 84.1 per cent for the same quarter in 2016, primarily due to a higher number of planned outages in 2016 as a result of the reservoir refurbishment of the Sir Adam Beck Pump generating station undertaken between April 2016 and February 2017. For the nine months ended September 30, 2017, the availability of the stations marginally decreased to 89.0 per cent, from 89.8 per cent for the same period in 2016. The marginal decrease in the availability was primarily due to a higher number of unplanned outage days at the Northwestern Ontario and Niagara region hydroelectric stations, partially offset by higher availability from the Sir Adam Beck Pump GS.

Contracted Generation Portfolio Segment

Lower generation from the Contracted Generation Portfolio 0.1 TWh and 0.6 TWh during the three and nine month periods ended September 30, 2017, was mainly due to lower generation from the segment's hydroelectric plants.

The availability of these hydroelectric stations for the three months ended September 30, 2017 was 66.1 per cent, compared to 68.2 per cent for the same quarter in 2017. The stations' availability for the nine months ended September 30, 2017 was 76.9 per cent, compared to 79.6 per cent for the same period in 2016. The decrease in the availability was primarily due to an increase in the number of planned outage days at the Lower Mattagami River hydroelectric generating stations.

Total Generating Cost

The Enterprise Total Generating Cost per megawatt hour (MWh) for the three months ended September 30, 2017 was $46.65, compared to $50.72 for the same quarter in 2016. The decrease was mainly due to lower OM&A expenses before the impact of regulatory variance and deferral accounts and higher hydroelectric generation adjusted for surplus baseload generation reflecting higher water flows. The Enterprise Total Generating Cost per MWh for the nine months ended September 30, 2017 was $47.77, compared to $46.74 for the same period in 2016. The increase was expected and mainly a result of lower electricity generation due to the Unit 2 refurbishment outage at the Darlington GS. The increase in Enterprise Total Generating Cost was largely offset

by lower OM&A expenses before the impact of regulatory variance and deferral accounts and higher hydroelectric generation adjusted for surplus baseload generation reflecting higher water flows.

If Unit 2 at the Darlington GS was not currently undergoing refurbishment and had continued to operate in a manner consistent with the performance of the remaining units at the Darlington GS, adjusted for generation constraints on these units related to the transition of the station toward refurbishment, the Enterprise Total Generating Cost would have been approximately $4 per MWh lower for the three and nine months ended September 30, 2017. This sensitivity was calculated using the estimated incremental electricity generation and associated fuel cost that are expected to have resulted in the absence of the refurbishment.

Generation Development

OPG is undertaking a number of generation development and life extension projects in support of Ontario's electricity planning initiatives. Significant developments during the third quarter of 2017 were as follows:

Darlington Refurbishment

The Darlington Refurbishment project is expected to extend the operating life of the four-unit Darlington GS by approximately 30 years. In October 2016, OPG commenced the refurbishment of the first unit, Unit 2, as part of the project. The de-fuelling and islanding of the reactor was completed in the first half of 2017. The Re-tube Tooling Platform for hosting the tooling for the removal, inspection, and installation activities and the setup of specialized tooling and equipment needed for the removal and replacement of the reactor components were completed in the third quarter of 2017. The disassembly of reactor components began in August 2017, with the removal of all 960 feeder tubes completed safely in September 2017. This was followed by the severing of pressure tubes, with the severing of bellows and the removal of end fittings expected to commence thereafter and through the end of 2017.

With the Re-tube Waste Processing Building becoming available for use in November 2017, 17 out of 18 pre-requisite projects in support of the refurbishment execution have been completed. The completion of the Heavy Water Storage and Drum Handling Facility, which has been delayed due to challenges with construction, will resume in the fourth quarter of 2017. The cost of the pre-requisite projects is included in the overall budget for the refurbishment of $12.8 billion.

The overall project continues to track on schedule and on budget. Unit 2 is scheduled to be returned to service, after a 40-month refurbishment outage, in the first quarter of 2020, at which time capital expenditures of approximately $4.8 billion are planned to be placed in service. This includes expenditures incurred during the definition and planning phase of the overall project. Life-to-date capital expenditures were approximately $4.1 billion as at September 30, 2017.

In addition to the execution of refurbishment activities for Unit 2, OPG is continuing planning activities for the refurbishment of the second unit, Unit 3, and is entering into associated commitments to procure major components that require long lead times. As of September 30, 2017, $70 million has been invested in planning activities related to the refurbishment of the second unit.

Ranney Falls Hydroelectric GS

During the third quarter of 2017, OPG continued construction work for a 10 MW single-unit powerhouse on the existing Ranney Falls GS site, as part of the Regulated – Hydroelectric segment. The new unit will replace an existing unit that reached its end of life in 2014. The existing forebay structure demolition has been completed and the upstream cofferdam has been constructed ahead of schedule. Construction continues on the expanded forebay, powerhouse and spillway. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget.

Nanticoke Solar Facility

The construction of a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands under a Large Renewable Procurement contract with the IESO, through Nanticoke Solar LP, a partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation, is planned to commence in the first quarter of 2018. During the third quarter of 2017, the partnership continued work to obtain approvals and permits required to enable the commencement of construction, and progressed procurement activities for equipment and for engineering and construction services. The facility is expected to be completed in the first quarter of 2019.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

(millions of dollars – except where noted)	Three Months Ended September 30 2017	2016	Nine Months Ended September 30 2017	2016
Revenue	**1,217**	1,400	**3,539**	4,265
Fuel expense	**185**	187	**518**	541
Gross margin	**1,032**	1,213	**3,021**	3,724
Operations, maintenance and administration	**635**	666	**2,054**	2,061
Depreciation and amortization	**178**	313	**517**	941
Accretion on fixed asset removal and nuclear waste management liabilities	**235**	232	**709**	696
Earnings on Nuclear Segregated Funds - (a reduction to expenses)	**(196)**	(248)	**(579)**	(620)
Income from investments subject to significant influence	**(11)**	(11)	**(29)**	(28)
Other net expenses (gains)	**11**	13	**(350)**	12
Income before interest and income taxes	**180**	248	**699**	662
Net interest expense	**21**	28	**56**	92
Income tax expense	**19**	22	**128**	109
Net income	**140**	198	**515**	461
Net income attributable to the Shareholder	**131**	194	**498**	449
Net income attributable to non-controlling interest [1]	**9**	4	**17**	12
Income before interest and income taxes				
Electricity generation business segments	**217**	238	**436**	736
Regulated – Nuclear Waste Management	**(36)**	18	**(123)**	(70)
Services, Trading, and Other Non-Generation	**(1)**	(8)	**386**	(4)
Total income before interest and income taxes	**180**	248	**699**	662
Cash flow				
Cash flow provided by operating activities	**485**	530	**698**	1,211
Electricity generation (TWh)				
Regulated – Nuclear Generation	**11.3**	11.7	**30.6**	34.6
Regulated – Hydroelectric	**7.3**	6.9	**23.5**	22.8
Contracted Generation Portfolio [2]	**0.8**	0.9	**1.9**	2.5
Total electricity generation	**19.4**	19.5	**56.0**	59.9
Nuclear unit capability factor (per cent) [3]				
Darlington Nuclear GS	**96.2**	89.6	**82.1**	87.6
Pickering Nuclear GS	**88.7**	77.3	**83.8**	73.8
Availability (per cent)				
Regulated – Hydroelectric	**87.6**	84.1	**89.0**	89.8
Contracted Generation Portfolio – hydroelectric stations	**66.1**	68.2	**76.9**	79.6
Equivalent forced outage rate				
Contracted Generation Portfolio – thermal stations	**2.6**	2.1	**6.0**	1.3
Enterprise Total Generating Cost per MWh ($/MWh) [4]	**46.65**	50.72	**47.77**	46.74
Return on Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI) for the twelve months ended September 30, 2017 and December 31, 2016 (%) [4]			**4.4**	4.2
Funds from Operations (FFO) Adjusted Interest Coverage for the twelve months ended September 30, 2017 and December 31, 2016 (times) [4]			**4.2**	5.1

[1] Relates to the 25 per cent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in the Lower Mattagami Limited Partnership, the 33 per cent interest of Coral Rapids Power Corporation, a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership, and the 10 per cent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP.

[2] Includes OPG's share of generation volume from its 50 per cent ownership interests in the Portlands Energy Centre and Brighton Beach GS.

[3] Nuclear unit capability factor excludes unit(s) during the period in which they are undergoing refurbishment. Unit 2 of the Darlington GS is excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

[4] Enterprise Total Generating Cost per MWh, ROE Excluding AOCI, and FFO Adjusted Interest Coverage are non-GAAP financial measures and do not have any standardized meaning prescribed by US GAAP. Additional information about the non-GAAP measures is provided in OPG's Management's Discussion and Analysis for the three and nine months ended September 30, 2017, in the sections *Highlights – FFO Adjusted Interest Coverage*, *Highlights – Return on Common Equity Excluding Accumulated Other Comprehensive Income*, and *Highlights – Enterprise Total Generating Cost per MWh*, as well as *Supplementary Non-GAAP Financial Measures.*

Ontario Power Generation Inc. is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. Our mission is providing low cost power in a safe, clean, reliable and sustainable manner for the benefit of our customers and shareholder.

Ontario Power Generation Inc.'s unaudited interim consolidated financial statements and Management's Discussion and Analysis as at and for the three and nine month periods ended September 30, 2017 can be accessed on OPG's web site (www.opg.com), the Canadian Securities Administrators' web site (www.sedar.com), or can be requested from the Company.

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ONTARIO POWER GENERATION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

2017 THIRD QUARTER REPORT

[DRAFT]

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ONTARIO POWER GENERATION

ONTARIO POWER GENERATION INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) should be read in conjunction with the unaudited interim consolidated financial statements and accompanying notes of Ontario Power Generation Inc. (OPG or Company) as at and for the three and nine months ended September 30, 2017. OPG's unaudited interim consolidated financial statements are prepared in accordance with United States generally accepted accounting principles (US GAAP) and are presented in Canadian dollars.

For a complete description of OPG's corporate strategies, risk management, corporate governance, and the effect of critical accounting policies and estimates on OPG's results of operations and financial condition, this MD&A should also be read in conjunction with OPG's audited consolidated financial statements, accompanying notes, the Annual Information Form, and the MD&A as at and for the year ended December 31, 2016.

As required by *Ontario Regulation 395/11*, as amended, a regulation under the *Financial Administration Act* (Ontario), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. In 2014, the Ontario Securities Commission approved an exemption which allows OPG to apply US GAAP up to January 1, 2019. The term of the exemption is subject to certain conditions, which may result in the expiry of the exemption prior to January 1, 2019. For details, refer to the section, *Critical Accounting Policies and Estimates* under the heading, *Exemptive Relief for Reporting under US GAAP,* in OPG's 2016 annual MD&A. This MD&A is dated November 9, 2017.

FORWARD-LOOKING STATEMENTS

The MD&A contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could", and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

All forward-looking statements involve inherent assumptions, risks, and uncertainties, including those set out in the section, *Risk Management,* and forecasts discussed in the section, *Core Business, Strategy, and Outlook.* All forward-looking statements could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's generating station performance and availability, fuel costs, surplus baseload generation (SBG), cost of fixed asset removal and nuclear waste management, performance and earnings of investment funds, refurbishment of existing facilities, development and construction of new facilities, pension and other post-employment benefit (OPEB) obligations and funds, income taxes, proposed new legislation, the ongoing evolution of Ontario's electricity industry, environmental and other regulatory requirements, health, safety and environmental developments, business continuity events, the weather, financing and liquidity, applications to the Ontario Energy Board (OEB) for regulatory prices, the impact of regulatory decisions by the OEB, and forecasts of earnings, cash flows, Funds from Operations (FFO) Adjusted Interest Coverage, Return on Common Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI), Total Generating Cost (TGC) and capital expenditures. Accordingly, undue reliance should not be placed on any forward-looking statement. The forward-looking statements included in this MD&A are made only as of the date of this MD&A. Except as required by applicable securities laws, OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events, or otherwise.

THE COMPANY

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG was established under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (Province or Shareholder).

As at September 30, 2017, OPG's electricity generation portfolio had an in-service capacity of 16,210 megawatts (MW). OPG operates two nuclear generating stations, 66 hydroelectric generating stations, three thermal generating stations, and one wind power turbine. In addition, OPG and TransCanada Energy Ltd. co-own the 550 MW Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS). OPG and ATCO Power Canada Ltd. co-own the 560 MW Brighton Beach gas-fired combined cycle GS (Brighton Beach). OPG's 50 percent share of the in-service capacity and generation volume of these co-owned facilities is included in the generation portfolio statistics set out in this report. The income from the co-owned facilities is accounted for using the equity method of accounting, and OPG's share of income is presented as income from investments subject to significant influence in the Contracted Generation Portfolio segment.

OPG also owns two other nuclear generating stations, the Bruce A GS and the Bruce B GS, which are leased on a long-term basis to Bruce Power LP (Bruce Power). Income from these leased stations is included in revenue under the Regulated – Nuclear Generation segment. The leased stations are not included in the generation portfolio statistics set out in this report.

All of OPG's owned and co-owned generating facilities are located in Ontario. OPG does not operate PEC, Brighton Beach, the Bruce A GS and the Bruce B GS.

A description of OPG's segments is provided in OPG's 2016 annual MD&A in the section, *Business Segments*.

In-Service Generating Capacity

OPG's in-service generating capacity by business segment as at September 30, 2017 and December 31, 2016 was as follows:

(MW)	As at September 30 2017	December 31 2016
Regulated – Nuclear Generation [1]	**5,728**	5,728
Regulated – Hydroelectric	**6,426**	6,421
Contracted Generation Portfolio [2]	**4,056**	4,028
Total	**16,210**	16,177

[1] The in-service generating capacity as of September 30, 2017 and December 31, 2016 excludes Unit 2 of the Darlington GS. The unit, which has a generating capacity of 878 MW, was taken offline in mid-October 2016 and is currently undergoing refurbishment.

[2] Includes OPG's share of in-service generating capacity of 275 MW for PEC and 280 MW for Brighton Beach.

During the nine months ended September 30, 2017, the total in-service capacity increased by 33 MW. The increase was primarily due to the completion of the Peter Sutherland Sr. hydroelectric GS, which was placed in-service at the end of the first quarter of 2017, and the upgrade of Unit 10 of the Sir Adam Beck 1 hydroelectric GS, which was completed in June 2017.

HIGHLIGHTS

Overview of Results

This section provides an overview of OPG's unaudited interim consolidated operating results. Significant factors which contributed to OPG's results during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, are discussed below.

(millions of dollars – except where noted) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Revenue	**1,217**	1,400	**3,539**	4,265
Fuel expense	**185**	187	**518**	541
Gross margin	**1,032**	1,213	**3,021**	3,724
Operations, maintenance and administration	**635**	666	**2,054**	2,061
Depreciation and amortization	**178**	313	**517**	941
Accretion on fixed asset removal and nuclear waste management liabilities	**235**	232	**709**	696
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(196)**	(248)	**(579)**	(620)
Income from investments subject to significant influence	**(11)**	(11)	**(29)**	(28)
Property taxes	**8**	12	**30**	35
	849	964	**2,702**	3,085
Income before other losses (gains), interest and income taxes	**183**	249	**319**	639
Other losses (gains)	**3**	1	**(380)**	(23)
Income before interest and income taxes	**180**	248	**699**	662
Net interest expense	**21**	28	**56**	92
Income before income taxes	**159**	220	**643**	570
Income tax expense	**19**	22	**128**	109
Net income	**140**	198	**515**	461
Net income attributable to the Shareholder	**131**	194	**498**	449
Net income attributable to non-controlling interest [1]	**9**	4	**17**	12
Electricity production (TWh) [2]	**19.4**	19.5	**56.0**	59.9
Cash flow provided by operating activities	**485**	530	**698**	1,211

[1] Relates to the 25 percent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in the Lower Mattagami Limited Partnership, the 33 percent interest of Coral Rapids Power Corporation, a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership, and the 10 percent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP.

[2] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

Third Quarter

Net income attributable to the Shareholder was $131 million for the third quarter of 2017, a decrease of $63 million compared to the same quarter in 2016. Income before interest and income taxes for the third quarter of 2017 was $180 million, a decrease of $68 million compared to the same quarter in 2016.

Significant factors that reduced income before interest and income taxes:

- Lower earnings from the nuclear base regulated price of approximately $24 million reflecting lower electricity generation of 0.4 terawatt hours (TWh) from the Regulated – Nuclear Generation segment and the continuation of existing base regulated prices set by the OEB in 2014. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS since October 2016, largely offset by an increase in generation from Pickering GS. The increase in generation from the Pickering GS was primarily due to outage optimization, favourable unit conditions and execution of planned outage work. The base regulated prices set in 2014 continue to be in effect pending the OEB's decision on OPG's current application for new regulated prices, expected later in 2017. **[MONITOR]** The existing nuclear base regulated price was set to allow the Company to recover its approved nuclear costs over a higher nuclear production volume, based on the 2014 and 2015 outage profile that did not include a refurbishment outage. OPG has requested January 1, 2017 as the effective date of the new regulated prices.
- Lower earnings on the nuclear fixed asset removal and nuclear waste management funds (Nuclear Segregated Funds) of $52 million.
- Higher depreciation and amortization expense of $16 million in the Regulated – Nuclear Generation segment, excluding amortization expense related to balances in OEB-authorized regulatory variance and deferral accounts (regulatory accounts), primarily due to new assets in service.

The expiry of rate riders for the recovery of approved balances in OEB-authorized regulatory accounts on December 31, 2016 contributed to the decrease in revenue for the three months ended September 30, 2017, compared to the same period in 2016, but was largely offset by a decrease in the amortization expense related to these balances. OPG has requested new rate riders in its current application to the OEB for new regulated prices, with a proposed effective date of January 1, 2017.

Significant factor that increased income before interest and income taxes:

- Lower operations, maintenance and administration (OM&A) expenses of $31 million, mainly in the Regulated – Nuclear Generation segment, as a result of a higher materials and supplies obsolescence charge recognized in the third quarter of 2016, Services, Trading and Other Non-Generation segment due to project expenditures incurred in the third quarter of 2016, and Regulated – Hydroelectric segment due to the timing of repairs and maintenance work in 2017 and a deferral of outages during the high water period.

Net interest expense decreased by $7 million during the third quarter of 2017, compared to the same quarter in 2016, primarily due to a higher amount of interest costs capitalized for the Darlington Refurbishment project expenditures and a higher amount of interest costs deferred in OEB-authorized regulatory accounts.

Income tax expense for the three months ended September 30, 2017 was $19 million, compared to $22 million for the same period in 2016. The decrease in income tax expense was primarily due to lower income before taxes and a higher change in reserves from the resolution of uncertainties, partially offset by a lower amount of tax expense deferred in regulatory assets.

Year-To-Date

Net income attributable to the Shareholder was $498 million for the first nine months of 2017, an increase of $49 million compared to the same period in 2016. Income before interest and income taxes for the first nine months of 2017 was $699 million, an increase of $37 million compared to the same period in 2016.

Significant factor that increased income before interest and income taxes:

- Higher earnings of $390 million from the Services, Trading, and Other Non-Generation segment, primarily reflecting the gain on sale of OPG's head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street that was recognized in the second quarter of 2017. The sale of the

assets was required by a Shareholder Declaration and a Shareholder Resolution. The gain on sale was $283 million, which is net of tax effects of $95 million.

Significant factors that reduced income before interest and income taxes:

- Lower earnings from the nuclear base regulated price of approximately $230 million, partially offset by a decrease in nuclear fuel expense of $22 million, reflecting lower electricity generation of 4.0 TWh from the Regulated – Nuclear Generation segment and the continuation of existing base regulated prices set by the OEB in 2014. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS, partially offset by an increase in generation from Pickering GS.
- Lower earnings on the Nuclear Segregated Funds of $41 million.
- Higher depreciation and amortization expense of $30 million in the Regulated – Nuclear Generation segment, excluding amortization expense related to regulatory account balances, primarily due to new assets in service.
- A gain of $22 million recorded in the first quarter of 2016 to reflect the OEB's decision on OPG's motion asking the OEB to review and vary parts of its November 2014 decision on OPG's regulated prices.

The expiry of rate riders for the recovery of approved balances in OEB-authorized regulatory accounts on December 31, 2016 contributed to the decrease in revenue for the nine months ended September 30, 2017, compared to the same period in 2016, but was primarily offset by a decrease in the amortization expense related to these balances.

Net interest expense decreased by $36 million for the nine months ended September 30, 2017, compared to the same period in 2016, primarily due to a higher amount of interest costs capitalized for the Darlington Refurbishment project expenditures and a higher amount of interest costs deferred in OEB-authorized regulatory accounts.

Income tax expense for the nine months ended September 30, 2017 was $128 million, compared to $109 million for the same period in 2016. The increase in income tax expense was primarily due to higher income before income taxes.

Segment Results

The following table summarizes OPG's income before interest and income taxes by business segment. A detailed discussion of OPG's performance by reportable segment is included in the section, *Discussion of Operating Results by Business Segment*.

(millions of dollars)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Income (loss) before interest and income taxes				
Regulated – Nuclear Generation	**20**	47	**(267)**	17
Regulated – Hydroelectric	**122**	117	**474**	500
Contracted Generation Portfolio	**75**	74	**229**	219
Total electricity generation business segments	**217**	238	**436**	736
Regulated – Nuclear Waste Management	**(36)**	18	**(123)**	(70)
Services, Trading, and Other Non-Generation	**(1)**	(8)	**386**	(4)
	180	248	**699**	662

Electricity Generation

Electricity generation for the three and nine month periods ended September 30, 2017 and 2016 was as follows:

(TWh)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Regulated – Nuclear Generation	**11.3**	11.7	**30.6**	34.6
Regulated – Hydroelectric	**7.3**	6.9	**23.5**	22.8
Contracted Generation Portfolio [1]	**0.8**	0.9	**1.9**	2.5
Total OPG electricity generation	**19.4**	19.5	**56.0**	59.9
Total electricity generation by all other generators in Ontario [2]	**16.6**	19.5	**51.7**	53.8

[1] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.
[2] Non-OPG generation is calculated as the Ontario electricity demand plus net exports, as published by the Independent Electricity System Operator (IESO), minus OPG electricity generation.

Total OPG electricity generation decreased by 0.1 TWh during the third quarter of 2017, compared to the same quarter in 2016, and by 3.9 TWh during the nine months ended September 30, 2017, compared to the same period in 2016. As expected, the lower electricity generation from the Regulated – Nuclear Generation segment was primarily the result of the removal from service of Unit 2 at the Darlington GS for the duration of the unit's refurbishment, which began in October 2016. This decrease in electricity generation was largely offset by an increase in generation from the Pickering GS, primarily due to outage optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station, and higher hydroelectric generation from the Regulated – Hydroelectric segment.

The higher electricity generation of 0.4 TWh and 0.7 TWh from the Regulated – Hydroelectric segment for the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016, was due to higher water flows primarily on the eastern Ontario river systems, net of water spilled as a result of SBG conditions, discussed below.

The lower electricity generation of 0.6 TWh from the Contracted Generation Portfolio segment for the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to higher SBG conditions. The electricity generation from the Contracted Generation Portfolio segment for the three months ended September 30, 2017 was comparable to the same period in 2016.

OPG's operating results are impacted by changes in grid-supplied electricity demand resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. For the three and nine month periods ended September 30, 2017, Ontario's electricity demand as reported by the IESO was 33.6 TWh and 98.5 TWh, respectively, compared to 36.7 TWh and 103.8 TWh for the same periods in 2016, respectively, excluding electricity exports out of the province.

Power that is surplus to the Ontario market is managed by the IESO, mainly through generation reductions at hydroelectric, other grid-connected renewable resources and nuclear stations. Reducing hydroelectric production is the first measure used by the IESO to manage SBG conditions. Low demand conditions in Ontario continued to be prevalent in 2017, resulting in forgone hydroelectric generation for OPG of 1.1 TWh and 4.5 TWh due to SBG conditions in the three and nine month periods ended September 30, 2017, respectively, compared to 0.5 TWh and 3.9 TWh during the same periods in 2016, respectively. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions during these periods was offset by the impact of a regulatory variance account authorized by the OEB. OPG did not forgo any electricity production at its nuclear stations due to SBG conditions.

Average Sales Prices

The majority of OPG's generation is from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments. The same base regulated prices for electricity generated by these segments, authorized by the OEB effective November 1, 2014, were in effect during the first nine months of 2017 as in 2016. These prices will remain in effect until such time as the OEB approves new regulated prices based on OPG's current application. **[MONITOR]** The base regulated prices established in 2014 are discussed in OPG's 2016 annual MD&A in the section, *Revenue Mechanisms for Regulated and Non-Regulated Generation*.

The average sales price for the Regulated – Nuclear Generation segment was 5.8 cents per kilowatt hour (¢/kWh) during the three and nine month periods ended September 30, 2017, respectively, compared to 6.9 ¢/kWh during the same periods in 2016. The decrease in the average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized nuclear rate rider of $10.84 per megawatt hour (MWh) for the recovery of variance and deferral account balances. The average sales price for the Regulated – Hydroelectric segment was 4.1 ¢/kWh during the three and nine month periods ended September 30, 2017, respectively, compared to 4.4 ¢/kWh during the same periods in 2016. The decrease in the average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized regulated hydroelectric rate rider of $3.19/MWh for the recovery of variance and deferral account balances. The rate riders were established to recover approved balances recorded in the variance and deferral accounts in prior years. As such, the year-over-year changes in revenue from the rate riders were largely offset by changes in amortization expense related to these balances. There were no rate riders in effect during the nine months ended September 30, 2017 for either nuclear or regulated hydroelectric generation, pending the outcome of OPG's current application with the OEB for new regulated prices.

Cash Flow from Operations

Cash flow provided by operating activities was $485 million for the three months ended September 30, 2017 and $698 million for the nine months ended September 30, 2017, compared to $530 million and $1,211 million for the same periods in 2016, respectively. The decrease in cash flow provided by operating activities was expected and primarily due to lower generation revenue receipts reflecting lower generation from the Regulated – Nuclear Generation segment as a result of the ongoing refurbishment of Unit 2 at the Darlington GS and the expiry, on December 31, 2016, of the OEB-authorized rate riders for nuclear and regulated hydroelectric generation. The decrease in cash flow during the nine months ended September 30, 2017 was also due to higher income tax instalments.

The decrease in cash flow provided by operating activities for the three and nine month periods ended September 30, 2017 was partly offset by lower OM&A expenditures and lower contributions to the Used Fuel Segregated Fund in 2017. Both the Used Fuel Segregated Fund and the Decommissioning Segregated Fund were determined to be fully funded based on an updated estimate of OPG's nuclear waste management and nuclear facilities decommissioning obligations pursuant to a reference plan approved by the Province, for years 2017 to 2021, under the Ontario Nuclear Funds Agreement (ONFA), effective January 1, 2017. Pursuant to the ONFA, the reference plan is required to be updated at least once every five years. Contributions to either or both of the Nuclear Segregated Funds may be required in the future should the funds be in an underfunded position at the time of the next ONFA reference plan update. The year-over-year decrease in cash flow also was partially offset by the payment of a supplemental rent rebate to Bruce Power in the first quarter of 2016 in relation to a period in 2015. The lease agreement for the Bruce nuclear generating stations was amended in late 2015 to eliminate this rebate provision going forward.

Return on Common Equity Excluding Accumulated Other Comprehensive Income

ROE Excluding AOCI is an indicator of OPG's performance consistent with the Company's strategy to provide value to the Shareholder. ROE Excluding AOCI is measured over a 12-month period.

ROE Excluding AOCI was 4.4 percent for the 12 months ended September 30, 2017, compared to 4.2 percent for the 12 months ended December 31, 2016. The increase was primarily due to higher net income attributable to the Shareholder for the 12 months ended September 30, 2017, which reflected the gain on sale of OPG's head office premises and associated parking facility recorded in the second quarter of 2017, partially offset by the lower earnings from the decrease in nuclear electricity generation reflecting the Unit 2 refurbishment outage at the Darlington GS without a corresponding increase in the nuclear base regulated price, as expected. The lower nuclear generation as a result of the refurbishment outage will continue to negatively affect OPG's ROE Excluding AOCI until such time as new regulated prices are approved by the OEB, anticipated in the fourth quarter of 2017. **[MONITOR]**

Funds from Operations Adjusted Interest Coverage

FFO Adjusted Interest Coverage is an indicator of OPG's ability to meet interest obligations from operating cash flows. The indicator is measured over a 12-month period. FFO Adjusted Interest Coverage for the 12 months ended September 30, 2017 was 4.2 times, compared to 5.1 times for the 12 months ended December 31, 2016. FFO Adjusted Interest Coverage in 2017 reflected a year-over-year decrease in FFO before interest due to lower cash flow provided by operating activities, partially offset by the impact of a lower adjusted interest expense due to a decrease in the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets.

The decrease in the excess of interest on pension and OPEB benefit obligations over expected return on pension plan assets in the nine months of 2017 was primarily due to the change in the method used to estimate the interest cost and service cost components of pension and OPEB costs. Effective January 1, 2017, OPG adopted a full yield curve approach to the estimation of these cost components, by applying the specific spot rates along the yield curve used in the determination of the projected benefit obligations to the relevant projected cash flows. Under the previous method, these components of pension and OPEB costs were calculated using the same single weighted-average discount rates as reflected in the calculation of the benefit obligations. This change in the method was accounted for prospectively, as a change in estimate. The resulting reduction in pension and OPEB costs for the three and nine month periods ended September 30, 2017 did not have a material impact on net income as it was largely offset by the impact of OEB-authorized variance and deferral accounts in the regulated business segments. Further details on the full yield curve approach can be found in the 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Pension and Other Post-Employment Benefits*.

Enterprise Total Generating Cost per MWh

The Enterprise TGC per MWh decreased to $46.65 for the three months ended September 30, 2017, compared to $50.72 for the same quarter in 2016. The decrease was mainly due to lower OM&A expenses before the impact of regulatory accounts and higher SBG-adjusted hydroelectric generation reflecting higher water flows.

The Enterprise TGC per MWh was $47.77 for the nine months ended September 30, 2017, an increase compared to $46.74 for the same period in 2016. The increase was expected and mainly a result of lower electricity generation due to the Unit 2 refurbishment outage at the Darlington GS, largely offset by lower OM&A expenses before the impact of regulatory accounts and higher SBG-adjusted hydroelectric generation reflecting higher water flows.

If Unit 2 at the Darlington GS was not currently undergoing refurbishment and had continued to operate in a manner consistent with the performance of the remaining units at the Darlington GS, adjusting for generation constraints on these units related to the transition of the station toward refurbishment, the Enterprise TGC would have been approximately $4 per MWh lower for both the three and nine month periods ended September 30, 2017. This sensitivity was calculated using the estimated incremental electricity and associated fuel cost that are expected to have resulted in the absence of the refurbishment.

Nuclear Total Generating Cost per MWh

The Nuclear TGC per MWh was $58.75 for the three months ended September 30, 2017, which was comparable to $58.55 for the same quarter in 2016. For the three months ended September 30, 2017, the higher generation at the Pickering GS and the impact of lower OM&A expenses before the impact of regulatory accounts was mostly offset by the expected decrease in nuclear electricity generation reflecting the Unit 2 refurbishment outage at the Darlington GS and higher sustaining capital expenditures. The Nuclear TGC per MWh was $67.87 for the nine months ended September 30, 2017, compared to $61.07 for the same period in 2016. The increase in the Nuclear TGC per MWh for the nine months ended September 30, 2017 was expected and primarily due to the decrease in nuclear electricity generation, partially offset by lower OM&A expenses before the impact of regulatory accounts.

Hydroelectric Total Generating Cost per MWh

The Hydroelectric TGC per MWh was $26.20 for the three months ended September 30, 2017, compared to $31.01 for the same quarter in 2016. The decrease was primarily due to higher SBG-adjusted hydroelectric electricity generation reflecting higher water flows. The Hydroelectric TGC per MWh was $21.74 for the nine months ended September 30, 2017, compared to $23.99 for the same period in 2016. The decrease was primarily due to lower OM&A expenses before the impact of regulatory accounts and lower sustaining capital expenditures.

ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are not measurements in accordance with US GAAP and should not be considered alternative measures to net income, cash flow provided by operating activities, or any other performance measure under US GAAP. OPG believes that these non-GAAP financial measures are effective indicators of its performance and are consistent with the Company's strategic imperatives and related objectives. The definition and calculation of ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are found in the section, *Supplementary Non-GAAP Financial Measures*.

Recent Developments

Ontario's 2017 Long Term Energy Plan

On October 26, 2017, Ontario's Ministry of Energy issued the 2017 Long Term Energy Plan. The Plan is currently being analyzed by OPG but is not expected to significantly impact OPG's business. There are no fundamental changes from the principles in the 2013 Long Term Energy Plan, which include cost effectiveness, reliability, clean energy and community engagement. The 2017 Long Term Energy Plan fully supports nuclear refurbishment projects in Ontario and the extension of commercial operation of all Pickering units to 2024. **[MONITOR & UPDATE DETAILS FOLLOWING RELEASE]**

OEB's Decision on New Regulated Prices **[MONITOR]**

Ontario's Fair Hydro Plan

OPG continues to prepare for its involvement as the Financial Services Manager for Ontario's Fair Hydro Plan (the Fair Hydro Plan) on a commercial basis. Accordingly, the financing entity was established in XX 2017 as the Fair Hydro Trust (the Trust), following the execution of its constating documents. The majority unitholder and beneficiary of the Trust is a wholly-owned subsidiary of OPG. Through this ownership and OPG's control over the key activities of the Trust, the Company will consolidate the Trust for accounting purposes commencing in the fourth quarter of 2017. **[MONITOR]**

In order for the Trust to provide financing for the deferred Global Adjustment costs, the Trust will incur senior debt from capital markets and subordinated debt from OPG. The Trust is structured to be bankruptcy remote and ring fenced from OPG to protect the Company's assets and operations. In support of the Fair Hydro Plan, the following developments have transpired:

- In October 2017, *Ontario Regulation 206/17 General* was amended to establish details of the recovery mechanism for the monthly carrying costs incurred by the Trust from June 1, 2017 to July 31, 2021 payable by the IESO to the Trust. Originally established in June 2017, this regulation provides more details on the funding obligations incurred by the Trust and the fair allocation amount, the determination and collection of clean energy adjustments, the determination of the finance amount, the true up amount, and the regulatory asset, as well as principles and assumptions relating to the financing plan.
- A plan to amend the Company's Articles of Amalgamation to allow for the creation and issuance of Class A shares to be issued to the Province for its equity investment through OPG in the Fair Hydro Plan is in progress. The Province is expected to provide 44 percent of the total funding requirement related to the deferred Global Adjustment costs, which OPG will invest as subordinated debt into the Trust. OPG's Board approval and a Shareholder Resolution are expected later in the year to authorize the amendment.
- OPG is expected to provide five percent of the total funding requirement of the Trust related to the deferred Global Adjustment costs of the Fair Hydro Plan. OPG issued senior notes payable in October 2017 under a short form base shelf prospectus for general corporate purposes and to fund OPG's subordinated debt investment in the Trust. Further details of the debt offering can be found in the section, *Liquidity and Capital Resources* under the heading, *Financing Activities*.

The first set of transactions of the Trust are expected to take place in the fourth quarter of 2017.

Canadian Nuclear Safety Commission Safety Rating for the Darlington GS and the Pickering GS

The Canadian Nuclear Safety Commission (CNSC) publishes an annual report on the safety performance of Canada's nuclear power plants. The report assesses how well plant operators are meeting regulatory requirements and program expectations in the areas of operational performance, safety analysis, radiation protection, waste management and conventional health and safety. On September 8, 2017, the CNSC issued an executive summary of its 2016 annual report. The CNSC gave both the Darlington GS and the Pickering GS the highest possible safety rating of "Fully Satisfactory". The Darlington GS achieved this rating for the eighth consecutive year, while the Pickering GS achieved this rating for the second consecutive year.

CORE BUSINESS, STRATEGY, AND OUTLOOK

The discussion in this section is qualified in its entirety by the cautionary statements included in the section, *Forward-Looking Statements,* at the beginning of the MD&A.

OPG's mission is to provide low cost power in a safe, clean, reliable and sustainable manner for the benefit of customers and its Shareholder. OPG also seeks to pursue, on a commercial basis, generation development projects and other business growth opportunities.

The following sections provide an update to OPG's disclosures in the 2016 annual MD&A related to its four key strategic imperatives – operational excellence, project excellence, financial strength, and social licence. A detailed discussion of these strategic imperatives is included in the 2016 annual MD&A in the section, *Core Business, Strategy, and Outlook*.

Operational Excellence

Operational excellence at OPG is accomplished by the safe and environmentally responsible generation of reliable and cost-effective electricity from the Company's generating assets through a highly trained and engaged workforce.

Electricity Generation Production and Reliability

- As part of the plan to extend Pickering operations, OPG is continuing to undertake the required technical work to confirm that the station's pressure tubes, a key life-limiting component of the station, will remain fit for service for operation to 2024. OPG is also nearing completion of component condition assessments to identify the work required to support the continued operation of the station. The accounting end of life assumptions for the Pickering GS, currently set at the end of 2020, will be reassessed based on the fuel channel analysis and safety case consistent with submissions for the CNSC approval, discussed below. The activities completed to date have had positive results, which will go towards re-confirming Pickering operations past 2020 are technically feasible. The Periodic Safety Review (PSR) is in progress and will confirm that extending operations of the Pickering units will be safe to the public, workers and the environment. The PSR consists of Safety Factor Reports (SFRs), a Global Assessment Report (GAR), and the Integration Improvement Plan (IIP). SFRs have been submitted to the CNSC and the GAR and IIP are on track for CNSC submission in October and November 2017, respectively. Other technical feasibility activities continue to progress as planned. Completion of various technical feasibility assessments are required to reach a high confidence conclusion to allow the station end of life to change for depreciation purposes. OPG's current application with the OEB for new base regulated prices, currently pending the OEB's decision, reflects OPG's plans to extend Pickering operations to 2024 and requests inclusion of the corresponding cost and generation impacts in the determination of the nuclear regulated price.
- OPG's current five-year operating licence for the Pickering GS was approved by the CNSC in 2013 and expires on August 31, 2018. This licence was issued assuming that the station would shut down in 2020. On June 28, 2017, OPG confirmed to the CNSC that it intends to cease commercial operation of all Pickering units on December 31, 2024. On August 28, 2017, OPG submitted a ten-year licence renewal application to the CNSC. The licence term spans the planned extended operations period, through to the end of commercial operation, defueling, dewatering and the start of placing the station in a safe storage state.
- Work continues on the rehabilitation of Unit 2 of the DeCew Falls hydroelectric GS and the rehabilitation and overhaul of Unit 2 of the Lower Notch hydroelectric GS.
- During the third quarter, a new control centre was opened at Saunders GS to merge its operations with Chenaux GS. The new control centre will overlook power production at ten hydroelectric stations along the Madawaska, Ottawa and St. Lawrence rivers.
- As part of the process to decommission the Nanticoke and Lambton generating stations, OPG has begun executing demolition plans that will ensure that the stations are closed safely, securely and in an environmentally responsible manner. The demolition of the Nanticoke coal yard equipment and structures is in progress, with a contract issued in July 2017 for the demolition of the Nanticoke powerhouse and associated structures. Project milestones for the Nanticoke site during the remainder of 2017 include completing the removal of coal yard equipment and structures, demolition of the ash silos, and mobilization of the contractor to prepare for removal of the stacks, powerhouse and associated structures. A competitive bidding process for the demolition of the Lambton GS has been completed, with a contract for the removal of the powerhouse and associated buildings expected to be awarded in 2018. An update of the associated asset retirement obligations related to the Nanticoke and Lambton sites is expected to be finalized in the fourth quarter of 2017.

Environmental Performance

There were no significant changes to environmental legislation affecting the Company during the third quarter of 2017. Disclosures related to the Company's environmental policy and environmental risks can be found in OPG's 2016 annual MD&A.

OPG communicates its environmental performance internally to employees and to external stakeholders, including the Ontario Ministry of the Environment and Climate Change, Environment and Climate Change Canada, the CNSC, and local communities. Details of OPG's environmental performance and initiatives to fulfill the Company's Environmental Policy can be found in OPG's 2016 Sustainability Report, available on the Company's website at www.opg.com. **[MONITOR]**

Project Excellence

OPG is pursuing a number of generation development and other major projects in support of Ontario's electricity planning initiatives. OPG remains focused on delivering projects safely, on time, on budget and with high quality. The status updates for OPG's major projects as at September 30, 2017 are outlined in the following table, with further details below.

Project	Capital expenditures		Approved budget	Expected in-service date	Current status
(millions of dollars)	Year-to-date	Life-to-date			
Darlington Refurbishment	924	4,109	12,800 [1]	First unit - 2020 Last unit - 2026	The setup of specialized tooling and equipment needed for the removal of reactor components was completed in the third quarter of 2017. All feeder tubes have been removed safely, and the pressure tubes have been severed in preparation for their removal. The Re-tube Waste Processing Building will be available for use in the fourth quarter of 2017. The project is tracking on schedule and on budget.
Peter Sutherland Sr. Hydroelectric GS	38	274	300	2017	The station was placed in-service on March 31, 2017, ahead of the originally planned schedule, and is expected to close below the approved budget. Project close-out activities are in progress.
Ranney Falls Hydroelectric GS	17	20	77	2019	Work is progressing on the expanded forebay, forebay wall concrete replacement, powerhouse and spillway areas. The project is tracking on schedule and on budget.
Nanticoke Solar Facility	1	2	107 **[MONITOR]**	2019	Project definition work is continuing, with construction planned to commence in the first quarter of 2018.
Deep Geologic Repository for low and intermediate level radioactive waste (L&ILW)	7 [2]	202 [2]			On August 21, 2017, the federal Minister of Environment and Climate Change requested further information on the project's environmental assessment (EA). OPG is reviewing the new request and will notify the Canadian Environmental Assessment Agency (CEAA) when it has a timeline for submission of that information.

[1] The total project budget of $12.8 billion is for the refurbishment of all four units at the Darlington GS.
[2] Expenditures are charged against the nuclear fixed asset removal and nuclear waste management liabilities (Nuclear Liabilities).

Darlington Refurbishment

The Darlington generating units are approaching their originally designed end-of-life. Refurbishment of the four generating units is expected to extend the operating life of the station by approximately 30 years. OPG commenced the planning of the refurbishment in 2010.

In 2016, the Darlington Refurbishment project transitioned from the planning phase to the execution phase, as OPG commenced the refurbishment of the first unit, Unit 2, in October 2016, as planned. The unit was taken offline on October 15, 2016. De-fuelling of the reactor, the first critical refurbishment activity undertaken once the unit is removed from service, was completed safely in January 2017, with a total of 480 fuel channels de-fuelled. Islanding of Unit 2, the physical separation of the unit under refurbishment from the three operating units, was completed in April 2017, signifying the completion of the first major segment of the project.

The second major segment includes preparatory work to support the removal of feeder tubes and fuel channel assemblies and the removal of reactor components. The preparatory work was completed in the second quarter of 2017. The Re-tube Tooling Platform for hosting the tooling for the removal, inspection, and installation activities and the setup of specialized tooling and equipment needed for the removal and replacement of the reactor components were completed in the third quarter of 2017. The disassembly of reactor components commenced in August 2017, with the removal of all 960 feeder tubes completed safely in September 2017. This was followed by the severing of pressure tubes, with the severing of bellows and the removal of end fittings expected to commence thereafter and through the end of 2017. Other key project activities executed during the second segment include the completion of the primary side steam generator layup, installation of steam generator access ports to support future inspections, continuation of the major turbine generator overhaul and continued execution of the major electrical scope. OPG is also continuing to execute work to support the requirements set out in the CNSC approved IIP for the station.

Once refurbished, Unit 2 is scheduled to be returned to service in the first quarter of 2020, at which time capital expenditures of approximately $4.8 billion are planned to be placed in service. This includes expenditures incurred during the definition and planning phase of the overall project. The project is tracking on schedule and on budget.

With the substantial completion of the Re-tube Waste Processing Building in November 2017, 17 out of 18 pre-requisite projects in support of the execution phase of the project, including construction of facilities, infrastructure upgrades and installation of safety enhancements, have been completed and placed in service. Completion of the Heavy Water Storage and Drum Handling Facility (HWSF) has been delayed due to challenges with construction. OPG suspended the project in the second quarter of 2017 to evaluate the best approach to optimize cost and schedule and complete the project. Construction activities for the HWSF recommenced in the fourth quarter of 2017 following substantial completion of the Re-tube Waste Processing Building. This plan ensures that the necessary resources are available for both projects and, through resource levelling, improves their execution and cost efficiency. The delay in the completion of the HWSF will not impact the overall Darlington Refurbishment project schedule, as the HWSF is not on the project's critical path. This also will not impact the overall project budget of $12.8 billion, as the costs of the HWSF are included in this total figure. The recovery of HWSF costs through regulated prices will be subject to a prudence review by the OEB, which OPG has proposed be conducted as part of a future OEB application.

In addition to the execution of refurbishment activities on Unit 2, OPG is continuing planning activities for the refurbishment of the second unit, Unit 3, and is entering into associated commitments to procure major components that require long lead times. As of September 30, 2017, $70 million has been invested in planning activities related to the refurbishment of the second unit, Unit 3. These planning activities are being undertaken in accordance with the refurbishment project schedule.

The Financial Accountability Office of Ontario has issued a report titled "*An Assessment of the Financial Risks of the Nuclear Refurbishment Plan*". The report assesses both OPG and Bruce Power's refurbishment activities and the method in which those refurbishments and subsequent nuclear generation is provided to the marketplace. The report

concludes that the base case of refurbishing the six units at the Bruce nuclear GS and the four units at the Darlington nuclear GS provide the most cost effective, low emission generation source available to meet Ontario's baseload electricity requirements. This report re-affirms the positive economic and societal benefits associated with a strong nuclear program in the Province. **[MONITOR]**

Ranney Falls Hydroelectric GS

During the third quarter of 2017, OPG continued construction work for a 10 MW single-unit powerhouse on the existing Ranney Falls GS site, as part of the Regulated – Hydroelectric segment. The new unit will replace an existing unit that reached its end of life in 2014. The existing forebay structure demolition has been completed and the upstream cofferdam has been constructed ahead of schedule. Construction continues on the expanded forebay, powerhouse and spillway. Excavation work is substantially complete and forebay wall concrete replacement is in progress. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget.

Nanticoke Solar Facility

The construction of a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands under a Large Renewable Procurement contract with the IESO, through Nanticoke Solar LP, a partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation, is planned to commence in the first quarter of 2018. During the third quarter of 2017, the partnership continued work to obtain approvals and permits required to enable the commencement of construction, and progressed procurement activities for equipment and for engineering and construction services. The facility is expected to be completed in the first quarter of 2019.

Deep Geologic Repository for Low and Intermediate Level Waste

OPG has proposed a deep geologic repository as the preferred solution for the safe long-term management of the L&ILW produced from the continued operation of OPG-owned nuclear generating stations. Agreement has been reached with local municipalities for OPG to develop the L&ILW Deep Geologic Repository (DGR) on lands adjacent to the Western Waste Management Facility (WWMF) in Kincardine, Ontario. The environmental effects of the proposed L&ILW DGR were examined by the CNSC and CEAA-appointed Joint Review Panel (JRP) to meet the requirements of the Canadian Environmental Assessment Act. The JRP submitted its report on the EA to the federal Minister of Environment in May 2015, concluding that, given mitigation, there is unlikely to be significant environmental impact from the project and recommending that the Minister approve the EA. In December 2016, at the request of the federal Minister of Environment and Climate Change, OPG submitted additional information on certain aspects of the EA, including information related to alternate locations for the project. Following its review of OPG's submission and a period of public comment, the CEAA requested further information that OPG subsequently provided in May 2017. In June 2017, the CEAA notified OPG that it had sufficient and adequate information to proceed with the next step of the environmental assessment process and advised that a draft report and updated terms and conditions will be prepared for public review.

On August 21, 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of potential cumulative effects of the project on the Saugeen Ojibway Nations' (SON) physical and cultural heritage, including a description of the potential effects of the project on the Nation's spiritual and cultural connection to the land. OPG is assessing the request and will notify the CEAA when it has determined the timeline for developing a response. The CEAA's draft report for public review will not be issued until this update is provided. The L&ILW DGR at the WWMF site remains OPG's preferred solution for the safe long-term management of the L&ILW.

OPG continues its engagement with the SON toward securing community support for the L&ILW DGR. The in-service date of the L&ILW DGR is expected to be approximately six to seven years from the start of construction.

Financial Strength

As a commercial enterprise, OPG's financial priority is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future growth.

Increase Revenue, Reduce Costs and Achieve Appropriate Return

In May 2016, OPG filed a 5-year application with the OEB for new regulated prices for production from its regulated hydroelectric and nuclear facilities, with a proposed effective date of January 1, 2017. Consistent with the requirements of *Ontario Regulation 53/05*, the application incorporates a rate smoothing proposal that would defer, for future collection, a portion of the approved annual nuclear revenue requirement for the period from January 1, 2017 to the end of the Darlington Refurbishment project, with a view to making changes in OPG's regulated prices more stable year-over-year. The application seeks to ensure that nuclear regulated prices under the rate smoothing approach allow for sufficient cash flow to meet the Company's liquidity needs, support cost effective funding for the Darlington Refurbishment project and other expenditures, and maintain the Company's investment grade credit rating, while taking into account both near-term and future impacts on customers. OPG expects to recognize amounts deferred under rate smoothing as income in the periods to which the underlying approved revenue requirements relate.

The application will further challenge and incentivize OPG to find additional cost reductions and efficiencies within its operations, as a result of greater de-coupling of nuclear and hydroelectric regulated prices from costs and a longer rate-setting period under the OEB's incentive ratemaking framework, which forms the basis for the ratemaking methodologies reflected in the application.

The application seeks an increase in the nuclear rate base, effective in early 2020, to reflect the planned placement in service of approximately $4.8 billion of capital expenditures upon the scheduled return to service of Unit 2 at the Darlington GS as part of the Darlington Refurbishment project and, effective in 2017, an increase in the deemed capital structure applied to the total regulated rate base to 49 percent equity and 51 percent debt, from 45 percent equity and 55 percent debt reflected in the existing regulated prices. The application also requests new rate riders, effective January 1, 2017, to recover or repay the December 31, 2015 balances in all of the Company's OEB-authorized variance and deferral accounts, with the exception of the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the portion of these balances previously approved for recovery or repayment through rate riders that were in effect during 2016.

The OEB's decision on the application, including the effective date of approved new regulated prices, is expected later in 2017. **[MONITOR]**

For generation assets that do not form part of the assets regulated by the OEB, OPG's strategy has been to secure appropriate long-term revenue arrangements. In line with this strategy, virtually all of OPG's non-regulated operating facilities and assets under construction are subject to long-term Energy Supply Agreements (ESAs) or other long-term contracts with the IESO.

Ensure Availability of Cost Effective Funding

In April 2017, DBRS Limited (DBRS) re-affirmed the long-term credit rating on OPG's debt at 'A (low)' and OPG's commercial paper rating at 'R-1 (low)'. All ratings from DBRS have a stable outlook. In July 2017, S&P Global Ratings (S&P) re-affirmed OPG's long-term credit rating at 'BBB+' with a stable outlook. S&P's commercial paper rating for OPG is 'A-1 (low)'.

Social Licence

As the largest electricity generator in Ontario with diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust. OPG is committed to maintaining high standards of public safety and corporate citizenship, including environmental stewardship, transparency, community engagement, and Indigenous relations.

OPG is focused on building long-term, mutually beneficial working relationships with Indigenous communities, businesses and organizations across Ontario, and continues to support procurement, employment and educational opportunities with its Indigenous community partners. The Company seeks to establish these relationships based on a foundation of respect for the languages, customs, and political, social and cultural organizations of the Indigenous communities.

In June 2017, OPG launched an Indigenous Business Engagement (IBE) Initiative. The purpose of this initiative is to increase access to procurement opportunities for Indigenous businesses interested in supplying materials and services to OPG. The IBE Initiative is based on a strategy that will identify opportunities in contracts, scopes of work and business plans for potential Indigenous business engagement; include criteria related to suppliers' ability to engage or partner with Indigenous people or businesses in assessing procurement proposals; and invest in relationships with Indigenous communities by increasing outreach efforts to enhance understanding of how to do business with OPG. OPG has continued to engage with various Indigenous business and communities as well as its suppliers to promote the IBE Initiative. In September 2017, OPG presented the IBE to the Mohawk Council of Akwesanse (Akwesanse). As a result, Akwesanse plans to create a database of businesses in the community that will participate in contracting and supply opportunities with OPG. In September 2017, OPG also hosted a similar presentation to the Williams Treaties First Nations, located proximate to the Pickering and Darlington Nuclear Generating Stations, at the quarterly meeting for these communities.

OPG is developing recruitment plans targeting Indigenous people. In October 2017, OPG participated in five Indigenous-specific career fairs to attract such talent. **[MONITOR]**

OPG has a transportation electrification strategy that will help position OPG as a leader in transportation electrification in Ontario. This strategy is intended to leverage OPG's clean electricity to support action on climate change, create growth opportunities for OPG, and enhance OPG's brand and social licence.

Outlook

The financial performance of OPG's regulated operations is driven, in large part, by the outcome of applications for regulated prices to the OEB. The existing base regulated prices were established by the OEB effective November 1, 2014 based on a forecast of costs and production for the regulated facilities for the 2014 to 2015 period. The future outcome of OPG's current application for new regulated prices, currently pending the OEB's decision, is expected to provide substantial price certainty for the regulated business for the 2017 to 2021 period.

In its application, OPG has requested January 1, 2017 as the effective date for the new regulated prices. In December 2016, the OEB issued an order declaring the existing base regulated prices interim, which preserves the OEB's ability to make the new regulated prices effective as early as January 1, 2017. Considering the timing of OPG's application and OPG's procedural adherence throughout the proceeding, the Company believes that the OEB could make the new regulated prices effective January 1, 2017. This would allow OPG to recover the difference between the approved new regulated prices and the existing regulated prices for the period between January 1, 2017 and the implementation date of the new prices based on the OEB's order. The OEB's decision on the application, including the effective date of the new regulated prices, is expected in the fourth quarter of 2017. **[MONITOR]** The continuation of existing regulated prices until the issuance of the OEB's decision is expected to continue to contribute to lower income, particularly from the Regulated – Nuclear Generation segment, and, excluding the gain on sale of the Company's head office premises and associated parking facility recorded in the second quarter of 2017, lower

ROE Excluding AOCI during 2017, compared to 2016. In large part, this is due to the year-over-year reduction in nuclear electricity generation resulting from the Unit 2 refurbishment outage at the Darlington GS, given that the existing nuclear regulated prices were determined in 2014 based on a higher production forecast that reflected the operation of all four units at the station. As such, the OEB's decision on the effective date of the new regulated prices, as well as the timing of the decision issuance, could have a significant impact on OPG's financial results during 2017.

Nuclear base regulated prices resulting from OPG's current application will be subject to a rate smoothing mechanism that defers collection of a portion of OEB-approved revenues to future periods. As expected, combined with the expiry of rate riders in effect to the end of 2016, a year-over-year reduction in nuclear generation due to the Unit 2 refurbishment outage at the Darlington GS and the continuation of existing regulated prices until such time as new prices are implemented by the OEB, this will result in lower cash flow from operating activities in 2017, compared to 2016. OPG expects to continue to have the necessary financial capacity and sufficient access to cost effective financing sources to continue to fund its capital requirements and other disbursements.

Lower nuclear generation due to the Darlington Refurbishment outages will continue, as planned, to negatively impact the Enterprise TGC metric for the duration of the refurbishment project. Variability in sustaining capital investment expenditures, including major sustaining projects for the hydroelectric operations, also will impact the Enterprise TGC in future periods.

Several OEB-authorized regulatory variance and deferral accounts currently in place contribute to reducing the relative variability of the Company's income and ROE Excluding AOCI. Among others, the regulatory accounts include those related to the revenue impact of variability in water flows and forgone production due to SBG conditions at the regulated hydroelectric stations. As there are no variance or deferral accounts in place related to the impact of generation performance of the nuclear stations on revenue from base regulated prices, the Regulated – Hydroelectric segment generally is expected to produce overall more predictable earnings. OPG continues to operate and maintain its nuclear facilities with a view to optimize their performance and availability, while focusing on improving the overall reliability and predictability of the fleet.

Electricity generated from most of OPG's non-regulated assets is subject to ESAs with the IESO. Based on these agreements, OPG expects the Contracted Generation Portfolio segment to continue to contribute a generally stable level of earnings and cash flow from operations going forward.

OPG's total forecast capital expenditures for the 2017 year are approximately $2.0 billion. This includes amounts for the Darlington Refurbishment project, hydroelectric and other development projects including the completion of the Peter Sutherland Sr. GS and the expansion of the Ranney Falls GS, and sustaining capital investments across the generating fleet. OPG's major projects are discussed in the section, *Project Excellence*.

In addition to the operating and financial performance of the electricity generation business, OPG's results are affected by the earnings on the Nuclear Segregated Funds, which are reported in the Regulated – Nuclear Waste Management segment. While the Nuclear Segregated Funds are managed to achieve, in the long term, the target rate of return based on the discount rate specified in the ONFA, the rates of return earned in a given period can be subject to various external factors including financial market conditions and, for the portion of the Used Fuel Segregated Fund guaranteed by the Province under the ONFA, changes in the Ontario consumer price index (CPI). In the near term, these factors can be volatile and cause fluctuations in the Company's income. This volatility is partially mitigated by the impact of the OEB-authorized Bruce Lease Net Revenues Variance Account and, as discussed below, the funded status of the two segregated funds.

As OPG does not have the right to withdraw surplus amounts from the Nuclear Segregated Funds, OPG limits the amount of Nuclear Segregated Funds assets reported on the balance sheet to the present value of such life cycle funding liability. This reduces the volatility of earnings on the Nuclear Segregated Funds reflected in net income when the funds are in a fully funded or overfunded position. As at September 30, 2017, the Decommissioning

Segregated Fund was overfunded by approximately 23 percent, and the Used Fuel Segregated Fund was marginally overfunded, by less than one percent, based on the 2017 ONFA Reference Plan. Variability in asset performance due to volatility inherent in financial markets and changes in Ontario CPI, or changes in funding liability estimates, may result in either or both funds becoming underfunded in the future.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

Regulated – Nuclear Generation Segment

(millions of dollars) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Revenue	**739**	885	**2,000**	2,631
Fuel expense	**81**	79	**217**	239
Gross margin	**658**	806	**1,783**	2,392
Operations, maintenance and administration	**511**	521	**1,693**	1,665
Depreciation and amortization	**116**	230	**333**	691
Property taxes	**7**	6	**20**	19
Income (loss) before other losses, interest, and income taxes	**24**	49	**(263)**	17
Other losses	**4**	2	**4**	-
Income (loss) before interest and income taxes	**20**	47	**(267)**	17

For the three and nine month periods ended September 30, 2017, the segment earnings decreased by $27 million and $284 million, respectively, compared to the same periods in 2016. The decrease in earnings was expected and primarily due to reduced revenue from the nuclear base regulated price of approximately $24 million and $230 million, respectively. The decrease was partially offset by an associated year-over-year decrease in fuel expense. The decrease in revenue during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, reflected lower electricity generation of 0.4 TWh and 4.0 TWh, respectively, primarily due to the ongoing Unit 2 refurbishment outage at the Darlington GS that began in October 2016, without a corresponding increase in the base regulated price. The existing nuclear base regulated price set by the OEB in 2014 continues to be in effect pending the OEB's decision on OPG's application for new regulated prices, proposed to be effective on January 1, 2017. The existing price does not reflect the lower generation as a result of the Darlington Refurbishment project, as it was set to allow the Company to recover its approved nuclear costs over a higher nuclear production volume, based on the 2014 and 2015 outage profile that did not include a refurbishment outage. The reduction in nuclear electricity generation for the three months ended September 30, 2017 was largely offset by the higher electricity generation from the Pickering GS.

OM&A expenses decreased by $10 million during the third quarter of 2017, compared to the same period in 2016, as a result of a higher materials and supplies obsolescence charge recognized in 2016. OM&A expenses increased by $28 million during the nine months ended September 30, 2017, compared to the same period in 2016, due to planned maintenance activities in 2017.

Depreciation and amortization expense, excluding amortization expense related to regulatory account balances, increased by $16 million and $30 million during the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016, primarily due to new assets in service.

The expiry of an OEB-authorized nuclear rate rider on December 31, 2016 contributed to the decrease in segment revenue for the three and nine month periods ended September 30, 2017, compared to the same periods in 2016. As rate riders allow for recovery of approved balances in OEB-authorized regulatory accounts, this decrease in revenue was largely offset by a decrease in amortization expense related to these balances. There was no rate rider

in effect during the nine months ended September 30, 2017, pending the outcome of OPG's current application to the OEB for new regulated prices.

The Unit Capability Factors for the Darlington and Pickering generating stations were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Unit Capability Factor *(%)* [1]				
Darlington GS	**96.2**	89.6	**82.1**	87.6
Pickering GS	**88.7**	77.3	**83.8**	73.8

[1] The nuclear Unit Capability Factor excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS was excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

The Unit Capability Factor at the Darlington GS increased in the third quarter of 2017, compared to the same quarter in 2016, primarily due to the lower number of planned outage days during the third quarter of 2017. The lower Unit Capability Factor at the Darlington GS for the nine months ended September 30, 2017, compared to the same period in 2016, reflected the higher number of planned outage days, largely driven by constraints related to the transition of the station toward refurbishment.

The increase in Unit Capability Factor at the Pickering GS for the three and nine month periods ended September 30, 2017 was primarily due to outage optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station compared to 2016.

Regulated – Nuclear Waste Management Segment

(millions of dollars) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Revenue	**33**	36	**90**	102
Operations, maintenance and administration	**35**	38	**96**	108
Accretion on nuclear fixed asset removal and nuclear waste management liabilities	**230**	228	**696**	684
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(196)**	(248)	**(579)**	(620)
(Loss) Income before interest and income taxes	**(36)**	18	**(123)**	(70)

The segment loss before interest and income taxes was $36 million and $123 million during the three and nine months ended September 30, 2017, respectively, a decrease in earnings of $54 million and $53 million compared to the same periods in 2016. The decline in earnings was primarily due to lower earnings from the Nuclear Segregated Funds, net of the impact of the impact of the Bruce Lease Net Revenues Variance Account, reflecting higher earnings from market returns on fund assets and the CPI-adjusted rate of return guaranteed by the Province for the portion of the Used Fuel Segregated Fund related to the initial 2.23 million used fuel bundles (committed return) in the third quarter of 2016.

As both the Decommissioning Segregated Fund and the Used Fuel Fund were in an overfunded position during the three and nine months period ended September 30, 2017, compared to the underlying funding liabilities per the approved ONFA Reference Plan, the earnings on the funds during these periods reflected the growth rate in the present value of the funding liabilities and were not impacted by market returns and committed return. The higher earnings on both funds during the three and nine months periods ended September 30, 2016 reflected market returns and committed return, as the Decommissioning Segregated Fund became over 120 percent funded during the third quarter of 2016 while the Used Fuel Fund was underfunded, compared to the corresponding funding liabilities.

Higher market returns and committed return in the third quarter of 2016 in relation to the funding liabilities' growth rate reflected in fund earnings during 2017 resulted in a year-over-year decrease in the amount of earnings on the Nuclear Segregated Funds.

As of December 31, 2016, OPG recorded a decrease of approximately $1,570 million to the Nuclear Liabilities and associated asset retirement costs capitalized as part of the carrying value of the nuclear generating stations. The resulting year-over-year decreases in accretion on fixed asset removal and nuclear waste management liabilities recorded in the Regulated – Nuclear Waste Management segment and depreciation and fuel expenses recorded in the Regulated – Nuclear Generation segment during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, were offset by the impact of the Bruce Lease Net Revenues Variance Account and the Nuclear Liability Deferral Account authorized by the OEB.

Under the current OEB-approved cost recovery methodology, these changes in expenses also are not expected to materially affect OPG's income during the rest of 2017, as they are expected to continue to be largely offset by the impact of the regulatory accounts until such time as the OEB implements corresponding changes to OPG's nuclear regulated prices, and subsequently by the impact of such new regulated prices. Further details on the change in the estimate of the Nuclear Liabilities as of December 31, 2016 are described in OPG's 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Asset Retirement Obligation*. **[MONITOR]**

Regulated – Hydroelectric Segment

(millions of dollars) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Revenue [1]	**327**	350	**1,069**	1,148
Fuel expense	**88**	88	**258**	259
Gross margin	**239**	262	**811**	889
Operations, maintenance and administration	**81**	87	**232**	238
Depreciation and amortization	**34**	56	**103**	169
Property tax	**1**	1	**1**	1
Income before other losses (gains), interest and income taxes	**123**	118	**475**	481
Other losses (gains)	**1**	1	**1**	(19)
Income before interest and income taxes	**122**	117	**474**	500

[1] During the three and nine month periods ended September 30, 2017, the Regulated – Hydroelectric segment revenue included incentive payments of $4 million and $9 million, respectively, related to the OEB-approved hydroelectric incentive mechanism (three and nine month periods ended September 30, 2016 – incentive payments of $6 million and $8 million, respectively). The mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers. The incentive payments are reduced to remove incentive revenues arising in connection with SBG conditions.

The increase in segment income before interest and income taxes of $5 million during the third quarter of 2017, compared to the same quarter in 2016, was primarily the result of a decrease in OM&A expenses, mainly due to the timing of repairs and maintenance work in 2017 and a deferral of outages during the high water period.

The decrease in segment income before interest and income taxes of $26 million during the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to a gain of $22 million recognized during the first quarter of 2016 to reflect the OEB's January 2016 decision to reverse a portion of an earlier capital cost disallowance related to the Niagara Tunnel project expenditures, in response to a motion by OPG. The income impact of OEB-approved variance accounts also contributed to the year-over-year decrease in income for the period. These factors were partially offset by the decrease in OM&A expenses related to the timing of repairs and maintenance work in 2017 and a deferral of outages during the high water period.

The decrease in revenue from the segment for the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was largely due to the expiry of an OEB-authorized rate rider on

December 31, 2016. As the rider allowed for the recovery of approved balances in OEB-authorized regulatory accounts, the resulting reduction in revenue was largely offset by lower amortization expense related to these balances. There was no rate rider in effect during the first nine months of 2017 pending the outcome of OPG's current application to the OEB for new regulated prices.

The Hydroelectric Availability for the stations included in the Regulated – Hydroelectric segment was as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Hydroelectric Availability *(%)*	**87.6**	84.1	**89.0**	89.8

The Hydroelectric Availability in the third quarter of 2017 was higher compared to the same period in 2016, primarily due to a higher number of planned outages in 2016 as a result of the refurbishment of the Sir Adam Beck Pump GS reservoir between April 2016 and February 2017. The marginal decrease in Hydroelectric Availability during the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to a higher number of unplanned outage days at the Northwestern Ontario and Niagara region hydroelectric stations, partially offset by higher availability from the Sir Adam Beck Pump GS.

Contracted Generation Portfolio Segment

(millions of dollars) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Revenue	**141**	149	**431**	431
Fuel expense	**15**	19	**42**	42
Gross margin	**126**	130	**389**	389
Operations, maintenance and administration	**39**	44	**118**	129
Depreciation and amortization	**20**	19	**59**	56
Accretion on fixed asset removal liabilities	**3**	2	**7**	6
Property taxes	**-**	1	**5**	6
Income from investments subject to significant influence	**(11)**	(11)	**(29)**	(28)
Income before other loss, interest and income taxes	**75**	75	**229**	220
Other loss	**-**	1	**-**	1
Income before interest and income taxes	**75**	74	**229**	219

Income before interest and income taxes from the segment increased by $1 million and $10 million during the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016. The increase in earnings for the three months ended September 30, 2017 mainly resulted from revenues from the Peter Sutherland Sr. GS that was placed in-service at the end of the first quarter of 2017 and lower OM&A expenses, partially offset by lower revenue from the Atikokan GS. The decrease in revenue from the Atikokan GS was primarily due to higher revenues in 2016, when the station was called upon to provide the needed support to the electricity system in Northwestern Ontario as a result of an outage at a local transformer station. For the nine months ended September 30, 2017, the increase in earnings was primarily due to lower OM&A expenses. The lower OM&A expenses for the three and nine month periods ended September 30, 2017 were mainly due to the prospective adoption of the full yield curve approach to the estimation of the service and interest cost components of pension and OPEB costs starting in 2017.

The Hydroelectric Availability and the Thermal Equivalent Forced Outage Rate (EFOR) for the Contracted Generation Portfolio segment were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Hydroelectric Availability *(%)*	**66.1**	68.2	**76.9**	79.6
Thermal EFOR *(%)*	**2.6**	2.1	**6.0**	1.3

Lower Hydroelectric Availability during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was primarily due to an increase in the number of planned outage days at the Lower Mattagami River hydroelectric generating stations.

The higher Thermal EFOR during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was primarily due to a higher number of unplanned outage days at a Lennox GS unit as a result of a transmission outage and a generator cooling water system outage in 2017.

Services, Trading, and Other Non-Generation Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue	**9**	15	**36**	52
Fuel expense	**1**	1	**1**	1
Gross margin	**8**	14	**35**	51
Operations, maintenance and administration	**1**	11	**2**	20
Depreciation and amortization	**8**	8	**22**	25
Accretion on fixed asset removal liabilities	**2**	2	**6**	6
Property taxes	**-**	4	**4**	9
(Loss) income before other gains, interest, and income taxes	**(3)**	(11)	**1**	(9)
Other gains	**(2)**	(3)	**(385)**	(5)
Income (loss) before interest and income taxes	**(1)**	(8)	**386**	(4)

Segment earnings improved by $7 million during the third quarter of 2017, compared to the same quarter in 2016. The improvement in earnings was primarily due to lower OM&A expenses reflecting project expenditures incurred in the third quarter of 2016, and OPG's decision, in the fourth quarter of 2016, to proceed with the decommissioning of Lambton GS.

Segment income before interest and income taxes increased by $390 million for the nine months ended September 30, 2017, compared to the same period in 2016. The increase in earnings mainly reflected the gain on the sale of OPG's head office premises and associated parking facility recorded during the second quarter of 2017.

LIQUIDITY AND CAPITAL RESOURCES

OPG's primary sources of liquidity and capital are funds generated from operations, bank financing, credit facilities provided by the Ontario Electricity Financial Corporation (OEFC), long-term corporate debt, and capital market financing. These sources are used for multiple purposes including: to invest in plants and technologies, to undertake major projects, to fund long-term obligations such as contributions to the pension fund and the Nuclear Segregated Funds, to make payments under the OPEB plans, to fund expenditures on Nuclear Liabilities not reimbursable from the Nuclear Segregated Funds, to service and repay long-term debt, to provide general working capital, and to fund OPG's investment in the Fair Hydro Plan.

Changes in cash and cash equivalents for the three and nine month periods ended September 30 are as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Cash and cash equivalents, beginning of period	**242**	295	**186**	464
Cash flow provided by operating activities	**485**	530	**698**	1,211
Cash flow used in investing activities	**(463)**	(390)	**(720)**	(1,253)
Cash flow provided by (used in) financing activities	**16**	(9)	**116**	4
Net increase (decrease)	**38**	131	**94**	(38)
Cash and cash equivalents, end of period	**280**	426	**280**	426

For a discussion of cash flow provided by operating activities and the FFO Adjusted Interest Coverage ratio, refer to the details in the section, *Highlights* under the heading, *Overview of Results*.

Investing Activities

Electricity generation is a capital-intensive business. It requires continued investment in plants and technologies to maintain and improve operating performance including asset reliability, safety and environmental performance, to increase the generating capacity of existing stations, and to invest in the development of new generating stations, emerging technologies and other business growth opportunities.

Cash flow used in investing activities during the third quarter of 2017 was $463 million, compared to $390 million for the same period in 2016. The increase in cash flow used for investing activities mainly resulted from higher expenditures on the Darlington Refurbishment project in the third quarter of 2017.

Cash flow used in investing activities decreased by $533 million for the nine months ended September 30, 2017, compared to the same period in 2016. The decrease in net cash flow used in investing activities was primarily due to the receipt of proceeds from the sale of OPG's head office premises and associated parking facility in the second quarter of 2017 pursuant to a Shareholder Declaration and Shareholder Resolution, and the acquisition of nine million common shares of Hydro One Limited (Hydro One) in the second quarter of 2016, partially offset by higher expenditures on the Darlington Refurbishment project in 2017. OPG acquired the Hydro One shares for investment purposes, to mitigate the risk of future price volatility related to the Company's future share delivery obligations under the collective agreements with the Power Workers' Union and The Society of Energy Professionals.

Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from the sale of head office premises and associated parking facility, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. OPG expects that the amount of designated proceeds to be transferred into the Consolidated Revenue Fund will be largely consistent with the after-tax gain on sale. The transfer is expected to take place later in 2017.

Financing Activities

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. In the second quarter of 2017, OPG renewed and extended the expiry date of both tranches from May 2021 to May 2022. There were no amounts outstanding under the bank credit facility as at September 30, 2017.

There was $160 million of commercial paper outstanding under OPG's commercial paper program as at September 30, 2017.

As at September 30, 2017, OPG also maintained $25 million of short-term, uncommitted overdraft facilities, and a further $463 million of short-term, uncommitted credit facilities, which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other general corporate purposes. As at September 30, 2017, a total of $388 million of Letters of Credit had been issued under these facilities. This included $349 million for the supplementary pension plans, $38 million for general corporate purposes, and $1 million related to the operation of the PEC.

The Company has an agreement to sell an undivided co-ownership interest in its current and future accounts receivable to an independent trust, expiring on November 30, 2018. The maximum amount of co-ownership interest that can be sold under this agreement is $150 million. As at September 30, 2017, no borrowings were issued under this agreement and there were Letters of Credit outstanding under this agreement of $150 million, which were issued in support of OPG's supplementary pension plans.

As at September 30, 2017, Lower Mattagami Energy Limited Partnership (LME) maintained a $400 million bank credit facility to support the funding requirements for the Lower Mattagami River project including support for LME's commercial paper program and the issuance of the Letters of Credit. The facility consists of a $300 million tranche which, in the third quarter of 2017, was extended to mature in August 2022 and a $100 million tranche which, in the third quarter of 2017, was reduced from $200 million and extended to mature in August 2018. As at September 30, 2017, there was no external commercial paper outstanding under LME's commercial paper program. A letter of credit of $55 million was issued in July 2017 and remains outstanding as at September 30, 2017 under the $300 million tranche of the credit facility.

In June 2016, OPG entered into a $700 million general corporate credit facility agreement with the OEFC, which expires on December 31, 2017. In the third quarter of 2017, the agreement was amended to increase the credit facility to $2,350 million and to extend its expiry date to December 31, 2018.

In February 2017, OPG issued senior notes payable to the OEFC totalling $200 million and maturing in February 2047. The effective interest rate and coupon interest rate of these notes was 4.12 percent. In June 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in June 2047. The effective interest rate and coupon interest rate of these notes was 3.65 percent. In August 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in August 2047. The effective interest rate and coupon interest rate of these notes was 3.86 percent. In September 2017, OPG issued senior notes payable to the OEFC totalling $400 million and maturing in September 2047. The effective interest rate and coupon interest rate of these notes was 4.07 percent. As at September 30, 2017, there were outstanding long-term borrowings of $800 million under this credit facility.

In October 2017, OPG issued $500 million of senior notes payable under a Medium Term Note Program. The notes bear a coupon interest rate of 3.32 percent and an effective rate of 3.43 percent, payable semi-annually until maturity on October 4, 2027. The offering was made under OPG's $2 billion short form base shelf prospectus dated September 12, 2017. The net proceeds will be used for general corporate purposes, including the financing of OPG's subordinated debt investment in the Fair Hydro Plan.

As at September 30, 2017, OPG's long-term debt outstanding was $5,482 million, including $628 million due within one year.

OPG continues to evaluate arrangements that would appropriately support the Company's financing needs and capital expenditure programs.

Contractual and Commercial Commitments

Pension Plan Actuarial Valuation

A new actuarial valuation of the OPG registered pension plan was filed with the Financial Services Commission of Ontario in September 2017 with an effective date of January 1, 2017. The annual funding requirements in accordance with the new actuarial valuation are $212 million for 2017, $215 million for 2018, and $219 million for 2019. The next actuarial valuation must have an effective date no later than January 1, 2020.

BALANCE SHEET HIGHLIGHTS

The following section provides highlights of OPG's unaudited interim consolidated financial position using selected balance sheet data:

(millions of dollars) (unaudited)	As At September 30 2017	As At December 31 2016
Property, plant and equipment - net	**20,801**	19,998
The increase was primarily due to capital expenditures on the Darlington Refurbishment project, partially offset by depreciation expense.		
Nuclear fixed asset removal and nuclear waste management funds *(current and non-current portions)*	**16,534**	15,984
The increase was primarily due to earnings on the Nuclear Segregated Funds, partially offset by reimbursements of eligible expenditures on nuclear fixed asset removal and nuclear waste management activities.		
Short-term debt	**160**	2
The increase was due to commercial paper issued under OPG's commercial paper program during the third quarter of 2017.		
Fixed asset removal and nuclear waste management liabilities	**20,075**	19,484
The increase was primarily a result of accretion expense representing the increase in the liabilities due to the passage of time, partially offset by expenditures on nuclear fixed asset removal and waste management activities.		

Off-Balance Sheet Arrangements

In the normal course of operations, OPG engages in a variety of transactions that, under US GAAP, are either not recorded in the Company's interim consolidated financial statements or are recorded in the Company's interim consolidated financial statements using amounts that differ from the full contract amounts. Principal off-balance sheet activities for OPG include guarantees and long-term contracts.

CHANGES IN ACCOUNTING POLICIES AND ESTIMATES

OPG's significant accounting policies are outlined in Note 3 to the audited consolidated financial statements as at and for the year ended December 31, 2016. A discussion of recent accounting pronouncements and change in accounting estimate are included in Note 2 to OPG's unaudited interim consolidated financial statements as at and for the three and nine month periods ended September 30, 2017 under the heading, *Significant Accounting Policies and Estimates*. Disclosure regarding OPG's critical accounting policies is included in OPG's 2016 annual MD&A.

RISK MANAGEMENT

The following provides an update to the discussion of the Company's risks and risk management activities included in OPG's 2016 annual MD&A. As such, the disclosure in this section should be read in conjunction with the *Risk Management* section included in the annual MD&A.

Risks to Achieving Project Excellence

Deep Geologic Repository for Low and Intermediate Level Waste

In August 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of the potential cumulative effects of the DGR project on the physical and cultural heritage of the SON, taking into account the results of the SON Community Process. OPG continues to work with the SON, however the timing and outcome of the SON Community Process and the EA decision by the Minister are uncertain.

Risks to Maintaining Financial Strength

Commodity Markets

Changes in the market price of fuels used to produce electricity can adversely impact OPG's earnings and cash flow from operations.

To manage the risk of unpredictable increases in the price of fuels, the Company has fuel hedging programs, which include fixed price and indexed contracts.

The percentages hedged of OPG's fuel requirements are shown in the following table. These amounts are based on yearly forecasts of generation and supply mix, and as such, are subject to change as these forecasts are updated.

	2017 [1]	2018	2019
Estimated fuel requirements hedged [2]	73%	73%	69%

[1] Based on actual fuel requirements hedged for the nine months ended September 30, 2017 and forecast for the remainder of the year.

[2] Represents the approximate portion of megawatt-hours of expected generation production (and year-end inventory targets) from each type of OPG-operated facility (nuclear, hydroelectric and thermal) for which the Company has entered into contractual arrangements or obligations in order to secure the price of fuel, or which is subject to regulation. In the case of hydroelectric generation, this represents the gross revenue charge and water rental charges. Excess fuel inventories (nuclear and thermal) in a given year are attributed to the next year for the purpose of measuring hedge ratios.

Foreign Exchange

OPG's earnings and cash flow can be affected by movements in the United States dollar (USD) relative to the Canadian dollar.

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are denominated in, or tied to, USD. To manage this risk, OPG periodically employs various financial instruments such as forwards and other

derivative contracts, in accordance with approved risk management policies. As at September 30, 2017, OPG had no foreign exchange contracts outstanding.

Trading

OPG's financial performance can be affected by its trading activities.

OPG's electricity trading operations are closely monitored, with total exposures measured and reported to senior management on a daily basis. The main metric used to measure the financial risk of trading activity is Value at Risk (VaR). VaR is defined as a probabilistic maximum potential future loss expressed in monetary terms for a portfolio based on normal market conditions over a set period of time. For the third quarter of 2017, the VaR utilization ranged between $0.2 million and $0.3 million.

Credit

Deterioration in energy markets counterparty credit and non-performance by suppliers and contractors can adversely impact OPG's earnings and cash flow from operations.

OPG manages its exposure to suppliers or counterparties by evaluating their financial condition and negotiating appropriate collateral or other forms of security. OPG's credit exposure relating to energy markets transactions as at September 30, 2017 was $356 million, including $346 million with the IESO. Management considers the Company's risk exposure relating to electricity sales through the IESO-administered spot market to be low as the IESO oversees the credit worthiness of all market participants. In accordance with the IESO's prudential support requirements, market participants are required to provide collateral to cover funds that they might owe to the market. Of the $10 million remaining exposure as at September 30, 2017, over 95 percent was related to investment grade counterparties.

Fair Hydro Plan

OPG's role in connection with the Fair Hydro Plan could have reputational impacts on the Company.

The *Ontario Fair Hydro Plan Act, 2017* received Royal Assent on June 1, 2017 and its attendant regulations came into force in June, July, and October 2017. **[UPDATE]** The regulations clarify aspects of the structure and program logistics required for OPG, as the Financial Services Manager of the Fair Hydro Plan, to refinance a portion of the Global Adjustment through the Trust. OPG's reputation could potentially be adversely impacted through its involvement with the Fair Hydro Plan and through stakeholder opinions related to this involvement.

Recovery of Pension and OPEB Costs

On September 14, 2017, the OEB issued its final report on the guiding principles and the policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the electricity and natural gas sectors. The report reaffirmed the conclusions of the initial report issued in May 2017, including the establishment of the accrual basis of accounting as the default rate-setting method and the establishment of a variance account to record asymmetric carrying charges in favour of ratepayers on the differences between the accrual costs recovered and cash payments made by a utility for pension and OPEB plans. The report requires OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the Pension & OPEB Cash Versus Accrual Differential Deferral Account that has been in effect since November 1, 2014, until such time as the OEB approves the resumption of the accrual basis of recovery. The future recovery of amounts recorded in the account will be subject to this approval. The report confirmed that OPG would become subject to the carrying charges on the differences between accrual costs and cash payments going back to November 1, 2014, with the charges calculated on the portion of such differences that have been recovered through regulated prices. The carrying charges will be determined at prescribed interest rate set quarterly by the OEB based on the quarterly return of a mid-term corporate bond index yield. This outcome has reduced OPG's risk related to the recovery of actual pension and OPEB accrual costs and the recovery of the balance in the Pension & OPEB Cash Versus Accrual Differential Deferral Account.

The account had a balance of $552 million as at September 30, 2017 and is recognized on the Company's consolidated balance sheet as a regulatory asset. OPG's financial results for the three and nine month periods ended September 30, 2017 were not impacted by the issuance of the OEB's report.

RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One, the IESO and the OEFC. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions are summarized below:

	Three Months Ended September 30			
	2017		2016	
(millions of dollars) (unaudited)	**Revenue**	**Expense**	**Revenue**	**Expense**
Hydro One				
Electricity sales	**2**	**-**	1	-
Services	**-**	**3**	-	3
Dividends	**2**	**-**	-	2
Province of Ontario				
Decommissioning Fund excess funding [1]	**-**	**(44)**	-	201
Used Fuel Fund rate of return guarantee and excess funding [1]	**-**	**(39)**	-	295
Gross revenue charges	**-**	**27**	-	28
ONFA guarantee fee	**-**	**2**	-	2
Other	**-**	**2**	-	-
OEFC				
Gross revenue charges	**-**	**62**	-	57
Interest expense on long-term notes	**-**	**40**	-	42
Income taxes, net of investment tax credits	**-**	**23**	-	28
IESO				
Electricity related revenue	**1,126**	**4**	1,293	7
	1,130	**80**	1,294	665

(millions of dollars) (unaudited)	Nine Months Ended September 30 2017 Revenue	2017 Expense	2016 Revenue	2016 Expense
Hydro One				
Electricity sales	**7**	**-**	4	-
Services	**1**	**8**	1	12
Dividends	**6**	**-**	-	4
Province of Ontario				
Decommissioning Fund excess funding [1]	**-**	**164**	-	137
Used Fuel Fund rate of return guarantee and excess funding [1]	**-**	**217**	-	190
Gross revenue charges	**-**	**84**	-	91
ONFA guarantee fee	**-**	**6**	-	6
Other	**-**	**3**	-	-
OEFC				
Gross revenue charges	**-**	**156**	-	147
Interest expense on long-term notes	**-**	**122**	-	127
Income taxes, net of investment tax credits	**-**	**132**	-	112
IESO				
Electricity related revenue	**3,228**	**11**	3,894	22
	3,242	**903**	3,899	848

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at September 30, 2017 and December 31, 2016, the Nuclear Segregated Funds were reported net of amounts due to the Province of $3,796 million and $3,415 million, respectively. The details of accounting for the Nuclear Segregated Funds are described in OPG's 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

The receivable, available-for-sale securities, payable and long-term debt balances between OPG and its related parties are summarized below:

(millions of dollars) (unaudited)	September 30 2017	December 31 2016
Receivables from related parties		
Hydro One	**1**	1
IESO	**346**	421
OEFC	**3**	1
PEC	**2**	4
Province of Ontario	**5**	2
Available-for-sale securities		
Hydro One shares	**190**	212
Accounts payable and accrued charges		
OEFC	**37**	61
Province of Ontario	**6**	2
IESO	**2**	2
Long-term debt (including current portion)		
Notes payable to OEFC	**3,245**	3,295

OPG holds interest-bearing Province of Ontario bonds in the Nuclear Segregated Funds and the OPG registered pension fund. As at September 30, 2017, the Nuclear Segregated Funds held $1,498 million of interest-bearing Province of Ontario bonds, while the registered pension fund had no such holdings. As at December 31, 2016, the Nuclear Segregated Funds and the registered pension fund held $1,652 million and $284 million of interest-bearing Province of Ontario bonds, respectively. These bonds are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

There have been no related party transactions related to the Fair Hydro Plan and associated financing activities. The first transaction between the Trust and the IESO is expected later in 2017.

INTERNAL CONTROLS OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

The Company maintains a comprehensive system of policies, procedures, and processes that represents its framework for internal controls over financial reporting and for its disclosure controls and procedures (together, ICOFR). There were no changes in the Company's internal control system during the current interim period that has or is reasonably likely to have a material impact to the ICOFR.

QUARTERLY FINANCIAL HIGHLIGHTS

The following tables set out selected financial information from OPG's unaudited interim consolidated financial statements for each of the eight most recently completed quarters.

(millions of dollars - except where noted) *(unaudited)*	**September 30 2017**	**June 30 2017**	**March 31 2017**	**December 31 2016**
Revenue	**1,217**	1,146	1,176	1,388
Net income (loss)	**140**	307	68	(8)
Less: Net income attributable to non-controlling interest	**9**	4	4	5
Net income (loss) attributable to the Shareholder	**131**	303	64	(13)
Per common share, attributable to the Shareholder *(dollars)*	**$0.51**	$1.18	$0.25	($0.05)

(millions of dollars - except where noted) *(unaudited)*	**September 30 2016**	**June 30 2016**	**March 31 2016**	**December 31 2015**
Revenue	1,400	1,387	1,478	1,312
Net income (loss)	198	135	128	(100)
Less: Net income attribute to the non-controlling interest	4	3	5	1
Net income (loss) attributable to the Shareholder	194	132	123	(101)
Per common share, attributable to the Shareholder *(dollars)*	$0.76	$0.51	$0.48	($0.39)

Trends

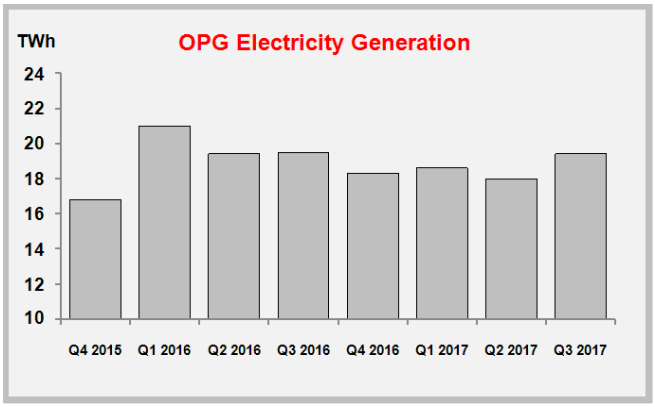
OPG's quarterly results are affected by changes in grid-supplied electricity demand, primarily resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. Weather conditions affect water flows, electricity demand, and prevalence of SBG conditions. Historically, OPG's revenues have been higher in the first

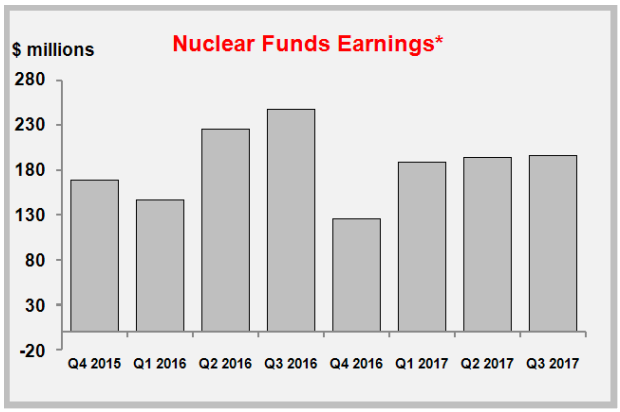
quarter of a fiscal year as a result of winter heating demands and in the third quarter due to air conditioning and cooling demands. The financial impact of forgone production due to SBG conditions at the regulated hydroelectric stations and the financial impact of differences between forecast water flows reflected in OEB-approved regulated prices and the actual water flows are mitigated by regulatory variance accounts authorized by the OEB.

The timing of planned outages at a nuclear generating station during the year can cause variability in year-over-year operating results for partial periods of a fiscal year, including the impact on revenue and OM&A expenses, but is not a significant driver of variability for full fiscal year results.

OPG's electricity generation was reduced as a result of the Unit 2 refurbishment outage at the Darlington GS, which began in October 2016 and is expected to continue until early 2020.

OPG's financial results are also affected by the earnings on the Nuclear Segregated Funds, net of the impact of the Bruce Lease Net Revenues Variance Account.





*net of regulatory variance account

Additional items that affected net income in certain quarters above are described in OPG's 2016 annual MD&A under the section, *Quarterly Financial Highlights*.

SUPPLEMENTARY NON-GAAP FINANCIAL MEASURES

In addition to providing net income and other financial information in accordance with US GAAP, certain non-GAAP financial measures are also presented in OPG's MD&A. These non-GAAP measures do not have any standardized meaning prescribed by US GAAP and, therefore, may not be comparable to similar measures presented by other issuers. OPG utilizes these measures to make operating decisions and assess performance. Readers of the MD&A would utilize these measures in assessing the Company's financial performance from ongoing operations. The Company believes that these indicators are important since they provide additional information about OPG's performance, facilitate comparison of results over different periods, and present measures consistent with the Company's strategies to provide value to the Shareholder, improve cost performance, and ensure availability of cost effective funding. These non-GAAP financial measures have not been presented as an alternative to net income, cash flow provided by operating activities, or any other measure in accordance with US GAAP, but as indicators of operating performance.

The definitions of the non-GAAP financial measures are as follows:

(1) **ROE Excluding AOCI** is defined as net income attributable to the Shareholder divided by average equity attributable to the Shareholder excluding AOCI, for the period. ROE Excluding AOCI is measured over a 12-month period and is calculated as follows:

	Twelve Months Ended	
(millions of dollars – except where noted) (unaudited)	**September 30 2017**	**December 31 2016**
ROE Excluding AOCI		
Net income attributable to the Shareholder	**485**	436
Divided by: Average equity attributable to the Shareholder, excluding AOCI	**11,055**	10,442
ROE Excluding AOCI *(percent)*	**4.4**	4.2

(2) **FFO Adjusted Interest Coverage** is defined as FFO before interest divided by adjusted interest expense. FFO before interest is defined as cash flow provided by operating activities adjusted for interest paid, interest capitalized to fixed and intangible assets, and changes to non-cash working capital balances for the period. Adjusted interest expense is calculated as net interest expense plus interest income, interest capitalized to fixed and intangible assets, interest related to regulatory assets and liabilities, and the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets, for the period.

FFO Adjusted Interest Coverage is measured over a 12-month period and is calculated as follows:

	Twelve Months Ended	
(millions of dollars – except where noted) (unaudited)	**September 30 2017**	**December 31 2016**
FFO before interest		
Cash flow provided by operating activities	**1,082**	1,595
Add: Interest paid	**270**	269
Less: Interest capitalized to fixed and intangible assets	**(161)**	(141)
Less: Changes to non-cash working capital balances	**38**	42
FFO before interest	**1,229**	1,765
Adjusted interest expense		
Net interest expense	**84**	120
Add: Interest income	**8**	7
Add: Interest capitalized to fixed and intangible assets	**161**	141
Add: Interest related to regulatory assets and liabilities	**43**	30
Add: Excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets [1]	**-**	45
Adjusted interest expense	**296**	343
FFO Adjusted Interest Coverage *(times)*	**4.2**	5.1

[1] A value of nil is used in the calculation when interest on pension and OPEB projected benefit obligations is equal to, or lower than, expected return on pension plan assets.

(3) **Enterprise Total Generating Cost per MWh** is used to measure OPG's overall organizational cost performance. Enterprise TGC per MWh is defined as OM&A expenses (excluding the Darlington Refurbishment project and other generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to OPG's electricity generation business), fuel expense for OPG-operated stations including hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures (excluding the Darlington Refurbishment project and other generation development projects) incurred during the period, divided by total electricity generation from OPG-operated generating stations plus electricity generation forgone due to SBG conditions during the period.

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars – except where noted) (unaudited)	**2017**	**2016**	**2017**	**2016**
Enterprise TGC				
Total OM&A expenses	**635**	666	**2,054**	2,061
Total fuel expense	**185**	187	**518**	541
Total capital expenditures	**476**	444	**1,335**	1,162
Less: Darlington Refurbishment capital and OM&A costs	**(328)**	(269)	**(943)**	(717)
Less: Other generation development project capital and OM&A costs	**(17)**	(42)	**(53)**	(121)
Add (Less): OM&A and fuel expenses (refundable through) deferred in regulatory variance and deferral accounts	**4**	35	**(19)**	76
Less: Nuclear fuel expense for non OPG-operated stations	**(13)**	(18)	**(42)**	(50)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**13**	5	**47**	38
Less: OM&A expenses ancillary to electricity generation business	**(4)**	(5)	**(13)**	(17)
Other adjustments	**(3)**	(12)	**(7)**	(15)
	948	991	**2,877**	2,958
Adjusted electricity generation *(TWh)*				
Total OPG electricity generation	**19.4**	19.5	**56.0**	59.9
Adjust for electricity generation forgone due to SBG conditions and OPG's share of electricity generation from co-owned facilities	**0.9**	0.1	**4.2**	3.4
	20.3	19.6	**60.2**	63.3
Enterprise TGC per MWh *($/MWh)* [1]	**46.65**	50.72	**47.77**	46.74

[1] Amounts may not calculate due to rounding.

(4) **Nuclear Total Generating Cost per MWh** is used to measure the cost performance of OPG's nuclear generating assets. Nuclear TGC per MWh is defined as OM&A expenses of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the nuclear electricity generation business), nuclear fuel expense for OPG-operated stations (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs) incurred during the period, divided by nuclear electricity generation for the period.

(millions of dollars – except where noted) (unaudited)	**Three Months Ended September 30**		**Nine Months Ended September 30**	
	2017	**2016**	**2017**	**2016**
Nuclear TGC				
Regulated – Nuclear Generation OM&A expenses	**511**	521	**1,693**	1,665
Regulated – Nuclear Generation fuel expense	**81**	79	**217**	239
Regulated – Nuclear Generation capital expenditures	**409**	339	**1,150**	896
Less: Darlington Refurbishment capital and OM&A costs	**(328)**	(269)	**(943)**	(717)
Add: Regulated – Nuclear Generation OM&A and fuel expenses deferred in regulatory variance and deferral accounts	**5**	31	**6**	84
Less: Nuclear fuel expense for non OPG-operated stations	**(13)**	(18)	**(42)**	(50)
Less: Regulated - Nuclear Generation OM&A expenses ancillary to nuclear electricity generation business	**(1)**	(1)	**(3)**	(4)
Other adjustments	**1**	3	**(1)**	(1)
	665	685	**2,077**	2,112
Nuclear electricity generation (TWh)	**11.3**	11.7	**30.6**	34.6
Nuclear TGC per MWh (*$/MWh*) [1]	**58.75**	58.55	**67.87**	61.07

[1] Amounts may not calculate due to rounding.

(5) **Hydroelectric Total Generating Cost per MWh** is used to measure the cost performance of OPG's hydroelectric generating assets. Hydroelectric TGC per MWh is defined as OM&A expenses of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the hydroelectric electricity generation business), hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding expenditures related to the Peter Sutherland Sr. GS, Ranney Falls GS, and other hydroelectric generation development projects) incurred during the period, divided by total hydroelectric electricity generation plus hydroelectric electricity generation forgone due to SBG conditions during the period. OPG reports hydroelectric gross revenue charge and water rental payments as fuel expense.

(millions of dollars – except where noted) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Hydroelectric TGC				
Regulated – Hydroelectric OM&A expenses	**81**	87	**232**	238
Regulated – Hydroelectric fuel expense	**88**	88	**258**	259
Contracted Generation Portfolio OM&A expenses	**39**	44	**118**	129
Contracted Generation Portfolio fuel expense	**15**	19	**42**	42
Regulated – Hydroelectric and Contracted Generation Portfolio capital expenditures	**56**	92	**141**	231
Less: Regulated – Hydroelectric and Contracted Generation Portfolio generation development project capital and OM&A costs	**(17)**	(41)	**(52)**	(117)
Less: Thermal OM&A and fuel expenses and capital expenditures in the Contracted Generation Portfolio	**(39)**	(51)	**(119)**	(126)
(Less) Add: Regulated – Hydroelectric OM&A and fuel expenses refundable through regulatory variance and deferral accounts	**(1)**	4	**(25)**	(8)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**13**	5	**47**	38
Other adjustments	**(1)**	(1)	**-**	(1)
	234	246	**642**	685
Adjusted hydroelectric electricity generation *(TWh)*				
Regulated – Hydroelectric electricity generation	**7.3**	6.9	**23.5**	22.8
Contracted Generation Portfolio electricity generation	**0.8**	0.9	**1.9**	2.5
Adjust for hydroelectric electricity generation forgone due to SBG conditions and non-hydroelectric electricity generation of the Contracted Generation Portfolio, including OPG's share of electricity generation from co-owned facilities	**0.8**	0.1	**4.1**	3.4
	8.9	7.9	**29.5**	28.7
Hydroelectric TGC per MWh *($/MWh)* [1]	**26.20**	31.01	**21.74**	23.99

[1] Amounts may not calculate due to rounding.

(6) **Gross margin** is defined as revenue less fuel expense.

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ONTARIO POWER GENERATION INC.

INTERIM CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

SEPTEMBER 30, 2017

[DRAFT]

ONTARIO POWER GENERATION

INTERIM CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

(millions of dollars except where noted)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Revenue *(Note 12)*	**1,217**	1,400	**3,539**	4,265
Fuel expense *(Note 12)*	**185**	187	**518**	541
Gross margin	**1,032**	1,213	**3,021**	3,724
Expenses *(Note 12)*				
Operations, maintenance and administration	**635**	666	**2,054**	2,061
Depreciation and amortization	**178**	313	**517**	941
Accretion on fixed asset removal and nuclear waste management liabilities	**235**	232	**709**	696
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(196)**	(248)	**(579)**	(620)
Property taxes	**8**	12	**30**	35
Income from investments subject to significant influence	**(11)**	(11)	**(29)**	(28)
	849	964	**2,702**	3,085
Income before other losses (gains), interest and income taxes	**183**	249	**319**	639
Other losses (gains) *(Note 12)*	**3**	1	**(380)**	(23)
Income before interest and income taxes	**180**	248	**699**	662
Net interest expense *(Note 5)*	**21**	28	**56**	92
Income before income taxes	**159**	220	**643**	570
Income tax expense	**19**	22	**128**	109
Net income	**140**	198	**515**	461
Net income attributable to the Shareholder	**131**	194	**498**	449
Net income attributable to non-controlling interest	**9**	4	**17**	12
Basic and diluted net income per common share *(dollars)*	**0.51**	0.76	**1.94**	1.75
Common shares outstanding *(millions)*	**256.3**	256.3	**256.3**	256.3

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

(millions of dollars)	Three Months Ended September 30 2017	2016	Nine Months Ended September 30 2017	2016
Net income	**140**	198	**515**	461
Other comprehensive income, net of income taxes *(Note 7)*				
Reclassification to income of amounts related to pension and other post-employment benefits [1]	**3**	3	**8**	9
Reclassification to income of losses on derivatives designated as cash flow hedges [2]	**4**	4	**13**	14
Unrealized (loss) gain on available-for-sale securities [3]	**(4)**	-	**(6)**	15
Other comprehensive income for the period	**3**	7	**15**	38
Comprehensive income	**143**	205	**530**	499
Comprehensive income attributable to the Shareholder	**134**	201	**513**	487
Comprehensive income attributable to non-controlling interest	**9**	4	**17**	12

[1] Net of income tax expense of nil and $1 million for the three months ended September 30, 2017 and 2016, respectively. Net of income tax expense of $2 million and $3 million for the nine months ended September 30, 2017 and 2016, respectively.

[2] Net of income tax expense of $1 million for the three months ended September 30, 2017 and 2016. Net of income tax expense of $2 million for the nine months ended September 30, 2017 and 2016.

[3] Net of income tax expense of nil for the three months ended September 30, 2017 and 2016. Net of income tax recovery of $1 million and income tax expense of $5 million for the nine months ended September 30, 2017 and 2016, respectively.

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

Nine Months Ended September 30 *(millions of dollars)*	**2017**	**2016**
Operating activities		
Net income	**515**	461
Adjust for non-cash items:		
Depreciation and amortization	**517**	941
Accretion on fixed asset removal and nuclear waste management liabilities	**709**	696
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(579)**	(620)
Pension and other post-employment benefit costs *(Note 8)*	**339**	351
Deferred income taxes	**50**	(41)
Mark-to-market on derivative instruments	**(4)**	1
Provision for used nuclear fuel and low and intermediate level nuclear waste	**84**	91
Regulatory assets and liabilities	**(97)**	(82)
Provision for materials and supplies	**13**	38
Other gains	**(374)**	(23)
Other	**(35)**	(14)
	1,138	1,799
Contributions to nuclear fixed asset removal and nuclear waste management funds	**-**	(112)
Expenditures on fixed asset removal and nuclear waste management	**(231)**	(189)
Reimbursement of expenditures on nuclear fixed asset removal and nuclear waste management	**59**	49
Contributions to pension funds and expenditures on other post-employment benefits and supplementary pension plans	**(270)**	(331)
Expenditures on restructuring	**(3)**	(3)
Distributions received from investments subject to significant influence	**37**	40
Net changes to other long-term assets and liabilities	**23**	17
Net changes in non-cash working capital balances *(Note 13)*	**(55)**	(59)
Cash flow provided by operating activities	**698**	1,211
Investing activities		
Net proceeds from sale of property, plant and equipment	**484**	-
Purchase of available-for-sale securities	**-**	(213)
Proceeds from deposit note *(Note 4)*	**70**	65
Investment in property, plant and equipment and intangible assets	**(1,274)**	(1,105)
Cash flow used in investing activities	**(720)**	(1,253)
Financing activities		
Issuance of long-term debt *(Note 4)*	**800**	-
Repayment of long-term debt	**(852)**	(2)
Contribution from non-controlling interest	**19**	-
Distribution to non-controlling interest	**(11)**	(11)
Issuance of short-term notes	**1,458**	2,916
Repayment of short-term notes	**(1,298)**	(2,899)
Cash flow provided by financing activities	**116**	4
Net increase (decrease) in cash and cash equivalents	**94**	(38)
Cash and cash equivalents, beginning of period	**186**	464
Cash and cash equivalents, end of period	**280**	426

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

As at *(millions of dollars)*	September 30 2017	December 31 2016
Assets		
Current assets		
Cash and cash equivalents	**280**	186
Available-for-sale securities	**190**	212
Receivables from related parties	**357**	429
Nuclear fixed asset removal and nuclear waste management funds	**19**	24
Fuel inventory	**290**	310
Materials and supplies	**96**	100
Income tax recoverable	**11**	-
Prepaid expenses	**212**	198
Other current assets	**108**	298
	1,563	1,757
Property, plant and equipment	**30,491**	29,315
Less: accumulated depreciation	**9,690**	9,317
	20,801	19,998
Intangible assets	**546**	503
Less: accumulated amortization	**425**	404
	121	99
Other non-current assets		
Nuclear fixed asset removal and nuclear waste management funds	**16,515**	15,960
Long-term materials and supplies	**364**	345
Regulatory assets *(Note 3)*	**6,002**	5,855
Investments subject to significant influence *(Note 14)*	**313**	321
Other long-term assets	**27**	37
	23,221	22,518
	45,706	44,372

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

As at *(millions of dollars)*	September 30 2017	December 31 2016
Liabilities		
Current liabilities		
Accounts payable and accrued charges	**1,144**	1,164
Deferred revenue	**12**	12
Short-term debt	**160**	2
Long-term debt due within one year *(Note 4)*	**628**	1,103
Income taxes payable	**-**	123
	1,944	2,404
Long-term debt *(Note 4)*	**4,840**	4,417
Other non-current liabilities		
Fixed asset removal and nuclear waste management liabilities *(Note 6)*	**20,075**	19,484
Pension liabilities	**2,867**	3,012
Other post-employment benefit liabilities	**2,959**	2,897
Long-term accounts payable and accrued charges	**235**	213
Deferred revenue	**338**	298
Deferred income taxes	**890**	829
Regulatory liabilities *(Note 3)*	**510**	310
	27,874	27,043
Equity		
Common shares [1]	**5,126**	5,126
Retained earnings	**6,034**	5,534
Accumulated other comprehensive loss *(Note 7)*	**(277)**	(295)
Equity attributable to the Shareholder	**10,883**	10,365
Equity attributable to non-controlling interest	**165**	143
Total equity	**11,048**	10,508
	45,706	44,372

[1] 256,300,010 common shares outstanding at a stated value of $5,126 million as at September 30, 2017 and December 31, 2016.

Commitments and Contingencies *(Notes 4, 10 and 11)*

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY (UNAUDITED)

Nine Months Ended September 30 *(millions of dollars)*	**2017**	**2016**
Common shares	**5,126**	5,126
Retained earnings		
Balance at beginning of period	**5,534**	5,098
Net income attributable to the Shareholder	**498**	449
Reclassification of non-controlling interest on change in ownership interest *(Note 15)*	**2**	-
Balance at end of period	**6,034**	5,547
Accumulated other comprehensive loss, net of income taxes		
Balance at beginning of period	**(295)**	(319)
Other comprehensive income	**15**	38
Reclassification of non-controlling interest on change in ownership interest *(Note 15)*	**3**	-
Balance at end of period	**(277)**	(281)
Equity attributable to the Shareholder	**10,883**	10,392
Equity attributable to non-controlling interest		
Balance at beginning of period	**143**	140
Equity contribution from non-controlling interest *(Note 15)*	**21**	-
Reclassification of non-controlling interest on change in ownership interest *(Note 15)*	**(5)**	-
Distribution to non-controlling interest	**(11)**	(11)
Income attributable to non-controlling interest	**17**	12
Balance at end of period	**165**	141
Total equity	**11,048**	10,533

See accompanying notes to the interim consolidated financial statements

NOTES TO THE INTERIM CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

For the three and nine months ended September 30, 2017 and 2016

1. BASIS OF PRESENTATION

These interim consolidated financial statements for the three and nine months ended September 30, 2017 and 2016 include the accounts of Ontario Power Generation Inc. (OPG or the Company) and its subsidiaries. The Company consolidates its interest in entities over which it is able to exercise control and attributes the results to its sole shareholder, the Province of Ontario (Province). Interests owned by other parties are reflected as non-controlling interest. These interim consolidated financial statements have been prepared and presented in accordance with United States generally accepted accounting principles (US GAAP). These interim consolidated financial statements do not contain all of the disclosures required by US GAAP for annual financial statements. Accordingly, they should be read in conjunction with the annual consolidated financial statements of the Company as at and for the year ended December 31, 2016. All dollar amounts are presented in Canadian dollars.

Certain of the 2016 comparative amounts have been reclassified from financial statements previously presented to conform to the 2017 interim consolidated financial statement presentation.

Use of Management Estimates

The preparation of consolidated financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the interim consolidated financial statements, and the reported amounts of revenues and expenses for the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in the period incurred. Significant estimates are included in the determination of pension and other post-employment benefit (OPEB) balances, asset retirement obligations and associated asset retirement costs capitalized as part of property, plant and equipment, income taxes (including deferred income taxes), contingencies, regulatory assets and liabilities, valuation of derivative instruments and investments in segregated funds, depreciation and amortization expenses, and inventories. Actual results may differ significantly from these estimates.

2. SIGNIFICANT ACCOUNTING POLICIES AND ESTIMATES

Change in Accounting Estimate

Pension and Other Post-Employment Benefits

Effective January 1, 2017, OPG changed the method used to estimate the service and interest cost components of pension and OPEB costs. OPG adopted a full yield curve approach to the estimation of these cost components, by applying the specific spot rates along the yield curve used in the determination of the projected benefit obligations to the relevant projected cash flows. Under the previous method, these components of pension and OPEB costs were calculated using the same single weighted-average discount rates as reflected in the calculation of the benefit obligations. This change in the method was accounted for prospectively, as a change in estimate. The resulting reduction in pension and OPEB costs is estimated at approximately $35 million and $105 million for the three and nine months ended September 30, 2017, respectively. Approximately 90 percent of this reduction in pension and OPEB costs was attributed to the Company's regulated business segments and therefore was offset by the impact of regulatory variance and deferral accounts authorized by the Ontario Energy Board (OEB).

Recent Accounting Pronouncements Not Yet Adopted

Revenue from Contracts with Customers [**MONITOR**]

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09, *Revenue from Contracts with Customers* (Topic 606), which supersedes nearly all existing revenue recognition guidance, including industry-specific guidance, under US GAAP. The core principle of Topic 606 is to recognize revenues when promised goods or services are transferred to customers in an amount that reflects the consideration to which an entity expects to be entitled for those goods or services. Either a full retrospective application or a modified retrospective application is required for annual periods beginning on or after January 1, 2018, including interim periods within that year. Early adoption is permitted.

As part of the project to implement the new revenue standard, OPG is continuing to assess the impact of the standard on accounting for the Company's revenue streams and consolidated financial statements. OPG's major revenue streams include regulated generation revenue from base regulated prices and rate riders established by the OEB, as well as revenue from generation assets under long-term contractual arrangements with the Independent Electricity System Operator (IESO). In March 2017, the American Institute of Certified Public Accountants (AICPA) issued Revenue Recognition Implementation Issue #13-1*, Scope Clarification Regarding Tariff Sales to Regulated Customers*. The draft implementation guidance was developed by the AICPA Power & Utilities task force. This draft guidance concludes that tariff-based revenue from the provision of regulated utility service to a utility's customers is within the scope of Topic 606. OPG has completed its analysis of the impact of Topic 606 on its accounting for generation revenue from base regulated prices and long-term contractual arrangements with the IESO, and has not identified any material differences in the timing or quantum of the recognition of revenue based on the analysis performed to date. The Company continues to work on its assessment of the impact of Topic 606 on its other revenue streams.

The Company currently expects to apply the new revenue standard in its 2018 first quarter interim financial statements and is in the process of concluding on the method of adoption.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost

In March 2017, the FASB issued ASU No. 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. Under the new guidance, employers that sponsor defined benefit plans for pensions and/or other postretirement benefits are required to present the service cost component of net periodic benefit cost in the same statement of income line item as other employee compensation costs arising from services rendered during the period. The other components of the net periodic benefit cost are to be presented separately from the line item that includes the service cost and outside of any subtotal of income from operations, if such a subtotal is presented. In addition, the new guidance requires that only the service cost component of net benefit cost be eligible for capitalization.

This guidance is effective for fiscal years beginning after December 15, 2017, including interim periods of those years. The guidance is not expected to have a material impact on OPG's consolidated financial statements, as OPG currently capitalizes only the service cost component of post-retirement benefits costs. Additionally, OPG already includes the service cost component of post-retirement benefit costs with other compensation costs, within the operations, maintenance and administration expenses line item in the consolidated statements of income, and does not show a subtotal of income from operations. As such, the new guidance is not expected to affect the presentation of OPG's consolidated financial statements.

3. REGULATORY ASSETS AND LIABILITIES

The regulatory assets and liabilities recorded as at September 30, 2017 and December 31, 2016 are as follows:

(millions of dollars)	**September 30 2017**	**December 31 2016**
Regulatory assets		
Variance and deferral accounts authorized by the OEB		
Pension and OPEB Cost Variance Account	**716**	716
Pension & OPEB Cash Versus Accrual Differential Deferral Account *(Note 8)*	**552**	497
Hydroelectric Surplus Baseload Generation Variance Account	**327**	210
Bruce Lease Net Revenues Variance Account	**131**	95
Other variance and deferral accounts	**137**	107
	1,863	1,625
Pension and OPEB Regulatory Asset *(Note 8)*	**3,260**	3,392
Deferred Income Taxes	**879**	838
Total regulatory assets	**6,002**	5,855
Regulatory liabilities		
Variance and deferral accounts authorized by the OEB		
Hydroelectric Water Conditions Variance Account	**143**	51
Impact Resulting from Changes in Station End-of-Life Dates Deferral Account	**124**	71
Other variance and deferral accounts	**243**	188
Total regulatory liabilities	**510**	310

[**MONITOR**] OPG's May 2016 application with the OEB for new regulated prices included a request for new rate riders to recover or repay the December 31, 2015 balances in all of the Company's OEB-authorized variance and deferral accounts, with the exception of the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the portion of these balances previously approved for recovery or repayment through rate riders in effect during 2016. The application also requested the continuation of all applicable existing variance and deferral accounts. In March 2017, the OEB approved a settlement agreement reached by OPG and intervenors on a limited set of issues in the application (Settlement Agreement). Among the settled issues, the agreement provided for the continuation of all applicable existing variance and deferral accounts and accepted a number of variance and deferral account balances for recovery, as requested in OPG's application. The periods of recovery or repayment for the accepted variance and deferral account balances are excluded from the scope of the Settlement Agreement. The Settlement Agreement did not impact OPG's financial results for the three and nine months ended September 30, 2017. The final arguments were completed in the second quarter of 2017. The OEB's decision is expected in the fourth quarter of 2017.

As at September 30, 2017 and December 31, 2016, regulatory assets for other variance and deferral accounts included amounts for the Nuclear Deferral and Variance Over/Under Recovery Variance Account, the Nuclear Liability Deferral Account, the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account, the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account, and the Nuclear Development Variance Account. As at September 30, 2017 and December 31, 2016, regulatory liabilities for other variance and deferral accounts included the amounts for the Pension & OPEB Cash Payment Variance Account, the Capacity Refurbishment Variance Account, the Ancillary Services Net Revenue Variance Account, the Income and Other Taxes Variance Account and the Hydroelectric Incentive Mechanism Variance Account.

4. LONG-TERM DEBT

Long-term debt consists of the following:

(millions of dollars)	**September 30 2017**	**December 31 2016**
Notes payable to the Ontario Electricity Financial Corporation	**3,245**	3,295
UMH Energy Partnership	**182**	184
PSS Generating Station Limited Partnership	**245**	245
Lower Mattagami Energy Limited Partnership	**1,795**	1,795
Other	**15**	15
	5,482	5,534
Less: bond issuance fees	**(14)**	(14)
Less: due within one year	**(628)**	(1,103)
Long-term debt	**4,840**	4,417

In the fourth quarter of 2015, PSS Generating Station Limited Partnership (PSS), a subsidiary of OPG, issued long-term debt totalling $245 million in support of the Peter Sutherland Sr. Generating Station (GS) project. The majority of the debt proceeds, totalling $180 million, were invested in a structured deposit note with staggered maturity dates ranging from January 2016 to April 2017. As at September 30, 2017, the deposit note has matured.

In June 2016, OPG entered into a $700 million general corporate credit facility agreement with the Ontario Electricity Financial Corporation (OEFC), which expires on December 31, 2017. In the third quarter of 2017, the agreement was amended with the credit facility increased to $2,350 million and expiry date extended to December 31, 2018.

In February 2017, OPG issued senior notes payable to the OEFC totalling $200 million and maturing in February 2047. The effective interest rate and coupon interest rate of these notes was 4.12 percent. In June 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in June 2047. The effective interest rate and coupon interest rate of these notes was 3.65 percent. In August 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in August 2047. The effective interest rate and coupon interest rate of these notes was 3.86 percent. In September 2017, OPG issued senior notes payable to the OEFC totalling $400 million and maturing in September 2047. The effective interest rate and coupon interest rate of these notes was 4.07 percent.

In October 2017, OPG issued $500 million of senior notes payable under a Medium Term Note Program. The notes bear a coupon interest rate of 3.32 percent and an effective rate of 3.43 percent, payable semi-annually until maturity on October 4, 2027. The offering was made under OPG's $2 billion short form base shelf prospectus dated September 12, 2017.

5. SHORT-TERM DEBT AND NET INTEREST EXPENSE

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. In the second quarter of 2017, OPG renewed and extended the expiry date of both tranches from May 2021 to May 2022. As at September 30, 2017, there were no amounts outstanding under the bank credit facility. There was $160 million commercial paper outstanding under OPG's commercial paper program as at September 30, 2017.

As at September 30, 2017, the Lower Mattagami Energy Limited Partnership (LME) maintained a $400 million bank credit facility to support the funding requirements for the Lower Mattagami River project including support for LME's commercial paper program. The facility consists of a $300 million tranche maturing in August 2022 and a $100 million tranche maturing in August 2018. As at September 30, 2017, there was no external commercial paper

outstanding under LME's commercial paper program. There were also no amounts outstanding under LME's bank credit facility as at September 30, 2017. A letter of credit of $55 million was issued in July 2017 under the first tranche of the credit facility.

As at September 30, 2017, OPG maintained $25 million of short-term, uncommitted overdraft facilities and $463 million of short-term, uncommitted credit facilities, which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other general corporate purposes. As at September 30, 2017, a total of $388 million of Letters of Credit had been issued under these facilities. This included $349 million for the supplementary pension plans, $38 million for general corporate purposes, and $1 million related to the operation of the Portlands Energy Centre (PEC), a jointly controlled entity in which OPG holds a 50 percent interest.

The Company has an agreement to sell an undivided co-ownership interest in its current and future accounts receivable to an independent trust. The maximum amount of co-ownership interest that can be sold under this agreement is $150 million, expiring on November 30, 2018. As at September 30, 2017, there were Letters of Credit outstanding under this agreement of $150 million, which were issued in support of OPG's supplementary pension plans.

UMH Energy Partnership has entered into an $8 million short-term, uncommitted overdraft facility and $16 million of irrevocable, standby Letters of Credit facilities in support of its operations. As at September 30, 2017, total Letters of Credit of $14 million had been issued under these facilities.

The following table summarizes the net interest expense:

(millions of dollars)	**Three Months Ended September 30**		**Nine Months Ended September 30**	
	2017	**2016**	**2017**	**2016**
Interest on long-term debt	**74**	73	**215**	217
Interest on short-term debt	**-**	-	**2**	2
Interest income	**(4)**	(1)	**(6)**	(5)
Interest capitalized to property, plant and equipment and intangible assets	**(39)**	(36)	**(121)**	(101)
Interest related to regulatory assets and liabilities [1]	**(10)**	(8)	**(34)**	(21)
Net interest expense	**21**	28	**56**	92

[1] Includes interest to recognize the cost of financing related to regulatory variance and deferral accounts, as authorized by the OEB, and interest deferred in the Bruce Lease Net Revenues Variance Account, the Capacity Refurbishment Variance Account, and the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account.

6. FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT LIABILITIES

The liabilities for fixed asset removal and nuclear waste management on a present value basis as at September 30, 2017 and December 31, 2016 consist of the following:

(millions of dollars)	**September 30 2017**	**December 31 2016**
Liability for nuclear used fuel management	**11,690**	11,292
Liability for nuclear decommissioning and nuclear low and intermediate level waste management	**8,009**	7,811
Liability for non-nuclear fixed asset removal	**376**	381
Fixed asset removal and nuclear waste management liabilities	**20,075**	19,484

7. ACCUMULATED OTHER COMPREHENSIVE LOSS

The changes in the balance of each component of accumulated other comprehensive loss (AOCL), are as follows:

	Nine Months Ended September 30, 2017			
(millions of dollars)	**Unrealized Losses on Cash Flow Hedges [1]**	**Pension and OPEB [1]**	**Available-for-sale Securities [1]**	**Total [1]**
AOCL, beginning of period	**(87)**	**(207)**	**(1)**	**(295)**
Unrealized loss on available-for-sale securities	**-**	**-**	**(6)**	**(6)**
Amounts reclassified from AOCL	**13**	**8**	**-**	**21**
Other comprehensive income for the period	**13**	**8**	**(6)**	**15**
Reclassification of non-controlling interest on change in ownership interest *(Note 15)*	**3**	**-**	**-**	**3**
AOCL, end of period	**(71)**	**(199)**	**(7)**	**(277)**

[1] All amounts are net of income taxes.

	Nine Months Ended September 30, 2016			
(millions of dollars)	**Unrealized Losses on Cash Flow Hedges [1]**	**Pension and OPEB [1]**	**Available-for-sale Securities [1]**	**Total [1]**
AOCL, beginning of period	(106)	(213)	-	(319)
Unrealized gain on available-for-sale securities	-	-	15	15
Amounts reclassified from AOCL	14	9	-	23
Other comprehensive income for the period	14	9	15	38
AOCL, end of period	(92)	(204)	15	(281)

[1] All amounts are net of income taxes.

The significant amounts reclassified out of each component of AOCL, net of income taxes, during the three and nine months ended September 30, 2017 are as follows:

(millions of dollars)	**Amount Reclassified from AOCL Three Months Ended September 30, 2017**	**Nine Months Ended September 30, 2017**	**Statement of Income Line Item**
Amortization of losses from cash flow hedges			
Losses	**5**	**15**	Net interest expense
Income tax recovery	**(1)**	**(2)**	Income tax expense
	4	**13**	
Amortization of amounts related to pension and OPEB			
Actuarial losses	**3**	**10**	See (1) below
Income tax recovery	**-**	**(2)**	Income tax expense
	3	**8**	
Total reclassifications for the period	**7**	**21**	

[1] These AOCL components are included in the computation of pension and OPEB costs (see Note 8 for additional details).

The significant amounts reclassified out of each component of AOCL, net of income taxes, during the three and nine months ended September 30, 2016 are as follows:

(millions of dollars)	**Amount Reclassified from AOCL Three Months Ended September 30, 2016**	**Nine Months Ended September 30, 2016**	**Statement of Income Line Item**
Amortization of losses from cash flow hedges			
Losses	5	16	Net interest expense
Income tax recovery	(1)	(2)	Income tax expense
	4	14	
Amortization of amounts related to pension and OPEB			
Actuarial losses	4	12	See (1) below
Income tax recovery	(1)	(3)	Income tax expense
	3	9	
Total reclassifications for the period	7	23	

[1] These AOCL components are included in the computation of pension and OPEB costs (see Note 8 for additional details).

8. PENSION AND OTHER POST-EMPLOYMENT BENEFITS

OPG's pension and OPEB costs for the three months ended September 30, 2017 and 2016 are as follows:

	Registered Pension Plans		Supplementary Pension Plans		OPEB	
(millions of dollars)	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**
Components of Cost Recognized for the period						
Current service costs	**68**	70	**2**	2	**17**	16
Interest on projected benefit obligation	**138**	158	**2**	3	**27**	34
Expected return on plan assets, net of expenses	**(191)**	(185)	**-**	-	**-**	-
Amortization of net actuarial loss [1]	**45**	49	**2**	1	**-**	5
Cost recognized [2]	**60**	92	**6**	6	**44**	55

[1] The amortization of net actuarial loss is recognized as an increase to other comprehensive income. This increase for the three months ended September 30, 2017 was partially offset by a decrease in the Pension and OPEB Regulatory Asset of $44 million (three months ended September 30, 2016 – $51 million).

[2] These pension and OPEB costs for the three months ended September 30, 2017 exclude the net addition of costs of $3 million from the recognition of changes in the regulatory assets for the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB Cash Payment Variance Account (three months ended September 30, 2016 – net reduction of costs of $35 million).

OPG's pension and OPEB costs for the nine months ended September 30, 2017 and 2016 are as follows:

	Registered Pension Plans		Supplementary Pension Plans		OPEB	
(millions of dollars)	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**
Components of Cost Recognized						
Current service costs	**205**	208	**5**	5	**51**	50
Interest on projected benefit obligation	**411**	475	**8**	9	**81**	100
Expected return on plan assets, net of expenses	**(574)**	(552)	**-**	-	**-**	-
Amortization of net actuarial loss [1]	**137**	145	**5**	3	**-**	15
Cost recognized [2]	**179**	276	**18**	17	**132**	165

[1] The amortization of net actuarial loss is recognized as an increase to other comprehensive income. This increase for the nine months ended September 30, 2017 was partially offset by a decrease in the Pension and OPEB Regulatory Asset of $132 million (nine months ended September 30, 2016 – $151 million).

[2] These pension and OPEB costs for the nine months ended September 30, 2017 exclude the net addition of costs of $10 million from the recognition of changes in the regulatory assets for the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB Cash Payment Variance Account (nine months ended September 30, 2016 − net reduction of costs of $107 million).

A new actuarial valuation of the OPG registered pension plan was filed with the Financial Services Commission of Ontario in September 2017 with an effective date of January 1, 2017. The annual funding requirements in accordance with the new actuarial valuation are $212 million for 2017, $215 million for 2018, and $219 million for 2019.

9. RISK MANAGEMENT AND DERIVATIVES

OPG is exposed to risks related to changes in market interest rates on debt expected to be issued in the future and movements in foreign currency that affect the Company's assets, liabilities, and forecasted transactions. Select derivative instruments are used to manage such risks. Derivatives are used as hedging instruments, as well as for trading purposes.

Interest rate risk is the risk that the value of assets and liabilities can change due to movements in related interest rates. Interest rate risk for OPG arises with the need to refinance existing debt and/or undertake new financing. The management of these risks includes using derivatives to hedge the exposure in accordance with corporate risk management policies. OPG periodically uses interest rate swap agreements to mitigate elements of interest rate risk exposure associated with anticipated financing.

OPG's financial results are exposed to volatility in the Canadian/United States (US) foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are denominated in, or tied to, US dollars. OPG enters into foreign exchange derivatives and agreements with major financial institutions, when appropriate, in order to manage the Company's exposure to foreign currency movements.

The majority of OPG's revenues are derived from sales through the IESO administered spot market. Market participants in the IESO spot market provide collateral in accordance with the IESO prudential support requirements to cover funds that they might owe to the market. Although the credit exposure to the IESO represents a significant portion of OPG's accounts receivable, the Company's management accepts this risk due to the IESO's primary role in the Ontario electricity market. The remaining receivables exposure is to a diverse group of generally high quality counterparties. OPG's allowance for doubtful accounts as at September 30, 2017 was less than $1 million. OPG's fair value derivatives totalled a net liability of $16 million as at September 30, 2017 (December 31, 2016 – $24 million).

Existing pre-tax net losses of $20 million deferred in AOCL as at September 30, 2017 are expected to be reclassified to net income within the next 12 months.

10. FAIR VALUE MEASUREMENTS

The fair value of financial instruments traded in active markets is based on quoted market prices at the interim consolidated balance sheet dates. A market is regarded as active if quoted prices are readily and regularly available from an exchange, dealer, broker, industry group, pricing service, or regulatory agency, and those prices represent actual and regularly occurring market transactions on an arm's length basis. The quoted market price used for financial assets held by OPG is the current bid price. These instruments are included in Level 1 and are comprised primarily of equity investments and fund investments. The fair value hierarchy groups financial instruments into three levels, based on the significance of inputs used in measuring the fair value of the assets and liabilities.

For financial instruments for which quoted market prices are not directly available, fair values are estimated using forward price curves developed from observable market prices or rates. The estimation of fair value may include the use of valuation techniques or models, based wherever possible on assumptions supported by observable market prices or rates prevailing at the interim consolidated balance sheet dates. This is the case for over-the-counter derivatives and securities, which include energy commodity derivatives, foreign exchange derivatives, interest rate swap derivatives, and fund investments. Pooled fund investments are valued at the unit values supplied by the pooled fund administrators. The unit values represent the underlying net assets at fair values, determined using closing market prices. Valuation models use general assumptions and market data and therefore do not reflect the specific risks and other factors that would affect a particular instrument's fair value. The methodologies used for calculating the fair value adjustments are reviewed on an ongoing basis to ensure that they remain appropriate. If all significant inputs required to fair value an instrument are observable, the instrument is included in Level 2.

If one or more of the significant inputs is not based on observable market data, the instrument is included in Level 3. Specific valuation techniques are used to value these instruments. Significant Level 3 inputs include: recent comparable transactions, comparable benchmark information, bid/ask spread of similar transactions, and other relevant factors.

Certain alternative investments are measured at fair value by their investment managers using net asset value (NAV). Investments measured at NAV as a practical expedient for determining their fair value are excluded from the fair value hierarchy.

Transfers into, out of, or between levels are deemed to have occurred on the date of the event or change in circumstances that caused the transfer to occur.

The following is a summary of OPG's financial instruments and their fair value as at September 30, 2017 and December 31, 2016:

	Fair Value		Carrying Value [1]		
(millions of dollars)	**2017**	**2016**	**2017**	**2016**	**Balance Sheet Line Item**
Nuclear Segregated Funds (includes current portion) [2]	**16,534**	15,984	**16,534**	15,984	Nuclear fixed asset removal and nuclear waste management funds
Investment in Hydro One shares	**190**	212	**190**	212	Available-for-sale securities
Payable related to cash flow hedges	**(42)**	(48)	**(42)**	(48)	Long-term accounts payable and accrued charges
Long-term debt (includes current portion)	**(5,859)**	(6,033)	**(5,482)**	(5,520)	Long-term debt
Other financial instruments	**(11)**	(18)	**(11)**	(18)	Various

[1] The carrying values of other financial instruments included in cash and cash equivalents, receivables from related parties, other current assets, short-term debt, and accounts payable and accrued charges approximate their fair values due to the immediate or short-term maturity of these financial instruments.

[2] The Nuclear Segregated Funds are comprised of the Decommissioning Segregated Fund and the Used Fuel Segregated Fund.

The fair value of long-term debt instruments is determined based on a conventional pricing model, which is a function of future cash flows, the current market yield curve and term to maturity. These inputs are considered Level 2 inputs.

The following tables present financial assets and financial liabilities measured at fair value in accordance with the fair value hierarchy as at September 30, 2017 and December 31, 2016:

	September 30, 2017			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Used Fuel Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	**5,879**	**4,498**	**-**	**10,377**
Investments measured at NAV [1]				**1,231**
				11,608
Due to Province				**(2,155)**
Used Fuel Segregated Fund, net				**9,453**
Decommissioning Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	**4,363**	**3,343**	**-**	**7,706**
Investments measured at NAV [1]				**1,016**
				8,722
Due to Province				**(1,641)**
Decommissioning Segregated Fund, net				**7,081**
Investment in available-for-sale securities [2]	**190**	**-**	**-**	**190**
Other financial assets	**4**	**3**	**7**	**14**
Liabilities				
Other financial liabilities	**(22)**	**(3)**	**-**	**(25)**

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to amounts presented on the interim consolidated balance sheets.

(millions of dollars)	December 31, 2016 Level 1	Level 2	Level 3	Total
Assets				
Used Fuel Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	5,602	4,394	-	9,996
Investments measured at NAV [1]				1,086
				11,082
Due to Province				(1,938)
Used Fuel Segregated Fund, net				9,144
Decommissioning Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	4,171	3,243	-	7,414
Investments measured at NAV [1]				903
				8,317
Due to Province				(1,477)
Decommissioning Segregated Fund, net				6,840
Investment in available-for-sale securities	212	-	-	212
Other financial assets	6	2	9	17
Liabilities				
Other financial liabilities	(29)	(6)	-	(35)

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to amounts presented on the interim consolidated balance sheets.

During the nine months ended September 30, 2017, there were no transfers between Level 1 and Level 2. In addition, there were no transfers into or out of Level 3.

The following table presents the changes in OPG's net assets measured at fair value that are classified as Level 3 for the three months ended September 30, 2017:

(millions of dollars)	Other financial instruments
Opening balance, July 1, 2017	**9**
Realized losses included in revenue	**(4)**
Purchases	**2**
Closing balance, September 30, 2017	**7**

The following table presents the changes in OPG's net assets measured at fair value that are classified as Level 3 for the nine months ended September 30, 2017:

(millions of dollars)	Other financial instruments
Opening balance, January 1, 2017	**9**
Unrealized losses included in revenue	**(2)**
Realized losses included in revenue	**(7)**
Purchases	**7**
Closing balance, September 30, 2017	**7**

Nuclear Segregated Funds

The fair value of the investments within the Nuclear Segregated Funds' alternative investment portfolio is determined using appropriate valuation techniques, such as recent arm's length market transactions, references to current fair values of other instruments that are substantially the same, discounted cash flow analyses, third-party independent appraisals, valuation multiples, or other valuation methods. Any control, size, liquidity or other discount premiums on the investments are considered in the determination of fair value. Alternative investments are measured at fair value using NAV as a practical expedient.

The process of valuing investments for which no published market price exists is based on inherent uncertainties and the resulting values may differ from values that would have been used had a ready market existed for these investments. The values may also differ from the prices at which the investments may be sold.

The following are the classes of investments within the Nuclear Segregated Funds that are reported on the basis of NAV as at September 30, 2017:

(millions of dollars except where noted)	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice
Alternative Investments				
Infrastructure	**1,276**	**835**	**n/a**	**n/a**
Real Estate	**892**	**465**	**n/a**	**n/a**
Agriculture	**78**	**106**	**n/a**	**n/a**
Pooled Funds				
Short-term Investments	**12**	**n/a**	**Daily**	**1 - 5 Days**
Fixed Income	**643**	**n/a**	**Daily**	**1 - 5 Days**
Equity	**890**	**n/a**	**Daily**	**1 - 5 Days**
Total	**3,791**	**1,406**		

The fair value of the pooled funds is classified as Level 2. Infrastructure, real estate and agriculture investments are measured using NAV as a practical expedient for determining their fair value.

Infrastructure

This class includes investments in funds whose investment objective is to generate a combination of long-term capital appreciation and current income, generally through investments such as energy, transportation and utilities. The fair values of investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in partners' capital and/or underlying investments held by subsidiaries of an infrastructure fund. The investments in the respective infrastructure funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests/shares to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Distributions from each infrastructure fund will be received based on the operations of the underlying investments and/or as the underlying investments of the infrastructure funds are liquidated. It is not possible to estimate when the underlying assets of the infrastructure funds will be liquidated. However, the infrastructure funds have a maturity end period ranging from 2019 to 2025.

Real Estate

This class includes investments in institutional-grade real estate property. The investment objective is to provide a stable level of income with the opportunity for long-term capital appreciation. The fair values of the investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in these investments. The partnership investments are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests to another party, as stipulated in the partnership agreement. For investments in private real estate corporations, shares may be redeemed through a pre-established redemption process. It is not possible to estimate when the underlying assets in this class will be liquidated.

Agriculture

This class includes a diversified portfolio of global farmland and timberland investments. The investment objective is to provide a differentiated return source, income yield, and inflation protection. The fair values of the investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in these investments. The investments are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests/shares to another party, as stipulated in the partnership agreements and/or shareholders' agreements.

Pooled Funds

This class represents investments in pooled funds, which primarily include a diversified portfolio of fixed income securities, issued mainly by Canadian corporations, and diversified portfolios of Emerging Market listed equity. The investment objective of the pooled funds is to achieve capital appreciation and income through professionally managed portfolios. The fair value of the investments in this class has been estimated using NAV per share of the investments. There are no significant restrictions on the ability to sell the investments in this class.

11. COMMITMENTS AND CONTINGENCIES

Litigation

On August 9, 2006, a Notice of Action and Statement of Claim filed with the Ontario Superior Court of Justice in the amount of $500 million was served against OPG and Bruce Power L.P. (Bruce Power) by British Energy Limited and British Energy International Holdings Limited (together British Energy). The action is for contribution and indemnity of any amounts British Energy was liable for in an arbitration against it by some of the owners of Bruce Power regarding an alleged breach of British Energy's representations and warranties to the claimants when they purchased British Energy's interest in Bruce Power (the Arbitration). Both the action and the Arbitration relate to corrosion to a steam generator unit discovered after OPG leased the Bruce nuclear generating stations to Bruce Power.

In 2012, the arbitrator found that British Energy was liable to the claimants for some of the damages they claimed. The final settlement amount was valued by British Energy at $71 million. In September 2014, British Energy amended its Statement of Claim (Amended Claim) to reduce the claim amount to $100 million to reflect that the purchasers of British Energy's interest in Bruce Power did not receive the full damages they originally claimed in the Arbitration. British Energy also added an allegation to its Amended Claim that OPG breached a covenant to maintain the steam generator between the time of the initial agreement to lease and the effective date of the lease in accordance with "Good Utility Practices".

In November 2016, British Energy obtained consent to a timetable for the remaining steps in the litigation, pursuant to which the matter must be set down for trial by December 31, 2018. OPG has delivered a statement of defence in accordance with an extension of the original June 30, 2017 delivery deadline set out in the timetable.

Various other legal proceedings are pending against OPG or its subsidiaries covering a wide range of matters that arise in the ordinary course of business activities.

Each of these matters is subject to various uncertainties. Some of these matters may be resolved unfavourably. While it is not possible to determine the ultimate outcome of the various pending actions, it is the Company's belief that their resolution is not likely to have a material adverse impact on its financial position.

Guarantees

The Company and its joint venture partners have jointly guaranteed the financial performance of jointly owned entities related primarily to the payment of liabilities. As at September 30, 2017, the total amount of guarantees OPG provided to these entities was $82 million (December 31, 2016 − $83 million). OPG may terminate some of these

guarantees within a short time frame by providing written notice to the counterparties at any time. Other guarantees have terms ending between 2019 and 2029. As at September 30, 2017, the potential impact of the fair value of these guarantees to income has been estimated to be negligible and OPG does not expect to make any payments associated with these guarantees.

Contractual and Commercial Commitments

OPG's contractual obligations and commercial commitments as at September 30, 2017 are as follows:

(millions of dollars)	**2017** [1]	**2018**	**2019**	**2020**	**2021**	**Thereafter**	**Total**
Fuel supply agreements	52	169	96	76	62	98	553
Contributions to the OPG registered pension plan [2]	23	215	219	-	-	-	457
Long-term debt repayment	251	398	368	663	413	3,389	5,482
Interest on long-term debt	49	244	225	203	175	3,167	4,063
Commitments related to Darlington Refurbishment [3]	530	-	-	-	-	-	530
Commitments related to Peter Sutherland Sr. GS project	7	1	-	-	-	-	8
Commitments related to Ranney Falls GS project	9	29	5	-	-	-	43
Operating licences	10	40	41	24	28	115	258
Operating lease obligations	8	27	25	25	23	93	201
Unconditional purchase obligations	15	59	58	56	5	-	193
Accounts payable and accrued charges	844	8	-	-	-	16	868
Other	35	43	30	2	1	65	176
Total	1,833	1,233	1,067	1,049	707	6,943	12,832

[1] Represents amounts for the remainder of the year.

[2] The pension contributions include ongoing funding requirements and additional funding requirements towards the deficit, in accordance with the actuarial valuation of the OPG registered pension plan as at January 1, 2017. The next actuarial valuation of the OPG registered pension plan must have an effective date no later than January 1, 2020. The pension contributions are affected by various factors including market performance, changes in actuarial assumptions, plan experience, changes in the pension regulatory environment, and the timing of funding valuations. Funding requirements after 2019 are excluded due to significant variability in the assumptions required to project the timing of future cash flows. The amount of OPG's additional, voluntary contribution, if any, is revisited from time to time.

[3] Represents estimated currently committed costs to close the project, including accruals for completed work, demobilization of project staff and cancellation of existing contracts and material orders.

Contractual and commercial commitments as noted exclude certain purchase orders, as they represent purchase authorizations rather than legally binding contracts, and are subject to change without significant penalties.

12. BUSINESS SEGMENTS

Segment Income (Loss) for the Three Months Ended September 30, 2017 *(millions of dollars)*	Nuclear Generation	Regulated Nuclear Waste Manage-ment	Hydro-electric	Unregulated Contracted Generation Portfolio	Unregulated Services, Trading, and Other Non-Generation	Elimination	Total
Revenue	**739**	**33**	**327**	**141**	**9**	**(32)**	**1,217**
Fuel expense	**81**	**-**	**88**	**15**	**1**	**-**	**185**
Gross margin	**658**	**33**	**239**	**126**	**8**	**(32)**	**1,032**
Operations, maintenance and administration	**511**	**35**	**81**	**39**	**1**	**(32)**	**635**
Depreciation and amortization	**116**	**-**	**34**	**20**	**8**	**-**	**178**
Accretion on fixed asset removal and nuclear waste management liabilities	**-**	**230**	**-**	**3**	**2**	**-**	**235**
Earnings on nuclear fixed asset removal and nuclear waste management funds	**-**	**(196)**	**-**	**-**	**-**	**-**	**(196)**
Property taxes	**7**	**-**	**1**	**-**	**-**	**-**	**8**
Income from investments subject to significant influence	**-**	**-**	**-**	**(11)**	**-**	**-**	**(11)**
Other losses (gains)	**4**	**-**	**1**	**-**	**(2)**	**-**	**3**
Income (Loss) before interest and income taxes	**20**	**(36)**	**122**	**75**	**(1)**	**-**	**180**

Segment Income (Loss) for the Three Months Ended September 30, 2016 *(millions of dollars)*	Nuclear Generation	Regulated Nuclear Waste Manage-ment	Hydro-electric	Unregulated Contracted Generation Portfolio	Unregulated Services, Trading, and Other Non-Generation	Elimination	Total
Revenue	885	36	350	149	15	(35)	1,400
Fuel expense	79	-	88	19	1	-	187
Gross margin	806	36	262	130	14	(35)	1,213
Operations, maintenance and administration	521	38	87	44	11	(35)	666
Depreciation and amortization	230	-	56	19	8	-	313
Accretion on fixed asset removal and nuclear waste management liabilities	-	228	-	2	2	-	232
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(248)	-	-	-	-	(248)
Property taxes	6	-	1	1	4	-	12
Income from investments subject to significant influence	-	-	-	(11)	-	-	(11)
Other losses (gains)	2	-	1	1	(3)	-	1
Income (Loss) before interest and income taxes	47	18	117	74	(8)	-	248

Segment Income (Loss) for the Nine Months Ended September 30, 2017 *(millions of dollars)*	Nuclear Generation	Regulated Nuclear Waste Manage-ment	Hydro-electric	Unregulated Contracted Generation Portfolio	Unregulated Services, Trading, and Other Non-Generation	Elimination	Total
Revenue	**2,000**	**90**	**1,069**	**431**	**36**	**(87)**	**3,539**
Fuel expense	**217**	**-**	**258**	**42**	**1**	**-**	**518**
Gross margin	**1,783**	**90**	**811**	**389**	**35**	**(87)**	**3,021**
Operations, maintenance and administration	**1,693**	**96**	**232**	**118**	**2**	**(87)**	**2,054**
Depreciation and amortization	**333**	**-**	**103**	**59**	**22**	**-**	**517**
Accretion on fixed asset removal and nuclear waste management liabilities	**-**	**696**	**-**	**7**	**6**	**-**	**709**
Earnings on nuclear fixed asset removal and nuclear waste management funds	**-**	**(579)**	**-**	**-**	**-**	**-**	**(579)**
Property taxes	**20**	**-**	**1**	**5**	**4**	**-**	**30**
Income from investments subject to significant influence	**-**	**-**	**-**	**(29)**	**-**	**-**	**(29)**
Other losses (gains)	**4**	**-**	**1**	**-**	**(385)**	**-**	**(380)**
(Loss) Income before interest and income taxes	**(267)**	**(123)**	**474**	**229**	**386**	**-**	**699**

Segment Income (Loss) for the Nine Months Ended September 30, 2016 *(millions of dollars)*	Nuclear Generation	Regulated Nuclear Waste Manage-ment	Hydro-electric	Unregulated Contracted Generation Portfolio	Unregulated Services, Trading, and Other Non-Generation	Elimination	Total
Revenue	2,631	102	1,148	431	52	(99)	4,265
Fuel expense	239	-	259	42	1	-	541
Gross margin	2,392	102	889	389	51	(99)	3,724
Operations, maintenance and administration	1,665	108	238	129	20	(99)	2,061
Depreciation and amortization	691	-	169	56	25	-	941
Accretion on fixed asset removal and nuclear waste management liabilities	-	684	-	6	6	-	696
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(620)	-	-	-	-	(620)
Property taxes	19	-	1	6	9	-	35
Income from investments subject to significant influence	-	-	-	(28)	-	-	(28)
Other (gains) losses	-	-	(19)	1	(5)	-	(23)
Income (Loss) before interest and income taxes	17	(70)	500	219	(4)	-	662

Shareholder Declaration and Shareholder Resolution to Sell Certain Non-Core Real Estate Property

In December 2015, OPG received a Shareholder Declaration and a Shareholder Resolution that required the Company to sell its head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street in Toronto, Ontario. In December 2016, a purchase and sale agreement was executed, and the sale was completed in April 2017. A gain on sale of $283 million, which is net of tax effects of $95 million, was recognized in net income upon completion of the transaction for the nine months ended September 30, 2017. The pre-tax gain on sale was recorded as an item of Other gains in the interim consolidated statement of income in the Services, Trading and Other Non-Generation segment. Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. OPG is working with the Ontario Ministry of Finance to finalize the amount of designated proceeds to be transferred into the Province's Consolidated Revenue Fund. [**MONITOR**]

13. NET CHANGES IN NON-CASH WORKING CAPITAL BALANCES

(millions of dollars)	Nine Months Ended September 30 2017	2016
Receivables from related parties	**72**	107
Prepaid expenses	**(18)**	(52)
Other current assets	**10**	(7)
Fuel inventory	**20**	41
Income taxes payable	**(92)**	49
Materials and supplies	**4**	(2)
Accounts payable and accrued charges	**(51)**	(195)
	(55)	(59)

14. INVESTMENTS SUBJECT TO SIGNIFICANT INFLUENCE

Investments subject to significant influence consist of OPG's 50 percent ownership interest in the jointly controlled entities of the PEC gas-fired combined cycle generating station and the Brighton Beach gas-fired combined cycle generating station (Brighton Beach), which are accounted for using the equity method. Details of the balances as at September 30, 2017 and December 31, 2016 are as follows:

(millions of dollars)	September 30 2017	December 31 2016
PEC		
Current assets	**19**	18
Long-term assets	**244**	256
Current liabilities	**(9)**	(8)
Long-term liabilities	**(5)**	(5)
Brighton Beach		
Current assets	**5**	5
Long-term assets	**162**	168
Current liabilities	**(17)**	(16)
Long-term liabilities	**(8)**	(7)
Long-term debt	**(78)**	(90)
Investments subject to significant influence	**313**	321

15. NON-CONTROLLING INTEREST

PSS Generating Station LP

PSS is a limited partnership between OPG, Coral Rapids Power Corporation (CRP), and PSS Generating Station Inc. (PSS GS Inc.). The principal business of the partnership is the development, construction, ownership, operation and maintenance of the 28 MW Peter Sutherland Sr. hydroelectric GS on the New Post Creek. OPG and PSS GS Inc. are general partners and CRP is a limited partner in the partnership. CRP is a wholly owned subsidiary of the Taykwa Tagamou Nation.

The Peter Sutherland Sr. GS was placed in-service in March 2017 and, in April 2017, CRP increased its interest in PSS to 33 percent under the partnership agreement, by making contributions of $21 million, reducing OPG's interest to 67 percent. As a result of the contributions made by OPG and CRP, PSS has met the criteria of having sufficient equity at risk to finance its activities, and ceased being classified as a variable interest entity during the second quarter of 2017. OPG continues to consolidate the results of PSS in its consolidated financial statements. CRP's 33 percent interest in PSS is reported as non-controlling interest. As a result of CRP increasing its interest in the partnership, PSS' AOCL and partner's deficit were proportionately allocated to CRP as a reduction to its non-controlling interest as of September 30, 2017.

From:	HO Philip -FIN & C CTRL
To:	Shruti.Talwar@ontario.ca; Manu.Sud@ontario.ca; John Kim; Ronald Kwan
Cc:	GORE Michael -FIN & C CTRL; PAN Rebecca -FIN & C CTRL; DYKXHOORN Sandra -STAKEREL
Subject:	OPG Q4 2017 Submission to Province
Date:	Friday, February 16, 2018 5:11:25 PM
Attachments:	Q4 2017 Press Release - PROVINCE MAILING.docx Q4 2017 MD&A - DRAFT - Feb 16 - PROVINCE MAILING.docx 2017 AIF - DRAFT - Feb 16 - PROVINCE MAILING.docx Q4 2017 OPG FS PROVINCE MAILING Feb 16.docx

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Hi All,

Please find attached OPG's draft Q4 2017 Financial Results Press Release, Management's Discussion and Analysis (MD&A), Annual Information Form (AIF) and Financial Statements for the Province's review.

We would greatly appreciate comments on the above **no later than Thursday, Feb 22nd**.

These documents will be filed with the Ontario Securities Commission on **Thursday, March 8th** following OPG's Board of Directors meeting.

Kindly forward all comments directly to Philip Ho – philip.ho@opg.com.

To assist the review process, the following are the key items in the Q4 2017 MD&A:

Highlights	
Recent Developments	MD&A p.13-19
OEB's Decision on OPG's Application for New Regulated Prices	MD&A p.13-15
Darlington Refurbishment	MD&A p.16-17; 28-30
Ontario's Fair Hydro Plan	MD&A p.17-18

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ONTARIO POWER GENERATION

News
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[DRAFT]

Mar. 8, 2018

OPG REPORTS 2017 FINANCIAL RESULTS

OPG records increase in net income for third consecutive year

[Toronto]: – Ontario Power Generation Inc. (OPG or Company) today reported net income attributable to the Shareholder of $860 million for 2017, compared to $436 million in 2016.

"As stewards of Ontario's publicly-owned generating assets, I am pleased with our strong 2017 financial results, which marks the third year-over-year increase in net income. OPG's major focus remains on the largest clean energy project in Canada, the refurbishment of the Darlington Generating Station. This ten-year project will extend the life of this asset and ensure a safe, reliable, and clean source of electricity for another 30 years," said Jeff Lyash, OPG President and CEO. "Darlington's Unit 2 recently passed the halfway point, based on work performed, while remaining on time and on budget due to the hard work and dedication of our employees and partners. This success was recognized by our shareholder, the Province of Ontario, who has confirmed its commitment to proceed with Darlington's Unit 3 refurbishment in 2020."

Lyash continued, "The Peter Sutherland Sr. Generating Station was completed in 2017, on budget and ahead of schedule, and is the latest example of OPG's commitment to working closely in partnership with Indigenous communities."

"Pickering Generating Station significantly improved its operating performance over last year by increasing its capability factor to 80 per cent in 2017. By continuing to operate this important asset to 2024, we will ensure a safe and clean source of reliable power during the refurbishment of Darlington. OPG has applied to its regulator, the Canadian Nuclear Safety Commission, for a license to keep Pickering online until 2024 and expects a decision on this application in 2018," added Lyash.

The Ontario Energy Board's (OEB) decision on OPG's new regulated rates was issued in December 2017, establishing new rates to be applied with an effective date of June 1, 2017. OPG recognized the impact of the newly established base regulated rates for OPG's nuclear and most of its hydroelectric generation for the year resulting in additional net revenues of approximately $480 million **[MONITOR]**. Net income was negatively impacted by the planned reduction in nuclear electricity generation, primarily due to the Darlington Refurbishment, in conjunction with the continued application of previously established interim rates for the period in 2017 prior to the effective date of the new base regulated rates.

The OEB's approval of the final payment amounts order, including determinations on

the new regulated prices and rate smoothing, are not expected to have a material impact on the total revenue recorded for the June 1, 2017 to December 31, 2017 period. The OEB is expected to issue the final payment amounts order in the first half of 2018 **[MONITOR]**. OPG continues to provide electricity at a price that is 40 per cent less than other generators and is the only electricity generator in Ontario that has its prices set through a public hearing process by the OEB.

The gain of $283 million on the sale of OPG's head office building and parking facility recorded in the second quarter of 2017 and higher earnings on the nuclear fixed asset removal and nuclear waste management segregated funds of $24 million during 2017 compared to 2016 offset the year-to-date reduction in generation revenue.

The Fair Hydro Trust (the Trust) was established in December 2017 in accordance with the *Ontario Fair Hydro Act*, 2017, (the Fair Hydro Act) which appointed OPG as the Financial Services Manager of the Trust. The Fair Hydro Act established a framework under which the costs and benefits associated with the Government of Ontario's clean energy initiatives are to be allocated between present and future consumers of electricity under the Fair Hydro Plan. In December 2017, the Trust purchased its first tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $1.2 billion. In February 2018, the Trust issued $500 million of senior notes payable maturing on May 15, 2033.

Generating and Operating Performance

Electricity generated in 2017 decreased to 74.1 terawatt hours (TWh) from 78.2 TWh in 2016. The decrease in electricity generation reflected the expected lower generation from the Darlington GS and lower generation from the contracted plants. The decrease was partially offset by higher generation from the Pickering GS, primarily due to fewer outage days, and higher generation from the regulated hydroelectric stations.

Regulated – Nuclear Generation Segment

Lower nuclear generation of 4.9 TWh during 2017 was primarily due to the removal from service of Unit 2 at the Darlington GS for the duration of the unit's refurbishment that began in October 2016 and is expected to continue until early 2020. Offsetting the reduction in generation from the Darlington GS was an increase in generation of 1.5 TWh from the strong performance of the Pickering GS during 2017.

For 2017, the unit capability factor for the operating units at the Darlington GS was 85.2 per cent, compared to 89.5 per cent for 2016. The decrease was primarily a result of a higher number of planned outage days at the station in 2017, largely driven by the planned transition of the station towards refurbishment.

At the Pickering GS, the unit capability factor increased to 80.0 per cent for 2017, compared to 75.2 per cent for 2016, primarily due to outage cycle optimization and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station in 2017.

Regulated – Hydroelectric Segment

Higher generation from the regulated hydroelectric stations of 1.2 TWh during 2017 compared to 2016, was due to higher water flows, primarily on the eastern Ontario river

systems.

The availability of 88.0 per cent at these stations in 2017 was slightly lower than 89.0 per cent for 2016. The marginal decrease in the availability was primarily due to a higher number of unplanned outage days at the Northwestern Ontario, Niagara and Eastern Ontario region hydroelectric stations, partially offset by higher availability from the Sir Adam Beck Pump GS due to a higher number of planned outages days in 2016 as a result of the refurbishment of the station's reservoir.

Contracted Generation Portfolio Segment

Lower generation from the Contracted Generation Portfolio of 0.4 TWh during 2017 compared to 2016, was mainly due to higher surplus baseload generation conditions.

The availability of these hydroelectric stations for 2017 was 74.6 per cent, compared to 77.3 per cent for 2016. The decrease in the availability was primarily due to an increase in the number of planned outage days at the Lower Mattagami River hydroelectric generating stations.

Total Generating Cost

The Enterprise Total Generating Cost per megawatt hour (MWh) for 2017 was $50.66, compared to $48.45 for 2016. The increase was expected and mainly a result of lower electricity generation due to the Unit 2 refurbishment outage at the Darlington GS and higher sustaining capital expenditures, which was partially offset by higher hydroelectric electricity generation adjusted for surplus baseload generation.

If Unit 2 at the Darlington GS was not currently undergoing refurbishment and had continued to operate in a manner consistent with the performance of the remaining units at the station, adjusted for generation constraints on these units related to the transition of the station toward refurbishment, the Enterprise Total Generating Cost would have been approximately $4 to $5 per MWh lower for 2017. This sensitivity was calculated using the estimated incremental electricity generation and associated fuel cost that are expected to have resulted in the absence of the refurbishment.

Generation Development

OPG is undertaking a number of generation development and life extension projects in support of Ontario's electricity planning initiatives. Significant developments during 2017 were as follows:

Darlington Refurbishment

The Darlington Refurbishment project is expected to extend the operating life of the four-unit Darlington GS by approximately 30 years. The approved budget for the four-unit refurbishment is $12.8 billion, which includes the costs of the pre-requisite projects in support of the execution phase of the refurbishment. In October 2016, OPG commenced the refurbishment of the first unit, Unit 2. The de-fuelling of the reactor and islanding of Unit 2 were completed in the first half of 2017. The Re-tube Tooling Platform for hosting the tooling for the removal, inspection and installation activities, and the setup of specialized tooling and equipment needed for the removal and replacement of the reactor components were completed in the third quarter of 2017.

The disassembly of reactor components began in August 2017, with the removal of all 960 feeder tubes completed in September 2017. The removal of fuel channel assemblies commenced in October 2017. As part of the fuel channel assemblies, the removal of pressure tubes is in progress and will be followed by the removal of calandria tubes. The second major segment and the removal of all reactor components is expected to be completed in mid-2018.

Most of the pre-requisite projects, including construction of facilities, infrastructure upgrades and installation of safety enhancements, have been completed and placed in service. The Re-tube Waste Processing Building was completed in November 2017. Construction activities for the Heavy Water Storage and Drum Handling Facility (HWSF) have recommenced following the substantial completion of the Re-tube Waste Processing Building. This sequencing ensured that the necessary resources were available to support the execution of both projects. The HWSF is expected to be completed by the second quarter of 2019 and is not on the critical path for the Darlington Refurbishment project, which continues to track on schedule. The increase in the cost estimate for the HWSF will be accommodated within the overall Darlington Refurbishment budget of $12.8 billion. Taking into account the execution performance of the Unit 2 refurbishment, the overall Darlington Refurbishment project continues to track on budget.

In addition to the execution of refurbishment activities on Unit 2, OPG is continuing planning activities for the refurbishment of the second unit, Unit 3, and is entering into associated commitments to procure major components that require long lead times. As of December 31, 2017, $93 million has been invested in planning activities related to the refurbishment of the second unit.

Total life-to-date capital expenditures on the project were approximately $4.4 billion as at December 31, 2017.

Ranney Falls Hydroelectric GS

In 2017, OPG began construction work on a 10 MW single-unit powerhouse on the existing Ranney Falls GS site, as part of the Regulated – Hydroelectric segment. The new unit will replace an existing unit that reached its end of life in 2014. The existing forebay structure has been demolished and the new concrete structure has been completed. Excavation has been completed and construction continues in the expanded forebay, powerhouse and spillway area. The new forebay concrete wall has been completed, and concrete placement of the new powerhouse and the spillway integrated structure is in progress. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget.

Nanticoke Solar Facility

The construction of a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands, through Nanticoke Solar LP, a partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation, is planned to commence in the first quarter of 2018. During 2017, the partnership continued work to obtain approvals and permits required to enable the commencement of construction. Significant contracts for equipment and engineering construction services were executed in the first quarter of 2018. The facility, to operate under a contract with the IESO, is

expected to be completed in the first quarter of 2019, with a budget of $107 million. **[MONITOR]**

FINANCIAL AND OPERATIONAL HIGHLIGHTS

(millions of dollars – except where noted)	**2017**	**2016**
Revenue	**5,158**	5,653
Fuel expense	**689**	727
Gross margin	**4,469**	4,926
Operations, maintenance and administration	**2,824**	2,747
Depreciation and amortization	**679**	1,257
Accretion on fixed asset removal and nuclear waste management liabilities	**960**	929
Earnings on Nuclear Segregated Funds - (a reduction to expenses)	**(801)**	(746)
Earnings from Fair Hydro Trust - (a reduction to expenses)	**(1)**	-
Income from investments subject to significant influence	**(38)**	(37)
Other net (gains) expenses	**(339)**	35
Income before interest and income taxes	**1,185**	741
Net interest expense	**95**	120
Income tax expense	**209**	168
Net income	**881**	453
Net income attributable to the Shareholder	**860**	436
Net income attributable to non-controlling interest [1]	**21**	17
Income before interest and income taxes		
Electricity generation business segments	**971**	928
Regulated – Nuclear Waste Management	**(150)**	(174)
Services, Trading, and Other Non-Generation	**364**	(13)
Fair Hydro Trust	**-**	-
Total income before interest and income taxes	**1,185**	741
Cash flow		
Cash flow provided by operating activities	**944**	1,817
Electricity generation (TWh)		
Regulated – Nuclear Generation	**40.7**	45.6
Regulated – Hydroelectric	**30.7**	29.5
Contracted Generation Portfolio [2]	**2.7**	3.1
Total electricity generation	**74.1**	78.2
Nuclear unit capability factor (per cent) [3]		
Darlington Nuclear GS	**85.2**	89.5
Pickering Nuclear GS	**80.0**	75.2
Availability (per cent)		
Regulated – Hydroelectric	**88.0**	89.0
Contracted Generation Portfolio – hydroelectric stations	**74.6**	77.3
Equivalent forced outage rate		
Contracted Generation Portfolio – thermal stations	**2.4**	1.6
Enterprise Total Generating Cost (TGC) per MWh for the twelve months ended December 31, 2017 and 2016 ($/MWh) [4]	**50.66**	48.45
Return on Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI) for the twelve months ended December 31, 2017 and 2016 (%) [4]	**7.5**	4.2
Funds from Operations (FFO) Adjusted Interest Coverage for the twelve months ended December 31, 2017 and 2016 (times) [4]	**3.3**	5.1

[1] Relates to the 25 per cent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation in the Lower Mattagami Limited Partnership, the 33 per cent interest of Coral Rapids Power Corporation (CRP), a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership, and the 10 per cent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP. CRP increased its partnership interest to 33 percent in April 2017.

[2] Includes OPG's share of generation volume from its 50 per cent ownership interests in the Portlands Energy Centre and Brighton Beach GS.

[3] Nuclear unit capability factor excludes unit(s) during the period in which they are undergoing refurbishment. Unit 2 of the Darlington GS is excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

[4] Enterprise TGC per MWh, ROE Excluding AOCI, and FFO Adjusted Interest Coverage are non-GAAP financial measures and do not have any standardized meaning prescribed by US GAAP. Additional information about the non-GAAP measures is provided in OPG's Management's Discussion and Analysis for the year ended December 31, 2017, in the sections *Highlights – FFO Adjusted Interest Coverage*, *Highlights – Return on Common Equity Excluding Accumulated Other Comprehensive Income*, and *Highlights – Enterprise Total Generating Cost per MWh*, as well as *Supplementary Non-GAAP Financial Measures.*

Ontario Power Generation Inc. is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. Our mission is providing low cost power in a safe, clean, reliable and sustainable manner for the benefit of our customers and shareholder.

Ontario Power Generation Inc.'s audited consolidated financial statements and Management's Discussion and Analysis as at and for the year ended December 31, 2017 can be accessed on OPG's web site (www.opg.com), the Canadian Securities Administrators' web site (www.sedar.com), or can be requested from the Company.

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ONTARIO POWER GENERATION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

DECEMBER 31, 2017

[DRAFT]

2017 YEAR-END REPORT

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ONTARIO POWER GENERATION INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) should be read in conjunction with the audited consolidated financial statements and accompanying notes of Ontario Power Generation Inc. (OPG or Company) as at and for the year ended December 31, 2017. OPG's consolidated financial statements are prepared in accordance with United States generally accepted accounting principles (US GAAP) and are presented in Canadian dollars.

As required by *Ontario Regulation 395/11*, as amended, a regulation under the *Financial Administration Act* (Ontario) (FAA), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. In 2014, the Ontario Securities Commission (OSC) approved an exemption which allows OPG to apply US GAAP up to January 1, 2019. The term of the exemption is subject to certain conditions, which may result in the expiry of the exemption prior to January 1, 2019. For details, refer to the section, *Critical Accounting Policies and Estimates* under the heading, *Exemptive Relief for Reporting under US GAAP*. This MD&A is dated March 8, 2018.

FORWARD-LOOKING STATEMENTS

The MD&A contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could", and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

All forward-looking statements involve inherent assumptions, risks, and uncertainties, including those set out in the section, *Risk Management,* and forecasts discussed in the section, *Core Business, Strategy, and Outlook.* All forward-looking statements could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's generating station performance and availability, fuel costs, surplus baseload generation (SBG), cost of fixed asset removal and nuclear waste management, performance and earnings of investment funds, refurbishment of existing facilities, development and construction of new facilities, pension and other post-employment benefit (OPEB) obligations and funds, income taxes, proposed new legislation, the ongoing evolution of Ontario's electricity industry, environmental and other regulatory requirements, health, safety and environmental developments, business continuity events, the weather, financing and liquidity, applications to the Ontario Energy Board (OEB) for regulatory prices, the impact of regulatory decisions by the OEB, Ontario's Fair Hydro Plan (Fair Hydro Plan or the Plan) and forecasts of earnings, cash flows, Funds from Operations (FFO) Adjusted Interest Coverage, Return on Common Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI), Total Generating Cost (TGC) and capital expenditures. Accordingly, undue reliance should not be placed on any forward-looking statement. The forward-looking statements included in this MD&A are made only as of the date of this MD&A. Except as required by applicable securities laws, OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events, or otherwise.

THE COMPANY

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG was established under the *Business Corporations Act* (Ontario) (OBCA) and is wholly owned by the Province of Ontario (Province or Shareholder).

As at December 31, 2017, OPG's electricity generation portfolio had an in-service capacity of 16,210 megawatts (MW). OPG operates two nuclear generating stations, 66 hydroelectric generating stations, three thermal generating stations, and one wind power turbine. In addition, OPG and TransCanada Energy Ltd. co-own the 550 MW Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS). OPG and ATCO Power Canada Ltd. co-own the 560 MW Brighton Beach gas-fired combined cycle GS (Brighton Beach). OPG's 50 percent share of the in-service capacity and generation volume of these co-owned facilities is included in the generation portfolio statistics set out in this report. The income from the co-owned facilities is accounted for using the equity method of accounting, and OPG's share of income is presented as income from investments subject to significant influence in the Contracted Generation Portfolio segment.

OPG also owns two other nuclear generating stations, the Bruce A GS and the Bruce B GS, which are leased on a long-term basis to Bruce Power LP (Bruce Power). Income from these leased stations is included in revenue under the Regulated – Nuclear Generation segment. The leased stations are not included in the generation portfolio statistics set out in this report.

All of OPG's owned and co-owned generating facilities are located in Ontario. OPG does not operate PEC, Brighton Beach, the Bruce A GS and the Bruce B GS.

OPG's Reporting Structure

Effective in the fourth quarter of 2017, following the establishment of the Fair Hydro Trust (the Trust) as the financing entity to implement the Fair Hydro Plan under the *Ontario Fair Hydro Plan Act, 2017* (the Fair Hydro Act or the Act), OPG has modified its reportable business segments to include the Fair Hydro Trust segment. Through its control over the key activities of the Trust and its obligation to absorb losses through ownership of the Trust's subordinated debt, the Company consolidates the financial results of the Trust in accordance with US GAAP. The Fair Hydro Trust segment reports the income related to OPG's role as Financial Services Manager under the Act and holder of subordinated debt issued by the Trust, including the financial results of the Trust. The Fair Hydro Plan and the Fair Hydro Trust are discussed in the section, *Recent Developments* and in the section, *Core Business, Strategy, and Outlook* under the heading, *Business Segments*.

The composition of OPG's reportable business segments is as follows:

- Regulated – Nuclear Generation
- Regulated – Nuclear Waste Management
- Regulated – Hydroelectric
- Contracted Generation Portfolio
- Services, Trading, and Other Non-Generation
- Fair Hydro Trust.

OPG receives regulated prices for electricity generated from most of its hydroelectric facilities and all of the nuclear facilities that it operates (collectively, prescribed facilities or regulated facilities). The regulated facilities comprise 54 hydroelectric generating stations across a number of major river systems in the province, the Pickering Nuclear GS (Pickering GS) and Darlington Nuclear GS (Darlington GS).

The operating results related to these regulated facilities are described under the Regulated – Nuclear Generation, Regulated – Nuclear Waste Management, and Regulated – Hydroelectric segments. For the remainder of OPG's operating generating facilities, the operating results are described under the Contracted Generation Portfolio segment. A description of all OPG's segments is provided under the section, *Business Segments*.

In-Service Generating Capacity

OPG's in-service generating capacity by business segment as of December 31 was as follows:

(MW)	**2017**	**2016**
Regulated – Nuclear Generation [1]	**5,728**	5,728
Regulated – Hydroelectric	**6,426**	6,421
Contracted Generation Portfolio [2]	**4,056**	4,028
Total	**16,210**	16,177

[1] The in-service generating capacity as of December 31, 2017 and December 31, 2016 excludes Unit 2 of the Darlington GS. The unit, which has a generating capacity of 878 MW, was taken offline in mid-October 2016 and is currently undergoing refurbishment.

[2] Includes OPG's share of in-service generating capacity of 275 MW for PEC and 280 MW for Brighton Beach.

The total in-service capacity as at December 31, 2017 increased by 33 MW compared to 2016. The increase was primarily due to the completion of the 28 MW Peter Sutherland Sr. hydroelectric GS, which was placed in-service in the first quarter of 2017, and the upgrade of Unit 10 of the Sir Adam Beck 1 hydroelectric GS, which was completed in June 2017. Further details on the Peter Sutherland Sr. GS project are found in the section, *Core Business, Strategy, and Outlook* under the heading, *Project Excellence*.

REVENUE MECHANISMS FOR REGULATED AND NON-REGULATED GENERATION

Regulated Generation

The OEB sets the prices for electricity generated from OPG's regulated nuclear and regulated hydroelectric facilities. The following table presents the OEB-authorized regulated prices for electricity generated from these facilities during the periods from January 1, 2016 to May 30, 2017, as well as new regulated prices retrospectively effective June 1, 2017 that OPG has calculated and submitted to the OEB, based on the OEB's decision on OPG's 2017-2021 application for new regulated prices issued on December 28, 2017:

($/MWh)	2017		2016
	January 1 to May 31	**June 1 to December 31** [1]	
Regulated – Nuclear Generation			
Base regulated price	**59.29**	**80.65**	59.29
Variance and deferral account rate rider	**-**	**-**	10.84 [2]
	59.29	**80.65**	70.13
Regulated – Hydroelectric			
Base regulated price	**40.72**	**41.67**	40.72
Variance and deferral account rate rider	**-**	**-**	3.19 [2]
	40.72	**41.67**	43.91

[1] Regulated prices for the June 1, 2017 to December 31, 2017 period were calculated and submitted to the OEB by OPG in January 2018 based on the OEB's December 28, 2017 decision on OPG's 2017-2021 application for new regulated prices. The final regulated prices will be determined by the OEB as part of the final payment amounts order process, which is expected to be completed in the first half of 2018. As part of the process, the OEB is expected to authorize separate rate riders to allow for the recovery of the shortfall between the new regulated prices and the previous regulated prices that OPG continues to receive during the period between June 1, 2017 and the implementation date of the new regulated prices pending the issuance of the final payment amounts order. The incremental revenue for the period between June 1, 2017 and December 31, 2017 arising from this retrospective application of new regulated prices was accrued in 2017. **[MONITOR]**

[2] The OEB authorized interim period rate riders for the period from October 1, 2015 to December 31, 2016 to allow for the recovery of the riders effective July 1, 2015 for the period from July 1, 2015 to September 30, 2015. The nuclear interim period rate rider was $2.17 per megawatt hour (MWh) and the regulated hydroelectric interim period rate rider was $0.64/MWh. These interim period rate riders have not been included in the above table. All rate riders in effect during 2016 expired on December 31, 2016.

Based on the OEB's December 2017 decision, the new base regulated prices are determined on an incentive ratemaking methodology for the hydroelectric operations and under a custom incentive regulation framework for the nuclear operations. For the hydroelectric facilities, the new base regulated price is determined using a formula that annually escalates the previous regulated prices, subject to some adjustments, based on inflation less a stretch factor to incent additional innovation and efficiency. For the nuclear facilities, the new regulated price is determined under a rate smoothing approach that defers a portion of the approved nuclear revenue requirement for future collection, with the aim of making more stable changes in OPG's production-weighted regulated prices year over year. The nuclear revenue requirement is based on the OEB-approved forecasts of operating costs as reduced by a stretch factor and a return on rate base. Rate base for OPG represents the average net level of investment in regulated fixed and intangible assets in service and an allowance for working capital. The OEB's December 2017 decision and OPG's new regulated prices are discussed further in the section, *Recent Developments*.

The base regulated prices in effect during 2016 were established by the OEB's November 2014 decision and December 2014 order, effective November 1, 2014, using a forecast cost-of-service methodology based on the OEB-approved revenue requirements for the 2014 to 2015 period, taking into account the OEB-approved forecasts of production and operating costs for the regulated facilities and a return on rate base.

The increase in base regulated prices for the Regulated – Nuclear Generation segment from those last approved in 2014 is impacted by lower production for Darlington GS for the duration of Unit 2's refurbishment. The increase also

reflects OPG's ability to earn a return on higher in-service capital and recover costs to enable Pickering to operate beyond 2020 in line with the Long-Term Energy Plan (LTEP).

Rate riders for OPG are typically established to recover or repay approved balances in OEB-authorized regulatory variance and deferral accounts (regulatory accounts). Variance and deferral accounts typically capture, for subsequent review and approval, differences between actual costs and revenues and the corresponding forecast amounts approved by the OEB in setting regulated prices, or record the impact of items not reflected in the approved regulated prices. The rate riders in effect to the end of 2016 were established by the OEB's October 2015 order on OPG's 2014 application to recover the December 31, 2014 variance and deferral account balances. Revenue received from the recovery of variance and deferral account balances is largely offset by amortization expense related to these balances.

Non-Regulated Generation

Electricity generated from most of OPG's non-regulated assets is subject to Energy Supply Agreements (ESAs) with the Independent Electricity System Operator (IESO).

During 2017, ESAs were in effect for the following thermal generating facilities:

- Lennox GS: Capacity and production provided by the station are subject to an ESA for the period from January 1, 2013 to September 30, 2022
- Atikokan GS: Capacity and production provided by the station are subject to a ten-year ESA expiring in July 2024
- Thunder Bay GS: Capacity and production provided by the station are subject to a five-year ESA expiring in January 2020.

In addition, long-term hydroelectric ESAs are in place for the following facilities, with expiry dates ranging from 2059 to 2067:

- Lac Seul and Ear Falls generating stations
- Healey Falls GS
- Sandy Falls, Wawaitin, Lower Sturgeon, and Hound Chute generating stations
- Little Long, Harmon, Smoky Falls, and Kipling generating stations (collectively the Lower Mattagami River generating stations)
- Peter Sutherland Sr. GS, which was placed in-service in March 2017.

HIGHLIGHTS

Overview of Results

This section provides an overview of OPG's operating results for the years ended December 31, 2017 and December 31, 2016.

(millions of dollars – except where noted)	**2017**	**2016**
Revenue	**5,158**	5,653
Fuel expense	**689**	727
Gross margin	**4,469**	4,926
Operations, maintenance and administration	**2,824**	2,747
Depreciation and amortization	**679**	1,257
Accretion on fixed asset removal and nuclear waste management liabilities	**960**	929
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(801)**	(746)
Earnings from Fair Hydro Trust	**(1)**	-
Income from investments subject to significant influence	**(38)**	(37)
Property taxes	**40**	46
Restructuring	**-**	6
	3,663	4,202
Income before other gains, interest, and income taxes	**806**	724
Other gains	**379**	17
Income before interest and income taxes	**1,185**	741
Net interest expense	**95**	120
Income before income taxes	**1,090**	621
Income tax expense	**209**	168
Net income	**881**	453
Net income attributable to the Shareholder	**860**	436
Net income attributable to non-controlling interest [1]	**21**	17
Electricity production (TWh) [2]	**74.1**	78.2
Cash flow		
Cash flow provided by operating activities	**944**	1,817

[1] Relates to the 25 percent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in the Lower Mattagami Limited Partnership, the 33 percent interest of Coral Rapids Power Corporation (CRP), a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership (PSS), and the 10 percent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP. CRP increased its partnership interest to 33 percent in April 2017.

[2] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach and excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS was excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

Net income attributable to the Shareholder was $860 million for 2017, representing an increase of $424 million compared to 2016. Income before interest and income taxes was $1,185 million for 2017, representing an increase of $444 million compared to 2016. The following summarizes the significant factors which contributed to the variance:

Significant factors that increased income before interest and income taxes:

- Higher revenue from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments of approximately $480 million recorded in the fourth quarter of 2017 to reflect the OEB's decision on OPG's application for new regulated rates issued in December 2017 with a retrospective effective date of June 1,

2017. This revenue increase for the June 1, 2017 to December 31, 2017 period was recorded as an increase in regulatory assets, based on new regulated prices for that period proposed in OPG's January 2018 submission to the OEB based on the findings in the December 2017 decision, net of a regulatory liability recognized in relation to OPG's nuclear rate smoothing proposal included in that submission. The new regulated prices, the future collection period for the retrospective revenue increase, and the rate smoothing proposal are pending the OEB's approval through the payment amounts order process, which typically follows the OEB's issuance of a decision on a major rates application. The OEB's approval of the final payment amounts order, including determinations on the new regulated prices and rate smoothing, are not expected to have a material impact on the total revenue recorded for the June 1, 2017 to December 31, 2017 period. The OEB is expected to issue the final payment amounts order in the first half of 2018. **[MONITOR]**

- Higher earnings of $377 million from the Services, Trading, and Other Non-Generation segment, primarily as a result of the gain on sale of OPG's head office premises and associated parking facility, a non-core asset of the business. A gain on sale of $283 million, which is net of tax effects of $95 million, was recognized in net income upon completion of the transaction in the second quarter of 2017. The sale was undertaken pursuant to a Shareholder Declaration and a Shareholder Resolution. Further details can be found under the heading, *Recent Developments – Shareholder Declarations and Shareholder Resolutions to Sell Certain Non-Core Real Estate Properties*.
- Higher earnings of $24 million from the Regulated – Nuclear Waste Management segment, primarily due to higher earnings from the nuclear fixed asset removal and nuclear waste management funds (Nuclear Segregated Funds), partially offset by an increase in accretion expense on the nuclear fixed asset removal and nuclear waste management liabilities (Nuclear Liabilities).

Significant factors that reduced income before interest and income taxes:

- Lower revenue of approximately $285 million, partially offset by a decrease in fuel expense of $31 million, reflecting lower electricity generation of 4.9 terawatt hours (TWh) from the Regulated – Nuclear Generation segment. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS since October 2016, partially offset by an increase in generation from the Pickering GS. The increase in generation from the Pickering GS was primarily due to outage cycle optimization, favourable unit conditions and execution of planned outage work resulting in fewer unplanned and planned outage days at the station.
- Higher operations, maintenance and administration (OM&A) expenses of $77 million, mainly in the Regulated – Nuclear Generation segment, reflecting planned expenditures related to the major maintenance activities occurring at the nuclear stations.
- Higher depreciation and amortization expense of $22 million in the Regulated – Nuclear Generation segment, excluding amortization expense related to balances in regulatory accounts, primarily due to new assets in service.
- A gain of $22 million recorded in the first quarter of 2016 to reflect the OEB's decision on OPG's motion asking the OEB to review and vary parts of its November 2014 decision on OPG's regulated prices.

The expiry of rate riders for the recovery of OEB-approved balances in regulatory accounts on December 31, 2016 contributed to the decrease in revenue in 2017, compared to 2016, but was largely offset by a decrease in the amortization expense related to regulatory account balances.

Net interest expense decreased by $25 million in 2017, compared to 2016, primarily due to a higher amount of interest costs capitalized for the Darlington Refurbishment project.

Income tax expense increased by $41 million in 2017, compared to 2016, primarily due to higher income before income taxes, partially offset by a higher amount of income tax expense deferred in regulatory assets in 2017.

Segment Results

The following table summarizes OPG's income before interest and income taxes by business segment. Significant factors which contributed to the higher income during 2017, compared to 2016, are discussed above. A detailed discussion of OPG's performance by reportable segment is included in the section, *Discussion of Operating Results by Business Segment*.

(millions of dollars)	**2017**	**2016**
Income (loss) before interest and income taxes		
Regulated – Nuclear Generation	**57**	4
Regulated – Hydroelectric	**614**	642
Contracted Generation Portfolio	**300**	282
Total electricity generation business segments	**971**	928
Regulated – Nuclear Waste Management	**(150)**	(174)
Services, Trading, and Other Non-Generation	**364**	(13)
Fair Hydro Trust	**-**	-
	1,185	741

Electricity Generation

Electricity generation for 2017 and 2016 was as follows:

(TWh)	**2017**	**2016**
Regulated – Nuclear Generation	**40.7**	45.6
Regulated – Hydroelectric	**30.7**	29.5
Contracted Generation Portfolio [1]	**2.7**	3.1
Total OPG electricity generation	**74.1**	78.2
Total electricity generation by other generators in Ontario [2]	**70.5**	72.7

[1] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

[2] Non-OPG generation is calculated as the Ontario electricity demand plus net exports, as published by the IESO, minus OPG electricity generation.

Total OPG electricity generation decreased by 4.1 TWh in 2017, mainly due to lower electricity generation of 4.9 TWh from the Regulated – Nuclear Generation segment. As expected, this was primarily the result of the removal from service of Unit 2 at the Darlington GS for the duration of the unit's refurbishment, which began in October 2016. This decrease in electricity generation was partially offset by an increase in generation from the Pickering GS, primarily due to outage cycle optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of outage days at the station, as well as higher electricity generation from the Regulated – Hydroelectric segment.

The higher electricity generation from the Regulated – Hydroelectric segment in 2017 was due to higher water flows primarily on the eastern Ontario river systems, net of forgone electricity generation as a result of SBG conditions, discussed below.

The lower electricity generation from the Contracted Generation Portfolio segment was primarily due to higher SBG conditions.

OPG's operating results are affected by changes in grid-supplied electricity demand resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. Ontario's electricity demand as reported

by the IESO was 132.1 TWh in 2017 and 137.0 TWh and 2016, respectively, which excludes electricity exports out of the province.

Power that is surplus to the Ontario market is managed by the IESO, mainly through generation reductions at hydroelectric and nuclear stations and other grid-connected renewable resources. Reducing hydroelectric production is a measure used by the IESO to manage SBG conditions. Baseload generation supply surplus in Ontario was more prevalent in 2017 than in 2016, mainly due to higher water flows and reduced electricity demand in the province during 2017. During 2017 and 2016, OPG lost 5.9 TWh and 4.7 TWh of hydroelectric generation due to SBG conditions, respectively. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions in 2017 and 2016 was offset by the impact of a regulatory variance account authorized by the OEB. OPG did not forgo any electricity production at its nuclear stations due to SBG conditions.

Average Sales Prices

The majority of OPG's generation is from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments. The regulated prices authorized by the OEB for electricity generated from OPG's nuclear and regulated hydroelectric generating stations are discussed in the section, *Revenue Mechanisms for Regulated and Non-Regulated Generation*.

The average sales price for the Regulated – Nuclear Generation segment during 2017 was 7.1 cents per kilowatt hour (¢/kWh), compared to 6.9 ¢/kWh during 2016. The increase in this average sales price was primarily due to an increase in revenue for the period June 1, 2017 to December 31, 2017 recorded in the fourth quarter of 2017 to reflect the OEB's December 2017 decision on OPG's application for new regulated prices, with an effective date of June 1, 2017. The increase was partially offset by the expiry of an OEB-authorized nuclear rate rider of $10.84 per MWh, on December 31, 2016, for the recovery of variance and deferral account balances. The average sales price for the Regulated – Hydroelectric segment during 2017 was 4.2 ¢/kWh, compared to 4.4 ¢/kWh during 2016. The decrease in this average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized regulated hydroelectric rate rider of $3.19/MWh for the recovery of variance and deferral account balances, partially offset by the impact of an increase in revenue for the period June 1, 2017 to December 31, 2017 recorded in the fourth quarter of 2017 to reflect the OEB's December 2017 decision. The rate riders that expired on December 31, 2016 were established to recover approved balances recorded in the variance and deferral accounts in prior years. As such, the year-over-year changes in revenue from the rate riders were largely offset by changes in amortization expense related to these balances.

Cash Flow from Operations

Cash flow provided by operating activities for 2017 was $944 million, compared to $1,817 million for 2016. The decrease in cash flow provided by operating activities was expected and primarily due to lower generation revenue receipts reflecting lower generation from the Regulated – Nuclear Generation segment as a result of the ongoing refurbishment of Unit 2 at the Darlington GS and the expiry, on December 31, 2016, of the OEB-authorized rate riders for nuclear and regulated hydroelectric generation. The decrease in cash flow was also due to higher income tax instalments during 2017, compared to 2016.

The decrease in cash flow provided by operating activities was partly offset by lower contributions to the Used Fuel Segregated Fund in 2017. Both the Used Fuel Segregated Fund and the Decommissioning Segregated Fund were determined to be fully funded based on an updated estimate of OPG's nuclear waste management and nuclear facilities decommissioning obligations pursuant to an Ontario Nuclear Funds Agreement (ONFA) reference plan approved by the Province, effective January 1, 2017. Pursuant to the ONFA, the reference plan is required to be updated at least once every five years. Contributions to either or both of the Nuclear Segregated Funds may be required in the future should the funds be in an underfunded position at the time of the next ONFA reference plan update. The decrease in cash flow compared to the prior year also was partially offset by the payment of a supplemental rent rebate to Bruce Power in the first quarter of 2016 in relation to a period in 2015. The lease

agreement for the Bruce nuclear generating stations was amended in late 2015 to eliminate this rebate provision going forward.

Funds from Operations Adjusted Interest Coverage

FFO Adjusted Interest Coverage is an indicator of OPG's ability to meet interest obligations from operating cash flow. The indicator is measured over a 12-month period. The FFO Adjusted Interest Coverage was 3.3 times for 2017 compared to 5.1 times for 2016. FFO Adjusted Interest Coverage in 2017 reflected a year-over-year decrease in FFO before interest due to lower cash flow provided by operating activities and changes to non-cash working capital balances, offset by the impact of a lower adjusted interest expense due to a decrease in the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets.

The decrease in the excess of interest on pension and OPEB benefit obligations over expected return on pension plan assets in 2017 was primarily due to the change in the method used to estimate the interest cost and service cost component of pension and OPEB costs prospectively adopted as of January 1, 2017. The change in the method is discussed in the section, *Critical Accounting Policies and Estimates* under the heading, *Pension and Other Post-Employment Benefits*.

Return on Common Equity Excluding Accumulated Other Comprehensive Income

ROE Excluding AOCI is an indicator of OPG's performance consistent with the Company's strategy to provide value to the Shareholder. ROE Excluding AOCI is measured over a 12-month period. ROE Excluding AOCI for 2017 was 7.5 percent, compared to 4.2 percent for 2016. ROE Excluding AOCI increased for 2017, compared to 2016, primarily due to higher net income attributable to the Shareholder as a result of the gain on the sale of OPG's head office premises and associated parking facility recorded during the second quarter of 2017 and an increase in revenue for the period June 1, 2017 to December 31, 2017 recorded in the fourth quarter of 2017 to reflect the OEB's December 2017 decision on OPG's application for new regulated prices, with an effective date of June 1, 2017. The increase in net income attributable to the Shareholder was partially offset by the impact of lower nuclear electricity generation reflecting the Unit 2 refurbishment outage at the Darlington GS.

Enterprise Total Generating Cost per Megawatt-Hour

The Enterprise TGC per megawatt-hour (MWh) was $50.66 for the year ended December 31, 2017, compared to $48.45 for the same period in 2016. The increase in Enterprise TGC per MWh was expected and primarily due to lower nuclear electricity generation as a result of the Unit 2 refurbishment outage at the Darlington GS and higher sustaining capital expenditures, partially offset by higher SBG-adjusted hydroelectric electricity generation reflecting higher water flows.

If Unit 2 at the Darlington GS was not currently undergoing refurbishment and had continued to operate in a manner consistent with the performance of the remaining units at the station, adjusting for generation constraints on these units related to the transition of the station toward refurbishment, the Enterprise TGC would have been approximately $4 to $5 per MWh lower for the year ended December 31, 2017. This sensitivity was calculated using the estimated incremental electricity generation and associated fuel cost that are expected to have had resulted in the absence of the refurbishment.

Nuclear Total Generating Cost per Megawatt-Hour

The Nuclear TGC per MWh was $70.95 for the year ended December 31, 2017, compared to $62.30 for the same period in 2016. The increase in Nuclear TGC per MWh was expected and primarily due to the decrease in nuclear electricity generation primarily as a result of the Unit 2 refurbishment outage at the Darlington GS and higher sustaining capital expenditures.

Hydroelectric Total Generating Cost per Megawatt-Hour

The Hydroelectric TGC per MWh was $23.91 for the year ended December 31, 2017, compared to $25.49 for the same period in 2016. The improvement in the Hydroelectric TGC per MWh was primarily due to higher SBG-adjusted hydroelectricity generation reflecting higher water flows.

ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are not measurements in accordance with US GAAP and should not be considered alternative measures to net income, cash flow provided by operating activities, or any other performance measure under US GAAP. OPG believes that these non-GAAP financial measures are effective indicators of its performance and are consistent with the Company's strategic imperatives and related objectives. The definition and calculation of ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are found in the section, *Supplementary Non-GAAP Financial Measures*.

Recent Developments

OEB's Decision on OPG's Application for New Regulated Prices

The OEB's decision on OPG's May 2016 five-year application for new regulated prices for its nuclear and regulated hydroelectric generation was issued on December 28, 2017, following a public hearing process. The OEB set an effective date for OPG's new regulated prices of June 1, 2017. OPG had requested an effective date of January 1, 2017. The decision reflected the terms of an OEB-approved partial settlement agreement reached by OPG and intervenors on a limited set of issues in the first quarter of 2017 (Settlement Agreement). For the first time since OPG's prescribed facilities became subject to rate regulation, the new prices have been determined on an incentive ratemaking methodology for the hydroelectric operations and a custom incentive regulation framework for the nuclear operations.

For the hydroelectric facilities, effective June 1, 2017, the base regulated prices in effect prior to June 1, 2017, with some adjustments, will be escalated for each of years 2017 to 2021 using a formula equal to an industry-specific weighted inflation factor based on indices published annually by the OEB for use in incentive regulation formulas, less a stretch factor adjustment. The OEB accepted OPG's proposal to set the annual stretch factor adjustment at 0.3 percent. Based on the approved formula, the 2017 increase in the base regulated price for the regulated hydroelectric facilities is 1.4 percent as of June 1, 2017 and the 2018 increase is 0.9 percent as of January 1, 2018. For the 2019-2021 period, the base regulated price for the regulated hydroelectric facilities will be determined annually before the beginning of each year using the approved formula and inflation indices published by the OEB.

For the nuclear operations, a revenue requirement is determined for each of the years 2017 to 2021 based on the OEB-allowed level of OPG's forecast operating costs, reduced by a stretch factor amount, as well as a return on rate base determined using OEB's generic prescribed rate of return and an OPG-specific deemed capital structure. OPG has calculated that the findings of the OEB's December 2017 decision with respect to the forecast operating costs, rate base and deemed capital structure for the nuclear generating facilities will result in nuclear revenue requirements totalling $15.9 billion over the five years.

The OEB's findings with respect to the nuclear revenue requirement include approval for inclusion in rate base of in-service amounts related to the Darlington Refurbishment of $5.5 billion by 2021, including $4.8 billion forecast in the first quarter of 2020 upon return to service of Unit 2, $0.4 billion forecast for pre-requisite projects excluding the Heavy Water Storage and Drum Handling Facility (HWSF) over the 2016-2021 period and $0.3 billion for pre-requisite projects placed in service prior to 2016. The OEB is expected to review the HWSF project as part of a future application. In the decision, the OEB concluded that it is appropriate to evaluate OPG's performance on the Darlington Refurbishment project at an overall level rather by individual cost component, with recovery of any increases over the approved in-service amounts subject to a future prudence review. The revenue requirement impact of differences between the approved in-service additions and the actual in-service additions will be recorded in

the Capacity Refurbishment Variance Account authorized by the OEB pursuant to *Ontario Regulation 53/05*. The $4.8 billion forecast in-service amount upon return to service of Unit 2 includes expenditures incurred during the definition and planning phase of the project.

The OEB also approved OPG's requested forecast costs of approximately $292 million for activities to enable Pickering operations beyond 2020 and agreed to inclusion of operating cost and generation impacts associated with continued operation of Pickering in 2021 in nuclear regulated prices. The differences between approved forecast enabling costs for continued Pickering operations and the actual amounts will be recorded in the Capacity Refurbishment Variance Account for future review and disposition by the OEB.

Excluding amounts that otherwise would have been recorded in OEB-authorized regulatory accounts for repayment to, or recovery from, customers in the future, the OEB's decision reduced OPG's proposed five-year nuclear revenue requirement by $0.6 billion. The main adjustments made by the OEB included a reduction of $100 million per year to requested OM&A costs, a reduction of 10 percent per year to forecast non-Darlington refurbishment capital in-service additions entering rate base over the 2017-2021 period, an increase and expansion of the scope of the stretch factor for nuclear costs that further reduced the revenue requirement, and a rejection of OPG's request to increase the equity component of the existing deemed capital structure of 45 percent equity and 55 percent debt. The OEB increased and expanded the annual stretch factor to 0.6 percent to most of OPG's OM&A expenses incurred directly for, or allocated to, the nuclear facilities, as well as to non-Darlington refurbishment capital in-service additions. The stretch factor is applied starting in 2018 and compounds in each year to 2021.

In accordance with *Ontario Regulation 53/05*, the nuclear revenue requirement continues to be adjusted by the amount of OPG's revenues, net of costs, from leasing the Bruce nuclear generating stations to Bruce Power. As directed by the OEB, OPG's revenues and costs related to the Bruce nuclear generating stations continue to be determined in accordance with US GAAP for the purposes of establishing the nuclear revenue requirement and are subject to the Bruce Lease Net Revenues Variance Account in accordance with *Ontario Regulation 53/05*. This includes costs related to the portion of the Nuclear Liabilities associated with the Bruce nuclear generating stations. The OEB's decision maintained the previously approved cost recovery methodology for the costs of the Nuclear Liabilities for the prescribed facilities and for the Bruce facilities, directing OPG to file a future study examining such methodologies jurisdictionally and for OPG's assets specifically. The decision fully incorporated the impacts of the updated estimate of OPG's obligations for nuclear waste management and nuclear facilities decommissioning as at December 31, 2016, including through a new ONFA reference plan effective January 1, 2017 and the change in the Nuclear Liabilities recorded on December 31, 2016.

As proposed by OPG, the OEB set recovery of pension and OPEB costs in the nuclear revenue requirement on the basis of OPG's cash payments for pension and OPEB plans, with differences between pension and OPEB accrual costs and cash payments continuing to be recorded in the Pension & OPEB Cash to Accrual Differential Deferral Account. The regulatory treatment of pension and OPEB costs is discussed further under the heading, *OEB's Report on Regulatory Treatment of Pension and OPEB Costs*.

The OEB accepted all variance and deferral account balances proposed for recovery that were not already accepted as part of the Settlement Agreement, resulting in approval of recovery of $305 million recorded in variance and deferral variance accounts as at December 31, 2015, without adjustments. The Settlement Agreement provided for the continuation of all applicable existing variance and deferral accounts. In addition to the Rate Smoothing Deferral Account discussed below, the OEB established, as of the effective date of the new regulated prices, new variance and deferral accounts to record costs related to implementing the Canadian Nuclear Safety Commission's (CNSC) Fitness for Duty program and to record differences between forecast and actual amount of Scientific Research & Experimental Development investment tax credits attributable to the nuclear facilities.

Consistent with the requirements of *Ontario Regulation 53/05*, OPG's overall production-weighted regulated prices will be smoothed, with a resulting portion of the approved annual nuclear revenue requirements for the 2017-2021 period deferred in the Rate Smoothing Deferral Account for future collection. The non-deferred portion of each year's

nuclear revenue requirement is divided by the OEB-approved forecast of OPG's nuclear electricity generation for the corresponding year to determine the base nuclear regulated price. The OEB approved the nuclear electricity generation forecast as requested by OPG.

As amended in March 2017, *Ontario Regulation 53/05* requires rate smoothing to be applied in a manner that makes changes in OPG's weighted-average nuclear and hydroelectric regulated prices more stable year over year. Previously, the regulation required that rate smoothing be applied with a view of making more stable year-over-year changes in OPG's nuclear regulated prices only. Per the regulation, the deferral account records interest at a long-term debt rate reflecting OPG's cost of long-term borrowing approved by the OEB, compounded annually. The regulation requires the OEB to authorize recovery of the balance in the account on a straight line basis over a period not to exceed ten years following the end of the Darlington Refurbishment project. OPG recognizes positive amounts deferred under rate smoothing as an increase in net regulatory assets and an increase in revenue in the period to which the underlying approved revenue requirement relates. Negative amounts determined under rate smoothing are correspondingly recorded as a decrease in net regulatory assets and a decrease to revenue.

On January 17, 2018, OPG submitted a draft payment amounts order to the OEB that proposed nuclear base regulated prices for each year of the 2017-2021 period, including a rate smoothing proposal, based on the December 2017 decision's findings. The rate smoothing proposal takes into account the near-term and future impacts on customers, while seeking to ensure that resulting nuclear regulated prices allow for sufficient cash flow to maintain the Company's investment grade credit rating and support availability of cost effective funding, while taking into account both near-term and future impacts on customers. Based on the OEB's direction, the draft payment amounts order also included proposed periods for recovery, through interim period shortfall rate riders, of the retrospective revenue shortfall for the period between June 1, 2017 and the implementation date of the new regulated prices based on proposed new regulated prices that would have been in effect during that period. The draft payment amounts also included proposed recovery periods, through variance and deferral account rate riders, for regulatory account balances approved for recovery in this application. **[MONITOR]**

To reflect the OEB's decision, in the fourth quarter of 2017, OPG recorded incremental revenue of approximately $480 million for the period June 1, 2017 to December 31, 2017 based on the draft payment amounts order. The revenue was recorded as an increase in regulatory assets for the June 1, 2017 to December 31, 2017 revenue shortfall based on proposed new regulated prices for nuclear facilities and regulated hydroelectric facilities, net of a regulatory liability recognized in relation to OPG's rate smoothing proposal. The OEB's approval of the final payment amounts order, including the allocation of the approved revenue requirement between nuclear regulated prices and rate smoothing deferrals, is not expected to have a material impact on the net revenue increase recorded in the fourth quarter of 2017. The OEB is expected to issue the final payment amounts order and implement new regulated prices in the first half of 2018. **[MONITOR]**

Consistent with the effective date of the OEB's December 2017 decision, for the period from January 1, 2017 to May 31, 2017, OPG continued to record additions to the existing variance and deferral accounts for the nuclear and regulated hydroelectric facilities pursuant to the OEB's previous decisions and orders. These additions reflected differences between actual and forecast amounts embedded in the regulated prices in effect prior to the June 1, 2017 effective date.

In January 2018, OPG filed a motion asking the OEB to review and vary the effective date of the new regulated prices to January 1, 2017. The motion did not impact OPG's financial results for the year ended December 31, 2017.

Ontario's 2017 Long-Term Energy Plan

On October 26, 2017, Ontario's Ministry of Energy issued the 2017 LTEP that outlines the Province's plans for the future development of Ontario's electricity system. The 2017 LTEP focuses on the affordability, reliability and flexibility of a clean energy supply in the province. The 2017 LTEP replaces the previous LTEP issued in 2013.

As it relates to the supply of electricity, the 2017 LTEP recognizes the refurbishment of Ontario's nuclear generating stations as the most cost-effective option for producing emission-free baseload generation to meet Ontario's needs and reaffirms the Province's support for the refurbishment of the four units at the Darlington GS and the six units at the Bruce generating stations, subject to the principles established in the 2013 LTEP. The 2017 LTEP also recognizes the value to customers of continuing to operate the Pickering GS until 2024, as planned. With respect to hydroelectric electricity generation, the 2017 LTEP highlights the opportunity to continue to invest in optimizing existing hydroelectric facilities, noting that pumped hydroelectric storage could play an important role in the reliability of the electricity system.

Additionally, the 2017 LTEP discusses the potential impact of a number of innovative technologies on the future of the electricity system. Among others, these include the increased electrification of the transportation sector, the emergence of energy storage, and the opportunity for Ontario to foster nuclear innovation technologies. OPG continues to assess how best to capitalize on potential business opportunities in these and other areas. The 2017 LTEP also recognizes the importance of Indigenous peoples' continuing role in shaping Ontario's energy planning, projects and policies.

Darlington Refurbishment

In October 2016, OPG commenced the refurbishment of the first Darlington GS unit, Unit 2, as part of the Darlington Refurbishment project. The de-fuelling of the reactor and islanding of Unit 2, the physical separation of the unit under refurbishment from the three operating units, were completed in the first half of 2017.

The disassembly of reactor components commenced in the third quarter of 2017, with the removal of feeder tubes completed in September 2017. The removal of fuel channel assemblies commenced in October 2017. As part of the fuel channel assemblies, the removal of pressure tubes is in progress and will be followed by the removal of calandria tubes. The second major segment and the removal of all reactor components is expected to be completed by mid-2018.

All of the pre-requisite projects, including construction of facilities, infrastructure upgrades and installation of safety enhancements, with the exception of the HWSF, have been completed and placed in service. The completion of the HWSF has been delayed due to challenges with construction, with construction activities suspended for a portion of 2017. Construction to complete the facility recommenced in the fourth quarter of 2017, including work to preserve and protect the facility during winter. The HWSF is expected to be completed by the second quarter of 2019 and is not on the critical path for the Darlington Refurbishment project, which continues to track on schedule. The increase in the cost estimate for the HWSF will be accommodated within the overall Darlington Refurbishment budget of $12.8 billion. Taking into account the execution performance of the Unit 2 refurbishment, the overall Darlington Refurbishment project continues to track on budget.

On November 21, 2017, the Financial Accountability Office of Ontario issued a report, "*An Assessment of the Financial Risks of the Nuclear Refurbishment Plan*". The report assesses the impact of OPG and Bruce Power's nuclear refurbishments on customers and the Province based on mechanisms in place for the recovery of the costs to refurbish and subsequently operate the nuclear stations. The report concludes that refurbishment of the four units at the Darlington GS and the six units at the Bruce nuclear generating stations provides the most cost effective, low emission generation source available to meet Ontario's baseload electricity requirements.

The Darlington Refurbishment project is discussed further in the section, *Core Business, Strategy, and Outlook* under the heading, *Project Excellence*.

Canadian Nuclear Safety Commission Safety Rating for the Darlington GS and the Pickering GS

The CNSC publishes an annual report on the safety performance of Canada's nuclear power plants. The report assesses how well plant operators are meeting regulatory requirements and program expectations in the areas of operational performance, safety analysis, radiation protection, waste management and conventional health and

safety. On September 8, 2017, the CNSC issued an executive summary of its 2016 annual report, giving both the Darlington GS and the Pickering GS the highest possible safety rating of "Fully Satisfactory". The Darlington GS achieved this rating for the eighth consecutive year, while the Pickering GS achieved this rating for the second consecutive year.

Ontario's Fair Hydro Plan

On March 2, 2017, the Province announced the Fair Hydro Plan aimed at reducing electricity bills for residential, farm, small businesses and other eligible consumers (Specified Consumers) in the province by refinancing a portion of the Global Adjustment costs over a longer period of time. The Global Adjustment includes the difference between Ontario's electricity market clearing price used to dispatch generation and the prices paid to contracted and regulated generators in the province, and the cost of conservation and demand management programs. On June 1, 2017, the Fair Hydro Act received Royal Assent and the associated general regulation came into force in June 2017. The Act established a framework under which the costs and benefits associated with the Government of Ontario's clean energy initiatives are to be allocated between present and future consumers of electricity under the Fair Hydro Plan. The general regulation provides details on the structural, operational and financial elements required to implement the Fair Hydro Plan.

Pursuant to the Act, effective May 1, 2017, the IESO began to defer a portion of the Global Adjustment costs. The Act allows the IESO to transfer a portion of the deferred balance to a financing entity that would fund the deferral in exchange for an irrevocable right to recover the balance and associated financing and other costs from Specified Consumers in the future (Investment Interest). The legislation appointed OPG as the Financial Services Manager under the Act and conveyed upon the Financial Services Manager statutory obligations, including the creation of one or more financing entities that may acquire Investment Interests from the IESO.

In November 2017, OPG's Board of Directors provided its final approval regarding OPG's involvement with the Trust on commercial terms following the fulfilment of all conditions it established in May 2017. Accordingly, the Fair Hydro Trust was established as the financing entity contemplated by the Act in December 2017. The majority unitholder and beneficiary of the Trust is a wholly-owned subsidiary of OPG. The Trust is structured to be bankruptcy remote and ring fenced from OPG in order to protect the Company's assets and operations.

In order for the Trust to finance the Investment Interest acquired from the IESO, it will incur senior debt from capital markets and subordinated debt from OPG. The Trust's investment will attract financing amounts and other related fees, which, under the general regulation, will be payable by the IESO as carrying costs until July 2021 and by Specified Consumers through the Clean Energy Adjustment to be invoiced by local distribution companies commencing in May 2021, with the three-month lag in 2021 intended to cover the billing and collection lag from the introduction of the Clean Energy Adjustment. The carrying costs include all financing and third-party costs other than payment of principal on debt.

Concurrent with every issuance of the Trust's senior notes, it is expected that OPG will purchase subordinated debt of the Trust in an aggregate amount not to exceed 49 percent of the Trust's total outstanding debt, with 44 percent of the funding to be provided by the Province through equity injections and five percent to be provided by OPG. The subordination level may vary over time, but must at least equal to, or be greater than 35 percent of all outstanding debt. Through OPG's control over the key activities of the Trust and its obligation to absorb losses through ownership of the Trust's subordinated debt, the Company consolidates the financial results of the Trust in accordance with US GAAP.

On December 21, 2017, the Trust purchased its first tranche of Investment Interest from the IESO in the amount of approximately $1.18 billion. Fifty-one percent of the funding requirement or $601 million was financed by the Trust through a revolving warehouse facility ranked as senior notes, and the remaining 49 percent was funded through the issuance of short-term subordinated debt to OPG. The Investment Interest has been classified as a financing receivable on OPG's consolidated balance sheet.

OPG's subordinated debt investment in the Trust was funded through the following sources:

- The Province provided 44 percent of the total funding requirement or $519 million, through an equity injection in OPG in exchange for approximately 12.2 million non-voting Class A common shares at a price of $42.46 per share. The Company's Articles of Amalgamation were amended effective December 1, 2017 to allow for the creation and issuance of Class A shares. Refer to Note 14 of OPG's 2017 audited consolidated financial statements for further details; and
- OPG provided five percent of the total funding requirement or approximately $60 million.

In February 2018, the Trust issued $500 million of senior notes payable with a coupon interest rate of 3.36 percent and an effective interest rate of 3.42 percent, payable semi-annually until maturity on May 15, 2033. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility issued in December 2017. By the end of the first quarter of 2018, the Trust is expected to acquire another tranche of Investment Interest from the IESO, which it expects to fund using its revolving warehouse facility.

Refer to the section, *Liquidity and Capital Resources* under the heading, *Financing Activities* for further details on the Trust's financing arrangements and OPG's public debt offering.

OEB's Report on Regulatory Treatment of Pension and OPEB Costs

On September 14, 2017, the OEB issued its final report on the guiding principles and policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the Ontario electricity and natural gas sectors. The report establishes the accrual basis of accounting as the method of determining pension and OPEB amounts for rate-setting purposes, unless the OEB finds that this method does not result in just and reasonable rates in the circumstances of a particular utility. The report also provides for the establishment of a generic variance account to record asymmetric carrying charges in favour of ratepayers on the differences between the accrual costs recovered and cash payments made by a utility in respect of pension and OPEB plans. Carrying charges on this differential are to be assessed at the OEB's prescribed interest rate, on a prospective basis from the effective date of the new variance account. For OPG, this differential will include amounts going back to November 1, 2014, with the charges calculated on the portion of the differential that has been recovered through regulated prices. None of this differential has been recovered to date. The prescribed interest rate is set quarterly by the OEB based on the quarterly return of a mid-term corporate bond index yield.

The OEB's September 2017 report and the OEB's December 2017 decision on OPG's application for new regulated prices require OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the Pension & OPEB Cash to Accrual Differential Deferral Account in effect since November 1, 2014, until such time as the OEB approves resumption of the accrual basis of recovery for OPG. The future recovery of amounts recorded in the account will be subject to this approval. The OEB's report did not impact OPG's financial results for the year ended December 31, 2017.

The Company recognizes the amount set aside in the Pension & OPEB Cash Versus Accrual Differential Deferral Account as a regulatory asset. As at December 31, 2017, the regulatory asset had a balance of $614 million. Consistent with the expectations set out in the OEB's December 2017 decision, in 2018, OPG plans to file an application with the OEB requesting disposition of the Pension & OPEB Cash Versus Accrual Differential Deferral Account balance as well as balances accumulated since December 31, 2015 in other regulatory accounts.

Shareholder Declarations and Shareholder Resolutions to Sell Certain Non-Core Real Estate Properties

In December 2015, OPG received a Shareholder Declaration and a Shareholder Resolution requiring the Company to sell its head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street in Toronto, Ontario. The sale was completed in April 2017, with a gain on sale of $283 million, which is net of tax effects of $95 million, recognized in net income in the second quarter of 2017. The pre-tax gain on sale was recorded

as an item of Other gains in the consolidated statement of income in the Services, Trading and Other Non-Generation segment. Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. The amount of designated proceeds transferred into the Consolidated Revenue Fund will be equal to the after-tax gain on sale. The transfer is expected to take place as early as in the first quarter of 2018, through a special dividend authorized by OPG's Board of Directors in March 2018. **[MONITOR]**

In June 2016, OPG received a Shareholder Declaration and a Shareholder Resolution that requires the Company to sell its former Lakeview GS site located in Mississauga, Ontario. OPG has entered into a purchase and sale agreement with a purchaser with the sale scheduled to close in March 2018. An estimated after-tax gain on sale of approximately $200 million is expected to be recognized in net income upon completion of the transaction in the first quarter of 2018. **[MONITOR]** Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. OPG anticipates the amount of designated proceeds transferred into the Consolidated Revenue Fund to approximate the after-tax gain on the sale. In accordance with the Shareholder Resolution, approximately one-third of the site is to be transferred to the City of Mississauga, by the purchaser, for parkland, institutional, and cultural uses.

CORE BUSINESS, STRATEGY, AND OUTLOOK

OPG's mission is to provide low cost power in a safe, clean, reliable and sustainable manner for the benefit of its customers and its Shareholder. OPG also seeks to pursue, on a commercial basis, generation development projects and other business expansion opportunities to the benefit of the Shareholder.

OPG's four key strategic imperatives are as follows:

- Operational Excellence
- Project Excellence
- Financial Strength
- Social Licence.

Operational Excellence

Operational excellence at OPG is accomplished by the safe and environmentally responsible generation of reliable and cost-effective electricity from the Company's generating assets through a highly trained and engaged workforce.

Workplace Safety and Public Safety

Workplace safety and public safety are fundamental core values at OPG. OPG is committed to operating all of its facilities in a safe, secure, and reliable manner that minimizes risks to a reasonably achievable level. Safety is an overriding priority in all activities performed at OPG's generating and other facilities, and all employees and contractors are expected to conduct themselves in manner that ensures workplace safety and public safety in line with the Company's safety culture.

In the area of workplace safety, OPG is committed to achieving excellent performance through continuous improvement and a strong safety culture, with the ultimate goal of zero injuries. OPG utilizes an integrated health and safety management system and a set of operational risk control procedures to ensure continued monitoring of health and safety performance and to support continuous learning and improvement in this area. Over the past five years, OPG has repeatedly stood in the top quartile of its comparator Canadian electrical utilities in various safety performance metrics.

Workplace safety performance is measured using two primary indicators at OPG, All Injury Rate (AIR) and Accident Severity Rate (ASR). OPG's AIR and ASR results for employee workplace safety were as follows for the year ended December 31:

	2017	2016
AIR *(injuries per 200,000 hours worked)*	**0.48**	0.56
ASR *(days lost per 200,000 hours)*	**3.57**	2.59

In 2017, OPG's AIR improved from 2016 and was the third-best performance year in the Company's history. For those employee injuries that caused lost time from work, the total time lost from work in 2017 was greater than the previous year. OPG's analysis of the underlying safety events indicated that major contributors to the injuries and near misses included inadequate situational awareness and attention to detail, and suboptimal risk-based decisions, rather than missing or inadequate standards or programs. OPG continues to implement a number of initiatives to target the injury trends based on the analysis of the safety events, with a focus on the use of human performance tools including increased field supervisory oversight, situational awareness, communication, and procedural use and adherence.

In order to strengthen its safety performance, OPG continues to progress an organization-wide "iCare Enough to Act" initiative launched in 2016 and aimed at renewing employees' commitment to their own and each other's safety and well-being. Approaches to supervisory oversight, communication and safe work planning are being modified and updated to further strengthen safety as a foundational element of the Company's values-based culture.

Contractors are required to conduct work safely at OPG sites. In support of this requirement, OPG utilizes an independent contractor pre-qualification process, provides on-site safety support for many of its major projects, and works with contract partners to improve their health and safety programs to meet OPG's requirements. In the past nine years, OPG has consistently shown a Construction Contractor AIR that is markedly better than the Infrastructure Health and Safety Association Contractor AIR, a metric of construction contractor safety performance across Ontario. OPG has maintained this performance while engaging in the refurbishment of the Darlington GS, one of the largest infrastructure projects in Canada. The hours worked by contractors in 2017 were the largest in OPG's history, largely attributable to this project.

OPG continues to maintain a strong focus on the nuclear safety program and to invest in nuclear safety systems. To ensure continued public safety, radiation exposure to members of the public resulting from the operation of OPG's nuclear generating stations is estimated on an annual basis for individuals living or working near the stations. The annual dose to the public resulting from operations of each nuclear facility is expressed in microsieverts (μSv), which is an international unit of radiation dose measurement. For 2016, the annual public doses resulting from the Darlington GS operations and the Pickering GS operations were 0.6 μSv and 1.5 μSv, respectively, which is less than 0.1 and 0.2 percent of the annual legal limit of 1,000 μSv, respectively. While the public doses from OPG's nuclear operations for the 2017 operating year will not be finalized until the second quarter of 2018, they are not expected to differ significantly from the 2016 levels.

In June 2016 and August 2016, the CNSC released sampling results from its independent environmental monitoring program, which confirmed that the public and the environment around OPG's nuclear generating stations continued to be safe. In September 2017, the CNSC issued an executive summary of its 2016 annual report on the safety performance of Canada's nuclear power plants, which gave both the Pickering GS and the Darlington GS the highest possible safety rating of "Fully Satisfactory". For further details, refer to the CNSC safety rating discussion in the section, *Highlights* under the heading, *Recent Developments*.

OPG remains committed to high standards of public safety on waterways around hydroelectric generating stations and dams, and continues to make investments in waterway and dam safety upgrades. The Company's practices in this area are routinely reviewed by an independent panel comprised of internationally recognized experts, who have

concluded that OPG's Dam Safety Program is industry leading in a number of areas. During 2017, OPG continued its water safety campaign with a series of public service announcements illustrating the danger of water near hydroelectric dams and hydroelectric generating stations.

Electricity Generation Production and Reliability

Key strategic initiatives in support of operational excellence, specific to each of OPG's core generating operations, are discussed below. Generation and reliability performance for 2017 is discussed by operating segment in the section, *Discussion of Operating Results by Business Segment*.

Nuclear Operations

OPG is pursuing a number of strategic initiatives aimed at the continued safe and reliable operation of the Pickering GS and targeting top performance at the Darlington GS.

OPG's objective is to maximize the safe and reliable operating life of the Pickering units. As announced in 2016 and approved by the Province, OPG is continuing to execute on a plan to extend safe and reliable operation of the Pickering GS to 2024. In addition to providing Ontario with a clean, reliable source of baseload electricity during nuclear unit refurbishments at the Darlington GS and the Bruce nuclear generating stations, extending operations at the Pickering GS will provide continued employment for up to 4,000 full-time employees at OPG and help to reduce approximately 17 million tonnes of carbon dioxide emissions, which is equivalent to removing approximately 3.4 million cars from Ontario's roads.

As part of the plan to extend Pickering operations, OPG has been continuing to undertake the required technical work to confirm that the station's pressure tubes, a key life-limiting component of the station, will remain fit for service for operation to 2024. In the fourth quarter of 2017, OPG has confirmed that technical assessments completed to date provide sufficient confidence in the programs and provisions in place to assure fitness-for-service of fuel channel components in line with the planned extended operations period. This evaluation is consistent with the safety case reflected in OPG's operating licence renewal application for the Pickering GS submitted to the CNSC in 2017, discussed below. Taking these factors into account, OPG revised the accounting end-of-life assumptions for the Pickering GS from December 31, 2020 for all units to December 31, 2022 for Units 1 and 4 and December 31, 2024 for Units 5 to 8, effective December 31, 2017.

The change in the Pickering GS accounting end-of-life assumptions did not impact OPG's net income in 2017. The change is expected to decrease depreciation expense by $77 million in 2018, including the associated impact on the nuclear asset retirement obligation (ARO) recorded as of December 31, 2017 but before the impact of regulatory accounts. Regulatory accounts, including a new deferral account proposed by OPG in a December 2017 application to the OEB, are expected to largely offset the decrease in depreciation expense. The change in the nuclear ARO recorded in the fourth quarter of 2017 is discussed in the section, *Critical Accounting Policies and Estimates* under the heading, *Asset Retirement Obligation*. On December 29, 2017, OPG applied for an accounting order to establish a variance account to record, from January 1, 2018 until the effective date of the OEB's next payment amounts order, the revenue requirement impact of changes to nuclear liabilities and depreciation and amortization expense resulting from changes to station end-of-life dates for OPG's Pickering prescribed nuclear facilities that will be effective December 31, 2017. Pending the OEB's review of the application, an interim order was issued January 31, 2018 establishing the proposed variance account effective January 1, 2018. The OEB's final decision for the account is expected later in 2018.

OPG's current five-year operating licence for the Pickering GS was approved by the CNSC in 2013 and expires on August 31, 2018. This current licence was issued assuming that the station would shut down in 2020. On June 28, 2017, OPG confirmed to the CNSC that it intends to cease commercial operation of all Pickering units on December 31, 2024. On August 28, 2017, OPG submitted a ten-year licence renewal application to the CNSC. The requested licence term spans the planned extended commercial operations period, through to the planned period of de-fuelling,

de-watering and beginning to place the station in a safe storage state in 2028. In support of the licence renewal, OPG undertook a Periodic Safety Review (PSR), a comprehensive assessment of the station's design and operation to confirm that there is a high level of safety throughout the operating life and to determine what reasonable and practical enhancements can be made to further improve safety. The PSR also includes a component condition assessment of the station to identify the work required to support the station's continued operation. The PSR has confirmed that extending operations of the Pickering units will continue to pose minimal risk to the health, safety and security of workers, the public and the environment. The final major component of the PSR was submitted to the CNSC in November 2017. The CNSC's review of the PSR submission and licence application is in progress. Based on the evidence and documentation submitted to the CNSC, OPG is confident in obtaining a licence renewal that would support its extended operations plan for Pickering GS.

OPG's nuclear operations are regularly benchmarked against top performing nuclear facilities around the world. This allows OPG to identify, develop and implement initiatives to further improve performance. In September 2016, OPG hosted a team of experts from the International Atomic Energy Agency (IAEA) at the Pickering GS to conduct a standard Operational Safety Review Team mission. The team conducted an in-depth review of performance and adherence to international safety standards. In the second quarter of 2017, the IAEA's Operational Safety Review Team released the final report and confirmed that the Pickering GS demonstrates strong commitment to safety. In December 2017, OPG hosted a World Association of Nuclear Operators (WANO) peer evaluation for the Pickering GS, which focused on the safe and reliable operation of the station while evaluating the plant material condition, functional and cross-functional areas of the organization. Pickering showed significant improvement since its last review and has sustained its strong rating in 2018, resulting in its best ever WANO peer review.

OPG remains focused on improving reliability and increasing electricity generation output from its nuclear fleet. This includes improving equipment reliability, optimizing outages, implementing integrated asset management planning and enhancing maintenance programs. Improved equipment reliability generally results in fewer generation interruptions. Nuclear inspection and testing programs are largely driven by maintenance and regulatory requirements, and are designed to ensure that equipment is performing safely and reliably. Execution of this and other outage work continues to be a high priority. As part of its commitment to operational excellence, OPG continues to focus on improving the planning, execution, monitoring, and reporting of outage work.

OPG continues to make investments in the performance of the Pickering GS, with a focus on improving plant reliability and maximizing the value of the asset over its remaining life through implementing equipment modifications and fuel handling reliability improvements, reducing equipment maintenance backlogs, and completing critical and high priority work. OPG also continues to make investments in the Darlington GS necessary to sustain safe and reliable operations for the next three decades and aimed at positioning the station for industry-leading operating and cost performance in the longer term. This includes investments in life cycle and aging management projects, facility upgrades as well as work in support of regulatory commitments.

Delivering solutions that provide the best combination of safety, cost and effectiveness, as well as establishing challenging financial targets based on comprehensive benchmarking and taking into account the operating environment of the nuclear stations, continues to be a vital part of OPG's strategy to improve performance of the nuclear business unit. Financial and staffing targets continue to be reviewed and adjusted where necessary to reduce operating costs, while ensuring safety and reliability are not compromised.

In 2016, OPG submitted applications with the CNSC seeking a ten-year licence renewal for the Western Waste Management Facility (WWMF), located at the Bruce generating stations' site, to May 31, 2027, and a ten-year licence renewal for the Pickering Waste Management Facility (PWMF) to August 31, 2028. The licence renewal applications were presented to the CNSC at public hearings in April 2017. On May 30, 2017, the CNSC announced that the WWMF licence was renewed for a ten-year period and will be valid until May 31, 2027. On February 7, 2018, the CNSC announced that the PWMF licence was renewed for a ten-year period and will be valid until August 31, 2028.

In 2017, the CNSC approved regulatory document *REGDOC 2.2.4 – Fitness for Duty – Managing Alcohol and Drug Use* for use at Canadian nuclear power plants. This document sets out requirements for managing fitness for duty of workers in relation to alcohol and drug use at high-security sites, including for-cause alcohol and drug testing for workers in positions identified as safety-sensitive or safety-critical and random alcohol and drug testing for workers holding safety-critical positions. OPG intends to enhance its existing Fitness for Duty program to comply with these new requirements. OPG is working with its partners in the Canadian nuclear industry to develop a program suitable for Canada and its workers.

Hydroelectric Operations

The objectives of OPG's hydroelectric operations include operating and maintaining the generating facilities in a safe, efficient and cost-effective manner, while increasing the output from the facilities and pursuing opportunities to increase capacity. OPG aims to increase the facilities' output by improving operational flexibility, enhancing reliability, optimizing outage planning and, subject to water conditions, increasing availability to meet electricity system demand. OPG continues to evaluate and implement plans to increase capacity, maintain and improve operational performance, and extend the operating life of its hydroelectric generating assets.

OPG's hydroelectric operations are regularly benchmarked against peer utilities in North America. Based on 2016 data, 19 of the OPG's 25 large regulated hydroelectric facilities benchmarked in the top two quartiles for unit energy costs. This group of 19 facilities represents 94 percent of the energy delivered from the regulated hydroelectric fleet. Similarly, 18 of 25 large regulated hydroelectric facilities benchmarked in the top two quartiles for availability based on 2016 data. OPG continues to pursue innovation and technology-based improvements in its asset management and equipment maintenance strategies in order to increase reliability and further reduce costs of the hydroelectric fleet.

As part of OPG's ongoing strategy to reduce costs and increase operational efficiency, the operations of the Company's hydroelectric and thermal assets were previously combined into one organization, with five regional operations groups. In 2017, OPG reduced the number of regional operations groups to four, by integrating the Central Operations work centres into three of the other existing regional operations groups. In addition, during the third quarter of 2017, OPG opened an amalgamated control room located at the Saunders hydroelectric GS, combining the Chenaux and Saunders control rooms. The amalgamated control room will control all operational activities at the ten hydroelectric stations along the Madawaska, Ottawa and St. Lawrence rivers.

OPG's plans for its existing hydroelectric generating stations are accomplished through multi-year capital investment and other programs, including replacements and upgrades of turbine runners, and refurbishment or replacement of existing generators, transformers, and controls. The aim of OPG's runner replacement and upgrade program is to increase hydroelectric station capacity by leveraging efficiency enhancements in runner design. Where economical and practical, OPG also pursues opportunities to refurbish, expand or redevelop its existing hydroelectric stations. Over the next four years, OPG plans to increase the total capacity of its hydroelectric generating fleet by approximately 150 MW, which, in addition to the runner replacement and upgrade program, includes the Ranney Falls GS and Sir Adam Beck frequency conversion projects. OPG is also planning to repair, rehabilitate, or replace a number of aging civil hydroelectric structures.

As part of its commitment to operational excellence, OPG continues to make investments in its existing hydroelectric generating fleet. During 2017, OPG continued to execute a number of projects, including:

- Completion of the overhaul and upgrade of Unit 10 of the Sir Adam Beck 1 GS, which increased the station's capacity by 6 MW
- Continued work on the overhaul and rehabilitation of Unit 1 of the Sir Adam Beck Pump GS to ensure reliable unit operation for approximately the next 20 years
- Completion of the replacement of the Shebandowan Lake Control Dam at the Kakabeka Falls GS, which will maintain structural integrity and enhance dam safety for another 100 years

- Continued work on the overhaul and upgrade of Unit 1 of the Harmon GS with completion of the turbine upgrade, generator rehabilitation and upgrade of protection and control systems
- Continued work on the overhaul and upgrade of Unit 2 of the DeCew Falls GS, with turbine and generator rehabilitation and upgrade of protection and control systems completed during the year, and, in the fourth quarter of 2017, commencement of the overhaul and upgrade of Unit 2 of the Little Long GS
- Continued work on the overhaul and rehabilitation of Unit 2 of the Lower Notch GS, with generator rehabilitation completed during the year, and in the fourth quarter of 2017, commencement of the overhaul and rehabilitation of Unit 6 of the Sir Adam Beck Pump GS
- Commencement of definition phase work for the Water Conveyance System project to rehabilitate the Sir Adam Beck 1 GS canal and associated structures, ensuring their continued safe and reliable operations for approximately the next 50 years.

In 2018, OPG plans to commence execution of several major sustaining projects across the hydroelectric fleet, including the overhaul and upgrade of Unit 5 of the Sir Adam Beck 1 GS, the rehabilitation of Caribou Falls Block Dam No.2, and automatic sluicegates system replacement at the Whitedog Falls GS. Definition phase activities on several other major projects are also expected to commence in 2018, including frequency conversion of Units 1 and 2 of the Sir Adam Beck 1 GS and the overhaul and upgrade of the R.H. Saunders GS units.

Thermal Operations

OPG's thermal operations consist of biomass-fuelled generating units at each of Atikokan GS and Thunder Bay GS, and the oil/gas dual-fuelled Lennox GS.

These stations, which operate as peaking facilities under their respective energy supply requirements, provide Ontario's electricity system with the flexibility to meet changing daily system demand and capacity requirements and enable the system to accommodate the expansion of Ontario's renewable generation portfolio. The continued operation of these stations will continue to provide Ontario with over 2,000 MW of peaking generation capacity. The stations operate under their respective ESAs.

OPG's biomass-fuelled generating units are among the world's leading in their innovation. The Atikokan GS is the largest generating station in North America fuelled by 100 percent biomass, while the Thunder Bay GS unit uses advanced biomass that is thermally treated to allow it to be stored outdoors and withstand exposure to the weather.

Former thermal stations that are no longer available to generate electricity are included in the Services, Trading, and Other Non-Generation segment once they are removed from service. This includes the Lambton GS and Nanticoke GS sites, which ceased operations in 2013. Over 2015 and 2016, OPG announced that these stations would be decommissioned safely, securely and in an environmentally responsible manner. The costs of the decommissioning are charged to a previously established decommissioning provision.

During 2017, OPG substantially completed the demolition of the Nanticoke coal yard equipment and structures and issued a contract for the demolition of the Nanticoke powerhouse and associated structures. In the fourth quarter of 2017, the demolition contractor had been mobilized to prepare for the removal of the powerhouse and associated structures and initiated the preparatory work for the demolition of the stacks. The demolition of the stacks took place in February 2018. **[MONITOR]** A competitive bidding process for the demolition of the Lambton GS is in progress, with a contract for the removal of the powerhouse and associated structures expected to be issued during 2018. The decommissioning plan for the Nanticoke GS accommodates the construction and operation of the Nanticoke solar facility.

An update of the asset retirement obligations related to the Nanticoke and Lambton sites has been completed. For a discussion of the revaluation of this liability for non-nuclear fixed asset removal as at December 31, 2017, refer to the section, *Critical Accounting Policies and Estimates* under the heading, *Asset Retirement Obligations*.

Environmental Performance

OPG's Environmental Policy states that "OPG shall meet compliance obligations, including any environmental commitments that it makes, with the objective of exceeding these compliance obligations where it makes business sense". This policy commits OPG to:

- maintain an ISO 14001-registered environmental management system (EMS)
- work to prevent or mitigate adverse impacts on the environment with a long-term objective of continual improvement
- strive to be a leader in climate change mitigation
- manage sites in a manner that strives to maintain, or enhance where it makes business sense, significant natural areas and associated species of concern.

In 2017, OPG maintained the ISO 14001 registration of its company-wide EMS. Within the EMS, OPG has planning, operational control, and monitoring programs to manage the Company's positive and negative impacts on the environment. Significant environmental aspects of OPG's operations include: spills, chemical and thermal emissions to water, water flow and level changes, radiological emissions, low and intermediate level radioactive waste (L&ILW), enhancement and disruption of wildlife habitat, displacement of fossil fuels, and fish impingement and entrainment. Further details regarding OPG's environmental risks can be found in the section, *Risk Management* under the heading, *Environmental Risk*.

Environmental performance targets are set as part of the annual business planning process. These targets are based on past performance and external benchmarking to promote continual improvement. OPG met or outperformed its 2017 targets for spills, environmental infractions, carbon-14 emissions to air, and L&ILW. Targets for tritium emissions to air and water were not achieved due to equipment performance issues; however, emissions remained less than one percent of the regulatory limit. There were no significant environmental events during 2017.

In 2016, the Government of Ontario passed the *Climate Change Mitigation and Low-Carbon Economy Act, 2016* and the associated *Cap and Trade Program Regulation*. The legislation provides the foundation for regulating greenhouse gas (GHG) emissions in Ontario and establishes a cap and trade program, with the first compliance period being from January 1, 2017 to December 31, 2020.

The cap and trade program is a market mechanism intended to give Ontarians an incentive to reduce GHG emissions by putting a price on carbon. OPG has an internal program to meet its GHG emissions compliance obligations. With OPG's low GHG emitting fleet, these obligations are not expected to have a material financial impact on the Company.

OPG monitors actions being taken by the Government of Ontario and the Government of Canada to reduce GHG emission levels and transition to a low-carbon economy. In support of efforts to mitigate climate change, the Company continues to evaluate and implement plans to increase the generation capacity of its hydroelectric generating fleet, where economical, invest in other low-carbon technologies, and take a leadership role in the electrification of Ontario's transportation sector.

OPG has developed biodiversity management plans that identify priority natural areas, conservation goals, threats, and proposed actions to sustain biodiversity at its properties. To maximize benefits and manage impacts, initiatives include biodiversity monitoring, site naturalization, habitat creation, and control of invasive species.

OPG works with community partners to support regional ecosystems and biodiversity across Ontario. In 2017, OPG continued efforts to protect and restore habitat, promote biodiversity education and awareness, and help the recovery of species at risk. In November 2017, OPG's biodiversity program was recognized by the Canadian Electricity Association with the 2017 Sustainable Electricity award for Commitment to Continuous Performance Improvement.

OPG communicates its environmental performance internally to employees and to external stakeholders, including the Ontario Ministry of the Environment and Climate Change (MOECC), Environment and Climate Change Canada, the CNSC, and local communities. Details of OPG's environmental performance and initiatives to fulfill the Company's Environmental Policy can be found in OPG's 2016 Sustainability Report, available on the Company's website at www.opg.com.

Improving Efficiency and Reducing Costs

As part of its commitment to operational excellence, OPG remains strongly focused on reducing costs by pursuing sustainable efficiency and productivity improvements across operating business units and support functions, while ensuring that there is no adverse impact on the safety, reliability and environmental sustainability of the Company's operations. Building on significant efficiency achieved since 2011 under a more scalable, centre-led organizational model, this includes streamlining of processes, simplifying governance, upgrading technology, optimizing service delivery models, and continuing to leverage attrition to achieve human resource targets aligned with business requirements. Strategies to improve cost performance and organizational capability are being implemented at the enterprise and business unit level. These strategies are supported by continuing to embed an outcomes-driven culture that reinforces cost effectiveness, efficiency and organizational agility as part of business decision-making.

OPG is proceeding with an enterprise-wide process to evaluate the impact of the eventual shutdown of the Pickering GS on the Company's operating cost structure. This multi-year initiative, known as OPG25, involves identifying and implementing a coordinated set of plans and targets to ensure the optimization of the Company's longer-term operating model, business strategies and organizational design between now and the planned end of Pickering commercial operations. The overall aim of the initiative is to ensure ongoing cost effectiveness of the Company's operations after the eventual shutdown of the Pickering GS and to mitigate the cost impacts associated with the shutdown. Through this work and a continued focus on productivity enhancements, OPG expects to deliver increased value to customers and achieve improvement in outcomes of future applications for regulated prices under the OEB's incentive regulation framework.

In 2017, OPG also launched a strategy to accelerate the pace of digital transformation across the enterprise. The strategy is focused on making investments to modernize information technology infrastructure, enhance mobility, connectivity and field and office productivity, and improve equipment reliability and station performance through data management and data analysis. The strategy will increase operational efficiency, reduce operating costs and help to enable optimization initiatives in support of OPG25.

People and Culture

A well trained and engaged workforce is fundamental to the achievement of OPG's strategic imperatives. To succeed in a demanding business environment, OPG is focused on building a diverse, healthy, engaged workforce and fostering a culture of collaboration, accountability and innovation. OPG also continues to communicate and implement the values and behaviours expected from its employees in order to maintain a strong focus on safety, performance excellence, continuous improvement, and corporate citizenship.

The Company continues to focus on improving the capability of its workforce through leadership development, knowledge management, diversity and inclusion programs, and hiring in critical areas. Ability to secure the right talent mix in order to effectively meet the Company's immediate and longer term business needs on a timely basis is supported through workforce planning, resourcing and on-boarding strategies, both to acquire external talent into the organization and to develop existing employees. The goal of workforce planning and resourcing strategies is to ensure that the Company has a diverse workforce with the right skill set and capability for the safe and effective operation of the generating facilities and successful delivery of major projects, including the Darlington Refurbishment. These strategies take into account changes in anticipated staffing requirements leading up and subsequent to the end of planned commercial operations of the Pickering GS and the period to de-fuel, de-water and

place the station in a safe state condition after shutdown. The end of commercial operations at the Pickering GS is expected to lead to a significant reduction in OPG's workforce.

As part of the strategy to develop and engage employees and to build leadership talent in support of the Company's long-term success, OPG has an active succession planning program with a focus on accelerating development. This includes a company-wide high-potential leadership development program for qualified internal candidates. This 14-month cross-functional, competitive-entry program is designed to identify and develop candidates for future leadership positions while they are relatively early in their careers. OPG also has a talent management monitoring process to proactively assess staffing risks, challenges and opportunities.

Electricity generation involves complex technologies that require highly skilled and trained workers. Many positions at OPG have significant educational prerequisites and rigorous requirements for continuous training and periodic requalification. In addition to maintaining its internal training infrastructure, OPG relies on partnerships with government agencies, other electrical industry partners and educational institutions to meet the required level of qualification. Training delivery models are evaluated for effectiveness and efficiency.

Effective January 1, 2017, OPG implemented an Executive Compensation Program that is compliant with *Ontario Regulation 304/16: Executive Compensation Framework*, introduced in September 2016. While the Province released two subsequent amendments, *Ontario Regulation 187/17* and *Ontario Regulation 400/17* in June 2017 and November 2017, respectively, OPG's Executive Compensation Program continues to be subject to the original regulation's requirements. The regulation sets out how all employers designated under the *Broader Public Sector Executive Compensation Act, 2014*, including OPG, must establish and post compensation programs for executives. The program must include the compensation philosophy, salary and performance-related pay caps, comparative analysis details, and a description of other elements of compensation. OPG's Executive Compensation Program, which applies to employees at the Vice President level and higher, is designed to provide compensation that is at the 50th percentile of the market and focused on at-risk, performance based pay. The program will better enable OPG to attract, align and retain the executive talent critical to delivering Shareholder and customer value, while ensuring continued safe and reliable operations.

Project Excellence

OPG is pursuing a number of generation development and other major projects in support of Ontario's electricity planning initiatives. OPG also continues to plan and execute maintenance and capital improvement projects related to its existing assets. OPG strives for excellence in the planning and delivery of all projects across the Company.

OPG's vision for project excellence is to be an industry leader in project management capability and performance. As part of its commitment to project excellence, OPG continues to enhance and streamline its approach to project planning and execution, with the goal of delivering all projects safely, on time, on budget, and with high quality. Achieving project excellence at OPG involves, among other things, implementing a common, scalable project delivery model across all business units, establishing qualified project management teams, optimizing contracting strategies, engaging qualified and experienced vendors, and effectively monitoring and controlling performance.

The status updates for OPG's major projects as of December 31, 2017 are outlined below.

Project *(millions of dollars)*	Capital expenditures Year-to-date	 Life-to-date	Approved budget	Expected in-service date	Current status
Darlington Refurbishment	1,249	4,434	12,800 [1]	First unit - 2020 Last unit - 2026	All Unit 2 feeder tubes were removed safety in the fourth quarter of 2017 and the removal of fuel channel assemblies is in progress. Construction activities on the HWSF have recommenced in the fourth quarter. Planning and procurement activities for the refurbishment of Unit 3 are continuing. The overall project is tracking on schedule and on budget.
Peter Sutherland Sr. Hydroelectric GS	41	277	300	2017	The station was placed in-service on March 31, 2017, ahead of the originally planned schedule, and is expected to close below the approved budget. Project close-out activities are in progress.
Sir Adam Beck Pump GS Reservoir Refurbishment	3	49	58	2017	The refurbishment was completed and the reservoir was returned to service in February 2017, ahead of the originally planned in-service date and below the approved budget.
Ranney Falls Hydroelectric GS	25	28	77	2019	Excavation has been completed and construction is continuing in the expanded forebay, powerhouse and spillway area. Concrete placement of the new powerhouse and the spillway integrated structure is in progress. The project is tracking on schedule and on budget.
Nanticoke Solar Facility	2	3	107	2019	Significant contracts for equipment and engineering construction services have been executed, with construction planned to commence in the first quarter of 2018. **[MONITOR]**
Deep Geologic Repository (DGR) for L&ILW	9 [2]	204 [2]			On August 21, 2017, the federal Minister of Environment and Climate Change requested further information related to the project's environmental assessment (EA). OPG is working on a response to this information request.

[1] The total project budget of $12.8 billion is for the refurbishment of all four units at the Darlington GS.
[2] Expenditures are charged against the Nuclear Liabilities.

Darlington Refurbishment

The Darlington generating units are approaching their originally designed end-of-life. Refurbishment of the four generating units is expected to extend the operating life of the station by approximately 30 years. The approved budget for the four-unit refurbishment is $12.8 billion, which includes the costs of the pre-requisite projects in support of the execution phase of the refurbishment. The first refurbished unit is scheduled to be returned to service in the first quarter of 2020 and the last unit is scheduled to be completed by 2026. The project continues to track on schedule.

The Darlington Refurbishment project is a multi-phase program comprising the following five major sub-projects:

- **Retube and Feeder Replacement**, which includes the removal and replacement of fuel channel assemblies and feeder tubes in each reactor
- **Turbines and Generators**, which consists of inspections and repairs of turbine generator sets and the replacement of analog control systems with digital control systems
- **De-fuelling and Fuel Handling**, which involves the de-fuelling of the reactors and the refurbishment of the fuel handling equipment
- **Steam Generators**, which includes mechanical cleaning, water lancing, and inspection and maintenance work on the generators
- **Balance of Plant**, which consists of work on smaller projects to replace or repair certain other station components.

In 2016, the Darlington Refurbishment project transitioned from the planning phase to the execution phase, as OPG commenced the refurbishment of the first unit, Unit 2, in October 2016 as planned. The unit was taken offline on October 15, 2016. De-fuelling of the reactor was completed in January 2017, with a total of 480 fuel channels de-fuelled. Islanding of Unit 2, the physical separation of the unit under refurbishment from the three operating units, was completed in April 2017, signifying the completion of the first major segment of the project.

The second major segment includes preparatory work to support the removal of feeder tubes and fuel channel assemblies, followed by the removal of reactor components. The preparatory work was completed in the second quarter of 2017. The Re-tube Tooling Platform for hosting the tooling for the removal, inspection and installation activities, and the setup of specialized tooling and equipment needed for the removal and replacement of the reactor components were completed in the third quarter of 2017. The disassembly of reactor components commenced in August 2017, with the removal of all 960 feeder tubes completed safely in September 2017. The removal of fuel channel assemblies commenced in October 2017. As part of the fuel channel assemblies, the removal of pressure tubes is in progress and will be followed by the removal of calandria tubes. The second major segment and the removal of all reactor components is expected to be completed by mid-2018. Key projects in the second major segment finished in 2018 include the completion of the primary side steam generator layup and installation of steam generator access ports to support future inspections. Other key project activities being executed during the second segment include the continuation of the major turbine generator overhaul, which will be completed in the second quarter of 2018, and continued execution of the major electrical scope. OPG is also continuing to execute work to support the requirements set out in the CNSC-approved Integrated Implementation Plan for the station.

Most of the pre-requisite projects, including construction of facilities, infrastructure upgrades and installation of safety enhancements, have been completed and placed in-service. The Re-tube Waste Processing Building was completed in November 2017. Completion of the HWSF has been delayed due to challenges with construction. OPG suspended the project in the second quarter of 2017 to evaluate the best approach to optimize cost and schedule and complete the project. Construction to complete the facility recommenced in the fourth quarter of 2017. The HWSF is expected to be completed by the second quarter of 2019 and is not on the critical path for the Darlington Refurbishment project, which continues to track on schedule. The increase in the cost estimate for the HWSF will be accommodated within the overall Darlington Refurbishment budget of $12.8 billion. Taking into account the execution performance of the Unit 2 refurbishment, the overall Darlington Refurbishment project continues to track on budget.

In addition to the execution of refurbishment activities on Unit 2, OPG is continuing planning activities for the refurbishment of the second unit, Unit 3, and is entering into associated commitments to procure major components that require long lead times. As of December 31, 2017, $93 million has been invested in planning activities related to the refurbishment of the second unit, Unit 3. These planning activities are being undertaken in accordance with the refurbishment project schedule. In February 2018, the Province confirmed its commitment to proceed with Darlington's Unit 3 refurbishment in 2020. **[MONITOR]**

Peter Sutherland Sr. Hydroelectric GS

In March 2017, the project to construct the 28 MW two-unit Peter Sutherland Sr. hydroelectric GS successfully completed final testing and commissioning of the turbine and generator units, and both units were declared substantially complete. On March 31, 2017, the project received a permit from the MOECC to take water for operations to allow the station to operate commercially. This in-service date was well ahead of the originally planned schedule of the first half of 2018. The project's schedule was accelerated to take advantage of favourable weather conditions. The project is expected to close below the approved budget of $300 million. Project close-out activities are in progress. OPG began to receive contracted revenue for the project following the IESO's confirmation of the station's commercial operations as of March 31, 2017, under a hydroelectric ESA.

Under the partnership agreement, as the unit is placed in-service, the CRP, a corporation wholly owned by the Taykwa Tagamou Nation, may acquire up to a 33 percent partnership interest through its investment in PSS. In April 2017, the CRP acquired a 33 percent interest in PSS.

Sir Adam Beck Pump GS Reservoir Refurbishment

The Sir Adam Beck Pump GS refurbishment construction began in April 2016 and the 300-hectare reservoir was returned to service in February 2017 upon completion of the reservoir commissioning program. The Sir Adam Beck Pump GS facility allows OPG to pump and store water diverted from the Sir Adam Beck generating complex during periods of low electricity demand, to be used to generate up to 600 MW of electricity during subsequent periods of high electricity demand. The work on the project included installation of a new partial liner and construction of a grout curtain in the bedrock foundation of the reservoir dyke. The refurbishment is expected to add approximately 50 more years to the reservoir's life. The project was completed ahead of the originally planned in-service date of April 2017 and below the approved budget of $58 million. The Sir Adam Beck Pump GS is reported in the Regulated – Hydroelectric segment.

Ranney Falls Hydroelectric GS

In 2017, OPG began construction work on a 10 MW single-unit powerhouse on the existing Ranney Falls GS site, as part of the Regulated – Hydroelectric segment. The new unit will replace an existing unit that reached its end of life in 2014. The existing forebay structure has been demolished and the new concrete structure has been completed. Excavation has been completed and construction continues in the expanded forebay, powerhouse and spillway area. The new forebay concrete wall has been completed, and concrete placement of the new powerhouse and the spillway integrated structure is in progress. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget.

Nanticoke Solar Facility

The construction of a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands under a Large Renewable Procurement contract with the IESO, through Nanticoke Solar LP, a partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation, is planned to commence in the first quarter of 2018. During 2017, the partnership continued work to obtain approvals and permits required to enable the commencement of construction. Significant contracts for equipment and engineering construction services were executed in the first quarter of 2018. The facility is expected to be completed in the first quarter of 2019, with a budget of $107 million. **[MONITOR]**

Deep Geologic Repository for Low and Intermediate Level Waste

OPG has proposed a deep geologic repository as the preferred solution for the safe long-term management of the L&ILW produced from the continued operation of OPG-owned nuclear generating stations. Agreement has been reached with local municipalities for OPG to develop the L&ILW DGR on lands adjacent to the WWMF in Kincardine, Ontario. The environmental effects of the proposed L&ILW DGR were examined by the CNSC and Canadian Environmental Assessment Agency (CEAA)-appointed Joint Review Panel (JRP) to meet the requirements of the *Canadian Environmental Assessment Act*. The JRP submitted its report on the EA to the federal Minister of Environment in May 2015, concluding that, given mitigation, there is unlikely to be significant environmental impact from the project and recommending that the Minister approve the EA. In December 2016, at the request of the federal Minister of Environment and Climate Change, OPG submitted additional information on certain aspects of the EA, including information related to alternate locations for the project. Following its review of OPG's submission and a period of public comment, the CEAA requested further information that OPG subsequently provided in May 2017. In June 2017, the CEAA notified OPG that it had sufficient and adequate information to proceed with the next step of the environmental assessment process and advised that a draft report and updated terms and conditions would be prepared for public review.

On August 21, 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of potential cumulative effects of the project on the Saugeen Ojibway Nation's (SON) physical and cultural heritage, including a description of the potential effects of the project on the Nation's spiritual and cultural connection to the land, taking into account the results of the SON Community Process. OPG is working closely with the SON to formulate a response to the information request.

The L&ILW DGR at the WWMF site remains OPG's preferred solution for the safe long-term management of the L&ILW. The in-service date of the L&ILW DGR is expected to be approximately six to seven years from the start of construction.

Financial Strength

As a commercial enterprise, OPG's financial priority is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future expansion. Inherent in this priority are four objectives:

- Increasing revenue, reducing costs and achieving appropriate return
- Ensuring availability of cost effective funding for operational needs, generation development projects and other business opportunities, and long-term obligations
- Pursuing opportunities to expand the existing core business and capitalize on new growth paths
- Managing risks, which is discussed in the section, *Risk Management*.

Increasing Revenue, Reducing Costs and Achieving Appropriate Return

In line with its commercial mandate, OPG is focused on increasing revenue and net income and achieving an appropriate rate of return on the Shareholder's investment, while taking into account the impact on Ontario electricity customers by seeking further efficiencies in the Company's cost structure.

For the regulated operations, achievement of the above objectives is largely dependent on outcomes of rate applications to the OEB and growth of the asset base earning a return as part of the regulated prices.

With respect to rate application outcomes, OPG has been focused on demonstrating in its rate applications that the costs required to operate and invest in the assets are reasonable and being prudently incurred, and should be fully recovered, and that the Shareholder's investment in these assets should earn an appropriate rate of return. While the OEB's decision on OPG's 2017-2021 application for new regulated prices reduced OPG's forecasted costs used to set new regulated prices, the decision will result in a substantial increase in revenue and net income compared to

existing regulated prices. The existing base regulated prices were set in 2014 to allow the Company to recover its approved nuclear costs over a higher nuclear production volume, based on the 2014 and 2015 outage profile that did not include a Darlington refurbishment outage.

The OEB's decision to reduce recovery of OPG's forecasted cost levels, including through the use of stretch factors under an incentive rate-making model, will negatively impact OPG's ability to earn an appropriate return on the Shareholder's investment in the regulated assets. To improve the financial strength of the regulated operations, OPG will continue to focus on optimizing operational performance and outage plans across the generating fleet and on pursuing further efficiency improvements in the Company's cost structure and operating model. OPG's cost and productivity improvement strategies are discussed further in the section, *Core Business, Strategy and Outlook* under the heading, *Operational Excellence – Improving Efficiency and Reducing Costs*.

OPG continues to invest in the regulated asset base, with the Darlington Refurbishment project being the single largest such capital investment. In its decision on OPG's 2017-2021 application for new regulated prices, the OEB has allowed inclusion of a total of $5.5 billion in Darlington Refurbishment in-service capital additions by 2021, including pre-requisite projects other than HWSF and including in-service amounts upon planned return to service of Unit 2 in the first quarter of 2020. Once in-service, these assets will attract a return on equity of approximately 8.8 percent during the 2017-2021 period set by the OEB, based on a deemed capital structure of 45 percent equity and 51 percent debt. The average OEB-approved cost of deemed debt for the 2017-2021 period is approximately 4.6 percent. OPG also continues to pursue an extensive capital program across its regulated hydroelectric operations that includes expansion, redevelopment and life extension of the generating facilities, where economic. These renewable assets have long service lives and, with either maintenance efforts or rebuilding, will continue to supply electricity for the foreseeable future. The OEB's decision on OPG's application for new regulated prices is discussed further in the section, *Highlights* under the heading, *Recent Developments*.

For generation assets that do not form part of the assets regulated by the OEB, OPG's strategy has been to secure appropriate long-term revenue arrangements. In line with this strategy, virtually all of OPG's non-regulated operating facilities and assets under construction are subject to long-term ESAs or other long-term contracts with the IESO. This includes the Peter Sutherland Sr. GS, which was placed in service and began receiving contracted revenue under a hydroelectric ESA as of March 31, 2017. The Peter Sutherland Sr. GS ESA expires in 2067.

OPG's capital structure currently reflects lower levels of debt than the deemed capital structure reflected in the Company's existing regulated prices and maintained by the OEB's December 2017 decision on new regulated prices. OPG continues to evaluate strategies to enhance Shareholder returns by optimizing the Company's capital structure through better alignment with the deemed capital structure, taking into account the overall financial strength of the Company and the potential impact on the Company's investment grade credit rating.

Ensuring Availability of Cost Effective Funding

OPG actively monitors its funding requirements and forecasts availability of funds to ensure that it can meet the Company's operational needs, project commitments and long-term obligations. OPG utilizes multiple sources of funds, including funds generated from operations, commercial paper, securitization of assets, letters of credit, credit facilities, long-term corporate debt (sourced from both the OEFC and public debt offerings), credit facilities with the OEFC, private placement project financing, and equity issuance. The Company's financing strategy leverages the strength of its balance sheet to obtain cost effective long-term corporate debt. OPG also accesses the capital markets for private placement project financing, secured by the assets of the project, where the characteristics of the project support such financing. Maintaining an investment grade credit rating is critical to OPG's ability to access cost effective financing.

In April 2017, DBRS Limited (DBRS) re-affirmed the long-term credit rating on OPG's debt at 'A (low)' and OPG's commercial paper rating at 'R-1 (low)'. All ratings from DBRS have a stable outlook. In July 2017, S&P Global

Ratings (S&P) re-affirmed OPG's long-term credit rating at 'BBB+' with a stable outlook. S&P's commercial paper rating for OPG is 'A-1 (low)'.

OPG intends to continue to access the capital markets, where appropriate, to obtain cost effective financing for future generation development projects. The Company continues to evaluate arrangements that would appropriately support its financing needs, its capital expenditure programs, its financing of OPG's subordinated debt investment in the Trust, and the Trust's acquisition of Investment Interest from the IESO. OPG's liquidity and capital resources are discussed in the section, Liquidity and Capital Resources.

Building Our Business

Through pursuit of commercial-based opportunities to expand its business, OPG strives to be a leader in the North American transition toward a low carbon future while maintaining and expanding the Company's scale and energy industry leadership. This strategy considers the Company's financial position and anticipated future changes in the generating fleet, including the eventual end of Pickering commercial operations. The strategy is also informed by industry, technological, environmental, social, and economic external factors. Opportunities are evaluated using financial and risk-based analyses as well as strategic considerations.

Currently, OPG's strategy primarily focuses on the renewal and expansion of the Company's portfolio of generating assets in Ontario, including the redevelopment and expansion of existing sites and potential new developments. The strategy leverages OPG's operating and project development expertise as well as the Company's existing diverse physical asset base. Acquisition opportunities are considered as they arise, taking into account operating synergies, strategic benefits, financial returns and risk profile. OPG's current major generation development projects and asset life extension initiatives are discussed in the section, *Core Business, Strategy, and Outlook* under the headings, *Operational Excellence* and *Project Excellence*.

OPG also actively seeks to expand beyond its core generation business through investments in innovation and emergent low-carbon technologies, including selective solar generation, nuclear innovation, energy storage, distributed generation, electric vehicle infrastructure and other development. Additionally, OPG continues to consider potential paths to extend its business through broader electricity sector opportunities, within and outside Ontario. Business expansions opportunities may be pursued in partnership with other commercial entities where appropriate synergies exist and are aligned with OPG's business objectives.

Social Licence

As the largest electricity generator in Ontario with diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust. OPG is committed to maintaining high standards of public safety and corporate citizenship, including environmental stewardship, transparency, community engagement, and Indigenous relations. OPG works to maintain public trust with stakeholders by engaging site communities, sharing information, and being transparent about performance. In addition, OPG's operations are subject to extensive regulatory oversight, with public participation, by the CNSC, the OEB, and other bodies. OPG's commitment to safety is discussed in the section, *Core Business, Strategy, and Outlook* under the heading, *Workplace and Public Safety*.

OPG is focused on building long-term, mutually beneficial working relationships with Indigenous communities, businesses and organizations across Ontario, and continues to support procurement, employment and educational opportunities with its Indigenous community partners. The Company seeks to establish these relationships based on a foundation of respect for the languages, customs, and political, social and cultural organizations of the Indigenous communities.

OPG's commitment in this area includes pursuing generation-related development partnerships on the basis of long-term commercial arrangements, such as the construction of the Peter Sutherland Sr. GS in partnership with Taykwa Tagamou Nation and the development of the Nanticoke solar facility in partnership with the Six Nations of the Grand

River. During 2017, OPG also continued to engage with Indigenous communities regarding the Company's nuclear waste management operations, through regularly scheduled meetings and ongoing dialogue in connection with OPG's proposed L&ILW DGR, the re-licensing of the PWMF and the WWMF, and the Pickering GS re-licensing. Engagement was also conducted with First Nations in southwestern Ontario regarding the demolition of the Lambton and Nanticoke generating stations and with the Mississaugas of New Credit regarding the Shareholder-directed sale of the former Lakeview GS site.

OPG is also committed to improving Indigenous access to procurement and employment opportunities, including increasing the profile of the nuclear generation industry in Indigenous communities. In 2017, OPG launched an Indigenous Business Engagement (IBE) Initiative. The purpose of this initiative is to increase access to procurement opportunities for Indigenous businesses interested in supplying materials and services to OPG. The IBE Initiative is based on a strategy that will identify opportunities in contracts, scopes of work and business plans for potential Indigenous business engagement; include criteria related to suppliers' ability to engage or partner with Indigenous people or businesses in assessing procurement proposals; and invest in relationships with Indigenous communities by increasing outreach efforts to enhance understanding of how to do business with OPG. OPG has been engaging with Indigenous businesses and communities as well as its suppliers to promote the IBE Initiative, including the Mohawk Council of Akwesasne as well as the Williams Treaties First Nations, located proximate to the Pickering and Darlington nuclear generating stations.

OPG has been actively developing recruitment plans targeting Indigenous peoples. As part of this initiative, during the fourth quarter of 2017, OPG participated in several Indigenous-specific career fairs, hosted a Day in the Trades event for Indigenous students and job seekers as part of an open house at the Darlington Energy Centre, and approved plans aimed at increasing the number of Indigenous apprentices as part of the nuclear operations' recruitment program.

OPG also contributes to the well-being of its host communities through the Company's Corporate Citizenship Program (CCP), which supports charitable and non-profit grassroots initiatives in the areas of environment, education, and community involvement, including support for Indigenous initiatives. In 2017, OPG's CCP provided support to over 800 initiatives, of which 84 were Indigenous.

OPG has a strategy to help position the Company as a leader in transportation electrification in the province. The strategy aims to leverage the Company's clean, reliable and cost-effective electricity to power transportation, capitalize on future commercial growth opportunities, and enhance the Company's social licence. OPG is pursuing initiatives to increase the use of electric vehicles within its operations, and is assessing vehicle grid integration and hydrogen applications for the transportation sector. Ontario's climate change plan aims for electric and hydrogen passenger vehicles to represent five percent of new vehicle sales in the province by 2020.

As part of its commitment to help de-carbonize Ontario's transportation sector, OPG is a founding sponsor of Plug'n Drive, a non-profit organization working to accelerate the adoption of electric vehicles and to maximize their environmental and economic benefits. In May 2017, Plug'n Drive announced the opening of the world's first experiential learning facility dedicated to electric vehicle education and awareness, with OPG sponsoring the Centre's training facility.

Further details regarding OPG's commitment to sustainable development, including information regarding the Company's environmental and social performance and initiatives, are provided in OPG's 2016 Sustainability Report available on the Company's website at www.opg.com.

Outlook

The financial performance of OPG's regulated operations is driven, in large part, by the outcome of applications for regulated prices to the OEB. Subject to the OEB's issuance of the final payment amounts order expected in the first half of 2018, the OEB's December 2017 decision on OPG's application for new regulated prices provides substantial

price certainty for the regulated business for the 2017 to 2021 period. During this period, OPG will continue to focus on optimizing operational performance and outage plans across the generating fleet and on pursuing further efficiency improvements in the Company's cost structure and operating model.

The OEB's decision established June 1, 2017 as the effective date of the new regulated prices, which negatively affected OPG's net income and ROE Excluding AOCI in 2017 relative to OPG's requested effective date of January 1, 2017. The full-year effect of new regulated prices in 2018 is expected to contribute to an improvement in net income and ROE Excluding AOCI over the 2017 results.

Subject to the OEB's final determination on nuclear rate smoothing as part of the payment amounts order process, OPG expects an improvement in cash flow from operating activities in 2018, compared to 2017. This will reflect OPG beginning to receive revenue from the IESO based on new regulated prices following the OEB's implementation of these prices, expected in the first half of 2018. Additionally, the Fair Hydro Trust segment will begin to contribute positive cash flow from operating activities in 2018. OPG expects to continue to have the necessary financial capacity and sufficient access to cost effective financing sources to continue to fund its capital requirements and other disbursements, including the financing of the Fair Hydro Trust.

Several OEB-authorized regulatory variance and deferral accounts currently in place contribute to reducing the relative variability of the Company's net income and ROE Excluding AOCI. Among others, the regulatory accounts include those related to the revenue impact of variability in water flows and forgone production due to SBG conditions at the regulated hydroelectric stations. As there are no variance or deferral accounts in place related to the impact of generation performance of the nuclear stations on revenue from base regulated prices, the Regulated – Hydroelectric segment generally is expected to produce overall more predictable earnings. OPG continues to operate and maintain its nuclear facilities with a view to optimize their performance and availability, while focusing on improving the overall reliability and predictability of the fleet.

Electricity generated from most of OPG's non-regulated assets is subject to ESAs or other long-term contracts with the IESO. Based on these agreements, OPG expects the Contracted Generation Portfolio segment to continue to contribute a generally stable level of earnings and cash flow from operating activities going forward.

Lower nuclear generation due to the Darlington Refurbishment outages will continue, as planned, to negatively impact the Enterprise TGC and Nuclear TGC metrics for the duration of the refurbishment project. Lower hydroelectric generation due to outages related to various refurbishment and operational projects may negatively impact Enterprise TGC and Hydroelectric TGC for the duration of these projects. Variability in sustaining capital investment expenditures and nuclear outage profile may also impact TGC metrics in future periods.

OPG's total forecast capital expenditures for the 2018 year are approximately $2.1 billion. **[CONFIRM]** This includes amounts for the Darlington Refurbishment project, hydroelectric and other development projects including the Ranney Falls GS redevelopment and construction of the Nanticoke solar facility, and sustaining capital investments across the generating fleet. OPG's major projects are discussed in the section, *Project Excellence*.

In addition to the operating and financial performance of the electricity generation business, OPG's results are affected by the earnings on the Nuclear Segregated Funds, which are reported in the Regulated – Nuclear Waste Management segment. While the Nuclear Segregated Funds are managed to achieve, in the long term, the target rate of return based on the discount rate specified in the ONFA, the rates of return earned in a given period can be subject to various external factors including financial market conditions and, for the portion of the Used Fuel Segregated Fund guaranteed by the Province under the ONFA, changes in the Ontario consumer price index (CPI). In the near term, these factors can be volatile and cause fluctuations in the Company's income. This volatility is partially mitigated by the impact of the OEB-authorized Bruce Lease Net Revenues Variance Account and the funded status of the two segregated funds, discussed below.

As OPG does not have the right to withdraw surplus amounts from the Nuclear Segregated Funds, OPG limits the amount of Nuclear Segregated Funds assets reported on the balance sheet to the present value of the underlying life cycle funding liabilities per the most recently approved ONFA Reference Plan. This reduces the volatility of earnings on the Nuclear Segregated Funds reflected in net income when the funds are in a fully funded or overfunded position. As at December 31, 2017, the Decommissioning Segregated Fund was overfunded by approximately 27 percent, and the Used Fuel Segregated Fund was marginally overfunded, by less than one percent, based on the 2017 ONFA Reference Plan. Variability in asset performance due to volatility inherent in financial markets and changes in Ontario CPI, or changes in funding liability estimates, may result in either or both funds becoming underfunded in the future.

OPG's results are also affected by the earnings from the Fair Hydro Trust segment. Management expects an increase in 2018 earnings from the segment, primarily related to interest income from OPG's investment in subordinated debt of the Trust. OPG's involvement with the Fair Hydro Plan over time is expected to put downward pressure on ROE Excluding AOCI as a result of increases in shareholder's equity through future issuances of Class A common shares to partially fund OPG's subordinated debt investment in the Trust.

KEY OPERATING AND FINANCIAL PERFORMANCE INDICATORS

OPG evaluates the performance of its generating stations using a number of key indicators. Key operating performance indicators aligned with corporate strategic imperatives are measures of production reliability, cost effectiveness, environmental performance, and safety performance. Certain of the measures used vary depending on the generating technology.

Enterprise TGC, Nuclear TGC, Hydroelectric TGC, ROE Excluding AOCI, and FFO Adjusted Interest Coverage ratio discussed below are not measurements in accordance with US GAAP. They should not be considered as alternative measures to net income or any other measure of performance under US GAAP. However, OPG believes that these non-GAAP financial measures are effective indicators of its performance and are consistent with the Company's strategic imperatives and related objectives. The definition and calculation of Enterprise TGC per MWh, Nuclear TGC per MWh, Hydroelectric TGC per MWh, ROE Excluding AOCI, and FFO Adjusted Interest Coverage are found in the section, *Supplementary Non-GAAP Financial Measures*.

Enterprise Total Generating Cost per Megawatt-Hour

Enterprise TGC per MWh is used to measure OPG's overall organizational cost performance. Enterprise TGC per MWh is defined as OM&A expenses (excluding the Darlington Refurbishment project and other generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to OPG's electricity generation business), fuel expense for OPG-operated stations including hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures (excluding the Darlington Refurbishment project and other generation development projects) incurred during the period, divided by total electricity generation from OPG-operated generating stations plus electricity generation forgone due to SBG conditions during the period.

Nuclear Total Generating Cost per Megawatt-Hour

Nuclear TGC per MWh is used to measure the cost performance of OPG's nuclear generating assets. Nuclear TGC per MWh is defined as OM&A expenses of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to OPG's nuclear electricity generation business), nuclear fuel expense for OPG-operated stations (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs) incurred during the period, divided by nuclear electricity generation for the period.

Hydroelectric Total Generating Cost per Megawatt-Hour

Hydroelectric TGC per MWh is used to measure the cost performance of OPG's hydroelectric generating assets. Hydroelectric TGC per MWh is defined as OM&A expenses of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segments (excluding generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the hydroelectric electricity generation business), hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding expenditures related to the Peter Sutherland Sr. GS, Ranney Falls GS, and other hydroelectric generation development projects) incurred during the period, divided by total hydroelectric electricity generation plus hydroelectric electricity generation forgone due to SBG conditions during the period. OPG reports hydroelectric gross revenue charge and water rental payments as fuel expense.

Nuclear Unit Capability Factor

OPG's nuclear stations are baseload facilities that are not designed for fluctuating production levels to meet peaking demand. The nuclear Unit Capability Factor is a key measure of nuclear station performance. It measures the amount of energy that the unit(s) generated over a period of time, adjusted for externally imposed constraints such as transmission or demand limitations, as a percentage of the amount of energy that would have been produced over the same period had the unit(s) produced maximum generation. Capability factors are primarily affected by planned and unplanned outages. By industry definition, capability factors exclude production losses beyond plant management's control, such as grid-related unavailability. The nuclear Unit Capability Factor also excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS is excluded from the measure effective October 15, 2016, when the unit was taken offline as part of the Darlington Refurbishment project.

Hydroelectric Availability

OPG's hydroelectric stations operate as baseload, intermediate, or peaking stations. Hydroelectric Availability represents the percentage of time the generating unit is capable of providing service, whether or not it is actually generating electricity, compared to the total time for the respective period.

Thermal Equivalent Forced Outage Rate

Equivalent Forced Outage Rate (EFOR) is an index of the reliability of a generating unit at OPG's thermal stations. It is measured by the ratio of time a generating unit is forced out of service by unplanned events, including any forced deratings, compared to the amount of time the generating unit was available to operate.

Return on Common Equity Excluding Accumulated Other Comprehensive Income

ROE Excluding AOCI is an indicator of OPG's performance consistent with its objective to deliver value to the Shareholder. ROE Excluding AOCI is defined as net income attributable to the Shareholder for the period divided by average equity attributable to the Shareholder excluding AOCI for that period, and is measured over a period of 12 months.

Funds from Operations Adjusted Interest Coverage

The FFO Adjusted Interest Coverage ratio is an indicator of OPG's ability to meet interest obligations from operating cash flow and is consistent with the Company's objective of ensuring availability of cost effective funding. The FFO Adjusted Interest Coverage ratio is defined as FFO before interest divided by adjusted interest expense, and is measured over a period of 12 months.

Other Key Indicators

In addition to production reliability, cost effectiveness, and financial performance indicators, OPG has identified certain environmental and safety performance measures. These measures are discussed in the section, *Core Business, Strategy, and Outlook*.

BUSINESS SEGMENTS

Effective in the fourth quarter of 2017, OPG has the following six reportable business segments:

- Regulated – Nuclear Generation
- Regulated – Nuclear Waste Management
- Regulated – Hydroelectric
- Contracted Generation Portfolio
- Services, Trading, and Other Non-Generation
- Fair Hydro Trust.

Regulated – Nuclear Generation Segment

The Regulated – Nuclear Generation business segment operates in Ontario, generating and selling electricity from the Pickering GS and the Darlington GS, both owned and operated by OPG. The business segment also includes revenue under the terms of a long-term lease arrangement and related agreements with Bruce Power related to the Bruce nuclear generating stations. This revenue includes lease revenue, fees for nuclear waste management, and revenue from heavy water sales and detritiation services. The segment also earns revenue from isotope sales and ancillary services supplied by OPG from the nuclear stations it operates. Ancillary revenues are earned through voltage control and reactive support. Revenues under the agreements with Bruce Power, including a portion of heavy water sales, and from existing isotope sales contracts and ancillary services are included by the OEB in the determination of the regulated prices for production from OPG's nuclear facilities, which has the effect of reducing these prices.

Regulated – Nuclear Waste Management Segment

OPG's Regulated – Nuclear Waste Management segment reports the results of the Company's operations associated with the management of nuclear used fuel and L&ILW, the decommissioning of OPG's nuclear generating stations including the stations on lease to Bruce Power and other facilities, the management of the Nuclear Segregated Funds, and related activities including the inspection and maintenance of the waste storage facilities. Accordingly, accretion expense, which is the increase in the Nuclear Liabilities carried on the consolidated balance sheets in present value terms due to the passage of time, and earnings from the Nuclear Segregated Funds are reported under this segment.

As the nuclear generating stations operate over time, OPG incurs incremental costs related to used nuclear fuel and L&ILW, which increase the Nuclear Liabilities. OPG charges these incremental costs to current operations in the Regulated – Nuclear Generation segment to reflect the cost of producing energy from the Pickering and Darlington nuclear generating stations and earning revenue under the Bruce Power lease arrangement and related agreements. Since the incremental costs increase the Nuclear Liabilities reported in the Regulated – Nuclear Waste Management segment, OPG records an inter-segment charge between the Regulated – Nuclear Generation and the Regulated – Nuclear Waste Management segments. The impact of the inter-segment charge is eliminated in the consolidated statements of income and balance sheets.

The Regulated – Nuclear Waste Management segment is considered rate regulated because OPG's costs associated with the Nuclear Liabilities are included in the OEB's determination of regulated prices for production from the Pickering and Darlington nuclear generating stations.

Regulated – Hydroelectric Segment

OPG's Regulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from most of the Company's hydroelectric generating stations. The business segment comprises the results of 54 hydroelectric generation stations across a number of major river systems in the province.

In addition, the business segment includes ancillary and other revenues from OPG's regulated hydroelectric stations. Ancillary revenues are earned through offering available generating capacity as operating reserve and through the supply of other ancillary services including voltage control and reactive support, certified black start facilities, regulation service, and other services. These ancillary revenues and other revenues are included by the OEB in the determination of the regulated prices for production from OPG's prescribed hydroelectric facilities, which has the effect of reducing these prices.

Contracted Generation Portfolio Segment

The Contracted Generation Portfolio business segment operates in Ontario, generating and selling electricity from the Company's generating stations that are not prescribed for rate regulation. The segment primarily includes generating facilities that are under an ESA with the IESO or other long-term contracts.

The Contracted Generation Portfolio segment also includes OPG's share of equity income from its 50 percent ownership interests in the PEC and Brighton Beach stations. Brighton Beach operates under an energy conversion agreement between Brighton Beach and Shell Energy North America (Canada) Inc., and the PEC station is operated under the terms of an Accelerated Clean Energy Supply contract with the IESO. OPG's share of the in-service generating capacity and generation volume from its interests in the PEC and Brighton Beach stations are reported in this segment.

The business segment also includes ancillary revenues and other revenues from the stations included in the segment, which are earned through offering available generating capacity as operating reserve, and the supply of other ancillary services including voltage control and reactive support, certified black start facilities, regulation service, and other services.

Services, Trading, and Other Non-Generation Segment

The Services, Trading, and Other Non-Generation segment is a non-generation segment that is not subject to rate regulation. It includes the revenue and expenses related to OPG's trading and other non-hedging activities. As part of trading activities, OPG transacts with counterparties in Ontario and neighbouring energy markets in predominantly short-term trading activities of typically one year or less in duration. These activities relate to electricity that is purchased and sold at the Ontario border, financial energy trades, financial risk management energy product revenues, and sales of energy-related products. In addition, OPG has a wholly owned trading subsidiary that transacts solely in the United States (US) market. The results of this subsidiary are reported in this segment. All contracts that are not designated as hedges are recorded as assets or liabilities at fair value on the consolidated balance sheets, with changes in fair value recorded in the revenue of this segment.

In addition, the segment includes revenue from real estate rentals and non-regulated services, gains or losses on disposition of non-regulated real estate assets, costs associated with non-regulated business development activities, and costs related to the Lambton GS and Nanticoke GS sites.

Fair Hydro Trust Segment

The Fair Hydro Trust segment is a non-generation segment that is not subject to rate regulation. It includes OPG's earnings from the Fair Hydro Trust, which includes the financial results of the Trust, as well as income related to OPG's role as Financial Services Manager of the Fair Hydro Trust and holder of subordinated debt issued by the Trust. Earnings include interest income from OPG's investment in subordinated debt of the Trust of up to 49 percent of the Trust's total outstanding debt, recovery of third-party costs and fees for financial management and ongoing administration services, partially offset by interest costs on debt issued by OPG to fund five percent of the subordinated investment in the Trust, incurred third-party costs, and other incurred costs related to the management and administration of the Trust.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

Regulated – Nuclear Generation Segment

(millions of dollars)	**2017**	**2016**
Revenue	**3,095**	3,481
Fuel expense	**284**	315
Gross margin	**2,811**	3,166
Operations, maintenance and administration	**2,293**	2,210
Depreciation and amortization	**431**	925
Property taxes	**26**	26
Income before other losses, interest, and income taxes	**61**	5
Other gains	**4**	1
Income before interest and income taxes	**57**	4

Income before interest and income taxes from the segment increased by $53 million in 2017, compared to 2016. Segment earnings were favourably affected by the OEB's decision on OPG's application for new regulated prices issued in December 2017 with a retrospective effective date of June 1, 2017. The revenue increase of approximately $465 million in relation to the June 1, 2017 to December 31, 2017 period resulting from the OEB's decision was recorded as an increase in net regulatory assets in the fourth quarter of 2017. This revenue increase was based on new regulated prices for that period proposed in OPG's January 2018 submission to the OEB based on the findings in the decision and is net of a regulatory liability recognized in relation to OPG's nuclear rate smoothing proposal in that submission.

Segment earnings were unfavourably affected by a reduction in electricity generation of 4.9 TWh in 2017, compared to 2016. This reduced revenue by approximately $285 million, partially offset by a decrease in fuel expense. The lower electricity generation was primarily due to the ongoing Unit 2 refurbishment outage at the Darlington GS that began in October 2016, partially offset by the higher electricity generation from the Pickering GS. The income impact of OEB-approved regulatory accounts also contributed to the decrease in income for the year.

The increase in OM&A expenses of $83 million in 2017, compared to 2016, reflected planned expenditures related to the major maintenance activities and higher project expenditures occurring at the nuclear stations. Depreciation and amortization expenses, excluding amortization expense related to regulatory account balances, increased by $22 million primarily due to new assets in service in 2017.

The expiry of a nuclear rate rider for the recovery of OEB-approved balances in regulatory accounts on December 31, 2016 contributed to the decrease in segment revenue in 2017, compared to 2016, but was largely offset by a decrease in amortization expense related to these balances.

The Unit Capability Factors for the Darlington GS and Pickering GS for 2017 and 2016 were as follows:

	2017	2016
Unit Capability Factor *(%)* [1]		
Darlington GS	**85.2**	89.5
Pickering GS	**80.0**	75.2

[1] The nuclear Unit Capability Factor excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS was excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

The lower Unit Capability Factor at the Darlington GS in 2017, compared to 2016, reflected the higher number of planned outage days in 2017, largely driven by constraints related to the transition of the station's operating units toward refurbishment.

The increase in the Unit Capability Factor at the Pickering GS in 2017, compared to 2016, was primarily due to outage cycle optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station compared to 2016.

The definition of the nuclear Unit Capability Factor is found in the section, *Key Operating and Financial Performance Indicators.*

Regulated – Nuclear Waste Management Segment

(millions of dollars)	2017	2016
Revenue	**121**	138
Operations, maintenance and administration	**129**	146
Accretion on nuclear fixed asset removal and nuclear waste management liabilities	**943**	912
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(801)**	(746)
Loss before interest and income taxes	**(150)**	(174)

Earnings from the segment improved by $24 million in 2017 compared to 2016. The improvement was primarily due to higher earnings from the Nuclear Segregated Funds, partially offset by an increase in accretion expense on the Nuclear Liabilities. Accretion expense represents a financing cost due to the increase in the present value of the underlying liabilities with the passage of time.

The year-over-year increase in the earnings from the funds was primarily due to a reduction in the earnings recorded in the fourth quarter of 2016 to reflect an accounting adjustment to limit Nuclear Segregated Funds assets reported on the consolidated balance sheet to the underlying funding liabilities based on an updated ONFA reference plan approved by the Province. The updated ONFA reference plan resulted in a reduction in the funding liabilities. As both the Decommissioning Segregated Fund and the Used Fuel Fund have been in an overfunded position since the beginning of 2017, the earnings on the funds recognized in net income during the year reflected the growth rate in the present value of the funding liabilities and were not impacted by market returns and the rate of return guaranteed by the Province for the portion of the Used Fuel Segregated Fund. Further details on the accounting for the Nuclear Segregated Funds can be found in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

The year-over-year increase in accretion on nuclear fixed removal and nuclear waste management liabilities in 2017, compared to 2016, was primarily due to the impact on accretion expense related to the increase in asset retirement obligation associated with the life extension of the Bruce nuclear assets from the agreement executed between Bruce Power and the Province in late 2015. This increase was offset in 2016 due to the Bruce Lease Net Revenues Variance Account but is reflected in accretion with the resetting of base rates in 2017. This increase was partially

offset by the impact of the decrease in Nuclear Liabilities to reflect an updated estimate as part of the ONFA reference plan update process.

As of December 31, 2016, OPG recorded a decrease of approximately $1,570 million to the Nuclear Liabilities and associated asset retirement costs capitalized as part of the carrying value of the nuclear generating stations to reflect an updated estimate of OPG's obligations for nuclear waste management and nuclear facilities decommissioning determined as part of the ONFA reference plan update process. The resulting year-over-year decreases in accretion expense recorded in the Regulated – Nuclear Waste Management segment and depreciation and fuel expenses recorded in the Regulated – Nuclear Generation segment were offset by the impact of the OEB-authorized Bruce Lease Net Revenues Variance Account and Nuclear Liability Deferral Account recorded in the corresponding segments for the period up to May 31, 2017, and by the retrospective revenue impact of the OEB's decision for the period from June 1, 2017 to December 31, 2017 recorded in the Regulated – Nuclear Generation segment.

Regulated – Hydroelectric Segment

(millions of dollars)	**2017**	**2016**
Revenue [1]	**1,436**	1,527
Fuel expense	**351**	353
Gross margin	**1,085**	1,174
Operations, maintenance and administration	**330**	325
Depreciation and amortization	**139**	225
Property tax	**1**	1
Income before other gains, interest and income taxes	**615**	623
Other losses (gains)	**1**	(19)
Income before interest and income taxes	**614**	642

[1] During 2017 and 2016, the Regulated – Hydroelectric segment revenue included incentive payments of $12 million and $14 million, respectively, related to the OEB-approved hydroelectric incentive mechanism. The mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers.

The decrease in income before interest and income taxes of $28 million in 2017, compared to 2016, was primarily due to a gain of $22 million recognized during the first quarter of 2016 to reflect the OEB's January 2016 decision reversing a portion of an earlier capital cost disallowance related to the Niagara Tunnel project expenditures, in response to a motion by OPG. The income impact of OEB-approved regulatory accounts and higher OM&A expenses also contributed to the decrease in income for the year. The higher OM&A expenses were primarily related to overhaul work and civil repairs completed during the year.

These factors were partially offset by the recognition of a revenue increase of approximately $15 million in the fourth quarter of 2017 to reflect the OEB's decision on OPG's application for new regulated prices. This incremental revenue was in relation to the June 1, 2017 to December 31, 2017 period based on the June 1, 2017 retrospective effective date of the new regulated prices and was recorded as an increase to regulatory assets.

The decrease in revenue from the segment for the year ended December 31, 2017, compared to the same period in 2016, was largely due to the expiry of an OEB-authorized hydroelectric rate rider on December 31, 2016. As the rate rider allowed for the recovery of approved balances in OEB-authorized regulatory accounts, this decrease in revenue was largely offset by lower amortization expense related to these balances.

The Hydroelectric Availability for the stations included in the Regulated – Hydroelectric segment was as follows:

	2017	2016
Hydroelectric Availability *(%)*	**88.0**	89.0

The Hydroelectric Availability decreased during 2017, compared to 2016, primarily due to a higher number of unplanned outage days at the Northwestern Ontario, Niagara, and Eastern Ontario regions' hydroelectric stations, partially offset by higher availability from the Sir Adam Beck Pump GS due to a higher number of planned outages days in 2016 as a result of the refurbishment of the station's reservoir.

The definition of Hydroelectric Availability is found in the section, *Key Operating and Financial Performance Indicators*.

Contracted Generation Portfolio Segment

(millions of dollars)	2017	2016
Revenue	**579**	573
Fuel expense	**53**	58
Gross margin	**526**	515
Operations, maintenance and administration	**169**	178
Depreciation and amortization	**79**	75
Accretion on fixed asset removal liabilities	**9**	9
Property taxes	**7**	7
Income from investments subject to significant influence	**(38)**	(37)
Income before other losses, interest, and income taxes	**300**	283
Other losses	**-**	1
Income before interest and income taxes	**300**	282

Income before interest and income taxes increased by $18 million during 2017, compared to 2016. The increase in earnings primarily resulted from revenues from the Peter Sutherland Sr. GS that was placed in-service at the end of the first quarter of 2017 and lower OM&A expenses, partially offset by lower revenues from the Lower Mattagami River hydroelectric generating stations and Atikokan GS. The lower OM&A expenses were mainly due to the prospective adoption of the full yield curve approach to the estimation of the service and interest cost components of pension and OPEB costs starting in 2017.

The Hydroelectric Availability and the Thermal EFOR for the Contracted Generation Portfolio segment were as follows:

	2017	2016
Hydroelectric Availability *(%)*	**74.6**	77.3
Thermal EFOR *(%)*	**2.4**	1.6

Lower Hydroelectric Availability during 2017, compared to 2016, was primarily due to an increase in the number of planned outage days at the Lower Mattagami River hydroelectric generating stations.

The higher thermal EFOR in 2017, compared to 2016, was primarily due to a higher number of unplanned outage days at a Lennox GS unit as a result of a transmission outage and a generator-related outage in 2017.

The definitions of Hydroelectric Availability and Thermal EFOR are found in the section, *Key Operating and Financial Performance Indicators*.

Services, Trading, and Other Non-Generation Segment

(millions of dollars)	2017	2016
Revenue	**43**	68
Fuel expense	**1**	1
Gross margin	**42**	67
Operations, maintenance and administration	**18**	22
Depreciation and amortization	**30**	32
Accretion on fixed asset removal liabilities	**8**	8
Property taxes	**6**	12
Restructuring	**-**	6
Loss before other gain, interest, and income taxes	**(20)**	(13)
Other gains	**(384)**	-
Income before interest and income taxes	**364**	(13)

Segment earnings improved by $377 million in 2017 compared to 2016. The increase in earnings mainly reflected the gain on the sale of OPG's head office premises and associated parking facility recorded during the second quarter of 2017 of $283 million, which is net of tax effects of $95 million, partially offset by a decrease in rental revenue due to the sale of the head office premises.

The year-over-year decrease in OM&A expenses in 2017 reflected higher expenses incurred in 2016 prior to the decision taken in the fourth quarter of 2016 to proceed with the decommissioning of the Lambton GS, largely offset by a higher write-off of previously incurred project expenditures in 2017.

During the fourth quarter of 2017, OPG recorded $12 million in Other gains related to the revaluation of the asset retirement obligations for Lambton and Nanticoke generating stations in line with the current decommissioning plans and cost estimates. During each of 2017 and 2016, OPG recorded a charge against earnings to adjust the scrap value estimate for the Lambton GS, as a reduction to Other gains.

Fair Hydro Trust Segment

(millions of dollars)	2017
Operations, maintenance and administration	**1**
Earnings from Fair Hydro Trust	**(1)**
Income before interest and income taxes	**-**

The Fair Hydro Trust was established on December 20, 2017. The Fair Hydro Trust segment includes the revenue and expenses related to OPG's role as Financial Services Manager of the Fair Hydro Trust and holder of subordinated debt issued by the Trust, including the financial results of the Trust. Earnings from Fair Hydro Trust were $1 million in 2017, primarily due to net interest income earned on OPG's subordinated debt investment for the 11-day period following the acquisition of the first tranche of Investment Interest from the IESO on December 21, 2017. The earnings were offset by an allocation of OM&A expenses for labour costs relating to OPG's employees that are not exclusively dedicated to the segment but who provided services to set up the Trust during the year. Pursuant to the general regulation of the Fair Hydro Act, such labour costs are not recoverable as part of OPG's fees for 2017. Refer to the section, *Recent Developments* under the heading, *Ontario's Fair Hydro Plan* and the section, *Business Segments* under the heading, *Fair Hydro Trust Segment* for further details on the Fair Hydro Trust.

LIQUIDITY AND CAPITAL RESOURCES

OPG's primary sources of liquidity and capital are funds generated from operations, bank financing, credit facilities provided by the Ontario Electricity Financial Corporation (OEFC), long-term corporate debt, including public debt offerings and notes payable to the OEFC, private placement project financing, and equity issuance. These sources are used for multiple purposes including: to invest in plants and technologies, to undertake major projects, to fund long-term obligations such as contributions to the pension fund and the Nuclear Segregated Funds, to make payments under the OPEB plans, to fund expenditures on Nuclear Liabilities not eligible for reimbursement from the Nuclear Segregated Funds, and to service and repay long-term debt, to provide general working capital, and to fund a portion of OPG's subordinated debt investment in the Fair Hydro Trust and the Trust's acquisition of Investment Interest from the IESO.

Changes in cash and cash equivalents for 2017 and 2016 were as follows:

(millions of dollars)	**2017**	**2016**
Cash and cash equivalents, beginning of period	**186**	464
Cash flow provided by operating activities	**944**	1,817
Cash flow used in investing activities	**(2,478)**	(1,919)
Cash flow provided by (used in) financing activities	**1,582**	(176)
Net increase (decrease) in cash and cash equivalents	**48**	(278)
Cash and cash equivalents, end of period	**234**	186

For a discussion regarding cash flow provided by operating activities and the FFO Adjusted Interest Coverage ratio, refer to the details in the section, *Highlights* under the heading, *Overview of Results*.

Investing Activities

Electricity generation is a capital-intensive business. It requires continued investment in plants and technologies to maintain and improve operating performance including asset reliability, safety and environmental performance, to increase the generating capacity of existing stations, and to invest in the development of new generating stations, emerging technologies and other business growth opportunities.

Cash flow used in investing activities in 2017 increased by $834 million compared to 2016. The increase in net cash flow used in investing activities was primarily due to the Trust's acquisition of the first tranche of Investment Interest from the IESO in the amount of approximately $1.18 billion in December 2017 and higher expenditures on the Darlington Refurbishment project in 2017.

The increase in net cash flow used in investing activities was partially offset by the receipt of proceeds from the sale of OPG's head office premises and associated parking facility in 2017 and the acquisition of nine million common shares of Hydro One Limited (Hydro One) in 2016. OPG acquired the Hydro One shares for investment purposes, to mitigate the risk of future price volatility related to the Company's future share delivery obligations under the current collective agreements with the Power Workers' Union (PWU) and The Society of Energy Professionals (The Society).

Financing Activities

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. In the second quarter of 2017, OPG renewed and extended the expiry date of both tranches from May 2021 to May 2022. There were no amounts outstanding under the bank credit facility as at December 31, 2017.

There was $100 million of commercial paper outstanding under OPG's commercial paper program as at December 31, 2017.

As at December 31, 2017, OPG also maintained $25 million of short-term, uncommitted overdraft facilities, and a further $468 million of short-term, uncommitted credit facilities which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other general corporate purposes. As at December 31, 2017, a total of $390 million of Letters of Credit had been issued under these facilities. This included $353 million for the supplementary pension plans, $36 million for general corporate purposes, and $1 million related to the operation of the PEC.

The Company has an agreement to sell an undivided co-ownership interest in its current and future accounts receivable to an independent trust, expiring on November 30, 2018. The maximum amount of co-ownership interest that can be sold under this agreement is $150 million. As at December 31, 2017, no borrowings were issued under this agreement and there were Letters of Credit outstanding under this agreement of $150 million, which were issued in support of OPG's supplementary pension plans.

As at December 31, 2017, Lower Mattagami Energy Limited Partnership (LME) maintained a $400 million bank credit facility to support the funding requirements for the Lower Mattagami River project including support for LME's commercial paper program. The facility consists of a $300 million tranche maturing in August 2022 and a $100 million tranche maturing in August 2018. As at December 31, 2017, there was $160 million commercial paper outstanding under LME's commercial paper program. A letter of credit of $55 million was issued in July 2017 and remains outstanding as at December 31, 2017 under the $300 million tranche of LME's credit facility.

In June 2016, OPG entered into a $700 million general corporate credit facility agreement with the OEFC, with an expiry date of December 31, 2017. During 2017, the agreement was amended to increase the credit facility to $2,350 million and to extend its expiry date to December 31, 2018. As at December 31, 2017, there were outstanding long-term borrowings of $800 million under this credit facility.

In February 2017, OPG issued senior notes payable to the OEFC totalling $200 million and maturing in February 2047. The effective interest rate and coupon interest rate of these notes was 4.12 percent. In June 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in June 2047. The effective interest rate and coupon interest rate of these notes was 3.65 percent. In August 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in August 2047. The effective interest rate and coupon interest rate of these notes was 3.86 percent. In September 2017, OPG issued senior notes payable to the OEFC totalling $400 million and maturing in September 2047. The effective interest rate and coupon interest rate of these notes was 4.07 percent.

In October 2017, OPG issued $500 million of senior notes payable under a Medium Term Note Program. The notes bear a coupon interest rate of 3.32 percent and an effective rate of 3.43 percent, payable semi-annually until maturity on October 4, 2027. The offering was made under OPG's $2 billion short form base shelf prospectus dated September 12, 2017. The net proceeds will be used for general corporate purposes.

In December 2017, the Fair Hydro Trust entered into an $800 million revolving warehouse facility agreement with an expiry date of December 21, 2019. As at December 31, 2017, there were outstanding senior notes of $601 million under this credit facility, which were used to finance 51 percent of the Trust's funding requirement for the acquisition of the first tranche of Investment Interest from the IESO in December 2017.

In February 2018, the Trust issued $500 million of senior notes payable with a coupon interest rate of 3.36 percent and an effective interest rate of 3.42 percent, payable semi-annually until maturity on May 15, 2033. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility issued by the Trust in December 2017. By the end of the first quarter of 2018, the Trust is expected to acquire another tranche of Investment Interest from the IESO, which it expects to fund using its revolving warehouse facility.

As at December 31, 2017, OPG's long-term debt outstanding was $5,735 million, including $398 million due within one year and excluding Fair Hydro Trust's senior debt included in OPG's consolidated balance sheets. The Fair Hydro Trust's senior debt outstanding was $601 million as at December 31, 2017.

Contractual Obligations

OPG's contractual obligations as at December 31, 2017, are as follows:

(millions of dollars)	2018	2019	2020	2021	2022	Thereafter	Total
Fuel supply agreements	158	125	115	88	67	67	620
Contributions to the OPG registered pension plan [1]	215	219	-	-	-	-	434
OPG long-term debt repayment	398	368	663	413	172	3,721	5,735
Interest on OPG long-term debt	244	226	204	175	161	3,006	4,016
Fair Hydro Trust senior debt repayment [2]	-	601	-	-	-	-	601
Interest on Fair Hydro Trust senior debt	15	15	-	-	-	-	30
Commitments related to Darlington Refurbishment project [3]	473	-	-	-	-	-	473
Commitments related to Ranney Falls GS project	29	5	-	-	-	-	34
Operating licences	40	41	24	28	28	87	248
Operating lease obligations	28	24	24	22	22	79	199
Unconditional purchase obligations	59	58	56	5	-	-	178
Accounts payable and accrued charges	957	8	-	-	-	16	981
Other	57	30	2	1	1	64	155
Total	2,673	1,720	1,088	732	451	7,040	13,704

[1] The pension contributions include ongoing funding requirements and additional funding requirements towards the deficit, in accordance with the actuarial valuation of the OPG registered pension plan as at January 1, 2017. The next actuarial valuation of the OPG registered pension plan must have an effective date no later than January 1, 2020. The pension contributions are affected by various factors including market performance, changes in actuarial assumptions, plan experience, changes in the pension regulatory environment, and the timing of funding valuations. Funding requirements after 2019 are excluded due to significant variability in the assumptions required to project the timing of future cash flows. The amount of OPG's additional, voluntary contribution, if any, is revisited from time to time.

[2] The notes were issued by the Fair Hydro Trust under an $800 million two-year revolving warehouse facility in December 2017. In February 2018, the Trust issued $500 million of senior notes payable to repay the majority of the outstanding balance of the revolving warehouse facility.

[3] Represents estimated currently committed costs to close the project, including accruals for completed work, demobilization of project staff and cancellation of existing contracts and material orders.

Other Commitments

Collective Agreements

As of December 31, 2017, OPG had approximately 9,200 regular employees. Most of OPG's regular employees are represented by two unions:

- The PWU – This union represents approximately 4,850 OPG employees or approximately 53 percent of OPG's regular workforce as at December 31, 2017. Union membership includes operators, technicians, skilled trades, clerical, and security personnel. The current collective agreement between OPG and the PWU has a three-year term, expiring on March 31, 2018. Negotiations for a new labour agreement with the PWU are underway. **[MONITOR]**
- The Society – This union represents approximately 3,250 OPG employees or approximately 35 percent of OPG's regular workforce as at December 31, 2017. Union membership includes supervisors, professional engineers, scientists, and other professionals. The current collective agreement between OPG and The Society has a three-year term, expiring on December 31, 2018.

In addition to the regular workforce, construction work is performed through 19 craft unions with established bargaining rights at OPG facilities. These bargaining rights are established either through the Electrical Power Systems Construction Association (EPSCA) or directly with OPG. Collective agreements between the Company and its construction unions are negotiated either directly or through EPSCA. All of these collective agreements currently have multi-year terms, expiring on April 30, 2020.

BALANCE SHEET HIGHLIGHTS

The following section provides other highlights of OPG's audited consolidated financial position using selected balance sheet data as at December 31:

(millions of dollars)	**2017**	**2016**
Property, plant and equipment – net	**21,322**	19,998
The increase was primarily due to capital expenditures on the Darlington Refurbishment project, partially offset by depreciation expense.		
Nuclear fixed asset removal and nuclear waste management funds *(current and non-current portions)*	**16,724**	15,984
The increase was primarily due to earnings on the Nuclear Segregated Funds, partially offset by reimbursement of eligible expenditures on nuclear fixed asset removal and nuclear waste management activities.		
Regulatory assets and liabilities – net *(current and non-current portions)*	**6,637**	5,545
The increase was primarily due to the addition of the Interim period revenue shortfall account, increases in the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB AOCI regulatory asset. In addition, there was no amortization recorded in 2017 consistent with OPG's proposal in the Draft Payment Amounts Order filed with the OEB in January 2018.		
Long-term debt *(current and non-current portions)*	**6,319**	5,520
The increase was primarily due to the issuance of senior notes payable by the Trust to finance the acquisition of an Investment Interest in the shortfall from the rate reductions mandated by the Fair Hydro Act of $601 million, issuance of senior notes payable totaling $804 million during 2017 primarily with the OEFC, and issuance of senior notes totaling $500 million under the Medium Term Note Program. The balance is offset by the debt repayment of $1 billion in 2017.		
Fixed asset removal and nuclear waste management liabilities	**20,421**	19,484
The increase was primarily a result of accretion expense representing the increase in the present value liabilities due to the passage of time, and an increase in the estimate for the nuclear ARO of $188 million recorded in 2017, which is discussed in *Critical Accounting Policies and Estimates* under the heading, Asset Retirement *Obligation*. The increase was partially offset by expenditures on nuclear fixed asset removal and waste management activities.		
Pension liabilities	**3,423**	3,012
The increase was primarily due to the re-measurement of the liabilities at the end of 2017 reflecting lower discount rates, partially offset by the excess of actual returns on pension plan assets over interest costs on the liabilities during 2017, as discussed in the section, *Critical Accounting Policies and Estimates* under the *heading, Pension and Other Post-Employment Benefits.*		
Other post-employment benefit liabilities	**3,092**	2,897
The increase was primarily due to the remeasurement of the liabilities at the end of 2017 reflecting lower discount rates, partially offset by the updated lower per capital health care claims costs assumption as part of the 2017 actuarial valuation.		

Off-Balance Sheet Arrangements

In the normal course of operations, OPG engages in a variety of transactions that, under US GAAP, are either not recorded in the Company's interim consolidated financial statements or are recorded in the Company's interim consolidated financial statements using amounts that differ from the full contract amounts. Principal off-balance sheet activities for OPG include guarantees and long-term contracts.

Guarantees

As part of normal business, OPG and certain of its subsidiaries and joint ventures enter into various agreements to provide financial or performance assurance to third parties. Such agreements include guarantees, standby Letters of Credit and surety bonds. For more details on guarantees issued by the company, refer to Note 15 of OPG's audited consolidated financial statements.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

OPG's significant accounting policies, including the impact of major recent accounting pronouncements, are outlined in Note 3 of the audited consolidated financial statements. Certain of these policies are recognized as critical accounting policies by virtue of the subjective and complex judgments and estimates required around matters that are inherently uncertain and could result in materially different amounts being reported under different conditions or assumptions. The critical accounting policies and estimates that affect OPG's US GAAP consolidated financial statements are highlighted below.

Exemptive Relief for Reporting under US GAAP

As required by *Ontario Regulation 395/11,* as amended, under the FAA, OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. Since January 1, 2012, OPG also has received exemptive relief from the OSC from the requirements of section 3.2 of National Instrument 52-107 *Acceptable Accounting Policies and Auditing Standards* (NI 52-107). The exemption allows OPG to file consolidated financial statements with the OSC based on US GAAP, rather than International Financial Reporting Standards (IFRS), without becoming a U.S. Securities and Exchange Commission registrant.

The current OSC exemption, received in 2014, will terminate on the earliest of the following:

- January 1, 2019
- The financial year that commences after OPG ceases to have activities subject to rate regulation
- The effective date prescribed by the International Accounting Standards Board (IASB) for the mandatory application of a standard within IFRS specific to entities with rate-regulated activities.

As a result of OPG's 2011 decision to adopt US GAAP, as required by the FAA regulation, OPG's earlier plan to convert to IFRS, effective January 1, 2012, was discontinued. OPG had substantively completed its IFRS conversion project, which included separate diagnostic, development, and implementation phases, when it suspended the project. If a future transition to IFRS for the purposes of OPG's consolidated financial statements is required, conversion work can be effectively restarted with sufficient lead time to evaluate and conclude on changes that occurred subsequent to the decision to suspend the project. OPG continues to monitor the IASB's current standard-setting project related to entities with rate-regulated activities and is evaluating alternatives with respect to the Company's future financial reporting.

Rate Regulated Accounting

The *Ontario Energy Board Act, 1998* and *Ontario Regulation 53/05* provide that OPG receives regulated prices for electricity generated from 54 hydroelectric generating stations and the Pickering and Darlington nuclear generating stations. OPG's regulated prices for these facilities are determined by the OEB.

The OEB is a self-funding Crown corporation. Its mandate and authority come from the *Ontario Energy Board Act, 1998*, the *Electricity Act, 1998*, and a number of other provincial statutes. The OEB is an independent, quasi-judicial tribunal that reports to the Legislature of the Province through the Ontario Ministry of Energy. It regulates market participants in Ontario's natural gas and electricity industries. The OEB carries out its regulatory functions through public hearings and other more informal processes such as consultations.

US GAAP recognizes that rate regulation can create economic benefits and obligations that are required by the regulator to be obtained from, or settled with, the customers. When the Company assesses that there is sufficient assurance that incurred costs in respect of the regulated facilities will be recovered in the future, those costs are deferred and reported as a regulatory asset. When the Company is required to refund amounts to customers in the future in respect of the regulated facilities, including amounts related to costs that have not been incurred and for which the OEB has provided recovery through regulated prices, the Company records a regulatory liability.

Certain of the regulatory assets and liabilities recognized by the Company relate to variance and deferral accounts authorized by the OEB, including those authorized pursuant to *Ontario Regulation 53/05.* The measurement of these regulatory assets and liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of *Ontario Regulation 53/05* and the OEB's decisions. The estimates and assumptions made in the interpretation of the regulation and the OEB's decisions are reviewed as part of the OEB's regulatory process.

Regulatory assets and liabilities for variance and deferral account balances approved by the OEB for inclusion in regulated prices are amortized based on approved recovery or repayment periods.

In addition to regulatory assets and liabilities for variance and deferral accounts, OPG recognizes regulatory assets and liabilities for unamortized amounts recorded in AOCI in respect of pension and OPEB obligations, and deferred income taxes, in order to reflect the expected recovery or repayment of these amounts through future regulated prices charged to customers. There are measurement uncertainties related to these balances due to the assumptions made in the determination of pension and OPEB obligations and deferred income taxes that are attributed to rate regulated business segments.

The regulatory asset for unamortized pension and OPEB amounts recorded in AOCI has reflected the OEB's use, since April 1, 2008, of the accrual basis of accounting for including pension and OPEB amounts in approved regulated prices for OPG. This is also the manner in which these costs are recognized in OPG's consolidated financial statements. Therefore, unamortized amounts in respect of OPG's pension and OPEB plans recognized in AOCI generally would not be reflected in regulated prices until they have been reclassified from AOCI and recognized as amortization components of the benefit costs for these plans.

Since November 1, 2014, the OEB has limited amounts for pension and OPEB costs included in the approved revenue requirements and regulated prices to the regulated business portion of the Company's cash expenditures for its pension and OPEB plans. The difference between actual pension and OPEB costs determined using the accrual method applied in OPG's audited consolidated financial statements and OPG's corresponding actual cash expenditures for these plans is captured in OEB-authorized Pension & OPEB Cash Versus Accrual Differential Deferral Account for future consideration. In 2017, the OEB issued a report outlining the guiding principles and policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the Ontario electricity and natural gas sectors. The report establishes the accrual basis of accounting as the method of determining pension and OPEB amounts for rate-setting purposes, unless the OEB finds that this method does not result in just and reasonable rates in the circumstances of a particular utility. The OEB's report and the OEB's December 2017 decision on OPG's

application for new regulated prices require OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the existing deferral account, until such time as the OEB approves resumption of the accrual basis of recovery for OPG. The future recovery of amounts recorded in the account will be subject to this approval. Further details on the OEB's 2017 report can be found in the section, *Highlights* under the heading, *Recent Developments – OEB's Decision on OPG's Application for New Regulated Prices*.

It remains the Company's position that, taken collectively, OEB's decisions on OPG's applications for regulated prices and the OEB's 2017 report in this area do not constitute a change in the basis of OPG's rate recovery of pension and OPEB costs. The Company continues to believe that there is sufficient likelihood that unamortized pension and OPEB amounts that have not yet been reclassified from AOCI will be included in future regulated prices, or in an OEB-authorized regulatory account for future recovery, as they are recognized in benefit costs. Similarly, the Company continues to believe that there is sufficient likelihood that amounts recorded in the Pension & OPEB Cash Versus Accrual Differential Deferral Account will be recovered, and consistent with the expectations set out in the OEB's December 2017 decision, plans to file an application with the OEB in 2018 requesting recovery of the account balance. Therefore, the Company continues to recognize regulatory assets for the above amounts.

See Notes 3, 5, 8, 9, and 11 of OPG's 2017 audited consolidated financial statements for additional disclosures related to the OEB's decisions, regulatory assets and liabilities, and rate regulated accounting.

Useful Lives of Long-Lived Assets

OPG reviews estimated station useful lives for its generating assets on a regular basis.

Nuclear Generating Stations

For the nuclear stations, this process involves reviewing major life limiting components (such as pressure tubes, feeders and steam generators) to determine an appropriate end-of-life date for the station. Useful lives are set such that, with normal and customary maintenance activities, stations are expected to be operational until such time as their life-limiting component's threshold is expected to be reached.

Hydroelectric and Thermal Generating Stations

Although there is a link between the age of a facility and the capital investment required to maintain that facility, age does not establish an upper limit on the expected useful life of hydroelectric facilities and dams. Regular maintenance and the replacement of specific components typically allow hydroelectric stations to operate for very long periods. For hydroelectric generating stations, an upper age limit of 100 years have been set.

Thermal generating stations reported in the Contracted – Generation Portfolio business segment primarily have useful lives that are in line with the term of the Energy Supply Agreements with the IESO.

Financing Receivables

Financing receivables consist of the current and irrevocable right of the Fair Hydro Trust to collect payments from Specified Consumers in the future in accordance with the Fair Hydro Act and associated general regulation. These amounts are measured at the transaction price entered into with the IESO on market terms upon acquisition and subsequently measured on an amortized cost basis. The basis of amortization follows the effective interest method.

Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

In accordance with the ONFA, OPG sets aside and invests funds that are held in segregated custodian and trustee accounts specifically for discharging its obligation for nuclear facilities decommissioning and long-term nuclear waste management. The Decommissioning Segregated Fund was established to fund the future costs of nuclear fixed asset removal and long-term L&ILW management, and certain costs of used fuel storage incurred after the stations are shut down. The Used Fuel Segregated Fund was established to fund the future costs of long-term nuclear used

fuel management and certain costs of used fuel storage incurred after the stations are shut down. Costs for L&ILW management and used fuel storage incurred during station operation are not funded by the Nuclear Segregated Funds. They are funded through the Company's operating cash flow or other sources of liquidity.

Based on the current approved ONFA reference plan, starting in 2017, OPG is not currently required to make overall contributions to the Used Fuel Segregated Fund or the Decommissioning Segregated Fund. Prior to 2017, OPG made contributions to the Used Fuel Segregated Fund quarterly, including a one-time special payment in earlier years, as required by the ONFA. These contributions reflected ONFA requirements to fund the majority of the underlying used fuel liability by the end of the initial estimated useful lives of the nuclear stations assumed in the ONFA, resulting in significantly higher contributions to the Used Fuel Segregated Fund in the earlier years of OPG's existence. OPG has not been required to make contributions to the Decommissioning Segregated Fund, which was fully funded at its inception through the initial contribution made by the Province and, taking into account asset performance and changes in underlying funding obligations over time, at the time of every subsequent approved ONFA reference plan. Contributions to either or both funds may be required in the future should the funds be in an underfunded position when a new reference plan is prepared. Such may be the case as a result of variability in asset performance due to volatility inherent in financial markets and, for the portion of the Used Fuel Segregated Fund guaranteed by the Province, changes in the Ontario CPI. Future contribution levels also are dependent on changes in baseline cost estimates and underpinning assumptions used to establish the funding obligations in subsequent ONFA reference plans.

Decommissioning Segregated Fund

Upon termination of the ONFA, the Province has the sole right to any excess funds in the Decommissioning Segregated Fund. Accordingly, when the Decommissioning Segregated Fund is overfunded, OPG limits the fund earnings it recognizes in the consolidated financial statements by recording an amount due to the Province, such that the fund asset recognized on the consolidated balance sheet is equal to the cost estimate of the liability based on the most recently approved ONFA reference plan. Additionally, OPG recognizes the portion of the surplus that it may direct to the Used Fuel Segregated Fund, which is possible when the surplus is such that the underlying liabilities, as defined by the most recently approved ONFA reference plan, are at least 120 percent funded. In those circumstances, OPG may direct, at the time a new or amended reference plan is approved, up to 50 percent of the surplus over 120 percent to the Used Fuel Segregated Fund, with the OEFC entitled to a distribution of an equal amount. Therefore, when the Decommissioning Segregated Fund is at least 120 percent funded, OPG recognizes 50 percent of the excess greater than 120 percent in income, up to the amount by which the Used Fuel Segregated Fund is underfunded.

The amount due to the Province in respect of the Decommissioning Segregated Fund could be reduced in subsequent periods in the event that the fund earns less than is target rate of return, a new ONFA reference plan is approved with a higher underlying liability, or the amount of the underfunding in the Used Fuel Segregated Fund increases.

When the Decommissioning Segregated Fund is underfunded, the earnings on the fund reflect actual fund returns based on the market value of the assets.

Used Fuel Segregated Fund

Under the ONFA, the Province guarantees OPG's annual return in the Used Fuel Segregated Fund at 3.25 percent plus the change in the Ontario CPI, as defined in the ONFA, for funding related to the first 2.23 million used fuel bundles ("committed return"). OPG recognizes the committed return on the Used Fuel Segregated Fund as earnings on the Nuclear Segregated Funds. The difference between the committed return and the actual market return determined based on the fair value of the fund's assets related to the first 2.23 million used fuel bundles is recorded as due to or due from the Province. This amount represents the amount OPG would pay to, or receive from, the Province if the committed return were to be settled as of the consolidated balance sheet date. Upon approval of a

new or amended ONFA reference plan, the Province is obligated to make an additional contribution to the Used Fuel Segregated Fund in relation to the first 2.23 million used fuel bundles if the fund's assets earned a rate of return that is less than the guaranteed rate of return. If the return on the fund's assets exceeds the Province's guaranteed rate of return, the Province is entitled to withdraw any portion of the excess related to the 2.23 million used fuel bundles, upon approval of a new or amended ONFA reference plan. The 2.23 million threshold represents the estimated total life cycle fuel bundles based on the initial estimated useful lives of the nuclear stations assumed in the ONFA.

As prescribed under the ONFA, OPG's contributions attributed to the used fuel bundles in excess of 2.23 million are not subject to the rate of return guaranteed by the Province, and earn a return based on changes in the market value of the assets of the Used Fuel Segregated Fund.

If there is a surplus in the Used Fuel Segregated Fund such that the funding liabilities, as defined by the most recently approved ONFA Reference Plan, are at least 110 percent funded, the Province has the right, at any time, to access the excess amount greater than 110 percent. Upon termination of the ONFA, the Province is entitled to any surplus in the fund. Accordingly, when the Used Fuel Segregated Fund is overfunded, OPG limits the fund earnings it recognizes in the consolidated financial statements by recording an amount due to the Province, such that the balance of the fund is equal to the cost estimate of the liability based on the most recently approved ONFA reference plan. In accordance with the ONFA, neither OPG nor the Province have a right to direct any amounts from the Used Fuel Segregated Fund to the Decommissioning Segregated Fund.

Provincial Guarantee

In accordance with the *Nuclear Safety and Control Act* (Canada), the CNSC requires OPG to have sufficient funds available to discharge its existing nuclear waste management and nuclear decommissioning obligations. The CNSC process requires the CNSC financial guarantee requirement to be updated once every five years and for OPG to provide an annual report to the CNSC on the assumptions, asset values, and resulting financial guarantee requirements. The CNSC financial guarantee requirement calculation takes into account nuclear waste expected to be generated to the end of each year.

In November 2017, the CNSC accepted OPG's proposed 2018-2022 CNSC financial guarantee requirement to be satisfied by the forecast fair market value of the Nuclear Segregated Funds without the requirement of a Provincial Guarantee for the 2018-2022 period. As required by the terms of the ONFA, the Province is committed to provide a Provincial Guarantee to the CNSC, on behalf of OPG, should there be a shortfall between the CNSC financial guarantee requirement and the fair market value of the Nuclear Segregated Funds in the 2018-2022 period, as it has done in the past. OPG pays the Province an annual guarantee fee equal to 0.5 percent of the outstanding amount, if any, of the Provincial Guarantee.

The value of the Provincial Guarantee in effect through to the end of 2017 was $1,551 million. Based on this guarantee amount, OPG paid a guarantee fee of $8 million to the Province for each of 2016 and 2017.

Pension and Other Post-Employment Benefits

The determination of OPG's pension and OPEB costs and obligations is based on accounting policies and assumptions, as discussed below.

Accounting Policy

OPG's post-employment benefit programs consist of a contributory defined benefit registered pension plan, a defined benefit supplementary pension plan, and other post retirement benefits (OPRB) including group life insurance and health care benefits, and long-term disability (LTD) benefits. Post-employment benefit programs also are provided by the Nuclear Waste Management Organization (NWMO), which is consolidated into OPG's financial results. Unless otherwise noted, information on the Company's post-employment benefit programs is presented on a consolidated basis.

OPG accrues its obligations under pension and OPEB plans in accordance with US GAAP. The obligations for pension and OPRB are determined using the projected benefit method pro-rated on service. The obligation for LTD benefits is determined using the projected benefit method on a terminal basis. Pension and OPEB obligations are impacted by factors including interest rates, adjustments arising from plan amendments, demographic assumptions, experience gains or losses, salary levels, inflation, and health care cost escalation assumptions. Pension and OPEB costs and obligations are determined annually by independent actuaries using management's best estimate assumptions.

Pension fund assets include equity securities, corporate and government debt securities, pooled funds, real estate, infrastructure and other investments. These assets are managed by professional investment managers. The pension fund does not invest in equity or debt securities issued by OPG. Pension fund assets are valued using market-related values for purposes of determining the amortization of actuarial gains or losses and the expected return on plan assets. The market-related value recognizes gains and losses on equity assets relative to a six percent assumed real return over a five-year period.

Pension and OPEB costs include current service costs, interest costs on the obligations, the expected return on pension plan assets, adjustments for plan amendments and adjustments for actuarial gains or losses, which result from changes in assumptions and experience gains and losses. Past service costs or credits arising from pension and OPRB plan amendments are amortized on a straight-line basis over the expected average remaining service life to full eligibility of the employees covered by the corresponding plan. Past service costs or credits arising from amendments to LTD benefits are immediately recognized as OPEB costs in the period incurred. Due to the long-term nature of pension and OPRB liabilities, the excess of the net cumulative unamortized gain or loss, over 10 percent of the greater of the benefit obligation and the market-related value of the plan assets (the corridor) for each plan is amortized over the expected average remaining service life of the employees covered by the plan, which represents the period during which the associated economic benefits are expected to be realized by the Company. Actuarial gains or losses for LTD benefits are immediately recognized as OPEB costs in the period incurred.

OPG recognizes the funded status of its defined benefit plans on the consolidated balance sheets. The funded status is measured as the difference between the fair value of plan assets and the benefit obligation, on a plan-by-plan basis.

Actuarial gains or losses and past service costs or credits arising during the year that are not recognized immediately as components of benefit costs are recognized as increases or decreases in other comprehensive income (OCI), net of income taxes. These unamortized amounts in AOCI are subsequently reclassified and recognized as amortization components of pension and OPRB costs as described above.

As at December 31, 2017, the unamortized net actuarial loss and unamortized past service costs for the pension and OPEB plans totalled $4,148 million (2016 – $3,668 million). Details of the unamortized net actuarial loss and unamortized past service costs as at December 31, 2017 and 2016 are as follows:

(millions of dollars)	Registered Pension Plans 2017	2016	Supplementary Pension Plans 2017	2016	Other Post-Employment Benefits 2017	2016
Net actuarial gain not yet subject to amortization due to use of market-related values	**(418)**	(570)	**-**	-	**-**	-
Net actuarial loss not subject to amortization due to use of the corridor	**1,735**	1,619	**36**	34	**299**	267
Net actuarial loss subject to amortization	**2,333**	2,238	**80**	72	**79**	3
Unamortized net actuarial loss	**3,650**	3,287	**116**	106	**378**	270
Unamortized past service costs	**-**	-	**-**	-	**4**	5

OPG records an offsetting regulatory asset or liability for the portion of the adjustments to AOCI that is attributable to the regulated operations in order to reflect the expected recovery or refund of these amounts through future regulated prices charged to customers. For the recoverable or refundable portion attributable to regulated operations, OPG records a corresponding change in this regulatory asset or liability for the amount of the increases or decreases in OCI and for the reclassification of AOCI amounts into benefit costs during the period.

When the recognition of the transfer of employees and employee-related benefits gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement. A curtailment is the loss by employees of the right to earn future benefits under the plan. A settlement is the discharge of a plan's liability.

Accounting Assumptions

Assumptions are significant inputs to actuarial models that measure pension and OPEB obligations and related effects on operations. Discount rate, inflation rate and changes in salary levels are three critical assumptions in the determination of benefit costs and obligations. In addition, the expected long-term rate of return on plan assets is a critical assumption in the determination of registered pension plan cost, and the health care cost trend rate is a critical assumption in the determination of OPEB cost and obligations. These assumptions, as well as other assumptions involving demographic factors such as retirement age, mortality, and employee turnover, are evaluated periodically by management in consultation with independent actuaries. During the evaluation process, the assumptions are updated to reflect past experience and expectations for the future. Actual results in any given year will often differ from actuarial assumptions because of economic and other factors giving rise to actuarial gains and losses.

The discount rates, which are representative of the AA corporate bond yields, are used to calculate the present value of the expected future cash flows on the measurement date in order to determine the projected benefit obligations for the Company's employee benefit plans. A lower discount rate increases the benefit obligations. The weighted-average discount rate used to determine the projected pension and OPEB benefit obligations as at December 31, 2017 was 3.6 percent. This represents a decrease compared to the 3.9 percent discount rate that was used to determine the obligations as at December 31, 2016.

In 2016 and prior years, benefit costs were calculated using the same single weighted-average discount rates as reflected in the calculation of the benefit obligations. Effective January 1, 2017, OPG adopted a full yield curve approach to the estimation of the service and interest cost components of pension and OPEB costs, by applying the specific spot rates along the yield curve used in the determination of the projected benefit obligations to the relevant projected cash flows. The change improves the correlation between projected benefit cash flows and the corresponding yield curve spot rates, and provides a more precise measurement of service and interest costs. This change in the method was accounted for prospectively, as a change in estimate. The resulting reduction in pension and OPEB costs is estimated at approximately $135 million for the twelve months ended December 31, 2017. Approximately 90 percent of this reduction in pension and OPEB costs was attributed to the Company's regulated

business segments and therefore was offset by the impact of OEB-authorized regulatory accounts. The change does not affect the measurement of the total benefit obligation as the change in the current service and interest cost components from the previous method is offset by a corresponding change in the actuarial gain or loss recorded in AOCI.

The expected rate of return on plan assets is determined based on the pension fund's asset allocation and the expected return considering long-term risks and returns associated with each asset class within the plan portfolio. A lower expected rate of return on plan assets increases pension cost.

A new actuarial valuation of the OPG registered pension plan was filed with the Financial Services Commission of Ontario in September 2017 with an effective date of January 1, 2017. The annual funding requirements in accordance with the new actuarial valuation are outlined in the section, *Liquidity and Capital Resources* under the heading, *Contractual and Commercial Commitments*. OPG conducted a comprehensive actuarial valuation for accounting purposes of its pension and OPEB plans in 2017, using demographic data as at January 1, 2017 consistent with the new funding valuation and using assumptions as at December 31, 2017. As part of the valuation, the plans' demographic and other assumptions were reviewed and revised, as necessary, by independent actuaries.

The deficit for the registered pension plan, for accounting purposes, increased from $2,693 million as at December 31, 2016 to $3,081 million as at December 31, 2017. This increase was largely due to a re-measurement of the liabilities at the end of 2017 reflecting lower discount rates, partially offset by the excess of actual returns on the pension plan assets over interest costs on the liabilities during the year.

The projected benefit obligations for OPEB increased from $2,992 million as at December 31, 2016 to $3,190 million as at December 31, 2017. This increase was largely due to a re-measurement of the liabilities at the end of 2017 reflecting a decrease in the discount rates, partially offset by the updated, lower per capita health care claims costs assumption as part of the 2017 actuarial valuation.

A change in the following assumptions, holding all other assumptions constant, would increase (decrease) pension and OPEB costs for the year ended December 31, 2017 as follows:

(millions of dollars)	**Registered Pension Plans [1]**	**Supplementary Pension Plans [1]**	**Other Post-Employment Benefits [1]**
Expected long-term rate of return			
0.25% increase	(32)	n/a	n/a
0.25% decrease	32	n/a	n/a
Discount rate			
0.25% increase	(56)	(1)	(2)
0.25% decrease	59	1	13
Inflation			
0.25% increase	98	1	-
0.25% decrease	(91)	(1)	-
Salary increases			
0.25% increase	22	3	-
0.25% decrease	(20)	(2)	-
Health care cost trend rate			
1% increase	n/a	n/a	77
1% decrease	n/a	n/a	(29)

n/a – change in assumption not applicable.

[1] Excludes the impact of regulatory accounts.

Asset Retirement Obligation

OPG recognizes ARO for fixed asset removal and nuclear waste management liabilities, discounted for the time value of money. OPG estimates both the amount and timing of future cash expenditures based on the plans for fixed asset removal and nuclear waste management. The ARO is comprised of expected costs to be incurred up to and beyond termination of operations and the closure of nuclear and thermal generating plant facilities and other facilities. Costs are expected to be incurred for activities such as preparation for safe storage and safe storage of nuclear stations, dismantlement, demolition and disposal of facilities and equipment, remediation and restoration of sites, and the ongoing and long-term management of nuclear used fuel bundles and L&ILW material. The liabilities associated with the decommissioning of the nuclear generating stations and the long-term management of used nuclear fuel comprise the most significant amounts of the total obligation.

The nuclear decommissioning liability includes the estimated costs of closing the nuclear stations after the end of their service lives, which includes preparation and placement of the stations into a safe state condition followed by an assumed 30-year safe store period prior to station dismantlement and site restoration. Activities associated with the placement of stations into a safe state condition include de-fuelling and de-watering of the nuclear reactors. OPG is responsible for the nuclear waste management and nuclear decommissioning obligations associated with the Bruce nuclear generating stations and includes the associated costs in its ARO. Pursuant to the lease agreement, Bruce Power must return the two Bruce stations to OPG together, in a de-fuelled and de-watered state. As such, these de-watering and de-fuelling costs are not part of OPG's ARO.

The life cycle costs of L&ILW management include the costs of processing and storage of such radioactive wastes during and following the operation of the nuclear stations, as well as the costs of the ultimate long-term management of these wastes. The current assumptions used to establish the obligation for these costs include an L&ILW DGR facility to be constructed and operated by OPG, as discussed in the section, *Core Business, Strategy, and Outlook* under the heading, *Project Excellence*. To estimate the liability for nuclear used fuel management, OPG has adopted an approach consistent with the Adaptive Phased Management concept approved by the Government of Canada, which assumes a deep geologic repository for the long-term management of Canada's nuclear used fuel waste. The NWMO is responsible for the design and implementation of Canada's plan for the long-term management of used nuclear fuel.

The following costs are recognized as a liability on OPG's consolidated balance sheets:

- the present value of the costs of decommissioning the nuclear and thermal production facilities and other facilities after the end of their useful lives
- the present value of the fixed cost portion of nuclear waste management programs that are required based on the total volume of waste expected to be generated over the assumed lives of the stations
- the present value of the variable cost portion of nuclear waste management programs taking into account waste volumes generated to date.

The significant assumptions underlying operational and technical factors used in the calculation of the accrued liabilities are subject to periodic review. Changes to these assumptions, including changes to assumptions on the timing of the programs including construction of assumed waste disposal facilities, station end-of-life dates, waste disposal methods, financial indicators, decommissioning strategy, and the technology employed may result in significant changes to the value of the accrued liabilities. With programs of such long-term duration and the evolving technology to handle nuclear waste, there is a significant degree of inherent uncertainty surrounding the measurement of the costs for these programs. These costs may increase or decrease over time.

The estimates for the Nuclear Liabilities are reviewed on an ongoing basis as part of the overall nuclear waste management program. A comprehensive reassessment of all underlying assumptions and baseline cost estimates is performed periodically, at least once every five years, in line with the required ONFA reference plan update process. Changes in the Nuclear Liabilities resulting from changes in assumptions or estimates that impact the amount or

timing of the estimated undiscounted future cash flows are recorded as an adjustment to the liabilities. Upward revisions in the Nuclear Liabilities represent the present value of a net increase in future undiscounted cash flows determined using a current credit-adjusted risk-free rate. Downward revisions in the Nuclear Liabilities represent the present value of a net decrease in future undiscounted cash flows determined using the weighted average discount rate reflected in the existing liability. Resulting changes in the related asset retirement costs are capitalized as part of the carrying amount of nuclear fixed assets in service.

As of December 31, 2017, OPG recorded an increase of $188 million in the Nuclear Liabilities and associated asset retirement costs capitalized as part of carrying value of property, plant and equipment (PP&E) reflecting the change in the Pickering GS accounting end-of-life assumptions from December 31, 2020 for all operating units to December 31, 2022 for Units 1 and 4 and December 31, 2024 for Units 5 to 8. The increase in the liabilities is primarily due to higher fixed costs associated with the Used Fuel Disposal and L&ILW Storage programs, discounted using the current credit-adjusted risk-free rate of 2.94 percent. The adjustment did not impact net income for 2017. The adjustment is not expected to have a material impact on net income in 2018 as the associated impact on expenses is expected to be largely offset by OEB-authorized regulatory accounts. The change in accounting end-of-life assumptions for the Pickering GS are discussed in further detail in the section, *Core Business, Strategy, and Outlook* under the heading, *Operational Excellence – Electricity Generation Production and Reliability*.

For the purposes of calculating OPG's Nuclear Liabilities, as at December 31, 2017, consistent with the current accounting end-of-life assumptions, nuclear station decommissioning activities are projected to occur over approximately the next 80 years.

The liability for nuclear fixed asset removal and nuclear waste management on a present value basis as at December 31, 2017 was $20,077 million (2016 – $19,103 million). As at December 31, 2017, the undiscounted cash flows of expenditures for OPG's Nuclear Liabilities in 2017 dollars are as follows:

(millions of dollars)	**2018**	**2019**	**2020**	**2021**	**2022**	**Thereafter**	**Total**
Expenditures for nuclear fixed asset removal and nuclear waste management [1]	323	326	323	311	598	40,513	42,394

[1] The majority of the expenditures are expected to be reimbursed by the Nuclear Segregated Funds established by the ONFA. Any contributions required under the ONFA are not included in these undiscounted cash flows. Accounting for the Nuclear Segregated Funds is discussed in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

The liability for non-nuclear fixed asset removal was $344 million as at December 31, 2017 (2016 – $381 million). This liability primarily represents the present value of estimated costs of decommissioning OPG's thermal generating stations at the end of their service lives. OPG has updated the asset retirement obligations for the thermal generating stations as of December 31, 2017, based on a review of required decommissioning, clean-up and restoration activities, underlying economic assumptions and anticipated timing of these activities in line with current accounting end-of-life assumptions for the operating sites. For the shutdown Nanticoke and Lambton generating stations, the update reflects the estimated cost of executing current decommissioning plans. For the currently operating sites, OPG recognized a decrease of $18 million in the non-nuclear fixed asset removal liabilities and associated asset retirement costs capitalized as part of the carrying value of PP&E as at December 31, 2017. For the Nanticoke and Lambton sites, a reduction in the non-nuclear fixed asset removal liabilities and a gain of approximately $12 million was recorded in net income in the fourth quarter of 2017, in the, Services, Trading, and Other Non-Generation segment.

For the purpose of measuring the non-nuclear fixed asset removal liability, asset removal activities are assumed to take place approximately over the next one to 12 years. The amount of undiscounted estimated future cash flows associated with the thermal liabilities is approximately $400 million.

OPG has no legal obligation associated with the decommissioning of its hydroelectric generating facilities and the costs cannot be reasonably estimated because of the long service life of these assets. With either maintenance efforts or rebuilding, the water control structures are assumed to be used for the foreseeable future. Accordingly, OPG has not recognized a liability for the decommissioning of its hydroelectric generating facilities.

Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly arm's-length transaction between market participants at the measurement date. Fair value measurements are required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model.

The fair value of financial assets and liabilities for which quoted prices in an active market are available, including exchange traded derivatives and other financial instruments, are determined directly from those quoted market prices.

For financial instruments for which quoted market prices are not directly available, fair values are estimated using forward price curves developed from observable market prices or rates. The estimation of fair value may include the use of valuation techniques or models, based wherever possible on assumptions supported by observable market prices or rates prevailing at the consolidated balance sheet dates. This is the case for over-the-counter derivatives and securities, which include energy commodity derivatives, foreign exchange derivatives, interest rate swap derivatives, and fund investments. Pooled fund investments are valued at the unit values supplied by the pooled fund administrators. The unit values represent the underlying net assets at fair values, determined using closing market prices. Valuation models use general assumptions and market data and therefore do not reflect the specific risks and other factors that may affect a particular instrument's fair value. The methodologies used for calculating the fair value adjustments are reviewed on an ongoing basis to ensure that they remain appropriate. If the valuation technique or model is not based on observable market data, specific valuation techniques are used, primarily based on recent comparable transactions, comparable benchmark information, bid/ask spread of similar transactions, and other relevant factors.

For the financing receivables related to the Investment Interest acquired from the IESO, fair value is estimated to equal the fair value of the underlying debt due to the direct relationship of the asset, and the debt instruments that financed the acquisition.

OPG's use of financial instruments exposes the Company to certain risks, including credit risk, foreign currency risk and interest rate risk. A discussion of how OPG manages these and other risks is found under the section, *Risk Management*.

Recent Accounting Pronouncements Not Yet Adopted

The recent US GAAP accounting pronouncements related to revenue recognition, leases, and financial instruments are described below. Other recent accounting pronouncements applicable to OPG are outlined in Note 3 of the audited consolidated financial statements.

Revenue from Contracts with Customers

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09, *Revenue from Contracts with Customers* (Topic 606), which supersedes nearly all existing revenue recognition guidance, including industry-specific guidance, under US GAAP. The core principle of Topic 606 is to recognize revenues when promised goods or services are transferred to customers in an amount that reflects the consideration to which an entity expects to be entitled for those goods or services. Either a full retrospective

application or a modified retrospective application is required for annual periods beginning on or after January 1, 2018, including interim periods within that year. Early adoption is permitted.

OPG has assessed the impact of the standard on accounting for the Company's revenue streams and consolidated financial statements. OPG's major revenue streams include regulated generation revenue from base regulated prices and rate riders established by the OEB, as well as revenue from generation assets under long-term contractual arrangements with the IESO. OPG has completed its analyses of the impact of Topic 606 on all of its revenue streams, and has not identified any material differences in the timing or amount of revenue recognition for these streams.

The Company will apply the new revenue standard in its 2018 first quarter interim financial statements and is in the process of evaluating the additional disclosures required under the new standard.

Lease Accounting

In February 2016, the FASB issued ASU No. 2016-02, *Leases* (Topic 842). The update includes comprehensive changes to existing guidance for lease accounting, particularly for lessees, and aims to increase transparency and comparability among organizations by requiring the recognition of lease assets and lease liabilities on the balance sheet. The standard is effective for annual periods beginning after December 15, 2018, including interim periods within that year.

Under the current guidance, entities are required to use a modified retrospective approach for leases that exist, or are entered into, after the beginning of the earliest comparative period presented in the financial statements of the period of adoption. Under this method, Topic 842 would effectively be implemented by recognizing any adjustments stemming from the transition, as of beginning of the earliest comparative period presented in the entities' financial statements. Full retrospective application is prohibited. In January 2018, the FASB issued a proposed ASU wherein entities would be able to utilize an additional optional transition method of recording the cumulative impact of adopting the new lease standard to the opening balance in the initial period of adoption; with comparative periods continuing to be presented in accordance with the existing leasing standard, Topic 840 - *Leases*, including disclosures. [**MONITOR**] The Company will continue to monitor the status of this proposed ASU.

The FASB also issued ASU No. 2018-01, *Land Easement Practical Expedient for Transition to Topic 842* in January 2018. The amendments therein allows an entity to choose not to evaluate under Topic 842 land easements that exist or expired before the entity's adoption of the new leasing standard and that were not previously accounted for as leases under Topic 840.

The Company continues to implement and execute a comprehensive project governance framework, which comprises a Steering Committee, Implementation & Stakeholder Committee, Project Management Office, and various working groups in order to evaluate the implement the new standard. The working groups are represented by cross functional finance and non-finance stakeholders who will support the financial and operational implementation of the standard. The Company continues to evaluate the impact of the new leasing standard on its consolidated financial statements.

Recognition and Measurement of Financial Assets and Financial Liabilities

In January 2016, the FASB issued ASU No. 2016-01, *Financial Instruments – Overall: Recognition and Measurement of Financial Assets and Financial Liabilities*. Under the updated guidance, entities will have to measure equity investments at fair value and recognize any changes in fair value in net income. The update will be effective for OPG's 2018 fiscal year, including interim periods. As a result of this update, effective January 1, 2018, the available-for-sale (AFS) classification for equity securities will no longer be available, with any unrealized gains and losses related to such securities recognized in net income instead of OCI. Any unrealized gains and losses for AFS securities reported by OPG in AOCI as of the end of 2017 will be reclassified to retained earnings as of January 1, 2018. OPG's equity shareholdings in Hydro One are currently the Company's only AFS securities. As at December

31, 2017, these shares are valued on the consolidated balance sheet at $188 million, for which a loss of $8 million has been recorded in AOCI. OPG does not expect the new standard to have any other significant impact on its consolidated financial statements.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost

In March 2017, the FASB issued ASU No. 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. Under the new guidance, employers that sponsor defined benefit plans for pensions and/or other postretirement benefits are required to present the service cost component of net periodic benefit cost in the same statement of income line item as other employee compensation costs arising from services rendered during the period. The other components of the net periodic benefit cost are to be presented separately from the line item that includes the service cost and outside of any subtotal of income from operations, if such a subtotal is presented. In addition, the new guidance requires that only the service cost component of net benefit cost be eligible for capitalization.

This guidance is effective for fiscal years beginning after December 15, 2017, including interim periods of those years. The guidance is not expected to have a material impact on OPG's consolidated financial statements, as OPG currently capitalizes only the service cost component of post-retirement benefits costs. Additionally, OPG already includes the service cost component of post-retirement benefit costs with other compensation costs, within the operations, maintenance and administration expenses line item in the consolidated statements of income, and does not show a subtotal of income from operations. As such, the new guidance is not expected to affect the presentation of OPG's consolidated financial statements.

RISK MANAGEMENT

Overview

OPG faces various risks that could significantly impact the achievement of its strategic imperatives. The objective of risk management is to identify, assess and mitigate key risks, and to preserve and increase the value of the Shareholder's investment in the Company.

The Audit and Risk Committee is mandated to fulfill the oversight responsibilities of the Board of Directors for matters relating to the identification and management of the Company's key business risks. OPG's Enterprise Risk Management framework is designed to identify and evaluate risks on the basis of their potential impact on the Company's strategic imperatives and business plan objectives. Formal risk management policies, procedures and systems are in place to identify, assess and mitigate risks to the Company. Senior management also establishes set limits for the market risk, credit risk and energy trading activities of the Company.

The key risks to OPG's strategic imperatives are briefly described below. These are key risks that management believes could materially affect its business, revenues, net income, assets or capital resources. There may be further risks and uncertainties that are not presently known, or that are not currently believed to be material, that may in the future adversely affect the Company's performance or financial condition.

Risks to Achieving Operational Excellence

OPG is exposed to variable output from its existing generating stations that could adversely impact its financial performance. The operational risks of a station are generally a function of its age, human performance, and the technology used.

Asset Conditions and Generation Variability

The uncertainty associated with electricity production by OPG's generating units is primarily driven by the condition of station components and systems, which are subject to the effects of aging and the manner in which the units operate. To safely operate the units to meet electricity system requirements, a unit could be derated resulting in reduced generation. The primary implications of these risks may include additional safety requirements, lower than expected generation and revenues, and higher operating or capital costs. To respond to this risk, OPG continues to:

- monitor performance, implement extensive inspection and maintenance programs;
- identify future work required to sustain and, as appropriate, upgrade a station equipment; and
- undertake projects required to reliably operate within design and operating parameters.

Extension of Commercial Operations at Pickering to 2024

In January 2016, the Province of Ontario announced its approval of OPG's plan to pursue the continued safe and reliable operation of the Pickering GS to 2024. Under OPG's plan, the six operating units at the Pickering GS would operate until 2022, at which point two units would be shut down and the remaining four units would continue to operate until 2024. The current operating licence for the Pickering GS, which expires in August 2018, was issued in 2013 assuming that the station would shut down in 2020. Technical assessments have been completed to determine the ability of the Pickering units to continue to be fit for service to support extended operations. There is high technical confidence in the programs and provisions in place to operate the station to the end of 2024.

Inability to extend operations as planned would result in a reduction of OPG's future generation revenue and cash flows and lead to the advancement of station shutdown and decommissioning expenditures.

Risk factors for extended operations include the discovery of unexpected conditions, equipment failures, the state of critical plant components that are reaching end-of-life and a requirement for significant plant modifications. To mitigate these risks, OPG has implemented actions recommended from the technical assessments as part of the outage work program. OPG has also incorporated those actions into the comprehensive inspection and maintenance program under the Life Cycle Management Plan.

Supply Chain

OPG's ability to operate effectively is in part dependent upon timely access to equipment, materials, and service suppliers. Loss of key equipment, materials and service suppliers, particularly for the nuclear business, could affect OPG's operations and execution of major capital projects. OPG mitigates this risk, to the extent possible, through contract negotiations, contract terms, vendor monitoring, diversification of supplier base and business continuity plans.

Cyber Security

OPG's operations depend in part, on the efficient operation and management of the Company's complex information technology and operational systems in a secure, vigilant and resilient manner that minimizes cyber risks. Cyber security incidents may have an adverse impact on OPG's reputation, energy production, and public and employee safety.

Cyber security incidents have been on the rise for the past few years and this trend is only expected to intensify as global reliance on technology increases. OPG has strategies in place to prepare for, respond to, and recover from cyber security incidents. OPG continuously monitors, assesses, and improves the effectiveness of its strategies and program considering leading industry practices and remains proactive in information and intelligence sharing to learn and adapt to the changing cyber environment. In 2017, the media reported several worldwide cyber-attacks, such as WannaCry and Petya, which impacted multiple sectors including power and utilities. OPG's operational responses to those cyber-attacks were timely and effective resulting in no or low operational impact to OPG.

As a registered Ontario market participant, OPG must comply with reliability standards that apply to the Bulk Electric System elements specified under North American Electric Reliability Corporation and the relevant Bulk Power System facilities as determined by the Northeast Power Coordinating Council. In addition, OPG's nuclear cyber assets are subject to CNSC licensing conditions and regulatory requirements. For other cyber assets not subject to applicable regulatory requirements, OPG has adopted a risk-based approach based on the National Institute of Standards and Technology cyber security framework to manage its cyber security. Policies are in place to manage the Company's cyber risks and programs which are subject to oversight by management and the Board.

Regulatory Compliance

OPG is subject to extensive federal and provincial legislation and regulations by various entities such as the OEB, CNSC and the IESO.

The uncertainty associated with nuclear regulatory compliance is driven by plant aging, changes to technical codes, and challenges raised by the public at regulatory hearings, particularly in the areas of safety, environment and emergency preparedness. Addressing these requirements could add to the cost of operations, including replacement or modification of a station component or additional requirements for waste management. In some instances, these requirements may result in a reduction or elimination of the productive capacity of a station.

The Provincial agency, Office of the Fire Marshal and Emergency Management (OFMEM) is required to periodically update the Provincial Nuclear Emergency Response Plan (PNERP). In 2016, the CNSC advised the OFMEM to consider more severe accidents in the update to the PNERP, which may result in potential changes to the planning basis. Potentially, these changes may include new protective requirements and expansion of the emergency plan requirements for Pickering. In December 2017, the Province approved the updated PNERP Master Plan. The development of a detailed Implementing Plan for the Pickering GS is in progress. To date, there is no significant impact on OPG from the updated PNERP.

In December 2015, the CNSC granted the Darlington GS a ten-year operating licence, valid until November 30, 2025. The new licence spans most of the planned duration of the Darlington Refurbishment project, which provides greater regulatory stability and reduces regulatory risk. As discussed in the section, *Core Business, Strategy and Outlook*, under the heading, *Nuclear Operations*, the plan to extend Pickering operations to 2024 is subject to the CNSC's approval of the Pickering licence renewal application and other regulatory requirements as set out by the CNSC.

Nuclear Waste Management

The handling, storage and disposal of nuclear waste exposes OPG to various risks that it manages in accordance with the applicable regulatory requirements. Additionally, the interim storage of nuclear waste is subject to rigorous oversight and monitoring.

Currently, there are no licenced facilities in Canada for the permanent disposal of used nuclear fuel or L&ILW. The risks to OPG's proposed L&ILW DGR for the safe long-term management of L&ILW are discussed below under the heading, *Risks to Achieving Project Excellence – Deep Geologic Repository for Low and Intermediate Level Waste*.

Human Resources and Organizational Structure

The development of new leaders and retention of staff in critical roles is a key factor to OPG's success. The risk associated with the alignment and availability of skilled and experienced resources continues to exist for OPG in specific areas, including leadership and project management positions. To mitigate this risk, OPG continues to focus on succession planning, leadership development and knowledge management programs to improve the capability of its workforce. OPG expects to meet the human resource needs of the business by developing existing employees and hiring in specific areas, while continuing to leverage attrition through realignment of work and streamlining of processes, where appropriate.

Labour Relations

As of December 31, 2017, approximately 88 percent of OPG's regular labour force was represented by a union. The collective agreements with the PWU and The Society are due for renewal in 2018. There is a risk that OPG may not be able to negotiate terms that allow for compensation levels consistent with its rate orders.

OPG's current collective agreements with the PWU expires on March 31, 2018 and renewal negotiations began in early 2018. In the event of a labour disruption by the PWU, OPG could face financial or reputational implications. OPG has contingency plans in place to minimize the impact. **[MONITOR]**

The collective agreement between OPG and The Society expires on December 31, 2018 and renewal negotiations are expected to begin in mid-2018. The parties do not have the right to strike or lock-out. If the parties are unable to reach an agreement, the terms of the new collective agreement would be decided through interest mediation/arbitration.

Health and Safety

OPG's operations involve inherent occupational safety risks and hazards that could impact the achievement of the Company's health and safety goals. OPG is committed to continuous improvement and achievement of its ultimate goal of zero injuries through a formal enterprise-wide safety management system and by continuing to foster a strong health and safety culture among its employees and contractors. The safety management system serves to focus the Company on proactively managing safety risks and hazard exposures to employees and contractors. OPG also strategically engages with external parties for benchmarking and auditing. This ensures that OPG's management system achieves its intended results and maximizes the opportunity to incorporate program improvements.

Business Continuity and Emergency Management

OPG may be exposed to natural, technological or human-caused hazards including significant events against which it is not fully insured or indemnified; or to parties that fail to meet their indemnification obligations. These hazards have the potential to disrupt operations resulting in decreased generation revenue or additional costs to repair damages and restore operations.

OPG's business continuity program provides a framework to build resilience into critical business processes to ensure continued operation of critical business functions. OPG's emergency management program is designed to ensure that the Company can manage an emergency in a timely and effective manner. OPG's plans and implementation procedures identify immediate response actions to be taken to protect the health and safety of workers and the public, and to limit the impact of the incident on site security, production capability and the environment. The program elements are designed to meet legal and regulatory requirements.

Risks to Achieving Project Excellence

OPG is undertaking several capital intensive projects with significant investments. There may be an adverse effect on the Company if it is unable to: obtain necessary approvals; raise the necessary funds; effectively manage the projects on time and on budget; or fully recover capital costs and earn an appropriate return on investment. These projects may also have a significant impact on OPG's borrowing capacity and credit rating. Some projects may be ultimately reassessed as being uneconomic. The risks associated with OPG's current major projects are described below.

Darlington Refurbishment

There are financial and reputational risk exposures for OPG if actual costs exceed the budget or if OPG does not meet the project schedule. In addition, failure to achieve the objectives of the refurbishment project may result in future forced outages and more complex planned outages, potentially impacting the post-refurbishment performance or useful life of the units. Failure to carry out the refurbishment of the first unit as planned may result in the Province

exercising an off-ramp for the refurbishment of the remaining units. In January 2018, Refurbishment senior management met with the Minister of Energy, Cabinet and Treasury Board to provide an update on the status of the Darlington Refurbishment project and to request a decision to not exercise the Unit 3 off-ramp. The request was based on the performance to date on the Unit 2 project. Additionally, OPG continues to apply lessons learned that have been captured on the execution of Unit 2 into the planning of future units.

There are a number of specific risks that OPG is managing and mitigating in relation to the Darlington Refurbishment project, which include OPG and vendor performance risks, delay or productivity risks, financial risks related to escalation of costs, technical risks such as equipment conditions resulting in additional scope and execution risks. A large portion of the costs for the Darlington Refurbishment project is being paid to contractors and suppliers, including vendors that will engineer, procure and construct components of the project. There is a risk that, as the volume of work increases significantly, vendor capability, capacity and performance shortfalls may impact project objectives and deliverables.

OPG systematically manages the risks associated with the Darlington Refurbishment project through robust risk management practices to achieve project deliverables on time and budget with quality. OPG engaged in an extensive five-year project planning phase to determine the project scope and to rigorously estimate costs. During this phase, OPG also took into account major lessons learned from other nuclear refurbishments and large scale, complex projects. In order to fully define the scope and material requirements for the project, the planning phase included the completion of detailed designs before proceeding with the execution of the unit refurbishments. Further risk mitigation has been implemented through the construction of a full scale model training reactor, which allows for simulations and training for unit refurbishment execution tasks.

OPG's risk management strategy aims to ensure that contractors are held accountable and appropriate incentives and disincentives are in place. There is also an increased risk of contractor initiated safety events, which may impact OPG's reputation. Mitigating actions include:

- Collaborative training and planning with vendors on executing work safely;
- An enhanced human performance program;
- Increased field presence by supervisory staff; and
- Collaboration with Bruce Power to streamline processes and reduce burden on vendors.

OPG is also managing other ongoing risks that could potentially impact the project, including those related to continuity of skilled leaders within OPG and its vendor partners, as well as the availability of technical resources to support the project through execution.

Both management and Board of Directors have engaged Independent, third-party oversight for the execution phase of the project.

Deep Geologic Repository for Low and Intermediate Level Waste

OPG, with the support of Bruce County municipalities, is proposing to construct and operate a deep geologic repository for the safe long-term management of L&ILW. While broad local community support for the proposed L&ILW DGR is stable, OPG continues its engagement with the SON towards securing support for the project.

In August 2017, the federal Minister of Environment and Climate Change wrote to OPG and commended OPG for its collaborative work with the SON and for the practical demonstration of reconciliation practises. In light of that work, the Minster requested OPG to update its analysis of the potential cumulative effects of the DGR project on the physical and cultural heritage of the SON, taking into account the results of the SON Community Process. OPG continues to work with the SON, however the timing and outcome of the SON Community Process and the EA decision by the Minister are uncertain.

Risks to Maintaining Financial Strength

Risks related to rate regulation, financial markets and long-term obligations could significantly impact OPG's financial performance. The Company is also exposed to risks such as weak electricity demand, displacement of generation by competitors and financial risk associated with energy trading.

Rate Regulation

There is an inherent risk that regulated prices established by the OEB may not provide for the recovery of actual costs incurred by OPG's regulated operations or allow the regulated operations to earn an appropriate rate of return. This could occur if, in setting regulated prices, the OEB makes adjustments to forecasts submitted by OPG, if actual production and costs significantly differ from the forecasts approved by the OEB, or if OPG is unable to achieve OEB-approved stretch factors included in regulated prices under incentive ratemaking. Differences between OPG's actual and forecast production and costs could be due to factors such as outages or project execution risks. In providing evidence in support of its applications for regulated prices, OPG aims to clearly demonstrate to the OEB that the costs for the regulated operations are reasonable, prudently incurred and should be fully recovered from customers.

Certain differences between elements of OEB-approved revenue requirements and OPG's actual results are recorded in OEB-approved variance and deferral accounts for future review by the OEB. Additionally, these accounts may be subject to an OEB prudence review. There is uncertainty associated with the outcomes of future proceedings for the recovery or refund of these balances.

Nuclear Rate Smoothing Proposal

Consistent with the requirements of *Ontario Regulation 53/05*, OPG's nuclear rates will be smoothed as a result of OPG deferring a portion of the approved annual nuclear revenue requirements during the period from January 1, 2017 to the end of the Darlington Refurbishment project in a Rate Smoothing Deferral Account.

There is a risk that the magnitude of the deferral ordered by the OEB will result in regulated prices that do not provide sufficient cash flow to the Company for meeting its financial objectives in an optimal manner, including ensuring sufficient liquidity, cost effectively funding the Darlington Refurbishment project and other expenditures and maintaining the Company's investment grade credit rating. Maintaining adequate levels of credit metrics will support OPG's investment grade credit rating. As such, OPG requested the OEB to consider the impact on its credit rating when smoothing the nuclear base rates. **[MONITOR]**

Post-Employment Benefit Obligations Risk

OPG's post-employment benefit obligations include pension, group life insurance, health care benefits, and LTD benefits. OPG's post-employment benefit obligations and costs and pension plan contributions could be materially affected in the future by numerous factors including: changes in discount rates, inflation rates and other actuarial assumptions; future investment returns; experience gains and losses; the funded status of the pension plans; changes in benefits; changes in the regulatory environment including potential changes to the *Pension Benefits Act* (Ontario); changes in OPG's operations and the measurement uncertainty incorporated into the actuarial valuation process.

The OPG registered pension plan, which covers most of OPG's employees and retirees, is a contributory defined benefit plan that is indexed to inflation up to a certain maximum. Contributions to the OPG registered pension plan are determined by actuarial valuations, which are filed with the appropriate regulatory authorities at least every three years. Future actuarial valuations could increase OPG's funding requirements due to market and economic-related conditions. A significant decline in the financial markets could trigger an immediate requirement to update the actuarial valuation based on declines in the funded status. OPG continues to assess the requirements for contributions to the registered pension plan, including the timing of future actuarial valuations. OPG's OPEB

obligations are not funded and the associated employee benefits are paid from cash flows provided by operating activities or other sources of liquidity.

Nuclear Liabilities and Nuclear Segregated Funds

As required by the CNSC, OPG is responsible for the management of used nuclear fuel and L&ILW and the decommissioning of its nuclear stations and waste management facilities. The cost estimates for OPG's nuclear waste management and decommissioning obligations are based on multiple underlying assumptions and estimates that are inherently uncertain and may evolve over time. The assumptions include station end-of-life dates, waste volumes, waste disposal methods, the timing of construction of assumed waste disposal facilities, waste packaging systems, decommissioning strategy and financial indicators. To address the inherent uncertainty, OPG undertakes to perform a comprehensive review of the underlying assumptions and baseline cost estimates at least once every five years, in line with the required ONFA Reference Plan update process.

The most recent comprehensive update of the nuclear waste management and decommissioning obligations was approved by the Province in December 2016 as part the 2017 ONFA Reference Plan. An approved ONFA Reference Plan determines OPG's contributions to the Nuclear Segregated Funds. Based on the 2017 ONFA Reference Plan, no contributions are currently required to the Nuclear Segregated Funds. Additional contributions may be required should the Nuclear Segregated Funds be in an underfunded position in the future.

Nuclear Funds are segregated under ONFA in order to fund the long-term waste management, used fuel management and decommissioning expenditures. These funds are managed to achieve, in the long term, the target rate of return based on the discount rate specified in the ONFA. Investments in the Nuclear Segregated Funds are allocated to certain asset classes including fixed income securities, domestic and international equity securities, pooled funds, infrastructure, agriculture and real estate. The rates of return earned on these segregated funds may vary depending on current and future financial market conditions. The asset mix of the funds is determined jointly by OPG and the Province in accordance with the ONFA.

Under ONFA, OPG bears the market risk related to the portion of the Nuclear Segregated Funds set aside for:

- decommissioning of Pickering and Darlington nuclear generating stations; and
- long-term management of the irradiated used fuel bundles in excess of the first 2.23 million bundles and L&ILW after the respective Pickering GS and Darlington GS shut down.

A significant drawdown in the Nuclear Funds would first reduce the surplus in the respective funds before impacting OPG's net income. As such, the income statement impact of this risk is reduced when the Nuclear Segregated Funds are in a fully funded position.

Liquidity

OPG operates in a capital intensive business. Significant financial resources are required to fund major development and other capital improvement projects, including the Darlington Refurbishment project. In addition, the Company has other significant disbursement requirements including pension contributions, payments towards OPEB and other benefit plans, funding ongoing operations, debt maturities with the OEFC, OPG's investment in the Fair Hydro Plan and investments in new generating capacity and other business development opportunities. OPG must ensure that it has the financial capacity and sufficient access to cost effective financing sources to fund its capital requirements and other disbursements. In support of this objective, OPG utilizes multiple sources and forecasts availability of funds, actively monitors funding requirements and is focused on maintaining its investment grade credit rating. The Company's ability to arrange sufficient and cost-effective debt financing could be adversely affected by a number of factors, including, financial market and general economic conditions, the regulatory environment in Ontario, the Company's results of operations and financial conditions, the ratings assigned to the Company by credit rating agencies and the current timing of debt maturities.

A discussion of corporate liquidity is included in the section, *Liquidity and Capital Resources*.

Commodity Markets

Changes in the market price of fuels used to produce electricity can adversely impact OPG's earnings and cash flow from operations.

To manage the risk of unpredictable increases in the price of fuels, the Company has fuel hedging programs, which include using fixed price and indexed contracts.

The percentages hedged of OPG's fuel requirements are shown in the following table. These amounts are based on yearly forecasts of generation and supply mix and, as such, are subject to change as these forecasts are updated.

	2018	2019	2020
Estimated fuel requirements hedged [1]	72.9%	68.2%	65.3%

[1] Represents the approximate portion of megawatt-hours of expected generation production (and year-end inventory targets) from each type of OPG-operated facility (nuclear, hydroelectric and thermal) for which the Company has entered into contractual arrangements or obligations in order to secure the price of fuel, or which is subject to regulation. In the case of hydroelectric generation, this represents the gross revenue charge and water rental charges. Excess fuel inventories (nuclear and thermal) in a given year are attributed to the next year for the purpose of measuring hedge ratios.

Foreign Exchange

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are primarily denominated in, or tied to US dollars (USD). To manage this risk, OPG employs various financial instruments such as forwards and other derivative contracts, in accordance with approved risk management policies. As at December 31, 2017, OPG had total foreign exchange contracts outstanding with a notional value of USD $5 million.

Trading

OPG's financial performance can be affected by its trading activities. OPG's electricity trading operations are closely monitored, with total exposures measured and reported to senior management on a daily basis. The main metric used to measure the financial risk of trading activity is Value at Risk (VaR). VaR is defined as a probabilistic maximum potential future loss expressed in monetary terms for a portfolio based on normal market conditions over a set period of time. During 2017, the VaR utilization ranged between $0.1 million and $0.4 million, compared to between nil and $1.5 million in 2016.

Credit

The Company's credit risk exposure is a function of its electricity sales, trading and hedging activities, treasury activities including investing and commercial transactions with various suppliers of goods and services. OPG's credit risk exposure relating to electricity sales is considered low as the majority of sales are through the IESO-administered spot market. The IESO oversees the credit worthiness of all market participants. In accordance with the IESO's prudential support requirements, market participants are required to provide collateral to cover funds that they might owe to the market.

The following table summarizes OPG's credit exposure to all counterparties from electricity transactions and trading as at December 31, 2017:

	All Counterparties		Largest Counterparties	
Credit Rating [1]	**Number of Counterparties** [2]	**Potential Exposure** [3] *(millions of dollars)*	**Number of Counterparties**	**Potential Exposure** *(millions of dollars)*
Investment grade	15	18	5	14
IESO [4]	1	360	1	360
Total	16	378	6	374

[1] Credit ratings are based on OPG's own analysis, taking into consideration external rating agency analysis where available, as well as recognizing explicit credit support provided through parental guarantees, Letters of Credit or other forms of security.

[2] OPG's counterparties are defined on the basis of individual master agreements.

[3] Potential exposure is OPG's statistical assessment of maximum exposure over the life of each transaction at a 95 percent confidence interval.

[4] Credit exposure is an estimate of the short-term receivable amount arising from OPG's electricity sales into the IESO market. The credit exposure and associated receivable vary each month based on electricity sales. The monthly receivable from the IESO is typically paid to OPG in the subsequent month as per the IESO payment schedule.

Other major components of OPG's credit risk exposure include those associated with vendors that are contracted to provide services or products. OPG manages its exposure to various suppliers or counterparties by evaluating their financial condition and ensuring that the Company holds appropriate collateral or other forms of security.

Contracted Generation

The Company's generating stations that operate under ESAs with the IESO or other long-term contracts are subject to several obligations, including but not limited to:

- availability targets;
- monthly and annual reporting; and
- must offer obligations, as specified in their respective contracts.

OPG could incur penalties up to and including termination of the respective contract if these facilities fail to meet their contractual obligations. This risk is mitigated through:

- education of staff who work with these facilities;
- continuous communication between staff managing the contracts and staff managing the stations;
- processes that monitor and address contractual obligations and milestones; and
- the implementation of maintenance, capital investment (approved by the IESO when required by the contracts) and other programs.

OPG's owned and co-owned thermal generating stations operate under ESAs with the IESO or other long-term agreements. While OPG expects that its thermal generating stations will continue to provide capacity to the market over the term of the respective agreements, there is a risk that, upon expiry of the current agreements, subsequent contracts for these stations may not be available or may not be financially viable. The Thunder Bay Biomass ESA is the first such contract to reach the end of its term, scheduled for early 2020.

Ontario Electricity Market

OPG's revenue can be impacted by external factors related to the electricity market including: the entrance of new participants into the Ontario market; the competitive actions of market participants; Ontario electricity demand; changes in the regulatory environment; and wholesale electricity prices in the interconnected markets.

The IESO is in the preliminary stages of a Market Renewal Program, which is expected to result in a fundamental redesign of Ontario's electricity markets and may impact OPG depending on the market design that is implemented. To mitigate this risk, OPG is actively participating in Market Renewal stakeholder committees as well as continuing to collaborate with the IESO.

Ownership by the Province

The Province owns all of OPG's issued and outstanding common shares. Accordingly, the Province, as represented by the Ontario Ministry of Energy, has the authority to make appointments to OPG's Board of Directors. OPG could be subject to Shareholder direction, under Section 108 of the OBCA that can directly influence major decisions. These directions could include those related to project development, timing and strategy of applications for regulated prices, acquisitions and asset divestitures, financing and capital structure. As a result, OPG could be required to undertake activities that result in increased expenditures, or that reduce revenues or cash flows relative to the business activities or strategies that would have otherwise been undertaken. In addition, the obligation of OPG's Shareholder to respond to a broad range of matters in its role as the Government of Ontario may compete with OPG's commitment to maximize the return on the Shareholder's investment in the Company. This includes, but is not limited to, the Province's response to mitigate the impact of rising electricity prices on consumers.

Government Legislation and Regulation Change

OPG's core business and strategy may be impacted by changes in federal and provincial legislation and regulations. Matters that are subject to regulation include, among others, rate regulation, electricity generating operations, nuclear waste management and nuclear decommissioning, the Ontario electricity market and taxation. Regulatory bodies may change or enact regulations or rules that could increase OPG's costs, decrease OPG's revenue, or limit the Company's ability to recover appropriate costs or earn a return on the assets.

The next Ontario provincial election is set to take place in June 2018 and electricity rates are a focus of each party's platform. Depending on the outcome of the election, there may be significant legislative changes that could impact OPG.

Since legal requirements are subject to change and to interpretation, OPG is unable to predict the impact of such changes on the Company and its operations. To mitigate legislative risks, OPG continues to monitor and actively engage with the federal and provincial governments in order to determine if future legislation will impact the Company.

Litigation

OPG or its subsidiaries are involved in various legal proceedings covering a range of matters arising out of their business activities. Each of these matters is subject to various uncertainties and some of these matters may be resolved unfavourably. Refer to Note 16 of OPG's 2017 audited consolidated financial statements under the heading, *Litigation* for further details.

Risks to Maintaining Social Licence

OPG is exposed to risks associated with its social licence and public profile due to changes in the opinions of:

- Various stakeholders, including Ontario electricity customers, local communities, government agencies; and
- Indigenous communities.

Maintaining public trust and meeting stakeholders and Indigenous communities' expectations are critical to OPG's success. OPG focuses on building and maintaining its social licence and corporate reputation through safe, reliable, environmentally-responsible operations as well as corporate citizenship initiatives across the province. The inability to maintain safe, reliable operations could negatively impact OPG's reputation and result in a loss of public support.

Ontario Fair Hydro Plan Act

The Fair Hydro Act received Royal Assent and came into force on June 1, 2017. As the Financial Services Manager under the Act, OPG's reputation could potentially be adversely impacted through this involvement and through stakeholder opinions related to this involvement.

Indigenous Communities

The quality of OPG's relationships and the outcome of negotiations with Indigenous communities may impact OPG's project and financial performance, as well as its social licence to operate.

OPG may be subject to claims by Indigenous communities. These claims stem from projects and generation development related to the operations of OPG and historic operations of OPG's predecessor company, Ontario Hydro, which may have impacted the Aboriginal and/or Treaty rights of Indigenous communities.

OPG has an Indigenous Relations Policy, which sets out the Company's commitment to proactively build and maintain positive relationships with Indigenous communities. OPG has been successful in working collaboratively with Indigenous communities to resolve a number of past grievances. However, the outcome of ongoing and any future negotiations depends on a number of factors, including legislation and regulations and precedents created by court rulings, which are subject to change over time. OPG pursues generation-related developments in partnerships with Indigenous communities on the basis of long-term mutually beneficial commercial arrangements.

Environmental Risks

OPG's operations and facilities are subject to environmental compliance obligations at the municipal, provincial and federal levels that include protection of land, water, air, living organisms and natural systems. A failure to comply with applicable environmental laws may result in enforcement actions, remediation actions or restrictions to operations. Changes in compliance obligations can result in new operational requirements and increased costs.

OPG has an ISO 14001 registered EMS to manage its environmental responsibilities. For further information, see discussion in the section, *Core Business, Strategy, and Outlook* under the heading, *Environmental Performance*.

OPG recognizes that efforts are required to plan for the impacts of climate change and has identified climate change adaptation as a strategic priority for the company. OPG monitors developments in climate science, adaptation activities, and potential changes to policy and regulatory requirements. OPG continues to work with stakeholders to better define adaptation requirements through analysis and understanding of impacts on watersheds, equipment and the electricity market. OPG undertakes a risk-based analysis to determine the extent of adaptation requirements to reduce the impact of climate change on its operations, and also collaborates with all levels of government and industry to increase the resiliency of the electricity infrastructure.

A carbon cap and trade program became effective in Ontario in January 2017. The program is not expected to have a material adverse economic impact on OPG due to the Company's low GHG emissions. Further details can be found in the section, *Core Business, Strategy and Outlook* under the heading, *Environmental Performance*.

RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One, the IESO and the OEFC. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly-owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions for the years ended December 31 are summarized below:

	2017		2016	
(millions of dollars)	**Revenue**	**Expense**	**Revenue**	**Expense**
Hydro One				
Electricity sales	**8**	**-**	6	-
Services	**1**	**10**	1	5
Dividends	**7**	**-**	6	-
Province of Ontario				
Change in Decommissioning Segregated Fund amount due to Province [1]	**-**	**456**	-	192
Change in Used Fuel Segregated Fund amount due to Province [1]	**-**	**591**	-	235
Hydroelectric gross revenue charge	**-**	**110**	-	120
ONFA guarantee fee	**-**	**8**	-	8
Other	**-**	**2**	-	-
OEFC				
Hydroelectric gross revenue charge	**-**	**216**	-	203
Interest expense on long-term notes	**-**	**158**	-	169
Income taxes, net of investment tax credits	**-**	**246**	-	104
IESO				
Electricity related revenue	**4,802**	**-**	5,082	-
Fair Hydro Trust	**4**	**3**	-	-
	4,822	**1,800**	5,095	1,036

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at December 31, 2017 and December 31, 2016, the Nuclear Segregated Funds were reported net of amounts due to the Province of $4,462 million and $3,415 million, respectively.

The receivable, AFS securities, payable and long-term debt balances between OPG and its related parties are summarized below:

(millions of dollars)	**December 31 2017**	**December 31 2016**
Receivables from related parties		
Hydro One	**1**	1
IESO – Electricity related receivables	**354**	421
IESO – Fair Hydro Trust [1]	**7**	-
OEFC	**-**	1
PEC	**4**	4
Province of Ontario	**3**	2
Financing receivables		
IESO – Fair Hydro Trust	**1,179**	-
Available-for-sale securities		
Hydro One shares	**188**	212
Accounts payable and accrued charges		
Hydro One	**1**	-
OEFC	**52**	61
Province of Ontario	**9**	2
IESO – Electricity-related payables	**5**	2
IESO – Fair Hydro Trust	**3**	-
Long-term debt (including current portion)		
Notes payable to OEFC	**3,195**	3,295

[1] Balance consists of unbilled revenue.

OPG holds interest-bearing Province of Ontario bonds in the Nuclear Segregated Funds and the OPG registered pension fund. As at December 31, 2017, the Nuclear Segregated Funds held $1,503 million of interest-bearing Province of Ontario bonds. As at December 31, 2016, the Nuclear Segregated Funds and the registered pension fund held $1,652 million and $284 million of interest-bearing Province of Ontario bonds, respectively. These bonds are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

In December 2017, the Trust purchased its first tranche of Investment Interest from the IESO for an exchange amount of $1.18 billion, which has been classified as a financing receivable on OPG's consolidated balance sheet. The transaction was settled in cash using proceeds from the Trust's issuance of senior and subordinated debt. Pursuant to the general regulation of the Act, the IESO is required to pay and remit carrying costs of the Trust, excluding repayment of principal on any debt obligations, up to July 31, 2021. Commencing May 1, 2021, Specified Consumers will be invoiced by their local distribution company for the Clean Energy Adjustment to pay financing and other costs of the Trust. These funds will be remitted to the Trust through the IESO and will be used to settle all funding and other related expenses of the Trust that underlie the financing receivable.

As at December 31, 2017, OPG's consolidated balance sheet included approximately $7 million of unbilled revenue from the IESO primarily for OPG's general fee for 2017 as Financial Services Manager relating to incurred third-party and certain direct labour costs. In February 2018, OPG submitted to the OEB its proposed general fee for 2017 in the amount of approximately $6 million for review pursuant to the requirements of the general regulation of the Fair Hydro Act. Once approved, the fees will be remitted to the Trust by the IESO and the Trust will pay OPG's fees as Financial Services Manager.

INTERNAL CONTROLS OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

Management, including the President and Chief Executive Officer (President and CEO) and the Chief Financial Officer (CFO), are responsible for maintaining Disclosure Controls and Procedures (DC&P) and Internal Controls over Financial Reporting (ICOFR). DC&P is designed to provide reasonable assurance that all relevant information is gathered and reported to senior management, including the President and CEO and the CFO, on a timely basis so that appropriate decisions can be made regarding public disclosure. ICOFR is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the financial statements in accordance with US GAAP.

There were no changes in OPG's ICOFR during the year ended December 31, 2017 that have materially affected or are reasonably likely to materially affect OPG's ICOFR.

Management, including the President and CEO and the CFO, concluded that, as of December 31, 2017, OPG's DC&P and ICOFR (as defined in National Instrument 52-109 – *Certification of Disclosure in Issuers' Annual and Interim Filings*) were effective.

FOURTH QUARTER

Discussion of Results

(millions of dollars) (unaudited)	Three Months Ended December 31 2017	2016
Revenue	**1,619**	1,388
Fuel expense	**171**	186
Gross margin	**1,448**	1,202
Operations, maintenance and administration	**770**	686
Depreciation and amortization	**162**	316
Accretion on fixed asset removal and nuclear waste management liabilities	**251**	233
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(222)**	(126)
Earnings from Fair Hydro Trust	**(1)**	-
Income from investments subject to significant influence	**(9)**	(9)
Property taxes	**10**	11
Restructuring	**-**	6
Income before other losses, interest, and income taxes	**487**	85
Other losses	**1**	6
Income before interest and income taxes	**486**	79
Net interest expense	**39**	28
Income before income taxes	**447**	51
Income tax expense	**81**	59
Net income (loss)	**366**	(8)
Net income (loss) attributable to the Shareholder	**362**	(13)
Net income attributable to non-controlling interest	**4**	5

Net income attributable to the Shareholder for the fourth quarter was $362 million, compared to a net loss of $13 million for the same quarter in 2016.

Income before interest and income taxes was $486 million during the fourth quarter of 2017, an increase of $407 million compared to income before interest and income taxes of $85 million during the same period in 2016. The following summarizes the significant factors which contributed to the variance:

Significant factors that increased income before interest and income taxes:

- Higher revenue from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments totaling approximately $480 million recorded in the fourth quarter of 2017 to reflect the OEB's decision on OPG's application for new regulated rates issued in December 2017 with a retrospective effective date of June 1, 2017.
- Higher earnings of $77 million from the Regulated – Nuclear Waste Management segment, primarily due to higher earnings from the Nuclear Segregated Funds reflecting the growth rate in the present value of the funding liabilities, partially offset by an increase in accretion expense on the Nuclear Liabilities.

Significant factors that decreased income before interest and income taxes:

- Lower revenue from the nuclear base regulated price of approximately $55 million, partially offset by a decrease in fuel expense of $9 million, reflecting lower electricity generation of 0.9 terawatt hours (TWh) from the Regulated – Nuclear Generation segment. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS since October 2016, partially offset by an increase in generation from the Pickering GS. The increase in generation from the Pickering GS was primarily due to outage cycle optimization, favourable unit conditions and execution of planned outage work resulting in fewer unplanned and planned outage days at the station.
- Higher OM&A expenses of $55 million, mainly in the Regulated – Nuclear Generation segment, reflected planned expenditures related to the major maintenance expenditures occurring at the nuclear stations.

The increase in income tax expense during the fourth quarter of 2017, compared to the same quarter in 2016, was primarily due to higher income before income taxes, partially offset by a higher amount of tax expense deferred in regulatory assets in 2017.

Average Sales Prices

The average sales price for the Regulated – Nuclear Generation segment during the fourth quarter of 2017 was 11.0 ¢/kWh, compared to 6.9 ¢/kWh during the same quarter in 2016. The increase in the average sales price was primarily due to the OEB ruling issued in December 2017, in which OPG received a base rate increase, retroactive to June 1, 2017. The average sales price for the Regulated – Hydroelectric segment during 2017 was 4.3 ¢/kWh, compared to 4.4 ¢/kWh during 2016. The decrease in this average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized regulated hydroelectric rate rider of $3.19/MWh for the recovery of variance and deferral account balances. The rate riders were established to recover approved balances recorded in the variance and deferral accounts in prior years. As such, the year-over-year changes in revenue from the rate riders were largely offset by changes in amortization expense related to these balances.

Electricity Generation

OPG's electricity generation for the three months ended December 31, 2017 and 2016 was as follows:

(TWh)	Three Months Ended December 31 2017	2016
Regulated – Nuclear Generation	**10.1**	11.0
Regulated – Hydroelectric	**7.2**	6.7
Contracted Generation Portfolio [1]	**0.8**	0.6
Total OPG electricity generation	**18.1**	18.3
Total electricity generation by all other generators in Ontario [2]	**18.8**	18.9

[1] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

[2] Non-OPG generation is calculated as the Ontario electricity demand plus net exports, as published by the IESO, minus OPG electricity generation.

The decrease in OPG's electricity generation of 0.2 TWh during the fourth quarter of 2017, compared to the same quarter in 2016, was mainly due to lower electricity generation of 0.9 TWh from the Regulated – Nuclear Generation segment. This was mainly the result of more planned outage days at Pickering in 2017 as well as the refurbishment of Unit 2 at the Darlington GS, which began in mid-October 2016 and continued for all of 2017. This was largely offset by higher production from the Regulated - Hydroelectric and Contracted Generation Portfolio segments mainly due to higher water flows on the eastern Ontario river systems.

Ontario's electricity demand as reported by the IESO was 33.6 TWh during the fourth quarter of 2017, compared to 33.2 TWh during the fourth quarter of 2016.

Liquidity and Capital Resources

Cash flow provided by operating activities during the three months ended December 31, 2017 was $246 million, compared to $606 million for the same period in 2016. The decrease in cash flow was primarily due to lower generation revenue receipts and higher OM&A expenditures during the fourth quarter of 2017.

Cash flow used in investing activities during the three months ended December 31, 2017 was $1,758 million, compared to $666 million during the same period in 2016. The increase was primarily due to the acquisition of the Fair Hydro Trust financing receivables and higher expenditures on the Darlington Refurbishment project in 2017.

Cash flow provided by financing activities during the three months ended December 31, 2017 was $1,466 million, compared to cash flow used in financing activities of $180 million for the same period in 2016. The increase in cash flow provided by financing activities was primarily due to higher net issuance of long-term debt and short-term notes by the Trust, as well as issuance of Class A shares in the four quarter of 2017. The increase was partially offset by the repayment of short term notes.

QUARTERLY FINANCIAL HIGHLIGHTS

The following tables set out selected annual financial information for the last three years and financial information for each of the eight most recently completed quarters. This information is derived from OPG's unaudited interim consolidated financial statements and the audited consolidated financial statements, and has been prepared in accordance with US GAAP.

Annual Financial Information

(millions of dollars – except where noted)	**2017**	**2016**	**2015**
Revenue	**5,158**	5,653	5,476
Net income attributable to the Shareholder	**860**	436	402
Earnings per common share *(dollars)*	**$3.35**	$1.70	$1.57
Total assets	**48,822**	44,372	44,250
Total long-term liabilities	**34,933**	31,460	32,404
Weighted average common shares outstanding *(millions)*	**256.7**	256.3	256.3

Quarterly Financial Information

(millions of dollars – except where noted) *(unaudited)*	**2017 Quarters Ended**				
	December 31	**September 30**	**June 30**	**March 31**	**Total**
Revenue	**1,619**	**1,217**	**1,146**	**1,176**	**5,158**
Net income	**366**	**140**	**307**	**68**	**881**
Less: Net income attributable to non-controlling interest	**4**	**9**	**4**	**4**	**21**
Net income attributable to the Shareholder	**362**	**131**	**303**	**64**	**860**
Earnings per common share, attributable to the Shareholder *(dollars)*	**$1.41**	**$0.51**	**$1.18**	**$0.25**	**$3.36**

Quarterly Financial Information

(millions of dollars – except where noted) *(unaudited)*	**2016 Quarters Ended**				
	December 31	**September 30**	**June 30**	**March 31**	**Total**
Revenue	1,388	1,400	1,387	1,478	5,653
Net (loss) income	(8)	198	135	128	453
Less: Net income attributable to non-controlling interest	5	4	3	5	17
Net (loss) income attributable to the Shareholder	(13)	194	132	123	436
Per common share, attributable to the Shareholder *(dollars)*	($0.05)	$0.76	$0.51	$0.48	$1.70

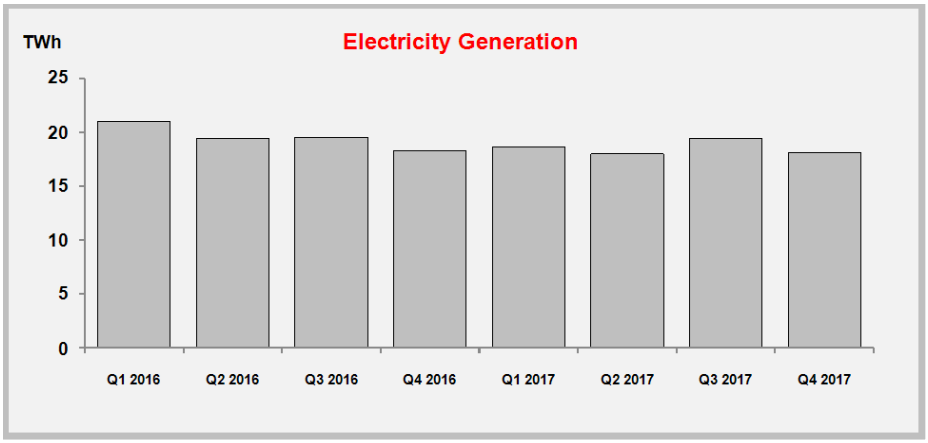
Trends

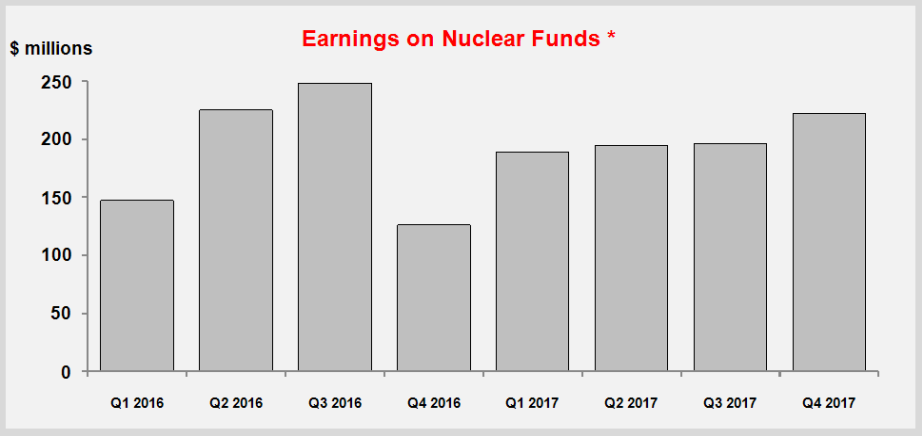
OPG's quarterly results are affected by changes in grid-supplied electricity demand, primarily resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. Weather conditions affect water flows, electricity demand, and prevalence of SBG conditions. Historically, OPG's revenues have been higher in the first quarter of a fiscal year as a result of winter heating demands and in the third quarter due to air conditioning and cooling demands. The financial impact of forgone production due to SBG conditions at the regulated hydroelectric stations and the financial impact of differences between forecast water flows reflected in OEB-approved regulated prices and the actual water flows are offset by regulatory variance accounts authorized by the OEB.

The timing of planned outages at a nuclear generating station during the year can cause variability in year-over-year operating results for partial periods of a fiscal year, including the impact on revenue and OM&A expenses, but is not a significant driver of variability for full fiscal year results.

OPG's electricity generation was reduced as a result of the Unit 2 refurbishment outage at the Darlington GS, which began in October 2016 and is expected to continue until early 2020.

OPG's financial results are also affected by the earnings on the Nuclear Segregated Funds, net of the impact of the Bruce Lease Net Revenues Variance Account. The volatility of the earnings on the Nuclear Segregated Funds is mitigated by their funded status.





*net of regulatory variance account

SUPPLEMENTARY NON-GAAP FINANCIAL MEASURES

In addition to providing net income and other financial information in accordance with US GAAP, certain non-GAAP financial measures are also presented in OPG's MD&A. These non-GAAP measures do not have any standardized meaning prescribed by US GAAP and, therefore, may not be comparable to similar measures presented by other issuers. OPG utilizes these measures to make operating decisions and assess performance. Readers of the MD&A would utilize these measures in assessing the Company's financial performance from ongoing operations. The Company believes that these indicators are important since they provide additional information about OPG's performance, facilitate comparison of results over different periods, and present measures consistent with the Company's strategies to provide value to the Shareholder, improve cost performance, and ensure availability of cost effective funding. These non-GAAP financial measures have not been presented as an alternative to net income, cash flow provided by operating activities, or any other measure in accordance with US GAAP, but as indicators of operating performance.

The definitions of the non-GAAP financial measures are as follows:

(1) ROE Excluding AOCI is defined as net income attributable to the Shareholder divided by average equity attributable to the Shareholder excluding AOCI, for the period.

ROE Excluding AOCI is measured over a 12-month period and is calculated as follows for the period ended December 31:

(millions of dollars – except where noted) (unaudited)	**2017**	**2016**
ROE Excluding AOCI		
Net income attributable to the Shareholder	**860**	436
Divided by: Average equity attributable to the Shareholder, excluding AOCI	**11,498**	10,442
ROE Excluding AOCI *(percent)*	**7.5**	4.2

(2) **FFO Adjusted Interest Coverage** is defined as FFO before interest divided by adjusted interest expense. FFO before interest is defined as cash flow provided by operating activities adjusted for interest paid, interest capitalized to fixed and intangible assets, and changes to non-cash working capital balances for the period. Adjusted interest expense is calculated as net interest expense plus interest income, interest capitalized to fixed and intangible assets, interest related to regulatory assets and liabilities, and the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets, for the period.

FFO Adjusted Interest Coverage is measured over a 12-month period and is calculated as follows for the period ended December 31:

(millions of dollars – except where noted) (unaudited)	**2017**	**2016**
FFO before interest		
Cash flow provided by operating activities	**944**	1,817
Add: Interest paid	**258**	269
Less: Interest capitalized to fixed and intangible assets	**(162)**	(141)
Less: Changes to non-cash working capital balances	**(54)**	(180)
FFO before interest	**986**	1,765
Adjusted interest expense		
Net interest expense	**95**	120
Add: Interest income	**9**	7
Add: Interest capitalized to fixed and intangible assets	**162**	141
Add: Interest related to regulatory assets and liabilities	**30**	30
Add: Excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets [1]	**-**	45
Adjusted interest expense	**296**	343
FFO Adjusted Interest Coverage *(times)*	**3.3**	5.1

[1] A value of nil is used in the calculation when interest on pension and OPEB projected benefit obligations is equal to, or lower than, expected return on pension plan assets.

(3) **Enterprise Total Generating Cost per MWh** is used to measure OPG's overall organizational cost performance. Enterprise TGC per MWh is defined as OM&A expenses (excluding the Darlington Refurbishment project and other generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to OPG's electricity generation business), fuel expense for OPG-operated stations including hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures (excluding the Darlington Refurbishment project and other generation development projects) incurred during the period, divided by total electricity generation from OPG-operated generating stations plus electricity generation forgone due to SBG conditions during the period.

Enterprise TGC per MWh is calculated as follows for the 12-month period ended December 31:

(millions of dollars – except where noted)	**2017**	**2016**
Enterprise TGC		
Total OM&A expenses	**2,824**	2,747
Total fuel expense	**689**	727
Total capital expenditures	**1,926**	1,704
Less: Darlington Refurbishment capital and OM&A costs	**(1,285)**	(1,022)
Less: Other generation development project capital and OM&A costs	**(65)**	(163)
Add: OM&A and fuel expenses (refundable through) deferred in regulatory variance and deferral accounts	**(1)**	62
Less: Nuclear fuel expense for non OPG-operated stations	**(57)**	(67)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**69**	49
Less: OM&A expenses ancillary to electricity generation business	**(18)**	(28)
Other adjustments	**(43)**	(19)
	4,039	3,990
Adjusted electricity generation *(TWh)*		
Total OPG electricity generation	**74.1**	78.2
Adjust for electricity generation forgone due to SBG conditions and OPG's share of electricity generation from co-owned facilities	**5.6**	4.1
	79.7	82.3
Enterprise TGC per MWh *($/MWh)* [1]	**50.66**	**48.45**

[1] Amounts may not calculate due to rounding.

(4) **Nuclear Total Generating Cost per MWh** is used to measure the cost performance of OPG's nuclear generating assets. Nuclear TGC per MWh is defined as OM&A expenses of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the nuclear electricity generation business), nuclear fuel expense for OPG-operated stations (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs) incurred during the period, divided by nuclear electricity generation for the period.

Nuclear TGC per MWh is calculated as follows for the 12-month period ended December 31:

(millions of dollars – except where noted)	**2017**	**2016**
Nuclear TGC		
Regulated – Nuclear Generation OM&A expenses	**2,293**	2,210
Regulated – Nuclear Generation fuel expense	**284**	315
Regulated – Nuclear Generation capital expenditures	**1,631**	1,338
Less: Darlington Refurbishment capital and OM&A costs	**(1,285)**	(1,022)
Add: Regulated – Nuclear Generation OM&A and fuel expenses deferred in regulatory variance and deferral accounts	**35**	81
Less: Nuclear fuel expense for non OPG-operated stations	**(57)**	(67)
Less: Regulated – Nuclear Generation OM&A expenses ancillary to electricity generation business	**(6)**	(10)
Other adjustments	**(10)**	(4)
	2,885	2,841
Nuclear electricity generation *(TWh)*	**40.7**	45.6
Nuclear TGC per MWh *($/MWh)* [1]	**70.95**	62.30

[1] Amounts may not calculate due to rounding.

(5) **Hydroelectric Total Generating Cost per MWh** is used to measure the cost performance of OPG's hydroelectric generating assets. Hydroelectric TGC per MWh is defined as OM&A expenses of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the hydroelectric electricity generation business), hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding expenditures related to the Peter Sutherland Sr. GS, Ranney Falls GS, and other hydroelectric generation development projects) incurred during the period, divided by total hydroelectric electricity generation plus hydroelectric electricity generation forgone due to SBG conditions during the period. OPG reports hydroelectric gross revenue charge and water rental payments as fuel expense.

Hydroelectric TGC per MWh is calculated as follows for the 12-month period ended December 31:

(millions of dollars – except where noted)	**2017**	**2016**
Hydroelectric TGC		
Regulated – Hydroelectric OM&A expenses	**330**	325
Regulated – Hydroelectric fuel expense	**351**	353
Contracted Generation Portfolio OM&A expenses	**169**	178
Contracted Generation Portfolio fuel expense	**53**	58
Regulated – Hydroelectric and Contracted Generation Portfolio capital expenditures	**226**	330
Less: Regulated – Hydroelectric and Contracted Generation Portfolio Generation Portfolio generation development project capital and OM&A costs	**(63)**	(158)
Less: Thermal OM&A and fuel expenses and capital expenditures in the Contracted Generation Portfolio	**(166)**	(177)
Less: Regulated – Hydroelectric OM&A and fuel expenses refundable through regulatory variance and deferral accounts	**(36)**	(24)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**69**	49
Other adjustments	**(1)**	(1)
	932	933
Adjusted hydroelectric electricity generation *(TWh)*		
Regulated – Hydroelectric electricity generation	**30.7**	29.5
Contracted Generation Portfolio electricity generation	**2.7**	3.1
Adjust for hydroelectric electricity generation forgone due to SBG conditions and non-hydroelectric electricity generation of the Contracted Generation Portfolio, including OPG's share of electricity generation from co-owned facilities	**5.5**	4.0
	38.9	36.6
Hydroelectric TGC per MWh *($/MWh)* [1]	**23.91**	25.49

[1] Amounts may not calculate due to rounding.

(6) **Gross margin** is defined as revenue less fuel expense**.**

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www.sedar.com

ONTARIO POWER GENERATION INC.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2017

[DRAFT]

March 8, 2018

ANNUAL INFORMATION FORM
FOR THE YEAR ENDED DECEMBER 31, 2017

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PRESENTATION OF INFORMATION

References in this Annual Information Form (AIF) to the "Company", the "Corporation" or "OPG" are made to Ontario Power Generation Inc. Unless otherwise noted, the information contained in this AIF is as at or for the year ended December 31, 2017. Amounts are expressed in Canadian dollars unless otherwise indicated. Financial information is presented in accordance with United States generally accepted accounting principles (US GAAP). This AIF is dated March 8, 2018.

ADDITIONAL INFORMATION

Additional information relating to the Company may be found on SEDAR at www.sedar.com. Additional financial information relating to the Company is provided in the Company's annual Management's Discussion and Analysis (MD&A) and audited consolidated financial statements as at and for the year ended December 31, 2017, which is available on SEDAR at www.sedar.com or on the Company's website at www.opg.com. ***The above information is made available in accordance with legal requirements of an AIF and is not, unless otherwise specifically stated, incorporated by reference into this AIF.***

Details regarding compensation paid to directors and executive officers of the Company during the financial year ended December 31, 2017 is included in OPG's Statement of Executive Compensation (Form 51-102F6), which is available on SEDAR at www.sedar.com and is incorporated by reference herein.

FORWARD-LOOKING INFORMATION

This AIF contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could", and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

All forward-looking statements involve inherent assumptions, risks, and uncertainties. All forward-looking statements could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's generating station performance and availability, fuel costs, surplus baseload generation (SBG), cost of fixed asset removal and nuclear waste management, performance and earnings of investment funds, refurbishment of existing facilities, development and construction of new facilities, pension and other post-employment benefit (OPEB) obligations and funds, income taxes, proposed new legislation, the ongoing evolution of Ontario's electricity industry, environmental and other regulatory requirements, health, safety and environmental developments, business continuity events, the weather, financing and liquidity, applications to the Ontario Energy Board (OEB) for regulatory prices, the impact of regulatory decisions by the OEB, Ontario's Fair Hydro Plan (Fair Hydro Plan or the Plan), OM&A expenditures, retention of critical talent, supplier and third party performance, and project expenditures. Accordingly, undue reliance should not be placed on any forward-looking statement. The forward-looking statements included in this AIF are made only as of the date of this AIF. Except as required by applicable securities laws, OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events, or otherwise.

OPG faces various risks that could have a material adverse effect on its business, strategy, generating stations, reputation, financial condition, operating results, generation development and other projects. There may be further risks and uncertainties that are not presently known, or that are not currently believed to be material, that may in the future adversely affect the Company's performance or financial condition. OPG may be exposed to a significant event that it is not fully insured or indemnified against, or to a party that fails to meet its indemnification obligations. For details on risks faced by OPG, refer to the section, *Risk Management*, in the Company's 2017 year-end MD&A.

CORPORATE STRUCTURE

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG was formed in April 1999 through the restructuring of Ontario Hydro's integrated electricity business. OPG was established under the *Business Corporations Act* (Ontario) (OBCA) and is wholly owned by the Province of Ontario (Province or Shareholder). OPG and the Province are parties to a Memorandum of Agreement (MOA) that sets out OPG's role and responsibilities. The current MOA was executed in July 2015 and reaffirmed for continuance by both the Ontario Minster of Energy and the OPG Board of Directors' Chair in the fourth quarter of 2016, as required by the MOA following a change in the Minister of Energy. Further details on the MOA are discussed in the section, *Interest of Management and Others in Material Transactions* under the heading, *Relationship with the Province and the OEFC*.

OPG's registered head office is located at 700 University Avenue, Toronto, Ontario, M5G 1X6, Canada.

OVERVIEW OF OPG

OPG is Ontario's largest clean energy generator. As at December 31, 2017, OPG operated two nuclear generating stations, three thermal generating stations, 66 hydroelectric generating stations, and one wind power turbine. The majority of OPG's generation is from its rate-regulated nuclear and rate-regulated hydroelectric stations. In addition, OPG and TransCanada Energy Ltd. co-own the 550 megawatt (MW) Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS). OPG and ATCO Power Canada Ltd. co-own the 560 MW Brighton Beach gas-fired combined cycle GS (Brighton Beach). Including its share of the co-owned facilities, OPG's total in-service generating capacity was 16,210 MW as at December 31, 2017, which represented approximately 45 percent of installed generation capacity in Ontario's electricity grid as reported by the Independent Electricity System Operator (IESO). OPG's in-service generating capacity as of December 31, 2017 excludes Unit 2 of the Darlington Nuclear GS. The unit, which has a generating capacity of 878 MW, was taken offline in mid-October 2016 and is currently undergoing refurbishment. OPG operates under an electricity generation licence issued by the OEB, which is valid until October 30, 2023. OPG expects the licence to be renewed in the future.

OPG also owns two other nuclear generating stations, the Bruce A GS and the Bruce B GS, which are leased on a long-term basis to Bruce Power L.P. (Bruce Power) and are not included in the generation and other operating statistics set out in this AIF.

All of OPG's owned and co-owned generating facilities are located in Ontario.

Effective in the fourth quarter of 2017, following the establishment of the Fair Hydro Trust (the Trust) as the financing entity to implement the Fair Hydro Plan under the *Ontario Fair Hydro Plan Act, 2017* (the Fair Hydro Act or the Act), OPG has modified its reportable business segments to include the Fair Hydro Trust segment. Through its control over the key activities of the Trust and its obligation to absorb losses through ownership of the Trust's subordinated debt, the Company consolidates the financial results of the Trust in accordance with US GAAP. The Fair Hydro Trust segment reports the income related to OPG's role as Financial Services Manager under the Act and holder of subordinated debt issued by the Trust, including the financial results of the Trust. The Fair Hydro Plan and the Fair Hydro Trust are discussed in the section, *General Development of the Business* under the heading, *General Development* and in the section, *Description of the Business* under the heading, *Fair Hydro Trust Segment*.

OPG's business operations are divided into six business segments and are discussed under the heading, *General Development* and in their respective sections. The six business segments are as follows:

- Regulated – Nuclear Generation
- Regulated – Nuclear Waste Management
- Regulated – Hydroelectric
- Contracted Generation Portfolio
- Services, Trading, and Other Non-Generation
- Fair Hydro Trust

Pursuant to the *Ontario Energy Board Act, 1998* and *Ontario Regulation 53/05,* OPG receives OEB-authorized regulated prices for electricity generated from the Pickering and Darlington nuclear generating stations and the 54 hydroelectric facilities prescribed for rate regulation (collectively, prescribed facilities or regulated facilities). The OEB is an independent, quasi-judicial tribunal that regulates market participants in Ontario's natural gas and electricity industries, and reports to the Legislature of the Province through the Ontario Ministry of Energy. OPG is Ontario's only electricity generator subject to rate regulation by the OEB.

Of OPG's 54 regulated hydroelectric facilities, 48 facilities were prescribed for rate regulation effective July 1, 2014 pursuant to a November 2013 amendment to *Ontario Regulation 53/05*. The remaining six regulated hydroelectric facilities and the Pickering and Darlington nuclear generating stations have been subject to rate regulation by the OEB since 2008.

Electricity generated from most of OPG's non-regulated assets is subject to Energy Supply Agreements (ESAs) with the IESO. The IESO is a non-profit corporate entity governed by an independent Board of Directors appointed by the Province and is responsible for operating the electricity market and directing the operation of the bulk electrical system in Ontario. Effective January 1, 2015, the Ontario Power Authority (OPA), an organization previously established by the Province with a mandate to contribute to the development of a reliable and sustainable electricity system in Ontario, merged with the IESO. The new entity continued under the name IESO. The IESO is the counterparty to the ESAs and other agreements that were previously executed with the OPA.

ESAs are in effect for the capacity and production from OPG's three operating thermal generating stations – the oil/gas dual-fuelled Lennox GS, the biomass powered Atikokan GS and the advanced biomass fuelled unit at the Thunder Bay GS. The results of these stations are reported under the Contracted Generation Portfolio segment. The expiry dates of these ESAs range from January 2020 to July 2024. In addition, 50-year ESAs are in place for the hydroelectric facilities reported under the Contracted Generation Portfolio segment. The hydroelectric ESAs for the operating stations have expiry dates ranging from February 2059 to March 2067. The ESAs for the contracted generating stations result in a relatively stable stream of revenues from the Contracted Generation Segment.

OPG's revenue and electricity generation by business segment for the years ended December 31, 2017, 2016 and 2015 and OPG's in-service generating capacity as at December 31, 2017, 2016 and 2015 are summarized in the table below.

		Regulated – Nuclear Generation	Regulated – Nuclear Waste Management	Regulated – Hydroelectric	Contracted Generation Portfolio [1]	Services, Trading, and Other Non-Generation	Fair Hydro Trust
2017	Revenue *(millions of dollars)* [2]	**3,095**	**121**	**1,436**	**579**	**43**	**1** [4]
	Electricity Generation *(terawatt hours)*	**40.7**	**N/A**	**30.7**	**2.7**	**N/A**	**N/A**
	In-service Generating Capacity *(MW)* [3]	**5,728**	**N/A**	**6,426**	**4,056**	**N/A**	**N/A**
2016	Revenue *(millions of dollars)* [2]	3,481	138	1,527	573	68	N/A
	Electricity Generation *(terawatt hours)*	45.6	N/A	29.5	3.1	N/A	N/A
	In-service Generating Capacity *(MW)* [3]	5,728	N/A	6,421	4,028	N/A	N/A
2015	Revenue *(millions of dollars)* [2]	3,245	122	1,619	535	73	N/A
	Electricity Generation *(terawatt hours)*	44.5	N/A	30.4	3.1	N/A	N/A
	In-service Generating Capacity *(MW)*	6,606	N/A	6,428	4,021	N/A	N/A

[1] The in-service generating capacity includes OPG's share of 275 MW for PEC and 280 MW for Brighton Beach, and the electricity generation includes OPG's share of its 50 percent ownership in these stations.
[2] Revenue for each segment is shown before inter-segment elimination.
[3] Regulated – Nuclear Generation segment excludes the generating capacity of 878 MW from Unit 2 of the Darlington GS, which has been undergoing refurbishment since mid-October 2016.
[4] This represents OPG's earnings from the Fair Hydro Trust, which consist of income related to OPG's role as Financial Services Manager under the Act and holder of subordinated debt issued by the Trust, including the financial results of the Trust.

For the year ended December 31, 2017, OPG's electricity generation accounted for over 50 percent of the total energy generated on Ontario's electricity grid, as reported by the IESO.

OPG is subject to a number of provincial and federal legislation and regulations, including the decisions of administrative tribunals or other regulatory bodies, and to Canada's international obligations under certain international treaties. Collectively, these sources dictate many of the constraints within which OPG is permitted to operate its facilities and manage its business.

Strategic Imperatives

OPG's mission is to provide low cost power in a safe, clean, reliable and sustainable manner for the benefit of its customers and its Shareholder. OPG also seeks to pursue, on a commercial basis, generation development projects and other business growth opportunities to the benefit of the Shareholder. The four strategic imperatives of OPG are briefly described below.

Operational Excellence

Operational excellence at OPG is accomplished by the safe and environmentally responsible generation of reliable and cost-effective electricity from the Company's generating assets through a highly trained and engaged workforce. Workplace safety and public safety are overriding priorities in all activities performed at OPG.

Project Excellence

OPG is pursuing a number of generation development and other projects in support of Ontario's electricity planning initiatives. OPG's major generation projects include the refurbishment of the Darlington GS, the expansion of the Ranney Falls hydroelectric GS, and the construction of a solar facility at the Nanticoke GS site. OPG aims to be an industry leader in project management capability and performance.

Financial Strength

As a commercial enterprise, OPG's financial priority is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future growth. Inherent in this priority are the following objectives:

- Increasing revenue, reducing costs and achieving appropriate return;
- Ensuring availability of cost effective funding for operational needs, generation development projects and other business opportunities, and long-term obligations;
- Pursuing opportunities to expand the existing core business and capitalize on new growth paths including emerging renewable energy opportunities; and
- Managing risks. Refer to the section, *Risk Management*, in the Company's 2017 year-end MD&A for more details.

Social Licence

As the largest, publicly-owned electricity generator in Ontario with geographically diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust. OPG is committed to maintaining high standards of public safety and corporate citizenship, including environmental stewardship, transparency, community engagement, and Indigenous relations.

OPG has in place a Code of Business Conduct that establishes the standards, expectations, and accountabilities for ethical behaviour. All employees and all parties with whom the Company does business are expected to abide by OPG's Code of Business Conduct. A copy of the Code of Business Conduct can be found on SEDAR at www.sedar.com and also is available on the Company's website at www.opg.com.

Further details on OPG's strategic imperatives can be found in the corresponding sections of the Company's 2017 year-end MD&A in the section, *Core Business, Strategy, and Outlook.*

GENERAL DEVELOPMENT OF THE BUSINESS

The following is a summary of key developments in OPG's business since January 2015.

General Development

OPG's Regulated Prices and Other OEB-Related Developments

Energy revenue generated from the Company's regulated nuclear and regulated hydroelectric facilities is based on regulated prices determined by the OEB through public proceedings. To date, the regulated prices have included a volumetric base regulated price, and volumetric rate riders for the recovery or repayment of approved variance and deferral account balances. As the regulated operations account for the majority of the Company's electricity generation, the outcomes of OPG's applications for regulated prices to the OEB determine a large portion of the Company's revenues and can have a significant impact on the Company's financial performance.

The following are the OEB-authorized regulated prices for electricity generated from the Company's regulated facilities in effect during the years ended December 31:

	2017		2016	2015	
($/megawatt hour)	**January 1 to May 31**	**June 1 to December 31** [1]		**January 1 to June 30**	**July 1 to December 31**
Regulated – Nuclear Generation					
Base regulated price	**59.29**	**80.65**	59.29	59.29	59.29
Variance and deferral account rate riders	**-**	**-**	10.84 [2]	1.33	12.17 [2]
	59.29	**80.65**	70.13	60.62	71.46
Regulated – Hydroelectric					
Hydroelectric generating stations prescribed for rate regulation prior to 2014					
Base regulated price	**40.20**	**41.67**	40.20	40.20	40.20
Variance and deferral account rate riders	**-**	**-**	3.19 [2]	6.04	9.23 [2]
	40.20	**41.65**	43.39	46.24	49.43
Hydroelectric generating stations prescribed for rate regulation effective in 2014					
Base regulated price	**41.93**	**41.67**	41.93	41.93	41.93
Variance and deferral account rate riders	**-**	**-**	3.19 [2]	-	3.19 [2]
	41.93	**41.67**	45.12	41.93	45.12

[1] Regulated prices for the June 1, 2017 to December 31, 2017 period were calculated and submitted to the OEB by OPG in January 2018 based on the OEB's December 28, 2017 decision on OPG's 2017-2021 application for new regulated prices. The final regulated prices will be determined by the OEB as part of the final payment amounts order process, which is expected to be completed in the first half of 2018. As part of the process, the OEB is expected to authorize separate rate riders to allow for the recovery of the shortfall between the new regulated prices and the previous regulated prices that OPG continues to receive during the period between June 1, 2017 and the implementation date of the new regulated prices pending the issuance of the final payment amounts order. The incremental revenue for the period between June 1, 2017 and December 31, 2017 arising from this retrospective application of new regulated prices was accrued in 2017. **[MONITOR]**

[2] The OEB authorized interim period rate riders for the period from October 1, 2015 to December 31, 2016 to allow for the recovery of the riders effective July 1, 2015 for the period from July 1, 2015 to September 30, 2015. The nuclear interim period rate rider was $2.17 per megawatt hour (MWh) and the regulated hydroelectric interim period rate rider was $0.64/MWh. These interim period rate riders have not been included in the above table. All rate riders in effect during 2016 expired on December 31, 2016.

Base Regulated Prices

The OEB's decision on OPG's May 2016 five-year application for new regulated prices for its nuclear and regulated hydroelectric generation was issued on December 28, 2017, following a public hearing process. Based on the OEB's December 2017 decision, the new base regulated prices are determined on an incentive ratemaking methodology for the hydroelectric operations and under a custom incentive regulation framework for the nuclear operations. For the hydroelectric facilities, the new base regulated price is determined using a formula that annually escalates the previous regulated prices, subject to some adjustments, based on inflation less a stretch factor to incent additional innovation and efficiency. For the nuclear facilities, the new regulated price is determined under a rate smoothing approach that defers a portion of the approved nuclear revenue requirement for future collection, with the aim of making more stable changes in OPG's production-weighted regulated prices year over year. The nuclear revenue requirement is based on the OEB-approved forecasts of operating costs as reduced by a stretch factor and a return on rate base. Rate base for OPG represents the average net level of investment in regulated fixed and intangible assets in service and an allowance for working capital.

For the first time since OPG's prescribed facilities became subject to rate regulation, the new prices have been determined on an incentive ratemaking methodology for the hydroelectric operations and a custom incentive regulation framework for the nuclear operations.

For the hydroelectric facilities, effective June 1, 2017, the base regulated prices in effect prior to June 1, 2017, with some adjustments, will be escalated for each of years 2017 to 2021 using a formula equal to an industry-specific weighted inflation factor based on indices published annually by the OEB for use in incentive regulation formulas, less a stretch factor adjustment. The OEB accepted OPG's proposal to set the annual stretch factor adjustment at 0.3 percent. Based on the approved formula, the 2017 increase in the base regulated price for the regulated hydroelectric facilities is 1.4 percent as of June 1, 2017 and the 2018 increase is 0.9 percent as of January 1, 2018. For the 2019-2021 period, the base regulated price for the regulated hydroelectric facilities will be determined annually before the beginning of each year using the approved formula and inflation indices published by the OEB.

For the nuclear operations, a revenue requirement is determined for each of the years 2017 to 2021 based on the OEB-allowed level of OPG's forecast operating costs, reduced by a stretch factor amount, as well as a return on rate base determined using OEB's generic prescribed rate of return and an OPG-specific deemed capital structure. OPG has calculated that the findings of the OEB's December 2017 decision with respect to the forecast operating costs, rate base and deemed capital structure for the nuclear generating facilities will result in nuclear revenue requirements totalling $15.9 billion over the five years.

The OEB's findings with respect to the nuclear revenue requirement include approval for inclusion in rate base of in-service amounts related to the Darlington Refurbishment of $5.5 billion by 2021, including $4.8 billion forecast in the first quarter of 2020 upon return to service of Unit 2, $0.4 billion forecast for pre-requisite projects excluding the construction of the Heavy Water Storage and Drum Handling Facility (HWSF) over the 2016-2021 period and $0.3 billion for pre-requisite projects placed in service prior to 2016. The OEB is expected to review the HWSF project as part of a future application. In the decision, the OEB concluded that it is appropriate to evaluate OPG's performance on the Darlington Refurbishment project at an overall level rather by individual cost component, with recovery of any increases over the approved in-service amounts subject to a future prudence review. The revenue requirement impact of differences between the approved in-service additions and the actual in-service additions will be recorded in the Capacity Refurbishment Variance Account authorized by the OEB pursuant to *Ontario Regulation 53/05*. The $4.8 billion forecast in-service amount upon return to service of Unit 2 includes expenditures incurred during the definition and planning phase of the project.

The OEB also approved OPG's requested forecast costs of approximately $292 million for activities to enable Pickering commercial operations beyond 2020 and agreed to inclusion of operating cost and generation impacts associated with continued operation of Pickering in 2021 in nuclear regulated prices. The differences between approved forecast enabling costs for continued Pickering operations and the actual amounts will be recorded in the Capacity Refurbishment Variance Account for future review and disposition by the OEB.

Excluding amounts that otherwise would have been recorded in OEB-authorized regulatory accounts for repayment to, or recovery from, customers in the future, the OEB's decision reduced OPG's proposed five-year nuclear revenue requirement by $0.6 billion. The main adjustments made by the OEB included a reduction of $100 million per year to requested OM&A costs , a reduction of 10 percent per year to forecast non-Darlington refurbishment capital in-service additions entering rate base over the 2017-2021 period, an increase and expansion of the scope of the stretch factor for nuclear costs that further reduced the revenue requirement, and a rejection of OPG's request to increase the equity component of the existing deemed capital structure of 45 percent equity and 55 percent debt. The OEB increased and expanded the annual stretch factor to 0.6 percent to most of OPG's OM&A expenses incurred directly for, or allocated to, the nuclear facilities, as well as to non-Darlington refurbishment capital in-service additions. The stretch factor is applied starting in 2018 and compounds in each year to 2021.

In accordance with *Ontario Regulation 53/05*, the nuclear revenue requirement continues to be adjusted by the amount of OPG's revenues, net of costs, from leasing the Bruce nuclear generating stations to Bruce Power. As directed by the OEB, OPG's revenues and costs related to the Bruce nuclear generating stations continue to be determined in accordance with US GAAP for the purposes of establishing the nuclear revenue requirement and are subject to the Bruce Lease Net Revenues Variance Account in accordance with *Ontario Regulation 53/05*. This includes costs related to the portion of the Nuclear Liabilities associated with the Bruce nuclear generating stations. The OEB's decision maintained the previously approved cost recovery methodology for the costs of the Nuclear Liabilities for the prescribed facilities and for the Bruce facilities, directing OPG to file a future study examining such methodologies jurisdictionally and for OPG's assets specifically. The decision fully incorporated the impacts of the updated estimate of OPG's obligations for nuclear waste management and nuclear facilities decommissioning as at December 31, 2016, including through a new ONFA reference plan effective January 1, 2017 and the change in the Nuclear Liabilities recorded on December 31, 2016.

As proposed by OPG, the OEB set recovery of pension and OPEB costs in the nuclear revenue requirement on the basis of OPG's cash payments for pension and OPEB plans, with differences between pension and OPEB accrual costs and cash payments continuing to be recorded in the Pension & OPEB Cash to Accrual Differential Deferral Account. The regulatory treatment of pension and OPEB costs is discussed further under the heading, *Pension and OPEB Cost Recovery Methodology*.

To reflect the OEB's decision, in the fourth quarter of 2017, OPG recorded incremental revenue of approximately $480 million for the period June 1, 2017 to December 31, 2017 based on the draft payment amounts order. The revenue was recorded as an increase in regulatory assetsfor the June 1, 2017 to December 31, 2017 revenue shortfall based on proposed new regulated prices for nuclear facilities and regulated hydroelectric facilities, net of a regulatory liability recognized in relation to OPG's rate smoothing proposal. The OEB's approval of the final payment amounts order, including the allocation of the approved revenue requirement between nuclear regulated prices and rate smoothing deferrals, is not expected to have a material impact on the net revenue increase recorded in the fourth quarter of 2017. The OEB is expected to issue the final payment amounts order and implement new regulated prices in the first half of 2018. **[MONITOR]**

The base regulated prices in effect from January 2015 through May 2017 were established by the OEB's November 2014 decision and December 2014 order on OPG's September 2013 rate application. This included regulated prices effective November 1, 2014 for the 48 hydroelectric facilities that were prescribed for rate regulation effective July 1, 2014. Prior to November 1, 2014, the generation revenue for these hydroelectric facilities was based on the Ontario electricity spot market price, including for the

period from July 1, 2014 to November 1, 2014 as determined by the OEB. The base regulated prices effective November 1, 2014 remained in effect until May 31, 2017.

The regulated prices in effect from January 2015 through May 2017 for the nuclear facilities and the hydroelectric facilities prescribed for rate regulation prior to 2014 were determined by the OEB based on approved 24-month revenue requirements for the 2014 to 2015 period totaling approximately $7.3 billion. This reflected a reduction of $833 million from the revenue requirements submitted by OPG. The regulated price for the 48 hydroelectric facilities prescribed for rate regulation beginning in 2014 was established based on an approved 18-month revenue requirement for the period from July 1, 2014 to December 31, 2015 of approximately $750 million, a reduction of $101 million from OPG's submission. The most significant adjustments made by the OEB to OPG's September 2013 rate request included the following:

- Allowed pension and OPEB costs were limited to the forecast 2014 and 2015 cash expenditures for these plans, which were approximately $600 million lower, including related tax impacts, than the forecast accrual costs submitted by OPG. The difference between accrual costs and cash expenditures is being recorded in a deferral account authorized by the OEB. For further details, see *Pension and OPEB Cost Recovery Methodology* in this section. **[CONFIRM]**
- A reduction in overall forecast compensation costs of $100 million in each of 2014 and 2015 across all of OPG's regulated facilities.
- An increase in the forecast nuclear production of 0.5 terawatt hours (TWh) annually used to set the nuclear regulated prices, which had the effect of reducing the approved nuclear regulated price.
- The rate base addition for the Niagara Tunnel project to construct a third tunnel to divert additional water to OPG's generating stations on the Niagara River was limited to $1,365 million, which resulted in a write-off of $77 million being charged to operations in 2014.
- A reduction in the 2014 income tax expense included in the regulated prices by the amount of the regulatory tax loss calculated for 2013, which reduced the 2014/2015 revenue requirement by approximately $70 million.

In December 2014, OPG filed a motion with the OEB asking it to review and vary the parts of its November 2014 decision related to the disallowance of the Niagara Tunnel project expenditures and the application of the 2013 regulatory tax loss against the 2014/2015 revenue requirement. In its January 2016 decision on the motion, the OEB reversed a portion of the Niagara Tunnel project disallowance and upheld the original tax loss decision. In the first quarter of 2016, OPG recorded a gain of $22 million to recognize the expected future recovery from customers of the reversed portion of the Niagara Tunnel project disallowance.

In its November 2014 decision, the OEB adjusted the deemed capital structure applied to OPG's total regulated rate base to 45 percent equity and 55 percent debt, from 47 percent equity and 53 percent debt used previously. In making this adjustment, the OEB found that there had been an overall improvement in the risk profile of OPG's regulated operations, based on the increased proportionate share of rate base related to hydroelectric facilities. This reduced the 2014/2015 revenue requirements. In general, OPG's actual capital structure contains a significantly higher proportion of equity than has been reflected in the OEB-approved deemed capital structure, which has had the effect of reducing OPG's return on shareholder's equity.

Variance and Deferral Accounts and Rate Riders

Consistent with the requirements of *Ontario Regulation 53/05*, OPG's overall production-weighted regulated prices will be smoothed, with a resulting portion of the approved annual nuclear revenue requirements for the 2017-2021 period deferred in the Rate Smoothing Deferral Account for future collection. The non-deferred portion of each year's nuclear revenue requirement is divided by the OEB-approved forecast of OPG's nuclear electricity generation for the corresponding year to determine the base nuclear regulated price. The OEB approved the nuclear electricity generation forecast as requested by OPG.

As amended in March 2017, *Ontario Regulation 53/05* requires rate smoothing to be applied in a manner that makes changes in OPG's weighted-average nuclear and hydroelectric regulated prices more stable year over year. Previously, the regulation required that rate smoothing be applied with a view of making more stable year-over-year changes in OPG's nuclear regulated prices only. Per the regulation, the deferral account records interest at a long-term debt rate reflecting OPG's cost of long-term borrowing approved by the OEB, compounded annually. The regulation requires the OEB to authorize recovery of the balance in the account on a straight line basis over a period not to exceed 10 years following the end of the Darlington Refurbishment project. OPG recognizes positive amounts deferred under rate smoothing as an increase in net regulatory assets and an increase in revenue in the period to which the underlying approved revenue requirement relates. Negative amounts determined under rate smoothing are correspondingly recorded as a decrease in net regulatory assets and a decrease to revenue.

On January 17, 2018, OPG submitted a draft payment amounts order to the OEB that proposed nuclear base regulated prices for each year of the 2017-2021 period, including a rate smoothing proposal, based on the December 2017 decision's findings. The rate smoothing proposal takes into account the near-term and future impacts on customers, while seeking to ensure that resulting nuclear regulated prices allow for sufficient cash flow to maintain the Company's investment grade credit rating and support availability of cost effective funding, while taking into account both near-term and future impacts on customers. Based on the OEB's direction, the draft payment amounts order also included proposed periods for recovery, through interim period shortfall rate riders, of the retrospective revenue shortfall for the period between June 1, 2017 and the implementation date of the new regulated prices based on proposed new regulated prices that would have been in effect during that period. The draft payment amounts also included proposed recovery periods, through variance and deferral account rate riders, for regulatory account balances approved for recovery in this application. **[MONITOR]**

Variance and deferral accounts are typically established by the OEB to capture, for subsequent review and approval, differences between actual costs and revenues and the corresponding forecast amounts approved by the OEB in setting regulated prices, or to record the impact of items not reflected in the approved regulated prices. Such accounts generally help to mitigate risks and uncertainties to the regulated entity and its customers.

The OEB has authorized several variance and deferral accounts for OPG, including those required by *Ontario Regulation 53/05*. The authorized accounts include, among others, those related to the gross margin impact of variability in regulated hydroelectric electricity production due to differences between the forecast and actual water conditions and due to the effect of SBG conditions, changes in liabilities for nuclear waste management and nuclear facilities decommissioning, changes in revenues and costs related to the lease and related agreements with Bruce Power for the Bruce nuclear generating stations, and variances in the revenue requirement impact of capital and non-capital costs incurred to increase the output of, refurbish, or add operating capacity to the regulated facilities, including the Darlington Refurbishment project. A number of these accounts are subject to an OEB prudence review. There is currently no regulatory variance or deferral account related to the impact of generation performance of OPG's nuclear stations on revenue from the base regulated prices. The Darlington Refurbishment project is discussed in the section, *General Development of the Business* under the heading, *Nuclear Business Development – Darlington Refurbishment*.

Approved balances in the regulatory variance and deferral accounts authorized by OPG are recovered or refunded through volumetric rate riders. The additional revenue from the riders is largely offset by a corresponding increase in amortization expense related to the variance and deferral account balances, which are typically recognized as assets (amounts recoverable from customers) or liabilities (amounts payable to customers) on the Company's balance sheet. Differences in amounts recovered or repaid through rate riders due to differences between actual and forecast production volumes are recorded in separate variance accounts for future disposition. **[MONITOR]**

The OEB accepted all variance and deferral account balances proposed for recovery that were not already accepted as part of the Settlement Agreement, resulting in approval of recovery of $305 million recorded in variance and deferral variance accounts as at December 31, 2015, without adjustments. The

Settlement Agreement provided for the continuation of all applicable existing variance and deferral accounts. In addition to the Rate Smoothing Deferral Account, the OEB established, as of the effective date of the new regulated prices, new variance and deferral accounts to record costs related to implementing the Canadian Nuclear Safety Commission's (CNSC) Fitness for Duty program and to record differences between forecast and actual amount of Scientific Research & Experimental Development investment tax credits attributable to the nuclear facilities. In January 2018, OPG filed a motion asking the OEB to review and vary the effective date of the new regulated prices to January 1, 2017. The motion did not impact OPG's financial results for the year ended December 31, 2017.

Consistent with the effective date of the OEB's December 2017 decision, for the period from January 1, 2017 to May 31, 2017, OPG continued to record additions to the existing variance and deferral accounts for the nuclear and regulated hydroelectric facilities pursuant to the OEB's previous decisions and orders. These additions reflected differences between actual and forecast amounts embedded in the regulated prices in effect prior to the June 1, 2017 effective date.

The rate riders in effect in 2015 and 2016 included those authorized by the OEB's October 2015 order on OPG's application in 2014 to recover or repay most of the December 31, 2014 variance and deferral account balances, discussed below. The 2015 rate riders also included those established by the OEB's December 2014 order on OPG's September 2013 rate application for the period January 1, 2015 to December 31, 2015. The December 2014 order allowed for recovery of $189 million recorded in certain variance and deferral accounts as at December 31, 2013, without adjustments.

The total balances approved for recovery by the OEB's October 2015 order were approximately $1.8 billion, of which approximately $1.5 billion was the subject of an OEB-approved partial settlement agreement reached by OPG and intervenors. The remaining balances of $263 million were approved by the OEB's September 2015 decision, without adjustments. The rate riders authorized by the October 2015 order were in effect from July 1, 2015 to December 31, 2016 and allowed for recovery of $933 million of the total approved balances.

Amendments to Ontario Regulation 53/05

In November 2015, the Province amended *Ontario Regulation 53/05* to establish a deferral account, effective January 1, 2017, that will record, for future recovery, a portion of the annual OEB-approved revenue requirements for OPG's regulated nuclear facilities during the period from January 1, 2017 to the end of the Darlington Refurbishment project. The amended regulation requires the OEB to determine the revenue requirements for OPG's nuclear facilities on a five-year basis for the ten-year period beginning on January 1, 2017. The portion of the approved revenue requirement deferred in the new account each year also will be determined by the OEB on a five-year basis during this ten-year period. The regulation stipulates that the deferral account will record interest at a long-term debt rate reflecting OPG's cost of long-term borrowing approved by the OEB, compounded annually, and that the OEB shall authorize recovery of the balance in the account on a straight line basis over a period not to exceed 10 years following the end of the Darlington Refurbishment project. OPG expects to recognize the deferred amounts as income in the period to which the underlying approved revenue requirements relate.

The November 2015 amendment required the portion of the approved annual nuclear revenue requirements deferred for future recovery to be determined with a view of making more stable year-over-year changes in OPG's nuclear regulated prices only. In March 2017, the Province amended *Ontario Regulation 53/05* to require that the deferred portion of the approved annual nuclear revenue requirements be determined with a view of making more stable year-over-year changes in OPG's weighted-average nuclear and hydroelectric regulated prices, including rate riders. The amendment is intended to make more predictable the impact on customer bills resulting from changes in OPG's overall regulated prices, reducing the average year-over-year change in customer bills over the term of OPG's May 2016 application for new regulated prices.

The regulation was also amended in November 2015 to require the OEB to accept the need for the Darlington Refurbishment project in light of Ontario's 2013 Long-Term Energy Plan (LTEP) and the

related policy of the Province endorsing the need for nuclear refurbishment. Furthermore, the 2017 LTEP reaffirms the Province's support for nuclear refurbishment. The 2017 LTEP is discussed in the section, *General Development of the Business* under the heading, *General Development – Ontario's Long-Term Energy Plan*.

Pension and OPEB Cost Recovery Methodology

Using the methodology previously applied by the OEB in setting OPG's regulated prices, the revenue requirements submitted by OPG in its September 2013 rate application included a forecast of 2014 and 2015 pension and OPEB costs determined on an accrual basis in accordance with US GAAP. In its November 2014 decision and December 2014 order on the application, the OEB approved revenue requirements based on OPG's estimated minimum required contributions to its registered pension plan, and a forecast of OPG's expenditures on the OPEB and supplementary pension plans. In directing this reduction in the revenue requirement, the OEB agreed with OPG and certain other parties that a generic proceeding on the regulatory treatment and recovery of pension and OPEB costs would be beneficial. The OEB also indicated that a change in the recovery methodology for OPG's pension and OPEB amounts from the accrual basis, if required, would be addressed in a future OPG rate proceeding, informed by the outcome of the generic proceeding.

Pending the generic proceeding, the OEB established the Pension & OPEB Cash Versus Accrual Differential Deferral Account. Effective November 1, 2014, this deferral account records the difference between OPG's actual pension and OPEB costs for the regulated business determined on an accrual basis and the corresponding actual cash expenditures for these plans. The OEB's November 2014 decision indicated that the future recovery, if any, of amounts recorded in the deferral account would be subject to the outcome of a future generic OEB proceeding on the regulatory treatment and recovery of pension and OPEB costs. The balance in the account is recognized as a regulatory asset on OPG's balance sheet.

On September 14, 2017, the OEB issued its final report on the guiding principles and policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the Ontario electricity and natural gas sectors. The report establishes the accrual basis of accounting as the method of determining pension and OPEB amounts for rate-setting purposes, unless the OEB finds that this method does not result in just and reasonable rates in the circumstances of a particular utility. The report also provides for the establishment of a generic variance account to record asymmetric carrying charges in favour of ratepayers on the differences between the accrual costs recovered and cash payments made by a utility in respect of pension and OPEB plans. Carrying charges on this differential are to be assessed at the OEB's prescribed interest rate, on a prospective basis from the effective date of the new variance account. For OPG, this differential will include amounts going back to November 1, 2014, with the charges calculated on the portion of the differential that has been recovered through regulated prices. None of this differential has been recovered to date. The prescribed interest rate is set quarterly by the OEB based on the quarterly return of a mid-term corporate bond index yield.

The OEB's September 2017 report and the OEB's December 2017 decision on OPG's application for new regulated prices require OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the Pension & OPEB Cash to Accrual Differential Deferral Account in effect since November 1, 2014, until such time as the OEB approves resumption of the accrual basis of recovery for OPG. The future recovery of amounts recorded in the account will be subject to this approval. The OEB's report did not impact OPG's financial results for the year ended December 31, 2017.

The Company recognizes the amount set aside in the Pension & OPEB Cash Versus Accrual Differential Deferral Account as a regulatory asset. As at December 31, 2017, the regulatory asset had a balance of $614 million. Consistent with the expectations set out in the OEB's December 2017 decision, in 2018, OPG plans to file an application with the OEB requesting disposition of the Pension & OPEB Cash Versus Accrual Differential Deferral Account balance as well as balances accumulated since December 31, 2015 in other regulatory accounts.

Supreme Court of Canada's Decision on 2011 OEB Ruling

In September 2015, the Supreme Court of Canada (Supreme Court) issued its decision upholding the OEB's disallowance of $145 million of OPG's forecast nuclear compensation costs for the 2011 to 2012 period. The majority of these costs were based on previously negotiated collective bargaining agreements. This disallowance was part of the OEB's March 2011 decision on OPG's application for regulated prices effective March 1, 2011. The Supreme Court decision underscores that OPG must continue to establish the reasonableness of both committed and future costs as part of the rate-setting process.

Ontario's Fair Hydro Plan

On March 2, 2017, the Province announced the Fair Hydro Plan aimed at reducing electricity bills for residential, farm, small businesses and other eligible consumers (Specified Consumers) in the province by refinancing a portion of the Global Adjustment costs over a longer period of time. The Global Adjustment includes the difference between Ontario's electricity market clearing price used to dispatch generation and the prices paid to contracted and regulated generators in the province, and the cost of conservation and demand management programs. On June 1, 2017, the Fair Hydro Act received Royal Assent and the associated general regulation came into force in June 2017. The Act established a framework under which the costs and benefits associated with the Government of Ontario's clean energy initiatives are to be allocated between present and future consumers of electricity under the Fair Hydro Plan. The general regulation provides details on the structural, operational and financial elements required to implement the Fair Hydro Plan.

Pursuant to the Act, effective May 1, 2017, the IESO began to defer a portion of the Global Adjustment costs. The Act allows the IESO to transfer a portion of the deferred balance to a financing entity that would fund the deferral in exchange for an irrevocable right to recover the balance and associated financing and other costs from Specified Consumers in the future (Investment Interest). The legislation appointed OPG as the Financial Services Manager under the Act and conveyed upon the Financial Services Manager statutory obligations, including the creation of one or more financing entities that may acquire Investment Interests from the IESO.

In November 2017, OPG's Board of Directors provided its final approval regarding OPG's involvement with the Trust on commercial terms following the fulfilment of all conditions it established in May 2017. Accordingly, the Fair Hydro Trust was established as the financing entity contemplated by the Act in December 2017. The majority unitholder and beneficiary of the Trust is a wholly-owned subsidiary of OPG. The Trust is structured to be bankruptcy remote and ring fenced from OPG in order to protect the Company's assets and operations.

In order for the Trust to finance the Investment Interest acquired from the IESO, it will incur senior debt from capital markets and subordinated debt from OPG. The Trust's investment will attract financing amounts and other related fees, which, under the general regulation, will be payable by the IESO as carrying costs until July 2021 and by Specified Consumers through the Clean Energy Adjustment to be invoiced by local distribution companies commencing in May 2021, with the three-month lag in 2021 intended to cover the billing and collection lag from the introduction of the Clean Energy Adjustment. The carrying costs include all financing and third-party costs other than payment of principal on debt.

Concurrent with every issuance of the Trust's senior notes, it is expected that OPG will purchase subordinated debt of the Trust in an aggregate amount not to exceed 49 percent of the Trust's total outstanding debt, with 44 percent of the funding to be provided by the Province through equity injections and five percent to be provided by OPG. The subordination level may vary over time, but must at least equal to, or be greater than 35 percent of all outstanding debt. Through OPG's control over the key activities of the Trust and its obligation to absorb losses through ownership of the Trust's subordinated debt, the Company consolidates the financial results of the Trust in accordance with US GAAP.

On December 21, 2017, the Trust purchased its first tranche of Investment Interest from the IESO in the amount of approximately $1.18 billion. Fifty-one percent of the funding requirement or $601 million was financed by the Trust through a revolving warehouse facility ranked as senior notes, and the remaining 49 percent was funded through the issuance of short-term subordinated debt to OPG. The Investment Interest has been classified as a financing receivable on OPG's consolidated balance sheet.

OPG's subordinated debt investment in the Trust was funded through the following sources:

- The Province provided 44 percent of the total funding requirement or $519 million, through an equity injection in OPG in exchange for approximately 12.2 million non-voting Class A common shares at a price of $42.46 per share. The Company's Articles of Amalgamation were amended effective December 1, 2017 to allow for the creation and issuance of Class A shares. Refer to Note 14 to the Company's audited annual financial statements as at and for the year ended December 31, 2017 for further details; and
- OPG provided five percent of the total funding requirement or approximately $60 million.

In February 2018, the Trust issued $500 million of senior notes payable with a coupon interest rate of 3.36 percent and an effective interest rate of 3.42 percent, payable semi-annually until maturity on May 15, 2033. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility issued in December 2017. By the end of the first quarter of 2018, the Trust is expected to acquire another tranche of Investment Interest from the IESO, which is expects to fund using its revolving warehouse facility.

Refer to the section, *Liquidity and Capital Resources* under the heading, *Financing Activities* for further details on the Trust's financing arrangements and OPG's public debt offering in the Company's 2017 year-end MD&A.

Ontario's Long-Term Energy Plan

On October 26, 2017, Ontario's Ministry of Energy issued the 2017 LTEP that outlines the Province's plans for the future development of Ontario's electricity system. The 2017 LTEP focuses on the affordability, reliability and flexibility of a clean energy supply in the province. The 2017 LTEP replaces the previous LTEP issued in 2013.

As it relates to the supply of electricity, the 2017 LTEP recognizes the refurbishment of Ontario's nuclear generating stations as the most cost-effective option for producing emission-free baseload generation to meet Ontario's needs and reaffirms the Province's support for the refurbishment of the four units at the Darlington GS and the six units at the Bruce generating stations, subject to the principles established in the 2013 Long-Term Energy Plan. The 2017 LTEP also recognizes the value to customers of continuing to operate the Pickering GS until 2024, as planned. With respect to hydroelectric electricity generation, the 2017 LTEP highlights the opportunity to continue to invest in optimizing existing hydroelectric facilities, noting that pumped hydroelectric storage could play an important role in the reliability of the electricity system.

Additionally, the 2017 LTEP discusses the potential impact of a number of innovative technologies on the future of the electricity system. Among others, these include the increased electrification of the transportation sector, the emergence of energy storage, and the opportunity for Ontario to foster nuclear innovation technologies. OPG continues to assess how best to capitalize on potential business opportunities in these and other areas. The 2017 LTEP also recognizes the importance of Indigenous peoples' continuing role in shaping Ontario's energy planning, projects and policies.

Renewal of Collective Agreements and Acquisition of Hydro One Limited Shares

Most of OPG's regular employees are represented by one of two unions: the Power Workers' Union (PWU) and The Society of Energy Professionals (The Society). As at December 31, 2017, the PWU

represented approximately 53 percent of OPG's regular workforce, while The Society represented approximately 35 percent of the regular workforce.

The previous collective agreement between OPG and the PWU expired on March 31, 2015. In May 2015, the parties agreed to renew the collective agreement for a three-year term, expiring on March 31, 2018. The changes to the collective agreement included increases to employee pension plan contributions in each year of the agreement. Negotiations for a new labour agreement with the PWU are underway. **[MONITOR]** The previous collective agreement between OPG and The Society expired on December 31, 2015. In November 2015, the parties agreed to renew the collective agreement for a three-year term, expiring on December 31, 2018. Changes to the collective agreement included increases to employee pension plan contributions in each of the first two years of the agreement. The changes in pension plan contributions apply to current employees and future employees of both unions, and do not have an end date.

The changes to both collective agreements provided existing employees with lump sum payments for each of the first two years of the respective contract and eligibility to annually receive shares in Hydro One Limited (Hydro One) for up to 15 years starting in the third year of the contract, as long as these employees continue to make contributions to the OPG pension plan and have less than 35 years of pensionable service. The lump sum payments and future share awards are intended to compensate current eligible employees, over a defined period, for their increased pension plan contributions.

In April 2016, OPG acquired nine million common shares of Hydro One at $23.65 per share as part of a secondary share offering by the Province through a syndicate of underwriters. The acquisition, totaling $213 million, was made for investment purposes to mitigate the risk of future price volatility related to OPG's future share delivery obligations under the collective agreements. The shares acquired in this transaction represent the substantial majority of OPG's currently anticipated purchases of Hydro One shares.

In addition to the regular workforce, construction work is performed through 19 craft unions with established bargaining rights at OPG facilities. These bargaining rights are established either through the Electrical Power Systems Construction Association (EPSCA) or directly with OPG. Collective agreements between the Company and its construction unions are negotiated either directly or through EPSCA. All of these collective agreements currently have multi-year terms, expiring on April 30, 2020.

Shareholder Declarations and Shareholder Resolutions to Sell Certain Non-Core Real Estate Properties

In December 2015, OPG received a Shareholder Declaration and a Shareholder Resolution requiring the Company to sell its head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street in Toronto, Ontario. The sale was completed in April 2017, with a gain on sale of $283 million, which is net of tax effects of $95 million, recognized in net income in the second quarter of 2017. The pre-tax gain on sale was recorded as an item of Other gains in the consolidated statement of income in the Services, Trading and Other Non-Generation segment. Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. The amount of designated proceeds transferred into the Consolidated Revenue Fund will be equal to the after-tax gain on sale. The transfer is expected to take place in the first quarter of 2018, through a special dividend authorized by OPG's Board of Directors in March 2018. **[MONITOR]**

In June 2016, OPG received a Shareholder Declaration and a Shareholder Resolution that requires the Company to sell its former Lakeview GS site located in Mississauga, Ontario. OPG has entered into a purchase and sale agreement with a purchaser with the sale scheduled to close in March 2018. An estimated after-tax gain on sale of approximately $200 million is expected to be recognized in net income upon completion of the transaction in the first quarter of 2018. **[MONITOR]** Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Act, into

the Province's Consolidated Revenue Fund. OPG anticipates the amount of designated proceeds transferred into the Consolidated Revenue Fund to approximate the after-tax gain on the sale. In accordance with the Shareholder Resolution, approximately one-third of the site is to be transferred to the City of Mississauga, by the purchaser, for parkland, institutional, and cultural uses.

Neither the former Lakeview GS site nor the Company's head office premises and associated parking facility are considered core assets to OPG's business.

For a complete list of Shareholder directives, refer to the section, *Interest of Management and Others in Material Transactions* under the heading, *Relationship with the Province and the OEFC – Shareholder Directives*.

Business Transformation **[UPDATE]**

OPG has completed a multi-year initiative with the objective of transforming itself into a more streamlined, agile and efficient organization. The business transformation initiative was intended to drive sustainable change across the Company, while ensuring that there is no adverse impact on the safety, reliability and environmental sustainability of OPG's operations. OPG's cumulative savings from reductions in regular headcount from ongoing operations, through the business transformation and other initiatives, since the beginning of 2011, reached $1 billion in 2016.

The business transformation initiative involved aggressively pursuing cost control and efficiency improvements at the enterprise and business unit level, including realignment of work, streamlining of processes and leveraging workforce attrition. As part of the initiative, OPG implemented a centre-led organizational model intended to more efficiently utilize resources. In 2015, OPG successfully completed a large-scale initiative, the Enterprise System Consolidation Project, to streamline the company's software systems and improve business processes by implementing a common enterprise software platform.

Although business transformation has concluded as a discrete initiative, improving organizational performance and building on efficiency gains achieved to date remains a key priority for the Company. OPG continues to review its cost structure, identify cost improvement strategies and embed an outcomes-driven culture that reinforces low cost, efficiency, and organizational agility as part of business decision-making.

Nuclear Business Development

Darlington Refurbishment

Government's Endorsement and Execution Phase

The Darlington generating units are approaching their originally designed end-of-life. Refurbishment of the four generating units to extend the operating life of the station by approximately 30 years, into the 2050s. In January 2016, the Government of Ontario's support for the Darlington Refurbishment project was affirmed through the Ontario Minister of Energy's announcement endorsing OPG's plan to refurbish the four Darlington units at a total project budget of $12.8 billion, including capitalized interest and escalation. The Province's announcement followed the approval of the project budget and schedule by OPG's Board of Directors in November 2015. The refurbishment of the last unit is scheduled to be completed by 2026. *Ontario Regulation 53/05* requires the OEB to ensure that OPG recovers capital and non-capital costs and firm financial commitments in respect of the Darlington Refurbishment project, if the OEB is satisfied that the costs were prudently incurred and that the firm financial commitments were prudently made.

The refurbishment project is a multi-phase program comprising several sub-projects. The major work streams include: de-fuelling of reactors and refurbishment of the fuel handling equipment; removal and replacement of feeder tubes and fuel channel assemblies in each reactor (Retube and Feeder Replacement or RFR); inspections and repairs of turbine generator sets and replacement of associated

control systems; mechanical cleaning, water lancing, and inspection and maintenance work on steam generators; and replacement or repairs of certain other station components referred to as balance of plant. The RFR is the largest sub-project and represents a majority of the critical path schedule.

In 2016, the Darlington Refurbishment project transitioned from the planning phase to the execution phase, as OPG commenced the refurbishment of the first unit, Unit 2, in October 2016 as planned. The unit was taken offline on October 15, 2016. De-fuelling of the reactor was completed in January 2017, with a total of 480 fuel channels de-fuelled. Islanding of Unit 2, the physical separation of the unit under refurbishment from the three operating units, was completed in April 2017, signifying the completion of the first major segment of the project.

The second major segment includes preparatory work to support the removal of feeder tubes and fuel channel assemblies, followed by the removal of reactor components. The preparatory work was completed in the second quarter of 2017. The Re-tube Tooling Platform for hosting the tooling for the removal, inspection and installation activities, and the setup of specialized tooling and equipment needed for the removal and replacement of the reactor components were completed in the third quarter of 2017. The disassembly of reactor components commenced in August 2017, with the removal of all 960 feeder tubes completed safely in September 2017. The removal of fuel channel assemblies commenced in October 2017. As part of the fuel channel assemblies, the removal of pressure tubes is in progress and will be followed by the removal of calandria tubes. The second major segment and the removal of all reactor components is expected to be completed by mid-2018. Key projects in the second major segment finished in 2018 include the completion of the primary side steam generator layup and installation of steam generator access ports to support future inspections. Other key project activities being executed during the second segment include the continuation of the major turbine generator overhaul, which will be completed in the second quarter of 2018, and continued execution of the major electrical scope. OPG is also continuing to execute work to support the requirements set out in the CNSC-approved Integrated Implementation Plan (IIP) for the station.

Most of the pre-requisite projects, including construction of facilities, infrastructure upgrades and installation of safety enhancements, have been completed and placed in-service. The Re-tube Waste Processing Building was completed in November 2017. Completion of the HWSF has been delayed due to challenges with construction. OPG suspended the project in the second quarter of 2017 to evaluate the best approach to optimize cost and schedule and complete the project. Construction to complete the facility recommenced in the fourth quarter of 2017. The HWSF is expected to be completed by the second quarter of 2019 and is not on the critical path for the Darlington Refurbishment project, which continues to track on schedule. The increase in the cost estimate for the HWSF will be accommodated within the overall Darlington Refurbishment budget of $12.8 billion. Taking into account the execution performance of the Unit 2 refurbishment, the overall Darlington Refurbishment project continues to track on budget.

The OEB accepted OPG's rate application with respect to the refurbishment of the Darlington units including an increase in the nuclear rate base, effective in the first quarter of 2020, to reflect the planned in service of $4.8 billion in capital expenditures upon the return to service of Unit 2, which includes expenditures incurred during the definition and planning phase of the project. Based on OPG's proposal in the application, the revenue requirement impact of the differences between the forecast Unit 2 in-service amount included in the regulated prices and the actual amounts placed in service would be subject to true up via the Capacity Refurbishment Variance Account established by the OEB pursuant to *Ontario Regulation 53/05*.

In addition to the execution of refurbishment activities on Unit 2, OPG is continuing planning activities for the refurbishment of the second unit, Unit 3, and is entering into associated commitments to procure major components that require long lead times. These planning activities are being undertaken in accordance with the refurbishment project schedule. In February 2018, the Province confirmed its commitment to proceed with Darlington's Unit 3 refurbishment in 2020. **[MONITOR]**

On November 21, 2017, the Financial Accountability Office of Ontario issued a report, "*An Assessment of the Financial Risks of the Nuclear Refurbishment Plan*". The report assesses the impact of OPG and Bruce Power's nuclear refurbishments on customers and the Province based on mechanisms in place for the recovery of the costs to refurbish and subsequently operate the nuclear stations. The report concludes that refurbishment of the four units at the Darlington GS and the six units at the Bruce nuclear generating stations provides the most cost effective, low emission generation source available to meet Ontario's baseload electricity requirements.

CNSC Regulatory Approvals

In December 2013, OPG submitted an application to the CNSC for the operating licence renewal for the Darlington GS. The CNSC granted the Darlington GS a ten-year operating licence in December 2015, which is the longest licence ever granted by the CNSC to a Canadian nuclear power plant. The new licence, which is effective from January 1, 2016 to November 30, 2025, spans most of the planned duration of the Darlington Refurbishment project.

In line with the CNSC's regulatory requirements related to life extensions of nuclear power plants in effect at the time that OPG began to undertake the Darlington Refurbishment project, OPG completed a series of assessments, including an environmental assessment (EA), an Integrated Safety Review, and a Global Assessment Report (GAR). The EA decision, issued by the CNSC and Fisheries and Oceans Canada in March 2013 following public hearings, confirmed that, taking into account identified mitigation measures, the project was not likely to cause significant adverse environmental effects. In April 2014, the CNSC accepted the GAR as meeting all regulatory requirements related to life extensions of nuclear power plants. In November 2014 and April 2016, respectively, certain intervenors' request for a judicial review and subsequent appeal to the Federal Court of Appeal related to the EA decision were dismissed by the courts.

Actions identified as part of the above assessments to meet updated codes, standards and practices, and to ensure that the operation of the station continues to pose minimal risk to health, safety, security and the environment, were integrated into the IIP. As part of the Darlington operating licence renewal in December 2015, the CNSC approved the regulatory scope defined in the IIP. OPG has been undertaking activities in support of the IIP requirements, including the commissioning of two safety enhancements at the station, the Third Emergency Power Generator and the Containment Filtered Venting System, which were placed in-service in April 2017. There were 17 IIP commitments scheduled and completed for 2017.

Extension of Commercial Operations at Pickering to 2024

In 2015, OPG completed the necessary work to demonstrate with sufficient confidence that the Pickering fuel channel life, a key life-limiting component of the station, will allow all six operating units of the station to operate to the end of 2020. OPG's early technical work at that time also showed that the Pickering GS can be operated safely beyond 2020. OPG's objective is to maximize the safe and reliable operating life of the Pickering units. As announced in 2016 and approved by the Province, OPG is continuing to execute on a plan to extend safe and reliable operation of the Pickering GS to 2024. Extending operations at the Pickering GS will provide Ontario with a clean, reliable source of baseload electricity during the Darlington GS and initial Bruce nuclear unit refurbishments, providing continued employment for up to 4,000 full-time employees at OPG.

OPG's current five-year operating licence for the Pickering GS was approved by the CNSC in 2013 and expires on August 31, 2018. This current licence was issued assuming that the station would shut down in 2020. On June 28, 2017, OPG confirmed to the CNSC that it intends to cease commercial operation of all Pickering units on December 31, 2024. On August 28, 2017, OPG submitted a ten-year licence renewal application to the CNSC. The requested licence term spans the planned extended commercial operations period, through to the planned period of de-fuelling, de-watering and beginning to place the station in a safe storage state in 2028. In support of the licence renewal, OPG undertook a Periodic Safety Review (PSR), a comprehensive assessment of the station's design and operation to confirm that there is a high level of safety throughout the operating life and to determine what reasonable and practical

enhancements can be made to further improve safety. The PSR also includes a component condition assessment of the station to identify the work required to support the station's continued operation. The PSR has confirmed that extending operations of the Pickering units will continue to pose minimal risk to the health, safety and security of workers, the public and the environment. The final major component of the PSR was submitted to the CNSC in November 2017. The CNSC's review of the PSR submission and licence application is in progress. Based on the evidence and documentation submitted to the CNSC, OPG is confident in obtaining a licence renewal that would support our extended operations plan for Pickering GS.

As part of the plan to extend Pickering operations, OPG has been continuing to undertake the required technical work to confirm that the station's pressure tubes, a key life-limiting component of the station, will remain fit for service for operation to 2024. In the fourth quarter of 2017, OPG has confirmed that technical assessments completed to date provide sufficient confidence in the programs and provisions in place to assure fitness-for-service of fuel channel components in line with the planned extended operations period. This evaluation is consistent with the safety case reflected in OPG's operating licence renewal application for the Pickering GS submitted to the CNSC in 2017, discussed above. Taking these factors into account, OPG revised the accounting end-of-life assumptions for the Pickering GS from December 31, 2020 for all units to December 31, 2022 for Units 1 and 4 and December 31, 2024 for Units 5 to 8, effective December 31, 2017.

The change in the Pickering GS accounting end-of-life assumptions did not impact OPG's net income in 2017. The change is expected to decrease depreciation expense by $77 million in 2018, including the associated impact on the nuclear asset retirement obligation recorded as of December 31, 2017 but before the impact of regulatory accounts. Regulatory accounts, including a new deferral account proposed by OPG in a December 2017 application to the OEB, are expected to largely offset the decrease in depreciation expense. As of December 31, 2017, OPG recorded an increase of $188 million in the Nuclear Liabilities and associated asset retirement costs capitalized as part of carrying value of property, plant and equipment reflecting the change in the Pickering GS accounting end-of-life assumptions from December 31, 2020 for all operating units to December 31, 2022 for Units 1 and 4 and December 31, 2024 for Units 5 to 8. The increase in the liabilities is primarily due to higher fixed costs associated with the Used Fuel Disposal and L&ILW Storage programs, discounted using the current credit-adjusted risk-free rate of 2.94 percent. The adjustment did not impact net income for 2017. The adjustment is not expected to have a material impact on net income in 2018 as the associated impact on expenses is expected to be largely offset by OEB-authorized regulatory accounts. On December 29, 2017, OPG applied for an accounting order to establish a variance account to record, from January 1, 2018 until the effective date of the OEB's next payment amounts order, the revenue requirement impact of changes to nuclear liabilities and depreciation and amortization expense resulting from changes to station end-of-life dates for OPG's Pickering prescribed nuclear facilities that will be effective December 31, 2017. Pending the OEB's review of the application, an interim order was issued January 31, 2018 establishing the proposed variance account effective January 1, 2018. The OEB's final decision in the account is expected later in 2018.

The income statement impacts associated with the changes to the Nuclear Liabilities are offset by the Bruce Lease Net Revenues Variance Account and the Nuclear Liability Deferral Account authorized by the OEB or new variance account to be authorized by OEB for the prescribed facilities.

Bruce Power Refurbishment and Bruce Lease Agreement

OPG leases the four-unit Bruce A (Units 1 to 4) and the four-unit Bruce B (Units 5 to 8) nuclear generating stations and associated lands and facilities to Bruce Power on a long-term basis. Bruce Units 1 and 2 were refurbished by Bruce Power under a refurbishment agreement with the IESO and returned to service in 2012. While Bruce Power is responsible for operating all of the leased units, OPG is primarily responsible for the management of the nuclear used fuel and other nuclear waste associated with the Bruce nuclear generating facilities, as well as the decommissioning of the facilities at the Bruce site. Under the lease agreement between Bruce Power and OPG (Bruce Lease) and related agreements, OPG receives base rent and supplemental rent payments from Bruce Power, fees for nuclear waste

management other than used fuel, and fees for certain other services. The output from the Bruce nuclear generating stations is not subject to rate regulation by the OEB.

In December 2015, the Province announced that the refurbishment agreement between the IESO and Bruce Power had been updated and that Bruce Power will proceed with the refurbishment of the six un-refurbished units of the Bruce nuclear generating stations. In order to facilitate Bruce Power's refurbishment plans, the Bruce Lease and related agreements were amended in December 2015 to extend Bruce Power's future options to renew the lease up to the end of 2064. To achieve better alignment with OPG's costs, the agreements were also amended to revise, starting in 2016, the approach for calculating supplemental rent payments and fees for nuclear waste management other than used fuel, and to modify the fee structure for OPG's heavy water detritiation services starting in 2017. Beginning in 2016, supplemental rent payments wholly represent fees for nuclear used fuel management. Amendments were also made to enable certain adjustments to future base rent, supplemental rent and other fees for potential future changes in OPG's decommissioning and nuclear waste management cost estimates related to the Bruce facilities, and to remove a conditional supplemental rent rebate provision effective December 4, 2015. Certain of the above amendments were executed by OPG pursuant to a Shareholder Declaration and Shareholder Resolutions issued in November 2015. For a complete list of Shareholder directives, refer to the section, *Interest of Management and Others in Material Transactions* under the heading, *Relationship with the Province and the OEFC – Shareholder Directives*.

The refurbishment of Bruce Power's Unit 6 is scheduled to commence on January 1, 2020. As part of the preparation activities, OPG is working with Bruce Power to develop a fixed price cost estimate for the non-routine nuclear waste that will be generated from the Unit 6 refurbishment. The parties will execute a separate agreement that sets out the terms and conditions that will apply to this refurbishment waste. Pursuant to a Memorandum of Understanding dated November 12, 2015, OPG and Bruce Power have committed to ongoing collaboration to improve their respective refurbishment programs.

Ontario Nuclear Funds Agreement Reference Plan Update

OPG is responsible for the management of radioactive used nuclear fuel and low and intermediate level radioactive waste material (L&ILW) and the decommissioning of its nuclear stations and waste management facilities. Pursuant to the Ontario Nuclear Funds Agreement (ONFA), OPG is required to set aside monies into two segregated funds, the Used Fuel Segregated Fund and the Decommissioning Segregated Fund, to fund the future life cycle costs of long-term nuclear used fuel and L&ILW management and nuclear facilities decommissioning. OPG's required contributions to the Nuclear Segregated Funds are determined based on periodically updated reference plans approved by the Province under the ONFA, at least once every five years. As part of the reference plan update process, OPG estimates the total funding liabilities for future nuclear waste management and nuclear decommissioning based on life cycle cost estimates and a set of underpinning assumptions, including remaining useful lives of the nuclear stations, proposed methods and timing of nuclear waste disposal, and economic indicators. In accordance with US GAAP, OPG carries a present value asset retirement obligation on the balance sheet related to its nuclear waste management and nuclear decommissioning liabilities. In accordance with *Ontario Regulation 53/05*, the OEB is required to ensure that OPG recovers the revenue requirement impact of its nuclear waste management and nuclear decommissioning liabilities arising from the current approved ONFA reference plan. The current methodology applied by the OEB for including OPG's costs associated with these liabilities in the regulated prices was established by the OEB in its 2008 decision on OPG's first application for new regulated prices.

In 2016, OPG completed a comprehensive update of the estimate for its obligations for nuclear waste management and nuclear facilities decommissioning, in line with the required ONFA reference plan update process. The results of the update were reflected in a new ONFA reference plan as well as a downward adjustment in the asset retirement obligation carried on OPG's balance sheet as at December 31, 2017. The new ONFA reference plan was approved by the Province in December 2016, with an effective date of January 1, 2017 (the 2017 ONFA Reference Plan). Reflecting the funded status of the Used Fuel Segregated Fund and the Decommissioning Segregated Fund based on the revised lower life cycle liability estimates per the 2017 ONFA Reference Plan, no overall contributions to either the Used

Fuel Segregated Fund or the Decommissioning Segregated Fund are currently required starting in 2017. Contributions may be required in the future should either or both of the funds be in an underfunded position when a new reference plan is approved. Such may be the case as a result of future variability in asset performance due to volatility inherent in financial markets and economic conditions. Future contribution levels also are dependent on changes in baseline cost estimates and underpinning planning assumptions used to establish the funding obligations in subsequent ONFA reference plans.

The overall reduction in OPG's nuclear waste management and nuclear decommissioning liabilities resulting from the comprehensive update was mainly due to a decrease in cost estimates to reflect a proposed new, more cost effective container design and engineered barrier concept to house used nuclear fuel for disposal, updated cost escalation rates, and a later expected in-service date for Nuclear Waste Management Organization's (NWMO) planned deep geologic repository for the long-term permanent disposal of Canada's used nuclear fuel. These decreases were partly offset by higher cost estimates related to station decommissioning, primarily due to a better definition of work required during the preparation for safe storage after station shutdown and a higher volume of waste expected to be generated during the decommissioning.

Further details on OPG's nuclear waste management and nuclear decommissioning obligations, the ONFA and proposed methods for long-term used fuel and L&ILW disposal are discussed in the section, *Description of the Business* under the heading, *Regulated – Nuclear Waste Management Segment.*

Hydroelectric Business Development

Peter Sutherland Sr. Hydroelectric Generating Station

In March 2015, OPG's Board of Directors approved a project to construct the Peter Sutherland Sr. GS, a new 28 MW hydroelectric station on the New Post Creek near its outlet to the Abitibi River, with a budget of $300 million. The station was constructed through PSS Generating Station LP, a partnership between OPG and Coral Rapids L.P., a wholly owned subsidiary of the Taykwa Tagamou Nation.

In March 2017, final testing and commissioning of the turbine and generator units were successfully completed and both units were declared substantially complete. On March 31, 2017, the project received a permit from the Ontario Ministry of the Environment and Climate Change (MOECC) to take water for operations to allow the station to operate commercially. The project is expected to close below the approved budget of $300 million. Project close-out activities are in progress. OPG began to receive contracted revenue for the project following the IESO's confirmation of the station's commercial operations as of March 31, 2017, under a 50-year hydroelectric ESA.

In April 2017, Coral Rapids Power Corporation (CRP) exercised its right under the partnership agreement to increase its interest in PSS to 33 percent.

Sir Adam Beck Pump Generating Station Reservoir Refurbishment

In August 2015, OPG's Board of Directors approved a project to refurbish the 300-hectare storage reservoir at the Sir Adam Beck Pump GS. The Sir Adam Beck Pump GS facility allows OPG to pump and store water diverted from the Sir Adam Beck generating complex during periods of low electricity demand to be used to generate up to 600 MW of electricity during subsequent periods of high electricity demand.

The refurbishment construction began in April 2016 and was completed in February 2017, ahead of the originally planned schedule date of April 2017 and below the approved budget of $58 million. The reservoir refurbishment work included the installation of a partial new reservoir liner and construction of a grout curtain in the bedrock foundation of the reservoir dyke. The refurbishment is expected to add approximately 50 more years to the reservoir's life. The Sir Adam Beck Pump GS is reported in the Regulated – Hydroelectric segment.

Ranney Falls Hydroelectric Generating Station

In 2017, OPG began construction work on a 10 MW single-unit powerhouse on the existing Ranney Falls GS site, as part of the Regulated – Hydroelectric segment. The new unit will replace an existing unit that reached its end of life in 2014. The existing forebay structure has been demolished and the new concrete structure has been completed. Excavation has been completed and construction continues in the expanded forebay, powerhouse and spillway area. The new forebay concrete wall has been completed, and concrete placement of the new powerhouse and the spillway integrated structure is in progress. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget.

Thermal and Solar Business Development

Nanticoke Solar Facility

In March 2016, Nanticoke Solar LP, then a partnership between OPG, SunEdison Canadian Construction LP (SECCLP) and a subsidiary of Six Nations of the Grand River Development Corporation, was selected through the first phase of IESO's Large Renewable Procurement (LRP) program to develop a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands in Haldimand County, Ontario. The LRP program was a competitive bidding process for procuring large renewable energy projects in Ontario. In March 2016, Nanticoke Solar LP and the IESO executed a 20-year LRP contract, which formalized the terms and conditions for the development and operation of the new solar facility. In the first quarter of 2017, OPG purchased SECCLP's interests in Nanticoke Solar LP and is working to obtain approvals and permits required to enable the commencement of construction planned for the first quarter of 2018. Significant contracts for equipment and engineering construction services were executed in the first quarter of 2018. The 20-year term of the LRP contract takes effect once the station achieves commercial operation, which is expected in the first quarter of 2019. The facility is expected to be completed in the first quarter of 2019, with a budget of $107 million. **[MONITOR]**

Decommissioning of Lambton and Nanticoke Coal-Fired Generating Stations

OPG ceased coal-fired generation at the Lambton and Nanticoke generating stations in September 2013 and December 2013, respectively. In November 2016 and July 2015, respectively, OPG announced that it would decommission the Lambton and Nanticoke generating stations as it could not commercially support continued preservation of these sites in light of the outlook for long-term electricity demand in the province that does not support the need for their future conversion. OPG has begun executing decommissioning plans for these two stations, which will ensure that they are closed safely, securely, and in an environmentally responsible manner. The decommissioning of the Nanticoke GS will accommodate the construction and operation of the Nanticoke solar facility.

During 2017, OPG substantially completed the demolition of the Nanticoke coal yard equipment and structures and issued a contract for the demolition of the Nanticoke powerhouse and associated structures. In the fourth quarter of 2017, the demolition contractor had been mobilized to prepare for the removal of the powerhouse and associated structures and initiated the preparatory work for the demolition of the stacks. The demolition of the stacks took place in February 2018. **[MONITOR]** A competitive bidding process for the demolition of the Lambton GS is in progress, with a contract for the removal of the powerhouse and associated structures expected to be issued during 2018. An update of the associated asset retirement obligations related to the Nanticoke and Lambton sites has been completed. For a discussion of the revaluation of this liability for non-nuclear fixed asset removal as at December 31, 2017, refer to the section, *Critical Accounting Policies and Estimates* under the heading, *Asset Retirement Obligations* in the Company's 2017 year-end MD&A.

DESCRIPTION OF THE BUSINESS

The Electricity Industry

The electricity industry is principally comprised of four components: generation, transmission, distribution, and marketing of energy and other services in wholesale and retail markets.

Generation is the production of electricity. Transmission is the transfer of electricity across high-voltage power lines from generating facilities to local areas. Distribution is the delivery of electricity within local areas to homes and businesses using relatively low-voltage power lines. Energy marketing relates to the purchase of large amounts of electricity or equivalent financial products, and the subsequent re-selling in smaller quantities to third parties in either the wholesale or retail markets.

Electricity has traditionally been generated in large, multi-unit, centralized facilities. These facilities are usually classified by: (i) the type of fuel used; (ii) capacity, typically expressed in MW; and (iii) dispatch mode (being whether or not the electricity generated by a particular facility is dispatched to meet peak, intermediate or baseload demand). The energy produced by a facility is generally expressed as its output over the time the facility operates, typically in terms of MWh. New supply from smaller scale, largely intermittent, renewable sources such as wind, solar, and bio-energy is being integrated into the power system, connected either directly to the transmission system or embedded in distribution networks. Distributed generation involves production of electricity closer to end users and away from large scale production facilities that require more transmission. Electricity systems typically require new capital expenditures and processes in order to accommodate intermittent generators.

Electricity is an essential commodity that cannot be stored without converting to other forms, a process that is more difficult in large volumes. Therefore, electricity supply must instantaneously match demand to maintain the stability and reliability of the electrical power system. This is accomplished by coordinating the supply of and demand for electricity, a responsibility typically assigned to regulated regional system operators. Electricity systems have evolved on a regional basis and are connected to neighbouring regional power grids. Such connections enhance system reliability and permit the economic purchase and sale of electricity between electricity markets.

Ontario's Electricity Industry

OPG's predecessor, Ontario Hydro, served as a vertically integrated electric utility in Ontario. Following the adoption of a restructuring plan for Ontario's electricity industry pursuant to the *Energy Competition Act, 1998,* five principal successors to Ontario Hydro's integrated electricity business began operating as separate entities on April 1, 1999:

- OPG, which purchased and assumed the electricity generation, wholesale energy, and ancillary services businesses of Ontario Hydro;
- Hydro One, which purchased and assumed the transmission, distribution, and retail energy services businesses of Ontario Hydro;
- the Independent Electricity Market Operator (later renamed the IESO), which was formed to act as both the independent electricity system operator and the market operator. The IESO is responsible for the dispatch of generation to meet demand, the control of the Ontario transmission grid, and the operation of energy and ancillary markets;
- the Electrical Safety Authority, which was established to carry out electrical equipment and electrical wiring safety and inspection functions; and
- the Ontario Electricity Financial Corporation (OEFC), which is the legal continuation of the former Ontario Hydro and is responsible for managing the debt and certain other obligations not transferred to other successor companies of Ontario Hydro.

OPG purchased and assumed all of the interest of Ontario Hydro in and to all officers, employees, assets, liabilities, rights and obligations of Ontario Hydro directly or indirectly relating in any manner to the applicable activities carried on by Ontario Hydro as of April 1, 1999, pursuant to the transfer orders made

by Order-in-Council under the *Electricity Act, 1998*. The transfer orders provide that if they fail for any reason to fully and effectively in law transfer any such asset, right, liability or obligation or that if such transfer would constitute a breach of the terms of the asset, right, liability or obligation or of any applicable law, such assets, rights, liabilities or obligations are not transferred, but are held by the OEFC for the benefit of OPG.

Ontario's competitive electricity market was opened by the IESO in 2002. The market is used to manage the purchase and sale of wholesale electricity in the province.

Since the opening of the competitive market, Ontario's power supply mix has experienced significant change. A significant amount of new capacity has been added, while coal-fired generation, which at its peak accounted for approximately 6,500 MW of capacity, has been eliminated. New natural gas powered capacity of approximately 5,000 MW as of the end of 2017 has largely replaced the peaking capacity previously provided by coal-fired generation, while the return to service of Units 1 and 2 at the Bruce A GS in 2012 added approximately 1,500 MW of baseload nuclear generation. New wind and solar capacity of over 7,000 MW has also been added as of the end of 2017, toward Ontario's longer-term target for total wind and solar capacity of about 10,000 MW.

While electricity supply in Ontario has increased, the province's electricity demand as reported by the IESO has fallen, by approximately 13 percent over the last decade, largely due to changes in economic conditions and conservation measures, and also in part due to the addition of small scale solar generation embedded in the distribution system. Embedded generation reduces the demand supplied by grid-connected generation. Reducing electricity demand by encouraging conservation and demand management has been a key part of the Government of Ontario's plan to reduce greenhouse gas (GHG) emissions from the province's electricity sector. Shorter-term fluctuations in electricity demand are impacted by variations in seasonal weather conditions. Ontario's electricity demand as reported by the IESO was 132 TWh in 2017, which excludes electricity exports out of the province.

In October 2017, Ontario's Ministry of Energy issued the 2017 LTEP that outlines the Province's plans for the future development of Ontario's electricity system. The 2017 LTEP focuses on the affordability, reliability and flexibility of a clean energy supply in the province. For further details on the LTEP, refer to the section, *General Development of the Business* under the heading, *General Development – Ontario's Long-Term Energy Plan.*

Ontario Electricity Market Activities

Real-time energy supply needs are met through the wholesale electricity market administered by the IESO, with the market clearing price, the Hourly Ontario Energy Price, set by offers or bids into the market. OPG offers its generation into this real-time energy market, or spot market, to be dispatched by the IESO. The IESO receives hourly offers from electricity generators and importers to provide energy, along with bids to withdraw energy from a few flexible loads and exporters, and then schedules the lowest-cost offers and bids needed to meet demand every five minutes.

Virtually all non-OPG generators in Ontario have bilateral contracts with the IESO that provide for payments that are different from the market price of electricity. In addition, the prices for all of OPG's nuclear and most of its hydroelectric stations are set by the OEB. The difference between the market price and the prices paid for regulated and contracted generation, as well the cost of conservation and demand management programs, are charged to Ontario electricity consumers through the Global Adjustment portion of the total price of electricity.

Maintaining power system reliability requires a continuous balance of supply and demand. Some generators are needed to produce a constant supply of energy to meet basic energy needs (baseload generation), while others are needed to adjust energy output to match changes in demand (peaking and intermediate generation). OPG's nuclear generating stations operate as baseload facilities, whereas its hydroelectric stations operate as baseload, intermediate or peaking stations, depending on their physical characteristics and hydrological conditions. OPG's thermal stations operate as peaking facilities.

SBG occurs when electricity production from the baseload facilities is greater than the market demand for electricity. Baseload generation supply surplus in Ontario is managed by the IESO, mainly through generation reductions at hydroelectric and certain nuclear stations and other grid-connected renewable resources. The prevalence of SBG conditions is impacted by weather conditions which affect electricity demand, wind and solar generation quantities, and through the impact on water flows, the availability of hydroelectric power. In 2017, OPG lost 5.9 TWh of hydroelectric generation due to SBG conditions. In each of 2016 and 2015, OPG lost 4.7 TWh and 3.2 TWh of hydroelectric generation due to SBG conditions. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions, which represents the majority of such production forgone by OPG to date, has been offset by a regulatory variance account authorized by the OEB. During 2017, 2016 and 2015, generation losses at OPG's regulated hydroelectric stations due to SBG conditions were 5.2 TWh, 4.3 TWh and 2.8 TWh, respectively.

The OEB has authorized an additional pricing mechanism for OPG's regulated hydroelectric generation that provides a financial incentive to OPG to shift hydroelectric generation from lower market price periods to higher market price periods. This is intended to benefit customers through the displacement of generation from the relatively higher cost sources such as natural gas. The time-shifting is made possible by the ability to store water in reservoirs located at a number of OPG's hydroelectric facilities, including the Sir Adam Beck Pump GS.

The IESO also administers the operating reserve market and a market for ancillary services. The objective of the operating reserve market is to ensure that additional supplies of energy are available to maintain power system reliability following an unforeseen event. Ancillary services include regulation service, reactive support, black start capacity, and other services required to maintain the reliability of the Ontario electricity system. OPG participates in these markets. Revenues earned by OPG's regulated facilities from providing services into these markets are applied by the OEB to reduce regulated prices for electricity generated from these facilities.

OPG and other Ontario electricity market participants are required to comply with market rules issued by the IESO. As an owner and operator of generating stations, OPG is also subject to reliability standards as set out by the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC) and the IESO. NERC, NPCC and IESO are standards authorities with the ability to create or modify reliability standards. Such standards are binding on OPG pursuant to the OEB-issued electricity generating license and the IESO market rules. The IESO monitors compliance with and enforces the market rules and coordinates with system operators and reliability agencies in other jurisdictions to ensure energy adequacy and security across the interconnected bulk electricity market in North America.

Interconnected Markets

The interconnected markets are electricity markets in neighbouring provinces and states whose transmission systems are connected to the Ontario power grid, either directly or through other contiguous interconnected markets. Ontario's market is interconnected with New York, Michigan, Minnesota, Manitoba, and Québec. Market intermediaries wishing to import or export electricity between Ontario and the interconnected markets are required to schedule these transactions through the Ontario spot market. OPG and its wholly owned subsidiary, OPG Energy Trading (OPGET), participate in the interconnected markets. Further details on OPGET are discussed under the heading, *Services, Trading, and Other Non-Generation Segment.*

Interconnection transmission capabilities between Ontario and the interconnected markets are subject to physical and weather dependent limitations. These limitations include planned or forced outages to transmission lines and other equipment that reduce transmission capacity. They also include wind and temperature conditions that affect the transfer capability of all transmission lines on the electrical system. For example, higher ambient air temperature lowers capacity, while higher wind speeds increase capacity. Overall power system parameters and conditions also can result in limitations on particular

interties, being one or more transmission lines that connect Ontario to a neighbouring region. For example, high flow on one intertie may result in a reduction in the limit on another intertie.

Water Rights

OPG's management of available water resources directly affects the generation output, efficiency, and ultimately return on investment for the Company's hydroelectric assets. The watersheds on which OPG's hydroelectric generating facilities are located are shared by many users and are subject to various governance requirements, such as international, federal and provincial agreements, water power leases, and regulations. Accordingly, OPG must balance the economic, environmental, social and legal requirements associated with the watersheds when utilizing water to optimize electricity generation.

International Rivers

The six OPG hydroelectric generating stations subject to OEB rate regulation since 2008 are directly or indirectly supplied by two major international waterways, the Niagara River and the St. Lawrence River, and are subject to treaties with the U.S. relating to water use. These stations represent approximately 45 percent of OPG's total in-service hydroelectric capacity.

Through a series of agreements between the Government of Canada and the Province, and certain federal and provincial laws, OPG has been granted the right to exercise Canada's rights with respect to the construction, maintenance, and operation of generating facilities under the *Boundary Waters Treaty of 1909* and the *Niagara Diversion Treaty of 1950* between Canada and the U.S. Both of these treaties continue in perpetuity but are terminable by either party with 12 months prior written notice. Given the significance of these treaties, OPG does not expect either party to exercise their respective termination rights in the foreseeable future.

The *Boundary Waters Treaty of 1909* established the International Joint Commission with the mandate of regulating shared water uses and preventing and resolving disputes between U.S. and Canada. In December 2016, the International Joint Commission issued an order implementing a new plan to manage water levels and flows in Lake Ontario and the St. Lawrence River, effective January 7, 2017. The new plan, which replaced the existing plan in use since 1963, is intended to allow for more natural water levels, while minimizing impacts to other users, including hydroelectric power production. No significant changes in OPG's operations are expected as a result of the new plan.

The *Niagara Parks Act* (Ontario) gives the Niagara Parks Commission the authority to grant certain rights for the use of the waters of the Niagara River for purposes of power generation. By agreement with OPG, the Niagara Parks Commission has agreed not to grant any rights to third parties until after 2056.

Under an agreement between OPG and the St. Lawrence Seaway Management Corporation, a federal agency, the DeCew Falls generating stations use water that is transported along the Welland Canal from Lake Erie. The agreement has been renewed through June 30, 2038.

The Province has granted OPG the right to use water from the International Rapids section of the St. Lawrence River for power generation at the R.H. Saunders GS, subject to an agreement between the Government of Canada and the Province. The Government of Canada has the right, upon notice and after unsuccessful arbitration, to take over the operation of and title to the R.H. Saunders GS in the unlikely event of a breach of the agreement by the Province.

Interprovincial Rivers

Four of OPG's hydroelectric stations are located on the Ottawa River, which forms part of the Ontario-Québec border. These stations represent approximately 12 percent of OPG's total in-service hydroelectric capacity. Three of these stations are subject to 999-year leases with each of the Provinces of Ontario and Québec. The fourth station is subject to a water power lease with the Province of Ontario, which is renewable to 2031, subject to certain conditions. OPG's use of water from the Ottawa River

basin is subject to guidelines established by the Ottawa River Regulation Planning Board, comprised of government and industry representatives.

Interior Rivers

Fifty-six of OPG's hydroelectric stations, representing approximately 43 percent of OPG's total in-service hydroelectric capacity, are located on 20 other Ontario river systems. OPG holds water power leases, Crown leases and licences with the Province on the river systems that supply 37 of these stations. A land use permit, issued for the Peter Sutherland Sr. GS, remains in effect while a water power lease for the site is prepared by the Ontario Ministry of Natural Resources and Forestry (MNRF). These leases and licences have expiry dates, including renewal periods, ranging between 2023 and 2075. Certain of these leases provide that the leased property and any fixed improvements, including generating stations and dams, will revert to the Province on the expiry of the lease. OPG intends to work towards new leases and licenses for these stations. OPG's use of Ontario's interior watersheds is constrained by restrictions contained in certain of the water power leases and licences. Eight of the 56 stations are located on the Trent and Rideau Waterways and are operated pursuant to licences from the federal government. These licences expire in February 2020. The process to renew the licences is currently underway with Parks Canada. Ten of the 56 stations are not subject to leases or licences.

The current provincial regulatory framework requires the development of Operational Plans for new storage dams and generating stations in Ontario, except for those on international rivers, interprovincial rivers, or rivers under federal jurisdiction. These plans include any limitations on water flows and elevations, and historically have been a component of formal Water Management Plans (WMPs). WMPs were established under the *Lakes and Rivers Improvement Act* (Ontario) and *Water Management Planning Guidelines for Waterpower (2002)*, on a watershed basis, in consultation with the Ontario Ministry of Natural Resources and Forestry, federal fisheries authorities, stakeholders, such as recreational and commercial users, local communities, environmental groups, and partners, such as Indigenous groups. In October 2016, the MNRF published a Technical Bulletin, *Maintaining Water Management Plans (2016),* eliminating the need for WMPs where they are not already in place, removing the expiry date from existing WMPs, and outlining the requirements for Operational Plans for new waterpower works going forward. Existing WMPs continue to be in effect. WMPs and Operational Plans may be amended as certain conditions change or new data becomes available. OPG operates in compliance with WMPs and Operational Plans.

The operations of certain OPG stations in northwestern Ontario can impact users in Manitoba and are subject to guidelines and directions provided by the Lake of the Woods Control Board, which is comprised of Ontario, Manitoba and federal government representatives.

Dams and Waterways

In Canada, dams fall under provincial jurisdiction, with the exception of dams situated in interprovincial and international boundary waters and canals, and those owned by the Government of Canada. The majority of OPG's dams fall within the jurisdiction of the Province, with approximately 20 dams falling within the jurisdiction of the Province of Québec and 13 dams associated with the Trent-Severn and Rideau Waterways falling under federal jurisdiction. The International Joint Commission has an oversight role for dams and associated works on international boundary waters, including the St. Lawrence River and the Niagara River.

The Province regulates dams under the *Lakes and Rivers Improvement Act* (Ontario) administered by the MNRF. The legislation requires MNRF approval for activities such as the construction, alteration, improvement, or repair of dams.

In August 2011, the MNRF published a revised set of Technical Guidelines for dams, following a period of public consultation. The Technical Guidelines represent the government standards for dam safety. OPG was an active participant in developing the Technical Guidelines through the MNRF's advisory panel. In general, OPG practices in the area of dam safety and public safety around dams exceed the minimum

requirements outlined in the Technical Guidelines. In cooperation with the MNRF, OPG is developing a new risk-informed approach to prioritize the outcomes of dam safety assessments.

Currently, there is no federal or provincial regulation with respect to public safety around dams that addresses dam public safety issues relating to changes in operating water levels, discharges from the hydroelectric or dam facilities, and other waterways-based hazards posed by such facilities. The *Navigation Protection Act* (Canada) does, however, require OPG to obtain approvals for the installation of all in-water works, such as safety booms and buoys associated with the OPG Waterways Public Safety Program. Additional details on OPG's Dam Safety and Waterways Public Safety Programs are discussed under the heading, *Workplace Safety and Public Safety – Dam Safety and Waterways Public Safety*.

Generation Operations

Nuclear (Regulated – Nuclear Generation Segment)

Overview of Generating Facilities

OPG owns and operates two nuclear generating stations, the results of which are reported in the Regulated – Nuclear Generation business segment. The Pickering GS, comprised of six operating units and two units in a permanent safe shutdown state, is located on the shore of Lake Ontario in Pickering, Ontario. As at December 31, 2017, the station's total in-service capacity was 3,094 MW. Four of the eight Pickering units originally went into service in the 1970s. A decision was made by Ontario Hydro in the late 1990s to place these four units in voluntary lay-up. In 2003 and 2005, respectively, two of the four laid-up units were returned to commercial operation, with the two remaining units placed in a permanent safe shutdown state. The other four operating units have been in service since the mid 1980s.

The Darlington GS, comprised of three operating units and one unit, Unit 2, undergoing refurbishment as of mid-October 2016, is located on the shore of Lake Ontario in the Municipality of Clarington, Ontario. As at December 31, 2017, the total in-service capacity of the three operating units was 2,634 MW. Unit 2 has a capacity of 878 MW. All four Darlington units have been in service since the early 1990s. Both the Pickering GS and the Darlington GS have been designed to operate at full power as baseload facilities.

The performance of OPG-operated nuclear generating stations during 2017, 2016 and 2015 was as follows:

Regulated – Nuclear Generation Performance (2015 to 2017)

Station	No. of In-Service Units	Unit Capability Factor [1] (%)		
		2017	2016	2015
Darlington [2]	3	**85.2**	89.5	76.9
Pickering	6	**80.0**	75.2	79.4
Total	9			

[1] Unit capability factor is the amount of energy a generating unit is capable of producing as a percentage of its maximum output assuming no external constraints such as transmission limitations. The nuclear unit capability factor excludes unit(s) during the period in which they are undergoing refurbishment.

[2] Excluding Unit 2, which has been undergoing refurbishment since mid-October 2016.

The lower Unit Capability Factor at the Darlington GS in 2017, compared to 2016, reflected the higher number of planned outage days in 2017, largely driven by constraints related to the transition of the station's operating units toward refurbishment. The increase in the Unit Capability Factor at the Pickering GS in 2017, compared to 2016, was primarily due to outage cycle optimization, favourable unit conditions

and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station compared to 2016.

OPG's Bruce A and Bruce B nuclear generating stations have been leased on a long-term basis to Bruce Power. The stations are located in the Municipality of Kincardine, Ontario on the shore of Lake Huron.

For additional information on OPG's nuclear operations, refer to the section, *Core Business, Strategy, and Outlook* under the heading, *Operational Excellence – Electricity Generation Production and Reliability* in the Company's 2017 year-end MD&A.

Nuclear Generation Technology

Nuclear generation harnesses the energy released during controlled nuclear fission reactions to produce steam that is used to drive turbines to generate electricity. Nuclear generation has two main advantages. It is a relatively low marginal-cost generation technology, and it produces virtually no GHG, sulphur dioxide, nitrogen oxide, or mercury emissions. The latter advantage has become more significant as governments implement climate change action plans and stricter air emission standards.

However, in contrast to other types of generating facilities, notwithstanding the lower fuel costs, nuclear generating stations incur nuclear waste management and decommissioning costs and greater operating and maintenance expenses. In addition, the construction of nuclear generating stations entails greater initial capital costs than other generation technologies. The higher initial costs reflect the complexity of the technical processes fundamental to nuclear electricity generation, and the additional design and safety precautions taken to protect the public from potential risks associated with nuclear operations.

All of OPG's nuclear generating stations use CANada Deuterium Uranium (CANDU) technology reactors. CANDU is a pressurized-heavy-water, natural-uranium power reactor, originally designed in the 1960s by a consortium of Canadian government agencies and private industry. CANDU reactors are unique in their use of natural-uranium fuel and deuterium oxide, or heavy water, as both a moderator to slow down the fission process and a coolant within the reactor. The refuelling system is also unique in that CANDU reactors can be refuelled at full power. This is due to the subdivision of the reactor core into hundreds of separate fuel channels, each holding a single string of natural uranium fuel bundles, allowing for greater fuel efficiency. In contrast, U.S. reactors, which use enriched uranium fuel, must be shut down during refuelling. All nuclear power reactors in Canada use CANDU technology. CANDU reactors are currently operating in Ontario, New Brunswick, Argentina, Romania, South Korea, India, Pakistan and China.

Nuclear Fuel Procurement

OPG's nuclear fuel supply chain engages in the purchase of uranium concentrate, the purchase of services for the conversion of uranium concentrate to uranium dioxide, and the purchase of services for the manufacture of fuel bundles containing uranium dioxide pellets. OPG currently establishes contractual arrangements with each of these components separately and as appropriate maintains ownership of the uranium throughout the supply chain. OPG maintains a portfolio of multi-year supply contracts for uranium concentrate with domestic and foreign suppliers and commodity traders. Occasionally, short-term spot market purchases are acquired to support a portion of its uranium concentrate needs. OPG's nuclear fuel bundles are supplied by a Canadian-based manufacturer.

Nuclear Regulation

The *Nuclear Safety and Control Act* (NSCA) establishes the mandate and authority of the CNSC to make regulations governing all aspects of the development and application of nuclear energy in Canada. The NSCA grants the CNSC the power to act as a court of record, the right to make regulations, the power to require financial guarantees for nuclear waste management and nuclear facilities decommissioning as a condition of granting a licence, order-making powers, and the power to impose monetary penalties for licence infractions. The NSCA also grants the CNSC the power to require periodic re-certification of nuclear operators and to set requirements for various nuclear facility security measures. It also provides

for regulatory authority over environmental matters, including a requirement that licence applicants make adequate provision for the protection of the environment. The NSCA grants the CNSC licensing authority for all nuclear activities in Canada, including but not limited to the issuance of new licences to operators, the renewal of existing licences, protection of the environment arising from nuclear activities, and making regulations related to nuclear activities.

A fundamental principle in nuclear regulation is that the licensee bears the responsibility for safe operation, with the CNSC setting safety objectives in areas such as radiation protection and physical security for nuclear generating stations and the transport of radioactive materials. The CNSC verifies compliance with the licence and performs audits and inspections of the licensee's performance against these objectives. The CNSC also has issued guidance documents to assist licensees in complying with regulatory requirements. Requirements specified in these guidance documents have been incorporated into the design and operating documents for OPG's nuclear generating stations.

Since the operation and regulation of nuclear energy has transboundary impacts, Canada has become a signatory to various international conventions relating to nuclear energy and emergency responses and is bound by conventions that it has ratified. In addition, the CNSC has a bilateral information exchange and co-operation agreement with the U.S. Nuclear Regulatory Commission, which provides, among other things, for the prompt, reciprocal notification of reactor safety problems that could affect both U.S. and Canadian nuclear generation facilities.

The CNSC publishes an annual Regulatory Oversight Report on the safety performance of Canada's nuclear power plants. The report assesses how well plant operators are meeting regulatory requirements and program expectations in the areas of operational performance, safety analysis, radiation protection, waste management and conventional health and safety. On September 8, 2017, the CNSC issued an executive summary of its 2016 annual report, giving both the Darlington GS and the Pickering GS the highest possible safety rating of "Fully Satisfactory". The Darlington GS achieved this rating for the eighth consecutive year, while the Pickering GS achieved this rating for the second consecutive year.

In 2017, the CNSC approved regulatory document *REGDOC 2.2.4 – Fitness for Duty – Managing Alcohol and Drug Use* for use at Canadian nuclear power plants. This document sets out requirements for managing fitness for duty of workers in relation to alcohol and drug use at high-security sites, including for-cause alcohol and drug testing for workers in positions identified as safety-sensitive or safety-critical and random alcohol and drug testing for workers holding safety-critical positions. OPG intends to enhance its existing Fitness for Duty program to comply with these new requirements. OPG is working with its partners in the Canadian nuclear industry to develop a program suitable for Canada and its workers.

All of OPG's nuclear power reactor operating licences and waste facility licences are current and up to date. In 2016, OPG submitted applications with the CNSC seeking a ten-year licence renewal for the Western Waste Management Facility (WWMF), located at the Bruce generating stations' site, to May 31, 2027, and a ten-year licence renewal for the Pickering Waste Management Facility (PWMF) to August 31, 2028. The licence renewal applications were presented to the CNSC at public hearings in April 2017. On May 30, 2017, the CNSC announced that the WWMF licence was renewed for a ten-year period and will be valid until May 31, 2027. On February 7, 2018, the CNSC announced that the PWMF licence was renewed for a ten-year period and will be valid until August 31, 2028. Further details on the operating licence for the Darlington GS are found in the section, *General Development of the Business* under the heading, *Nuclear Business Development – Darlington Refurbishment* and for the Pickering GS in the section, *General Development of the Business* under the heading, *Nuclear Business Development – Extension of Commercial Operations at Pickering to 2024*.

Details on Canada's nuclear liability regime and related insurance coverage can be found under the heading, *Insurance*.

Fukushima Daiichi Response

In response to the 2011 Fukushima Daiichi incident in Japan, OPG has confirmed that its stations are safe and that systems and procedures are in place to withstand significant emergencies. In 2013, a systematic review and verification of defences against external hazards was completed at OPG-operated stations. The review showed that:

- the nuclear safety systems and multiple back-up power systems in place at the stations are effective; and
- the current design of the stations is strong and the stations are able to withstand extreme external events.

The review also provided recommendations for further opportunities to enhance the safety margin and to develop preparedness for unexpected events that go beyond the extreme events already considered in the design of the stations.

OPG's action plan in response to the Fukushima Daiichi event is well aligned with the CNSC's Fukushima Action Plan, issued in mid-2012. In 2013, OPG submitted its plans for the majority of the CNSC's Fukushima Action Plan items applicable to OPG-operated stations to the CNSC. In January 2015, the CNSC recognized OPG's efforts in this area and confirmed that all of the Fukushima action items were closed. OPG's Fukushima Implementation Plan included a number of key safety enhancements for providing additional back-up capability to increase OPG's flexibility to respond to unexpected and highly unlikely external events that can impact either a single unit or multiple units at the same time. CNSC staff concluded that OPG had strengthened reactor defence and enhanced its emergency response at both the Darlington GS and the Pickering GS in response to the lessons learned from the Fukushima Daiichi incident.

Nuclear Generating Station Life

Service life predictions for OPG-operated nuclear stations are developed by assessing the impacts of a number of operating, technical, and regulatory considerations on both unit and station economics. A decision by OPG to remove a unit from service would be primarily an economic decision that becomes more likely as the number of components requiring replacement and the frequency and duration of inspections required to ensure a unit's fitness for service increases. The key life-limiting components at OPG's nuclear stations include fuel channels, feeder tubes, steam generators, and other reactor components. End-of-service life predictions are reviewed as new information on possible degradation mechanisms becomes available and as future generation expectations are revised.

In December 2015, OPG revised the accounting assumptions for the estimated useful lives of the nuclear generating stations it operates. Effective December 31, 2015:

- the average service life of the Darlington GS was extended by one year to 2052 to reflect the approval of the refurbishment schedule in 2015; and
- the average service life of the Pickering GS was extended by less than one year to reflect the technical confidence that all six operating units of the station will operate to the end of 2020.

The accounting end of life assumptions for the Pickering GS have been reassessed in December 2017 based on the technical work performed to confirm that the longer fuel channel life necessary to extend Pickering operations can be achieved and that the units would be fit to operate beyond 2020, taking into account the requirement for the CNSC's approval. Further information can be found in the section, *General Development of the Business* under the heading, *Nuclear Business Development – Extension of Commercial Operations at Pickering to 2024*.

Nuclear Facility Planning

OPG uses a structured approach to identify and prioritize projects to optimize returns from nuclear station reinvestment within the constraints imposed by technical and financial requirements, while ensuring that safety, environmental, and other regulatory programs are of the highest priority. Input from predictive maintenance programs, life cycle management plans, and system health monitoring is used to determine the activities necessary to sustain and improve nuclear unit performance.

A structured framework modeled on the best practices identified by the Electric Power Research Institute, the Institute for Nuclear Power Operations and the World Association of Nuclear Operators (WANO) is used to optimize the maintenance of the nuclear generating stations and assess the health of the facilities. The structured framework includes predictive maintenance programs, which combine technologies and human expertise to analyze equipment performance, maintenance and design data in order to make timely decisions about the scope and timing of inspections and maintenance for major or critical equipment. The predictive maintenance program for each station is prioritized on the basis of the importance of the equipment for reactor safety. Life cycle management plans are maintained for critical station components and are updated annually to incorporate operating experience and new information. The life cycle plans define the inspection and maintenance programs required to ensure that these components perform in accordance with their design basis. In addition, system engineers conduct performance monitoring of station systems according to system performance monitoring plans that are based on a comparison of performance indicators against established targets to improve system performance. System performance is assessed by collecting, trending and analyzing station data. This information is reported in system health reports which are updated, at a minimum, annually.

OPG's practices impacting the performance of the nuclear stations are audited regularly by WANO, with identified areas for improvement acted upon with priority. In May 2016, OPG hosted a WANO peer evaluation that compared the Darlington GS against standards of excellence through an in-depth and objective review by an international panel of industry experts. The review maintained Darlington's excellent standing as one of the top performing nuclear plants in the world. In December 2017, OPG hosted a WANO peer evaluation for the Pickering GS, which focused on the safe and reliable operation of the station while evaluating the plant material condition, functional and cross-functional areas of the organization. Pickering showed significant improvement since its last review and has sustained its strong rating in 2018, resulting in its best ever WANO peer review.

In September 2016, OPG hosted a team of experts from the International Atomic Energy Agency (IAEA) at the Pickering GS to conduct a standard Operational Safety Review Team mission. The team conducted an in-depth review of performance and adherence to international safety standards. In the second quarter of 2017, the IAEA's Operational Safety Review Team released the final report and confirmed that the Pickering GS demonstrates strong commitment to safety.

Nuclear planned outages are necessary to execute inspection and maintenance work related to asset management and regulatory requirements for systems and equipment where access is not possible under normal operating conditions. Planned outages also give OPG an opportunity to perform system and equipment upgrades, project work, configuration changes, and other improvements and modifications. The nuclear generation plan, by reference to the station's life cycle management plans, establishes the number, frequency and duration of the outages for each year required to ensure the continued safe and reliable long-term operation of the plant and its compliance with CNSC regulatory requirements.

The outage cycle determines the number of planned outages at each station in a particular year. The Darlington GS is on a 36-month outage cycle, where each of the four units undergoes an outage every three years, resulting in one or two outages per year for the station. The Pickering GS was on a 24-month outage cycle. Supported by technical assessments undertaken for the extension of Pickering GS, the outage frequency has been optimized and extended from 24 to 30 months. In addition, on a periodic basis all units at each station are required to be shut down to allow for inspection and maintenance on the station vacuum building, containment systems and other safety systems. The CNSC currently requires

these outages every 12 years at the Darlington GS and every ten years at the Pickering GS. The most recent vacuum building outage took place at the Darlington GS in 2015 and at the Pickering GS in 2010.

Nuclear Ancillary Operations

OPG's nuclear generating units contain approximately 7,500 tonnes of deuterium oxide, or heavy water, not including heavy water contained at the leased Bruce stations. The heavy water is required to operate CANDU reactors. Ontario Hydro ceased the operation of its heavy water plants in 1997 and the plants were subsequently decommissioned. There are currently no heavy water plants in Canada. OPG believes that its existing inventory of heavy water will be sufficient to replenish supplies as a result of normal operating losses at its nuclear stations, including the refurbishment of the Darlington GS. OPG also believes that sufficient quantities of heavy water are available for possible changes in operating conditions or for new nuclear generating facilities. OPG seeks opportunities to sell available surplus quantities of heavy water from its inventory.

Tritium is a radioactive substance produced as a by-product of operating CANDU reactors, through the use of heavy water in the reactor moderator and heat transport systems. OPG operates a specialized facility at its Darlington site, the Darlington Tritium Removal Facility (TRF), which removes tritium from the tritiated heavy water (detritiation) used at the nuclear generating stations, in order to control the occupational dose exposure to employees and limit the amount of tritium released to the environment. The extracted tritium is chemically immobilized, placed in special containers, and safely stored in a vault. The Darlington TRF is also expected to be used to detritiate heavy water during the eventual decommissioning of OPG's nuclear generating stations. Some tritium is sold to government-approved organizations for authorized commercial and health industry uses. OPG also provides detritiation services to Bruce Power. Opportunities for providing detritiation services to other third parties are limited because of storage and capacity restrictions at the Darlington TRF.

Cobalt-60 produced and sold by OPG is used mainly in the health industry to sterilize surgical and medical supplies. Cobalt-60 is produced in Units 6, 7 and 8 at the Pickering GS. Cobalt-60 can be produced in reactors which, like the CANDU reactors, use adjuster rods to regulate power. The production process involves replacing the stainless steel rod by a rod containing Cobalt-59, which is isotopically converted into Cobalt-60 after lengthy exposure to the atomic reaction in the reactor core. During planned maintenance outages, the rods are removed, cut, and packaged for sale as Cobalt-60, and new rods are inserted in the reactor to continue the production cycle.

Hydroelectric (Regulated – Hydroelectric and Contracted Generation Portfolio Segments)

Overview of Generating Facilities

Hydroelectric generating stations use the energy of falling water to drive hydraulic turbines that generate electricity. OPG's hydroelectric stations provide one of the Company's competitive advantages – a reliable, relatively low-cost source of renewable energy free of air emissions. Electricity generation from OPG's hydroelectric facilities depends primarily upon the availability of water, which is affected largely by natural factors such as precipitation and evaporation. It is also impacted by the prevalence of SBG conditions.

OPG currently owns and operates 66 hydroelectric generating stations and 241 associated dams located on 24 river systems across Ontario. The results of 54 of these stations that are rate regulated by the OEB are reported in the Regulated – Hydroelectric segment. The results of the remaining 12 stations are subject to long-term ESAs with the IESO and are included in the Contracted Generation Portfolio segment. The 54 regulated hydroelectric stations include the 48 stations prescribed for rate regulation beginning in 2014 and the six stations that have been rate regulated by the OEB since 2008.

As at December 31, 2017, OPG's regulated hydroelectric facilities had a total in-service capacity of 6,426 MW and the non-regulated hydroelectric facilities had a total in-service capacity of 1,042 MW. OPG's

hydroelectric generating stations range in age from the newly in-serviced Peter Sutherland Sr. GS to over 119 years and include the oldest assets in OPG's generation portfolio.

Hydroelectric ESAs with 50-year terms are in place for the following hydroelectric facilities:

- Lac Seul and Ear Falls generating stations, with an expiry date of February 2059;
- Healey Falls GS, with an expiry date of April 2060;
- Sandy Falls, Wawaitin, Lower Sturgeon, and Hound Chute generating stations, with an expiry date of December 2060;
- Little Long, Harmon, Smoky Falls, and Kipling generating stations, with an expiry date of January 2064; and
- Peter Sutherland Sr. GS placed in-service in March 2017, with an expiry date of March 2067.

In 2017, the number of regional groups was reduced from five to four, by integrating the central operations work centers into three of the other existing regional operations groups. The following are the four regional operations groups that operate and maintain OPG's hydroelectric facilities:

- Niagara Operations – includes the three Sir Adam Beck stations located on the Niagara River and the two DeCew Falls facilities located on the Welland River. These facilities have been rate regulated by the OEB since 2008. As part of the change in the regional groups, the Gravenhurst work centre joined with seven regulated stations on the Muskoka, Severn and Beaver Rivers. This operations group also includes OPG's wind turbine.
- Eastern Operations – includes the following ten regulated hydroelectric generating stations: the R.H. Saunders GS on the St. Lawrence River; the Otto Holden, Des Joachims, Chenaux, and Chats Falls generating stations on the Ottawa River; and the Mountain Chute, Barrett Chute, Calabogie, Stewartville, and Arnprior generating stations on the Madawaska River. The R.H. Saunders GS has been regulated by the OEB since 2008. As part of the change in the regional groups, the Campbellford work centre joined with eleven regulated stations and one non-regulated station on the Trent, Mississippi and Rideau Rivers.
- Northeast Operations – includes five regulated and eight non-regulated hydroelectric stations in northeastern Ontario. The regulated stations are the Chute and Lower Notch generating stations on the Montreal River; the Abitibi Canyon and Otter Rapids generating stations on the Abitibi River; and the Matabitchuan GS on the Matabitchuan River. The non-regulated stations are the Little Long, Harmon, Smoky Falls, and Kipling generating stations on the Lower Mattagami River; the Wawaitin, Sandy Falls, and Lower Sturgeon generating stations on the Upper Mattagami River; and the Hound Chute GS on the Montreal River. The North Bay and Coniston work centres joined this regional operations group with seven regulated stations on the Wanapitei and French Rivers.
- Northwest Operations – includes nine regulated and two non-regulated generating stations in northwestern Ontario. The regulated stations are the Pine Portage, Cameron Falls, and Alexander generating stations on the Nipigon River; the Silver Falls and Kakabeka Falls generating stations on the Kamanistikwia River; the Manitou Falls and Caribou Falls generating stations on the English River; the Aguasabon GS on the Aguasabon River; and the Whitedog Falls GS on the Winnipeg River. The non-regulated stations are the Lac Seul and Ear Falls generating stations on the English River.

These operations groups are also responsible for the operation and maintenance of OPG's thermal facilities discussed under the heading, *Generation Operations – Thermal (Contracted Generation Portfolio Segment)*.

The performance of OPG's hydroelectric generating stations during 2017, 2016 and 2015 was as follows:

Hydroelectric Generation Performance (2015 to 2017)

	Regulated – Hydroelectric			Contracted Generation Portfolio – Hydroelectric			Total Hydroelectric		
	2017	**2016**	**2015**	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Availability *(%)* [1]	**88.0**	89.0	91.2	**74.6**	77.3	88.6	**86.2**	87.5	90.9

[1] Availability is represented by the percentage of time the generating unit is capable of providing service, whether or not it is actually generating electricity, compared to the total time for the respective period.

Lower availability of the Regulated – Hydroelectric facilities during 2017 was primarily due to a higher number of unplanned outage days at the Northwestern Ontario, Niagara, and Eastern Ontario regions' hydroelectric stations, partially offset by higher availability from the Sir Adam Beck Pump GS due to a higher number of planned outages days in 2016 as a result of the refurbishment of the station's reservoir. Lower availability of the Contracted Generation Portfolio hydroelectric facilities in 2017 was primarily due to an increase in the number of planned outage days at the Lower Mattagami River hydroelectric generating stations.

Lower availability of the Regulated – Hydroelectric facilities during 2016 was primarily due to the planned reservoir refurbishment project at the Sir Adam Beck Pump GS. Lower availability of the Contracted Generation Portfolio hydroelectric facilities in 2016 was primarily due to a higher number of planned outage days at the Kipling and Harmon generating stations.

OPG's objectives for the hydroelectric operations include operating and maintaining the generating facilities in a safe, efficient and cost-effective manner, while increasing the output from the facilities and pursuing opportunities to increase capacity. OPG aims to increase the facilities' output by improving operational flexibility, enhancing reliability, optimizing outage planning and, subject to water conditions, increasing availability to meet electricity system demand. The Company continues to evaluate and implement plans to increase capacity, maintain and improve operational performance, and extend the operating life of its hydroelectric generating assets. These plans are accomplished through multi-year capital investment and other programs, including replacements and upgrades of turbine runners, and refurbishment or replacement of existing generators, transformers, and controls. Over the next four years, OPG plans to increase the total capacity of its renewable generating fleet by approximately 150 MW, which in addition to the runner replacement and upgrade program, includes the Ranney Falls GS and Sir Adam Beck frequency conversion projects. OPG is also planning to repair, rehabilitate, or replace a number of aging civil structures. Where economical and practical, OPG also pursues opportunities to refurbish, expand or redevelop its existing hydroelectric stations.

Additional information on OPG's hydroelectric operations are discussed in the section, *Core Business, Strategy, and Outlook* under the heading, *Operational Excellence – Electricity Generation Production and Reliability* in the Company's 2017 year-end MD&A.

Hydroelectric Facility Planning

Major components of hydroelectric facilities typically include: generating equipment such as turbines, generators and transformers; civil works such as powerhouses, dams, headworks, spillways and water conveyance canals and tunnels; and facilities required to operate and maintain the stations such as control rooms and work centres. Although there is a link between the age of a facility and the capital investment required to maintain that facility, age does not establish an upper limit on the expected useful life of hydroelectric facilities and dams. Regular maintenance and the replacement of specific components typically allow stations to operate for very long periods, especially for facilities built after 1925.

OPG operates six staffed control rooms across Ontario that provide remote control and monitoring for all of OPG's hydroelectric generating facilities. These control rooms are designed to minimize the number of staffed control rooms, reduce control system failures, and increase the amount of information available for production planning.

OPG uses a structured portfolio approach to identify and prioritize projects for its hydroelectric asset investment program. Engineering reviews and station condition assessments are performed to determine short-term and long-term expenditure requirements to sustain or improve the performance of each facility. These may be followed by the preparation of a facility life cycle plan, which is performed on an as-needed basis for marginal assets or assets potentially requiring significant expenditures relative to the value of the facility. This approach is designed to identify necessary capital, operating and maintenance expenditures for each facility and to direct resources towards those facilities that can best maintain or enhance their value.

OPG utilizes a preventive maintenance program that provides a consistent method of identifying, scheduling, and executing maintenance activities at the hydroelectric facilities. The maintenance program is based on the concept of streamlined reliability-centred maintenance, whereby the type and frequency of preventive maintenance applied to an individual component is determined based on the nature and consequences of failure, balancing cost and risk.

The cornerstone of OPG's project prioritization and preventive maintenance approaches for the hydroelectric assets is that safety, environmental, and other regulatory programs are of the highest priority.

Water Management

OPG's water management strategy for its hydroelectric facilities is to safely utilize available water for generation of electricity in conformance with legal, environmental, operational, and WMP and Operational Plan requirements. OPG uses hydrological and meteorological data to manage water levels, water flows and water storage, and strives to schedule water use for optimum utilization and to minimize controllable water spills due to SBG conditions.

Gross Revenue Charge and Water Rental Payments

Hydroelectric generating stations in Ontario are subject to taxes and charges as prescribed by *Ontario Regulation 124/02* under the *Electricity Act, 1998*. These taxes and charges, referred to as Gross Revenue Charge (GRC), are based on station gross revenue, which, for this purpose, is determined as the product of annual station energy generation and the prescribed revenue rate of $40/MWh (Gross Revenue). All OPG hydroelectric generating stations are subject to GRC Property Tax, which is determined by applying graduated tax rates, ranging from 2.5 percent to 26.5 percent through four tiers of production, to a station's annual Gross Revenue. GRC Property Tax payments are made to the OEFC. Hydroelectric generating stations that are subject to water power lease agreements with the MNRF are also subject to GRC Water Rental charges in addition to GRC Property Tax payments. The GRC Water Rental charge is determined as 9.5 percent of a station's annual Gross Revenue. GRC Water Rental payments are made to the Ontario Ministry of Finance.

Annual land rental fees are paid to the MNRF as prescribed by Crown leases and licences of occupation which authorize OPG's tenure (including flooding rights), typically at storage dam sites.

The eight OPG hydroelectric generating stations located on the Trent River and Rideau Canal are subject to rental charges prescribed by licences with Parks Canada. These licences authorize OPG to occupy the lands, maintain and operate the powerhouses and dams, and utilize water that is surplus to navigation needs for the generation of electricity.

Water conveyance charges are paid to the St. Lawrence Seaway Management Corporation as prescribed by a lease agreement providing for the withdrawal of water surplus to navigation needs from the Welland

Canal for utilization at the DeCew Falls generating stations. The water conveyance charges apply to the transport of water from Lake Erie through the Welland Canal to OPG's intakes at Allanburg.

Water rental payments are made to the Government of Québec, as prescribed by an agreement dated January 2, 1943 and a rate amending agreement effective January 2, 1993. These agreements pertain to the sharing of the water powers of the Ottawa River and were ratified by the Governments of Ontario and Québec. Water rental charges payable to the Province of Québec are based on one-half of the energy produced at the three regulated OPG hydroelectric generating stations located on the Ottawa River. The GRC payments made to the Province of Ontario with respect to these three sites are also based on one-half of the energy produced at the stations.

Under the aforementioned 1943 agreement, OPG also provides compensation to Hydro Québec for the generating value at OPG's stations on the Ottawa River attributed to the water diverted into the Ottawa River through the Dozois Reservoir in Québec. OPG shares in operation and maintenance costs pertaining to the dam enabling the Dozois diversion.

The GRC and water rental payments for the regulated hydroelectric stations are recoverable through OEB-approved regulated prices applicable to these stations.

Further details on water rights can be found in the section, *Description of the Business* under the heading, *Water Rights*.

Thermal (Contracted Generation Portfolio Segment)

Overview of Generating Facilities

Thermal generating stations use heat energy to drive steam turbines that generate electricity. OPG's wholly-owned operating thermal facilities are comprised of biomass-fuelled generating units at both Atikokan GS and Thunder Bay GS, and the dual-fuelled generating Lennox GS, which is capable of burning either oil or natural gas. The results of these facilities are reported in the Contracted – Generation Portfolio business segment.

The combined in-service capacity of the three operating thermal facilities was 2,458 MW as at December 31, 2017. The Lennox GS is located in Greater Napanee, Ontario and accounts for approximately 2,100 MW of this in-service capacity. The Atikokan GS is located in Atikokan, Ontario and has an in-service capacity of 205 MW. The Thunder Bay GS is located in Thunder Bay, Ontario and its advanced biomass fuelled unit has an in-service capacity of 153 MW.

Capacity and production from the Lennox GS are subject to an ESA with the IESO for the period from January 2013 to September 2022. Capacity and production from the Atikokan GS are subject to a ten-year ESA expiring in July 2024. For the Thunder Bay GS advanced biomass fuelled unit, capacity and production are subject to a five-year ESA expiring in January 2020.

OPG's three thermal generating stations operate as peaking facilities, depending on electricity demand. This provides Ontario's electricity system with the flexibility to meet changing daily system demand and capacity requirements and has enabled the system to accommodate the expansion of Ontario's renewable generation portfolio. The continued operation of these stations will continue to provide Ontario with capacity and peaking generation.

The three thermal generating stations are operated and maintained as part of regional operations groups used to operate and maintain the Company's hydroelectric facilities. The Lennox GS is operated under Eastern Operations, and the Atikokan and Thunder Bay generating stations are part of Northwest Operations.

Thermal stations that are no longer available to generate electricity are included in the Services, Trading, and Other Non-Generation business segment once they are removed from service. This includes the Lambton GS and Nanticoke GS sites, which ceased coal-fired generation in 2013.

Contracted Generation Portfolio – Thermal Performance (2015 to 2017)

	2017	2016	2015
Equivalent Forced Outage Rate (%) [1]	**2.4**	1.6	11.2

[1] Equivalent Forced Outage Rate is an index of the reliability of a generating unit at OPG's thermal stations. It is measured by the ratio of time a generating unit is forced out of service by unplanned events, including any forced deratings, compared to the amount of time the generating unit was available to operate.

The higher thermal EFOR in 2017, compared to 2016, was primarily due to a higher number of unplanned outage days at a Lennox GS unit as a result of a transmission outage and a generator-related outage in 2017. The change in thermal EFOR in 2016, compared to 2015, was primarily due to an outage in 2015 to perform repair work at the Lennox GS.

Additional information on OPG's thermal operations can be found in the section, *Core Business, Strategy, and Outlook* under the heading, *Operational Excellence – Electricity Generation Production and Reliability* in the Company's 2017 year-end MD&A.

Thermal Fuel Procurement

Due to the relatively low capacity factor of the Lennox GS, natural gas is purchased on the spot market, other than a small volume of fixed term natural gas required for non-generation operational services. Oil for the Lennox GS is contracted for and purchased on an as needed basis. Fuel switching at the station is based on market and fuel economics. Annual procurement of biomass fuel quantities for Atikokan GS and Thunder Bay GS is pre-determined by the corresponding ESAs. Agreements are in place with suppliers for the purchase of all biomass fuel pellets needed to provide fuel for the Atikokan GS for the duration of its ESA, and for most of the advanced biomass fuel pellets needed to provide fuel for the duration of the ESA for the Thunder Bay GS.

Thermal Facility Planning

OPG's facility planning approach is designed to identify necessary capital and operating and maintenance expenditures for each thermal facility. This planning approach aims to sustain facility availability for the remaining service life through station reinvestment within constraints imposed by technical, financial, safety, and system requirements, as well as regulatory and contractual limits. Periodic engineering reviews of major systems are conducted to identify performance issues, provide reinvestment recommendations where appropriate, and ensure that regulatory, safety and operating standards continue to meet expectations. OPG undertakes projects at thermal stations that are expected to achieve an appropriate return within the service life of the stations.

Thermal Station Decommissioning

OPG has recognized, and carries on its balance sheet, a liability to cover future expenditures to decommission and dismantle each of its thermal stations at the end of their estimated service lives. This provision is not funded and is estimated on the basis of station closure. Costs previously incurred by OPG to preserve Lambton and Nanticoke generating stations for potential conversion to natural gas in the future were not charged to the provision, as they were charged against net income as incurred.

Portlands Energy Centre Partnership

OPG has a 49.95 percent partnership interest in Portlands Energy Centre L.P., a limited partnership formed with TransCanada Energy Ltd. (49.95 percent) and the general partner of the partnership, Portlands Energy Centre Inc. (0.1 percent). The shareholders of Portlands Energy Centre Inc. are OPG (50 percent) and TransCanada Energy Ltd. (50 percent). PEC is a 550 MW combined cycle generation natural gas turbine electricity generating facility located on the former R. L. Hearn GS site in the port area of downtown Toronto, Ontario. The station was declared in-service in a combined cycle mode in April 2009. PEC operates under an Accelerated Clean Energy Supply contract with the IESO and trades electricity in the Ontario electricity market.

The Contracted Generation Portfolio segment includes OPG's share of equity income from its 50 percent ownership interest in the station. OPG's share of the in-service generating capacity and generation volume from its interest in the station are included in the operating statistics for the segment.

Brighton Beach Power Partnership

OPG has a 49.95 percent partnership interest in Brighton Beach Power L.P., a limited partnership formed with ATCO Power Canada Ltd. (49.95 percent) and the general partner of the partnership, Brighton Beach Power Ltd. (0.1 percent). The shareholders of Brighton Beach Power Ltd. are OPG (50 percent) and ATCO Power Canada Ltd. (50 percent). Brighton Beach is a 560 MW combined cycle gas turbine electricity generating facility located on the former J.C. Keith GS site in Windsor, Ontario. The station began commercial operation in July 2004. Brighton Beach operates under a tolling arrangement with Shell Energy North America (Canada) Inc. (Shell Energy), pursuant to which Shell Energy owns and trades the electricity produced by the facility in return for the supply of gas and the fees payable under the tolling agreement. Shell Energy's financial obligations are guaranteed by Shell Energy North America (US) L.P. (Shell L.P.), and Shell L.P.'s obligations are in turn guaranteed by Shell Oil Company.

The Contracted Generation Portfolio segment includes OPG's share of equity income from its 50 percent ownership interest in the station. OPG's share of the in-service generating capacity and generation volume from its interest in the station are included in the operating statistics for the segment.

Regulated – Nuclear Waste Management Segment

Overview

OPG is responsible for the ongoing management of radioactive wastes generated by its nuclear operations. In addition, OPG has the obligation for decommissioning its nuclear generating stations and nuclear waste facilities after the end of their useful lives and for managing radioactive wastes that arise in connection with the decommissioning. The handling and disposal of radioactive waste in Canada is subject to federal legislation.

The radioactive wastes generated by OPG's nuclear operations include the following:

- Used nuclear fuel bundles;
- Intermediate-level waste – material that has come in close contact with the reactors, but is less radioactive than used fuel, such as ion exchange resins and reactor equipment and components; and
- Low-level waste – material used in connection with station operation that is not highly radioactive, such as tools and protective clothing.

The Company's Regulated – Nuclear Waste Management segment reports the results of the Company's operations associated with the following:

- management of used nuclear fuel and L&ILW;

- decommissioning of OPG's nuclear generating stations including the stations on lease to Bruce Power and other nuclear facilities;
- management of the Nuclear Segregated Funds established under the ONFA to fund OPG's obligation for nuclear facilities decommissioning and the long-term management of nuclear waste; and
- Other related activities including the inspection and maintenance of the waste storage facilities.

The nuclear accretion expense, which is the increase in the carrying amount of the present value liabilities for nuclear fixed asset removal and nuclear waste management liabilities reported on the balance sheet due to the passage of time, and the earnings from the Nuclear Segregated Funds are reported under this segment. The Regulated – Nuclear Waste Management segment is considered rate regulated because OPG's costs associated with nuclear waste management and nuclear facilities decommissioning liabilities have been included by the OEB in the determination of regulated prices for production from the Pickering and Darlington nuclear generating stations.

Federal Government Policy

In accordance with the requirements of the *Nuclear Fuel Waste Act* (Canada) (NFWA), in 2002, OPG and the other owners of nuclear fuel waste in Canada established a separately incorporated NWMO, with a mandate to manage and coordinate the full range of activities relating to the long-term management of nuclear fuel waste in Canada. This includes the design and implementation of Canada's plan for the long-term management of used nuclear fuel. In 2007, the federal government approved NWMO's submitted option, the Adaptive Phased Management (APM) plan, as the long-term solution for nuclear fuel waste. The APM plan contemplates the eventual long-term permanent disposal of radioactive nuclear fuel waste in a deep geologic repository (DGR) after a collaborative process of communication and engagement with Canadians aimed at selecting a suitable geological site with an informed and willing host community. The NWMO is in the process of undertaking a multi-year site selection process for the used fuel DGR.

The NFWA also requires the nuclear fuel waste owners in Canada to establish and make payments into trust funds for the purpose of funding the implementation of the long-term management plan for used fuel. Accordingly, OPG has established the Ontario NFWA Trust (the NFWA Trust), which forms part of the Nuclear Segregated Funds under the ONFA. Additional details can be found in the section, *Description of the Business* under the heading, *Regulated – Nuclear Waste Management Segment – Funding Mechanisms.*

Current Practices

Used Nuclear Fuel

Used nuclear fuel bundles from OPG's reactors and leased reactors at the Bruce Nuclear site are temporarily stored at each nuclear generating station in water-filled pools, known as wet bays, for a cooling-off period of at least ten years, during which time their radioactivity is substantially reduced. Each nuclear generating station has sufficient capacity to store used nuclear fuel bundles in the wet bays for approximately 15 to 20 years of operation.

After the used nuclear fuel bundles have been stored for the cooling-off period, the bundles are transferred from the wet bays to above-ground dry storage containers at the corresponding nuclear station site. Currently, there is used nuclear fuel bundles in dry storage at the Pickering, Darlington and Bruce Nuclear sites.

OPG's planning assumption for the long-term management of used nuclear fuel bundles is consistent with the NWMO's APM concept of disposal in a deep geological repository. The NWMO has indicated that it currently expects an in-service date of 2043 at the earliest for the used fuel DGR.

Low and Intermediate Level Waste

The majority of OPG's L&ILW is stored at the radioactive waste management facility at WWMF located on the Bruce site. This facility, which continues to be owned and operated by OPG following the lease of the Bruce generating stations, operates under a separate licence issued by the CNSC. A smaller volume of ILW is stored at each of the radioactive waste management facilities at Pickering and Darlington sites. Respectively, these ILW storage facilities house the components from Pickering A's retube in the 1980's and from the recent Darlington Refurbishment of Unit 2. OPG's planning assumption for the long-term management of L&ILW is the placement of this nuclear waste in a separate L&ILW DGR.

Additional details can be found in the section, *Description of the Business* under the heading, *Regulated – Nuclear Waste Management Segment – Deep Geologic Repository for Low and Intermediate Level Waste.*

Station Decommissioning

OPG's planning assumption for the decommissioning of its nuclear generating stations is a deferred dismantlement strategy. Under this strategy, each station will be de-watered and de-fuelled immediately after it has ceased operations and prepared for safe storage and monitoring. Thereafter, OPG intends to monitor the station for approximately 30 years while in safe storage, after which time the station will be dismantled and the site restored over a period of approximately ten years. This strategy has been communicated to the CNSC through regular updates of OPG's preliminary decommissioning plans and liability estimates for the nuclear generating stations. Currently, OPG has received CNSC acceptance of the OPG Financial Guarantee for the five year period from 2018 to 2022 based on the fund performance and estimate for decommissioning the OPG nuclear assets. OPG's nuclear operating licences have been issued based on, amongst other things, CNSC's understanding of this strategy.

Deep Geologic Repository for Low and Intermediate Level Waste

OPG has proposed a deep geologic repository as the preferred solution for the safe long-term management of the L&ILW produced from the continued operation of OPG-owned nuclear generating stations and their eventual decommissioning. Agreement has been reached with local municipalities for OPG to develop the L&ILW DGR on lands adjacent to the WWMF in Kincardine, Ontario.

Under the NSCA, OPG requires licences from the CNSC for activities to be undertaken with respect to the L&ILW DGR project. Before the CNSC can make licensing decisions for the proposal, an EA must be conducted in compliance with the requirements of the *Canadian Environmental Assessment Act*. As part of the EA process for the L&ILW DGR, Environmental Impact Statement, Preliminary Safety Report, and Technical Support Documents were submitted to the CNSC in 2011. The purpose of these submissions was to obtain EA approval and a site preparation and construction licence from the Joint Review Panel (JRP) for the project. The responsibility of the JRP, which was appointed by the Canadian Environmental Assessment Agency (CEAA) and the CNSC in 2012, was to examine the environmental effects of the proposed DGR to meet the requirements of the *Canadian Environmental Assessment Act.* In May 2015, the JRP submitted its report and recommendations on the EA to the federal Minister of Environment. The report concluded that, given mitigation, there is unlikely to be significant environmental impact from the project and recommended that the Minister approve the EA. The report suggested that the project should be implemented expeditiously.

In August 2015, OPG responded to the CEAA's list of potential environmental conditions relating to the JRP report. In February 2016, the federal Minister of Environment and Climate Change requested additional information on certain aspects of the EA, including information related to alternate locations for the project and the impact on environmental effects if Canada's planned used fuel deep geologic repository being developed by the NWMO were to be located in close proximity to OPG's proposed L&ILW DGR. OPG has completed the requested studies and submitted the requested information in December 2016, as planned. Following its review of OPG's submission and a period of public comment, the CEAA requested further information that OPG subsequently provided in May 2017. In June 2017, the

CEAA notified OPG that it had sufficient and adequate information to proceed with the next step of the environmental assessment process and advised that a draft report and updated terms and conditions would be prepared for public review.

On August 21, 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of potential cumulative effects of the project on the Saugeen Ojibway Nation's (SON) physical and cultural heritage, including a description of the potential effects of the project on the Nation's spiritual and cultural connection to the land, taking into account the results of the SON Community Process. OPG is working closely with the SON to formulate a response to the information request.

The L&ILW DGR at the WWMF site remains OPG's preferred solution for the safe long-term management of the L&ILW. The in-service date of the L&ILW DGR is expected to be approximately six to seven years from the start of construction.

Funding Mechanisms

On April 1, 1999, Ontario Hydro's obligation for nuclear facilities decommissioning and nuclear waste management was transferred to OPG. The responsibility for funding the liabilities for nuclear facilities decommissioning and the long-term nuclear waste management between the Province and OPG is described in the ONFA. The key provisions of the ONFA are: (i) for OPG to establish two segregated funds, the Used Fuel Segregated Fund to fund the future costs of long-term nuclear used fuel waste management and certain costs of used fuel storage incurred after the stations are shut down, and the Decommissioning Segregated Fund to fund the future costs of nuclear decommissioning and long-term L&ILW management, and certain costs of used fuel storage incurred after the stations are shut down; (ii) for the OEFC to be responsible for funding approximately $2.4 billion present value as at April 1, 1999 that had been an accumulated liability of Ontario Hydro, which the OEFC has since then fully funded through an initial contribution to the Decommissioning Segregated Fund; (iii) for the Province to limit OPG's financial exposure in relation to the cost of used fuel management for the first 2.23 million bundles of used fuel; and (iv) for the Province to provide financial guarantees to the CNSC for OPG's nuclear decommissioning and nuclear waste management obligations, as required by the CNSC.

The Used Fuel Segregated Fund and the Decommissioning Segregated Fund are administered by a third party custodian and held in accounts segregated from OPG's other assets. OPG has granted a security interest in both funds to the Province. As a result, these funds are not available to satisfy the claims of OPG's creditors.

OPG's required contributions to the Used Fuel Segregated Fund and the Decommissioning Segregated Fund are determined based on reference plans and associated life cycle cost estimates periodically approved by the Province under the ONFA. These reference plans are prepared by OPG with the assistance of external consultants and based on external practices and international benchmarks. Under the ONFA reference plans, the total present value of OPG's future nuclear facilities decommissioning and nuclear waste management costs is determined based on baseline cost estimates and a set of underpinning major planning assumptions, including remaining useful lives of the nuclear stations, proposed methods and timing of nuclear waste disposal, and economic indicators. Given the long-term duration of these life cycle programs, the multiple assumptions involved and the evolving technology to handle nuclear waste, there is a significant degree of inherent uncertainty surrounding the measurement of the underlying costs, which may increase or decrease over time.

The limits to OPG's financial exposure under the ONFA with respect to the life cycle cost of long-term management of the first 2.23 million bundles of used fuel are as follows (all amounts are expressed in January 1, 1999 present value dollars): (i) OPG will bear all costs up to $4.6 billion; (ii) OPG and the Province will share, on an equal basis, costs incurred between $4.6 billion and $6.6 billion; (iii) OPG will be responsible for 10 percent of the costs incurred between $6.6 and $10 billion, and the Province will be responsible for the remaining 90 percent; (iv) the Province will be wholly responsible for any costs above $10 billion. As a result, OPG's funding liability for these used fuel costs under the ONFA is capped at $5.9 billion in January 1, 1999 present value dollars, which is equivalent to approximately

$15.7 billion in December 31, 2017 present value dollars. OPG is responsible for all incremental costs relating to the management of used fuel bundles in excess of the 2.23 million threshold. As at December 31, 2017, approximately 2.6 million bundles of used fuel waste had been produced. The 2.23 million fuel bundles threshold represents the estimated total life cycle bundles based on the initial estimated useful lives of the nuclear stations assumed in the ONFA.

Under the ONFA, the Province guarantees OPG's annual return earned in the Used Fuel Segregated Fund at 3.25 percent plus the rate of change in the Ontario Consumer Price Index, as defined in the ONFA, for funding related to the first 2.23 million used fuel bundles. Upon approval of a new or amended ONFA reference plan, the Province is obligated to make an additional contribution to the Used Fuel Segregated Fund in relation to the first 2.23 million bundles if the fund's assets earned a rate of return that is less than the guaranteed rate of return. If the return on the fund's assets exceeds the Province's guaranteed rate of return, the Province is entitled to withdraw any portion of the excess related to the first 2.23 million bundles, upon approval of a new or amended ONFA reference plan. OPG is responsible for cost increases and investment returns for the portion of the fund attributable to the used fuel bundles in excess of the 2.23 million threshold. OPG also is responsible for cost increases and investment returns for the Decommissioning Segregated Fund.

The investments in the Nuclear Segregated Funds include a diversified portfolio of equities and fixed income securities that are invested across geographic markets, as well as investments in real assets including infrastructure, real estate and agriculture. As the Nuclear Segregated Funds are invested to fund long-term liability requirements, the portfolio asset mix is structured to achieve the required return over a long-term horizon. While the Nuclear Segregated Funds are manage to achieve, in the long term, the target return rate based on the discount rate specified in the ONFA, the rates of return earned in a given period may be subject to various external factors including financial market conditions and changes in the Ontario Consumer Price Index, which, in the short-term, can be volatile and cause fluctuations in the Company's financial results. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

Under the current OEB-approved cost recovery methodology for OPG's nuclear waste management and nuclear facilities decommissioning liabilities, OPG's income is exposed to the rate of return risk for the portion of the Nuclear Segregated Funds related to the Pickering and Darlington nuclear generating stations.

Contributions to the Nuclear Segregated Funds

OPG's contribution requirements under the ONFA are recalculated each time there is an approved new or amended reference plan and under certain other events. Reference plans are required to be prepared at least every five years, or more frequently if there is an underlying change in the assumptions of the reference plan that both OPG and the Province agree are significant enough to trigger a recalculation of the contribution levels during the five-year period.

Prior to 2017, OPG made contributions to the Used Fuel Segregated Fund every quarter, including a one-time special payment in earlier years, as required by the ONFA. These contributions reflected ONFA requirements to fund the majority of the underlying used fuel liability by the end of the initial estimated useful lives of the nuclear stations assumed in the ONFA, resulting in significantly higher contributions to the Used Fuel Segregated Fund in the earlier years of OPG's existence. OPG has not been required to make contributions to the Decommissioning Segregated Fund, which was fully funded at its inception through the initial contribution made by the OEFC and, taking into account asset performance and changes in underlying funding obligations over time, at the time of every subsequent approved ONFA reference plan.

Based on the funded status of the Used Fuel Segregated Fund and the Decommissioning Segregated Fund reflecting the lower life cycle liability estimates per the 2017 ONFA Reference Plan, no overall contributions to either fund were required starting in 2017. Contributions to either or both funds may be required in the future should the funds be in an underfunded position when a new reference plan is

approved. Such may be the case as a result of future variability in asset performance due to volatility inherent in financial markets and economic conditions. Future contribution levels also are dependent on changes in baseline cost estimates and underpinning planning assumptions used to establish the funding obligations in subsequent ONFA reference plans, as well as any changes in the tax treatment of fund earnings. OPG's required contributions could increase, for example, if cost estimates increased, if the operating lives of the nuclear stations were revised, if fund assets earned less than the target rate of return, if the income earned in the funds became subject to tax, or if the NWMO were unable to receive the same sales tax treatment that OPG would be entitled to receive if the NWMO had not been established.

OPG is required to make annual contributions to the NFWA Trust based on a funding formula approved by the federal Minister of Natural Resources for OPG and the other nuclear fuel waste owners in Canada. The NFWA Trust forms part of the Used Fuel Segregated Fund. Any OPG contributions to the Used Fuel Segregated Fund as well as any portion of the Used Fuel Segregated Fund currently not in the NFWA Trust can be applied to satisfy the trust's annual contribution requirements. The funds in the Ontario NFWA Trust will be used for the purposes of long-term management of nuclear used fuel waste, in accordance with the NFWA. OPG and the Province are beneficiaries of the NFWA Trust.

If there is a surplus in the Decommissioning Segregated Fund such that the funding liabilities, as defined by the most recently approved ONFA Reference Plan, are at least 120 percent funded, OPG may direct, at the time a new or amended reference plan is approved, up to 50 percent of the surplus over 120 percent to the Used Fuel Segregated Fund, with the OEFC entitled to a distribution of an equal amount.

If there is a surplus in the Used Fuel Segregated Fund such that the funding liabilities, as defined by the most recently approved ONFA Reference Plan, are at least 110 percent funded, the Province has the right, at any time, to access the excess amount greater than 110 percent. Neither OPG nor the Province have a right to direct any amounts from the Used Fuel Segregated Fund to the Decommissioning Segregated Fund.

Upon termination of the ONFA, the Province has the sole right to any excess funds in the Decommissioning Segregated Fund and the Used Fuel Segregated Fund.

OPG has the responsibility for the management and disposal of the used nuclear fuel and L&ILW generated by the Bruce generating stations and for the eventual decommissioning of these stations. These obligations on the part of OPG are recovered from Bruce Power through annual rent payments and volume based fees per the Bruce Lease and related agreements. Pursuant to the lease agreement, Bruce Power must return the two Bruce stations to OPG together, in a de-fuelled and de-watered state. As such, these de-watering and de-fuelling costs will not be funded by OPG. Further details on the 2015 amendments to these agreements are found in the section, *General Development of the Business* under the heading, *Nuclear Business Development – Bruce Power Refurbishment and Bruce Lease Agreement*.

Provincial Guarantee

In accordance with the NSCA, the CNSC requires OPG to have sufficient funds available to discharge its existing nuclear waste management and nuclear decommissioning obligations. The CNSC process requires the CNSC financial guarantee requirement to be updated once every five years and for OPG to provide an annual report to the CNSC on the assumptions, asset values, and resulting financial guarantee requirements. The CNSC financial guarantee requirement calculation takes into account nuclear waste expected to be generated to the end of each year.

In November 2017, the CNSC accepted OPG's proposed 2018-2022 CNSC financial guarantee requirement to be satisfied by the forecast fair market value of the Nuclear Segregated Funds without the requirement of a Provincial Guarantee for the 2018-2022 period. As required by the terms of the ONFA, the Province is committed to provide a Provincial Guarantee to the CNSC, on behalf of OPG, should there be a shortfall between the CNSC financial guarantee requirement and the value of the Nuclear

Segregated Funds in the 2018-2022 period, as it has been done in the past. OPG pays the Province an annual guarantee fee equal to 0.5 percent of the outstanding amount, if any, of the Provincial Guarantee.

Services, Trading, and Other Non-Generation Segment

The Services, Trading, and Other Non-Generation segment is a non-generation segment that is not subject to rate regulation. It includes the revenue and expenses related to OPG's trading and other non-hedging activities. As part of trading activities, OPG transacts with counterparties in Ontario and neighbouring energy markets in predominantly short-term trading activities of typically one year or less in duration. These activities relate to electricity that is purchased and sold at the Ontario border, financial energy trades, financial risk management energy product revenues, and sales of energy-related products.

In addition, the segment includes the results of OPGET, which engages in U.S.-based wholesale energy trading activities in the U.S. northeast. The activities of OPGET include trading electricity in the U.S. using over-the-counter energy-related derivatives. OPGET retains Federal Energy Regulatory Commission market-based rate authorization.

The segment also includes revenue from real estate rentals and non-regulated services, gains or losses on disposition of non-regulated real estate assets, costs associated with non-regulated business development activities, and costs related to the Lambton GS and Nanticoke GS sites.

Fair Hydro Trust Segment

The Fair Hydro Trust segment is a non-generation segment that is not subject to rate regulation. It includes OPG's earnings from the Fair Hydro Trust, which includes the financial results of the Trust, as well as income related to OPG's role as Financial Services Manager of the Fair Hydro Trust and holder of subordinated debt issued by the Trust. Earnings include interest income from OPG's investment in subordinated debt of the Trust of up to 49 percent of the Trust's total outstanding debt, recovery of related to third-party costs and fees for financial management and ongoing administration services, partially offset by interest costs on debt issued by OPG to fund five percent of the subordinated investment in the Trust, incurred third-party costs, and other incurred costs related to the management and administration of the Trust.

Indigenous Relations

The Aboriginal and treaty rights of Indigenous communities are recognized and affirmed in the *Constitution Act, 1982*. OPG's corporate governance includes an Indigenous Relations policy to help build and develop mutually beneficial working relationships with Indigenous communities proximate to the Company's present and future operations. The policy focuses on building respectful relationships with Indigenous communities, businesses and organizations through partnership, collaboration, and support for procurement, employment and educational opportunities. The Company seeks to establish and maintain these relationships based on a foundation of respect for the languages, customs, and political, social and cultural organizations of the indigenous communities.

OPG may be subject to claims by Indigenous communities or other Indigenous groups and individuals. These claims may stem from generation development activities, historic operations of Hydro Electric Power Commission of Ontario and Ontario Hydro that may have impacted Aboriginal and treaty rights, or the absence of legal permits, rights-of-way, or easements. Legal precedents created by court rulings may impact negotiations and resolution of past grievances. To date, OPG has resolved 23 past grievance claims with 21 communities, achieving final settlement agreements.

In line with the company's Indigenous Relations policy, OPG is pursuing prospective generation-related developments and other joint projects with Indigenous communities. OPG currently has four generation development partnerships with Indigenous communities. OPG's first such partnership became operational in early 2009 as part of the Obishikokaang Waasiganikewigamig/Lac Seul GS project. The signing of the "*Amisk-oo-Skow*" Agreement with the Moose Cree First Nation (MCFN) in early 2010

marked the second such partnership. In 2011, the Lower Mattagami Limited Partnership agreement was amended and restated to include the MCFN and their wholly owned Amisk-oo-Skow Finance Corporation as limited partners and to enable the MCFN to acquire up to 25 percent limited partnership interest in the Lower Mattagami River project. During 2014, the MCFN acquired a 25 percent interest in the assets through its investment in the Lower Mattagami Limited Partnership as incremental units of the project were placed in-service.

OPG and CRP, a wholly owned corporation of the Taykwa Tagamou Nation, established Peter Sutherland Sr. GS Limited Partnership in January 2015. In March 2017, the Peter Sutherland Sr. GS was placed in-service and, in April 2017, the Taykwa Tagamou Nation, through CRP, increased their partnership interest in PSS to 33 percent under the partnership agreement.

Following selection by the IESO in March 2016, OPG and a subsidiary of the Six Nations of Grand River Development Corporation have partnered to develop a new 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands. The Nanticoke Solar Limited Partnership was formed in July 2015, and the Six Nations of Grand River Develop Coproration through its subsidiary acquired a 10 percent ownership interest in August 2015.

Other recent joint projects with Indigenous partners include two shoreline remediation projects completed in 2016. The Whitesand First Nation, working closely with OPG, completed a project to remediate nearly two kilometers of shoreline, while the Long Lake #58 First Nation undertook the management of a five-year shoreline remediation project. OPG also engaged the Mississaugas of New Credit regarding the sale of the Lakeview generating station site. OPG also has been engaging proactively with Indigenous communities regarding the Company's nuclear waste management operations, through regularly scheduled meetings and an ongoing dialogue in connection with OPG's proposed L&ILW DGR, the re-licensing of the PWMF and the WWMF, and the Pickering generating station's relicensing. Further engagement was conducted with First Nations in southwestern Ontario regarding the demolition of the Lambton and Nanticoke generating stations.

OPG is also committed to improving Indigenous access to procurement and employment opportunities, including increasing the profile of the nuclear generation industry in Indigenous communities. In 2017, OPG launched an Indigenous Business Engagement (IBE) Initiative. The purpose of this initiative is to increase access to procurement opportunities for Indigenous businesses interested in supplying materials and services to OPG. The IBE Initiative is based on a strategy that will identify opportunities in contracts, scopes of work and business plans for potential Indigenous business engagement; include criteria related to suppliers' ability to engage or partner with Indigenous people or businesses in assessing procurement proposals; and invest in relationships with Indigenous communities by increasing outreach efforts to enhance understanding of how to do business with OPG. OPG has been engaging with Indigenous businesses and communities as well as its suppliers to promote the IBE Initiative including the Mohawk Council of Akwesasne as well as the Williams Treaties First Nations, located proximate to the Pickering and Darlington nuclear generating stations.

OPG has been actively developing recruitment plans targeting Indigenous peoples. As part of this initiative, during the fourth quarter of 2017, OPG participated in several Indigenous-specific career fairs, hosted a Day in the Trades event for Indigenous students and job seekers as part of an open house at the Darlington Energy Centre, and approved additional plans aimed at increasing the number of Indigenous apprentices as part of the nuclear operations' recruitment program.

In November 2016, OPG was recognized for its ongoing commitment to engaging local Indigenous communities with the Canadian Electricity Association's (CEA) 2016 Sustainable Electricity award for Leadership in External Collaboration and Partnerships.

Workplace Safety and Public Safety

Workplace Health and Safety

In the area of workplace safety, OPG is committed to achieving excellent performance through continuous improvement and a strong safety culture, with the ultimate goal of zero injuries. OPG utilizes an integrated health and safety management system and a set of operational risk control procedures to ensure continued monitoring of health and safety performance and to support continuous learning and improvement in this area. Over the past five years, OPG has repeatedly stood in the top quartile of its comparator Canadian electrical utilities in various safety performance metrics.

Workplace safety performance is measured using two primary indicators at OPG, All Injury Rate (AIR) and Accident Severity Rate (ASR). OPG's AIR and ASR results for employee workplace safety were as follows for the year ended December 31:

	2017	2016	2015
AIR *(injuries per 200,000 hours worked)*	**0.48**	0.56	0.39
ASR *(days lost per 200,000 hours)*	**3.57**	2.59	0.50

In 2017, OPG's AIR improved from 2016 and was the third-best performance year in the history of the company. For those employee injuries that caused lost time from work, the total time lost from work in 2017 was greater than the previous year. OPG's analysis of the underlying safety events indicated that major contributors to the injuries and near misses included inadequate situational awareness and attention to detail, and suboptimal risk-based decisions, rather than missing or inadequate standards or programs. OPG continues to implement a number of initiatives to target the injury trends based on the analysis of the safety events, with a focus on the use of human performance tools including increased field supervisory oversight, situational awareness, communication, and procedural use and adherence.

In order to strengthen its safety performance, OPG continues to progress an organization-wide "iCare Enough to Act" initiative launched in 2016 and aimed at renewing employees' commitment to their own and each other's safety and well-being. Approaches to supervisory oversight, communication and safe work planning are being modified and updated to further strengthen safety as a foundational element of the Company's values-based culture.

Contractors are required to conduct work safely at OPG sites. In support of this requirement, OPG utilizes an independent contractor pre-qualification process, provides on-site safety support for many of its major projects, and works with contract partners to improve their health and safety programs to meet OPG's requirements. In the past nine years, OPG has consistently shown a better than average Construction Contractor AIR as compared to the Infrastructure Health and Safety Association Contractor AIR, a metric of construction contractor safety performance across Ontario. OPG has maintained this performance while engaging in the refurbishment of the Darlington GS, one of the largest infrastructure projects in Canada. The hours worked by contractors in 2017 were the largest in OPG's history, largely attributable to this project.

Since 2014, OPG has been operating under a single integrated health and safety management system and set of operational risk control procedures across the Company, providing consistent performance expectations for all employees. The control procedures are designed to ensure continued enterprise-wide monitoring of health and safety performance and to support continuous learning and improvement in these areas. Oversight and reporting by corporate and site safety functions is in place to provide senior management with regular information on the effectiveness of the safety management efforts, compliance with legal and corporate requirements, and safety performance trends. OPG's incident management system requires that all incidents, including near misses, be reported and investigated and that where beneficial, corrective action plans be developed and completed in order to prevent reoccurrences.

In 2014, OPG launched a Total Health initiative that aims to embed a health culture that supports employees and their families in their efforts to achieve an optimal level of health and functioning, through health education, health promotion, disease and injury prevention, and crisis intervention. In 2016, the Company launched the Mental Health First Aid training course for employees, an accredited training program facilitated by the Mental Health Commission of Canada. The training aims to increase awareness and empathy for mental illness, reduce stigma, support affected employees, and improve return to work outcomes. By the end of 2017, over 1600 "people leaders" had participated in this training.

Nuclear Radiation Safety

OPG manages a radiation protection program designed to minimize detrimental health effects to employees and members of the public. OPG follows developments in the field of radiation protection as documented by the International Commission on Radiological Protection (ICRP), the United Nations Scientific Committee on the Effects of Atomic Radiation, and the U.S. National Council on Radiation Protection and Measurements. Widely recognized as the main source of expert advice regarding protection from the harmful effects of ionizing radiation, the ICRP periodically issues recommendations concerning principles of radiation protection. These recommendations are usually adopted by most countries without significant modification and are incorporated into the applicable laws. The Canadian Radiation Protection Regulations are based on the recommendations of the ICRP, and OPG's nuclear facilities conform to these regulations. The CNSC is the federal agency that regulates radiation protection in Canada.

Radiation exposures to station personnel and the public are limited by station design and adherence to approved operating procedures. Over the years, OPG has been a leader in applying the principles of keeping radiation doses as low as reasonably achievable. OPG's internal operating limits for occupational exposure are set well below the regulatory limits to ensure that the regulatory limits are not exceeded. OPG's operating targets for radiological emissions are set at even more restrictive levels and typically represent small fractions of the regulatory limits.

To ensure continued public safety, radiation exposure to members of the public resulting from the operation of OPG's nuclear generating stations is estimated on an annual basis for individuals living or working near the stations. The annual dose to the public resulting from operations of each nuclear facility is expressed in microsieverts (μSv), an international unit of radiation dose measurement. For 2015, the annual public doses resulting from the Darlington GS operations and the Pickering GS operations were 0.5 μSv and 1.2 μSv, respectively, which is approximately 0.1 percent of the annual legal limit of 1,000 μSv. For 2016, the annual public doses resulting from the Darlington GS operations and the Pickering GS operations were 0.6 μSv and 1.5 μSv, respectively, which is less than 0.1 and 0.2 percent of the annual legal limit of 1,000 μSv, respectively. While the public doses from OPG's nuclear operations for the 2017 operating year will not be finalized until the second quarter of 2018, they are not expected to differ significantly from the 2016 levels.

As a condition of receiving operating licences for its nuclear facilities, OPG has developed comprehensive emergency plans that detail the Company's planned response to reactor accidents, as well as accidents involving the transportation of radioactive materials. These plans dictate how OPG will work with municipal, regional, provincial, and federal agencies to safeguard station personnel and members of the public in the unlikely event of a radiation emergency at one of OPG's facilities. Station staff are required to regularly participate in emergency exercises to maintain and continuously improve response capability for such events.

Dam Safety and Waterways Public Safety

OPG manages dam safety and other risks associated with the production of hydroelectric power through OPG's Safe Operations Policy and Dam Safety Program. The Safe Operations Policy directs that dams be designed, constructed, operated, and maintained in a manner that meets all regulatory requirements, or, in the absence of regulations, the safety guidelines published by the Canadian Dam Association or

other industry best practices. OPG is one of the first dam owners in Canada to have developed and implemented a dam safety program and is considered an industry leader in many aspects of the program.

In addition to effectively managing the safety of dams against catastrophic failure, OPG has developed a number of technical standards and procedures concerning public safety around dams, and materials to educate the public and raise awareness of the hazards associated with the operation of the hydroelectric facilities. This includes the implementation of control measures in the form of signage, safety booms, buoys, fencing and audible alerts at the appropriate facilities. These measures are actively managed to maintain their effectiveness. OPG also strives to entrench a "Stay Clear – Stay Safe" message as part of its public education program, through strategically placed advertisements and engagement of other agencies, such as the MNRF, Ontario Provincial Police, Life Saving Society, Ontario Waterpower Association, and other stakeholders.

Since 2007, OPG has engaged an independent advisory panel consisting of internationally recognized experts to conduct an annual review of its Dam Safety Program. The Chair of the independent panel establishes areas of in-depth review and presents the observations to OPG's Board of Directors. The panel has consistently found that the risks associated with the dams owned and operated by OPG are being managed in alignment with industry best practices and guidelines. OPG remains committed to high standards of public safety on waterways around hydroelectric generating stations and dams, and continues to make investments in waterway and dam safety upgrades.

Additional details on the regulatory regime related to dams and waterways can be found in the section, *Description of the Business* under the heading, *Water Rights.*

Environment

Overview

OPG is committed to meeting compliance obligations, including any environmental commitments that it makes, with the objective of exceeding these compliance obligations where it makes business sense. OPG's Environmental Policy specifically commits the Company to:

- Establish an environmental management system (EMS) and maintain registration for this system to the ISO 14001 Environmental Management System standard;
- Work to prevent or mitigate adverse impacts on the environment with a long-term objective of continual improvement;
- Strive to be a leader in climate change mitigation; and
- Manage sites in a manner that strives to maintain, or enhance where it makes business sense, significant natural areas and associated species of concern.

The policy is implemented through OPG's EMS. Within the EMS, OPG sets environmental objectives and maintains planning, operational control, and monitoring programs to manage its negative and positive impacts on the environment. The most significant environmental aspects of OPG's operations include: chemical emissions to water, spills, fish impingement and entrainment, thermal effluent emissions, displacement of fossil fuels, enhancement and disruption of wildlife habitat, radiological emissions, radioactive waste generation, and water flow and level changes. The policy is reviewed annually as part of the EMS to ensure that it remains appropriate to the nature, scale and environmental impacts of OPG's activities.

OPG communicates its environmental performance to external and internal stakeholders through a range of engagement methods such as reports and correspondence to regulators, meetings, newsletters, open houses, consultations, news releases, advertising campaigns, social media, and participation in community events.

Details of OPG's environmental performance and initiatives to fulfill the Environmental Policy can be found in OPG's annual *Sustainability Report*, which is available on the Company's website at

www.opg.com. ***Unless otherwise specifically stated, none of the information contained on, or connected to the Company's website nor any of the contents of the Sustainability Report are incorporated by reference herein.***

Environmental Compliance

OPG must comply with a large number of environmental requirements contained in statutes, regulations, by-laws, licences, permits and approvals. Failure to comply with applicable environmental laws may result in enforcement action, including the potential for orders or charges. OPG reports any incidents of non-compliance to the appropriate federal, provincial or municipal authorities as required, with corrective action plans developed and implemented accordingly.

Changes in environmental regulatory requirements may result in existing operations being in a state of non-compliance, a potential inability to comply, and potential costs and liabilities for OPG. To ensure compliance, such circumstances may require OPG to install control technologies, develop new processes, allowances or offsets, or place constraints on electricity production.

Protection of Fish

Electricity generating facilities located on waterways can impact fish in a number of ways. At nuclear and thermal stations, the intake of water for cooling purposes can result in fish being impinged on station equipment and fish larvae and eggs being entrained in the water as it passes through the station. The warmer water returned to the water body also has the potential to impact aquatic organisms and habitat near the station. At hydroelectric stations, the flow of water through the station turbines can result in fish entrainment and mortality, while physical barriers such as dams can prevent the migration of fish.

OPG utilizes measures such as fish ladders, trap and transport programs, stocking programs, barriers and deterring structures, water flow alterations, habitat protection and creation, and station effluent temperature limits to manage and mitigate impacts to fish. Potential regulatory changes being monitored and managed as risks by the Company include electricity production constraints and water flow management requirements to protect fish and fish habitat, and expanded fish passage requirements.

Biodiversity and Habitat Stewardship

The generation of electricity can have an impact on biodiversity, either directly through habitat loss and fragmentation or indirectly through emissions to the environment. OPG is committed to managing its sites in a manner that strives to maintain significant natural areas and associated species of concern. OPG also works with its community partners to support regional ecosystems and biodiversity through science-based habitat stewardship. OPG's regional biodiversity program strategically funds and promotes efforts to protect and restore biodiversity in areas of Ontario where genetic, species or ecosystem diversity have been most impacted, and substantive threats remain. In 2017, OPG continued efforts to protect and restore habitat, promote biodiversity education and awareness, and help the recovery of species at risk. In November 2017, OPG's biodiversity program was recognized by the CEA with the 2017 Sustainable Electricity award for Commitment to Continuous Performance Improvement.

Climate Change Mitigation and Air Quality

OPG's operational and growth strategies support reductions in GHG emissions and improved air quality. After safely ending coal-fired generation in the province, OPG has become Ontario's largest clean energy provider, producing and selling electricity that is 99 percent free of GHG and smog-causing emissions. The elimination of coal-fired electricity production at OPG's generating stations resulted in coal being reduced from one-quarter of Ontario's energy supply mix in 2003 to zero in 2014.

OPG monitors and reports GHG emissions from its facilities in accordance with the regulatory requirements set out by Environment and Climate Change Canada and the MOECC. In 2016, the Government of Ontario passed the *Climate Change Mitigation and Low-Carbon Economy Act, 2016* and

the associated *Cap and Trade Program Regulation*. The legislation provides the foundation for regulating GHG emissions in Ontario and includes a cap and trade program, with the first compliance period being from January 1, 2017 to December 31, 2020. The cap and trade program is a market mechanism intended to give Ontarians an incentive to reduce GHG emissions by putting a price on carbon. The program requirements are expected to result in increased fuel costs for some OPG-owned and co-owned generating facilities. Fuel costs for these stations are generally recovered from the electricity market. With OPG's low GHG emitting fleet, this is not expected to have a material adverse financial impact on the Company. OPG has established the necessary processes to comply with the cap and trade program requirements.

OPG is monitoring actions being taken by the Government of Ontario and the Government of Canada to reduce GHG emission levels and transition to a low-carbon economy. In support of efforts to mitigate climate change, the Company continues to evaluate and implement plans to increase the generation capacity of its hydroelectric generating fleet, where economical, and invest in other low-carbon technologies. OPG also has a strategy to help position the Company as a leader in transportation electrification in the province. The strategy aims to leverage the Company's clean, reliable and cost-effective electricity to power transportation, capitalize on future commercial growth opportunities, and enhance the Company's social licence. OPG is pursuing initiatives to increase the use of electric vehicles within its operations, and is assessing vehicle grid integration and hydrogen applications for the transportation sector. Ontario's climate change plan aims for electric and hydrogen passenger vehicles to represent five percent of new vehicle sales in the province by 2020.

As part of its commitment to help de-carbonize Ontario's transportation sector, OPG is a founding sponsor of Plug'n Drive, a non-profit organization working to accelerate the adoption of electric vehicles and to maximize their environmental and economic benefits. In May 2017, Plug'n Drive announced the opening of the world's first experiential learning facility dedicated to electric vehicle education and awareness, with OPG sponsoring the Centre's training facility.

Radiological Emissions

Very low levels of radioactivity are released to air and water as a result of operating the reactors at OPG's nuclear generating stations. OPG maintains an effluent monitoring and control program to ensure radiological emissions are kept well below the release limits specified in the station operating licences. OPG also has environmental monitoring programs in the vicinity of the nuclear stations to ensure operations have no adverse impacts on human health and the environment. These programs are designed to assess impacts, demonstrate compliance with regulatory limits, validate the effectiveness of containment and effluent controls, and verify predictions made by environmental risk assessments. Results from the monitoring programs have confirmed OPG's radiological emissions are a small fraction of the regulatory release limits.

In June 2016 and August 2016, the CNSC released sampling results from its independent environmental monitoring program, which confirmed that the public and the environment around OPG's nuclear generating stations continued to be safe.

Further details are discussed under the heading, *Workplace Safety and Public Safety – Nuclear Radiation Safety.*

People and Culture

Workforce Resourcing Strategies

Electricity generation involves complex technologies that require highly skilled and trained workers, and a well trained and engaged workforce is fundamental to the achievement of OPG's strategic imperatives. The Company is focused on improving the capability of its workforce through leadership development, knowledge management, diversity and inclusion programs, and hiring in key areas. Ability to secure the right talent mix in order to effectively meet the Company's immediate and longer term business needs on

a timely basis is supported through workforce planning, resourcing and on-boarding strategies, both to acquire external talent into the organization and to develop existing employees. The goal of resourcing strategies and workforce planning is to ensure that the Company's workforce is diverse and has the right skill set and capability for the safe and effective operation of the generating facilities and successful delivery of major projects, including the Darlington Refurbishment. These strategies are being designed to take into account anticipated staffing requirements to the end of planned commercial operations of the Pickering GS, through to the end of the planned period to de-fuel, de-water and place the station in a safe state condition.

As part of the strategy to develop and engage employees and to build leadership talent in support of the Company's long-term success, OPG has an active succession planning program with a focus on accelerating development. This includes a company-wide high potential leadership development program for qualified internal candidates. This 14-month cross-functional, competitive-entry program is designed to identify and develop candidates for future leadership positions while they are relatively early in their careers. OPG also has a talent management monitoring process to proactively assess staffing risks, challenges and opportunities.

Many positions at OPG have significant educational prerequisites and rigorous requirements for continuous training and periodic requalification. In addition to maintaining its internal training infrastructure, OPG relies on partnerships with government agencies, other electrical industry partners, and educational institutions to meet the required level of qualification.

Effective January 1, 2017, OPG implemented an Executive Compensation Program that is compliant with *Ontario Regulation 304/16: Executive Compensation Framework*, introduced in September 2016. While the Province released two subsequent amendments, *Ontario Regulation 187/17* and *Ontario Regulation 400/17* in June 2017 and November 2017, respectively, OPG's Executive Compensation Program continues to be subject to the original regulation's requirements. The regulation sets out how all employers designated under the *Broader Public Sector Executive Compensation Act, 2014*, including OPG, must establish and post compensation programs for executives. The program must include the compensation philosophy, salary and performance-related pay caps, comparative analysis details, and a description of other elements of compensation. OPG's Executive Compensation Program is designed to provide compensation that is at the 50th percentile of the market and focused on at-risk, performance based pay. The program will better enable OPG to attract, align and retain the executive talent critical to delivering Shareholder and customer value, while ensuring continued safe and reliable operations. For further information, refer to the section, *Corporate Governance* under the heading, *Compensation.*

Employees

OPG's average number of full-time employees and average number of seasonal, casual construction and non-regular staff (Other Staff) in 2017 were as follows:

Business Segment	**Full-time Employees**	**Other Staff**
Regulated – Nuclear Generation [1]	7,360	1,432
Regulated – Hydroelectric	1,125	54
Contracted Generation Portfolio	531	49
Services, Trading, and Other Non-Generation [2]	96	7
Total	**9,111**	**1,541**

[1] Including employees associated with the Regulated – Nuclear Waste Management segment.
[2] The Fair Hydro Trust, a non-generation segment that is not subject to rate regulation, was established in December 2017. As of December 31, 2017 there were 3 full-time employees in the Fair Hydro Trust segment.

The majority of OPG's employees are represented by the PWU and The Society. The PWU includes most workers below the level of first line manager – from clerical staff to technicians and trades staff and station operators. The Society includes supervisors, professional engineers, scientists, and other professionals.

Bargaining rights with the 19 craft unions that perform construction work at OPG's generating facilities in addition to the regular workforce are established either through the EPSCA or directly with OPG. EPSCA is a voluntary association of owners and contractors who perform work in the electrical power systems sector. The primary purpose of EPSCA is negotiating and administering collective agreements on behalf of employers performing work on what is now OPG property. Collective agreements between the Company and its construction unions are negotiated either directly or through EPSCA. OPG currently has 17 agreements through EPSCA and two direct trade agreements. The two direct trade agreements are with the Canadian Union of Skilled Workers and the Brick and Allied Craft Union.

Insurance

The principal types of discretionary insurance carried by OPG include directors' and officers' liability, excess commercial general liability, all risks property, boiler and machinery breakdown, including statutory boiler and pressure vessel inspections, and business interruption. In addition to providing coverage for OPG's non-nuclear facilities, this insurance applies to the conventional operations at OPG's nuclear generating stations. OPG also maintains nuclear property insurance, including nuclear boiler and machinery breakdown, for damage to the nuclear portions of its generating stations and for perils propagating from the nuclear to the conventional side of its assets. This coverage complements the conventional property insurance program.

OPG also purchases or requires contractors to purchase discretionary insurance for construction projects. For the Darlington Refurbishment project, the insurance coverage for the pre-requisite construction works was placed in 2013 and for refurbishment execution in 2016. The owner-controlled insurance program for the refurbishment consists of wrap-up liability, course of construction and marine transit insurance.

OPG purchases certain insurance coverage as required by statute, namely owned and leased motor vehicle liability, aviation liability (for drone operations) and nuclear energy liability insurance. The federal *Nuclear Liability and Compensation Act* (NLCA) that came into effect on January 1, 2017, and its predecessor legislation, the *Nuclear Liability Act* (NLA), impose absolute liability on a licensed operator of a nuclear generating station for any damage to property of, or injury to, the public arising from a nuclear incident, other than damage resulting from sabotage or acts of war. As such, the legislation protects all other persons from liability, including suppliers of nuclear fuel and components used in nuclear reactors.

The NLCA requires all operators of nuclear generating stations in Canada to maintain specified amounts of nuclear liability insurance purchased from a federal government approved insurer or other equivalent forms of financial security approved by the federal government. Under the NLCA, OPG is required to maintain an initial $650 million per incident of nuclear energy liability insurance for each of its nuclear installations as defined by the NLCA effective in 2017, for which there is no deductible amount, with successive annual increases to $750 million, $850 million, and $1 billion over the 2018-2020 period. The Pickering GS site and the Darlington GS site are considered to be two separate nuclear installations under the NLCA. OPG is also required to maintain $13 million per incident of nuclear energy liability insurance for the WWMF. OPG is not responsible for purchasing nuclear liability insurance for the Bruce nuclear generating stations. Previously, the NLA required OPG to maintain $75 million per incident of nuclear energy liability insurance for each of the Pickering GS site and the Darlington GS site and $6 million for the WWMF, purchased from a federal government approved insurer. OPG continues to maintain nuclear liability insurance or other forms of financial security that have been approved by the federal government equal to the required liability limits.

Under Part I of the NLCA, an operator is liable for all damages resulting from a nuclear incident. If, in the opinion of the Governor in Council, OPG's liability could exceed the specified insured amount in respect of a nuclear incident, or it would be in the public interest to do so, the Governor in Council shall proclaim Part II of the NLCA as applicable in respect of a nuclear incident. Under Part II of the NLCA, OPG's liability would be effectively limited to the amount of required abovementioned insurance, and the Governor in Council may authorize additional funds to be paid by the federal government as may be specified in an order.

RISK FACTORS

For details on risks faced by OPG, see *Risk Management* in the Company's 2017 year-end MD&A.

DIVIDENDS

The declaration and payment of dividends remains at the sole discretion of OPG's Board of Directors and is dependent on the results of OPG's operations, the Company's financial condition and cash requirements, securities legislation requirements, and other factors considered relevant by the Board of Directors in exercising its discretion and judgment on an ongoing basis. OPG did not declare or pay any dividends for the years 2015 to 2017.

There are no restrictions in the articles of the Company that could prevent the Company from paying dividends. However, the declaration and payment of dividends are subject to financial tests set forth in the OBCA.

DESCRIPTION OF CAPITAL STRUCTURE

The authorized share capital of OPG consists of an unlimited number of common shares (the voting shares of the Company) and Class A shares. As at December 31, 2017, OPG had 256,300,010 common shares issued and outstanding, all of which are owned directly by the Province at a stated value of $5,126 million. As at December 31, 2017, OPG had 12,217,616 Class A shares issued and outstanding, all of which are owned directly by the Province at a stated value of approximately $519 million. OPG is authorized to issue an unlimited number of common shares and Class A shares without nominal or par value. Holders of common shares are entitled to one vote per share at meetings of the shareholders of the Company and, along with Class A shares, to receive dividends if, as, and when declared by the Board of Directors of the Company. Holders of common shares and Class A shares would participate, pro rata to their holding of common shares, and Class A share, in any distribution of the assets of the Company upon its liquidation, dissolution, or winding up. Any issuance of new shares is subject to the consent of all of OPG's shareholders.

All of the Company's voting securities are held by the Province. Accordingly, the Company is controlled by the Province.

CREDIT RATINGS

DBRS Limited (DBRS) and S&P Global Ratings (S&P) provide credit ratings for commercial entities. A credit rating generally provides investors with an independent measure of credit quality of an issue of securities. Credit rating categories for long-term debt instruments range from highest credit quality (generally 'AAA') to default in payment (generally 'D').

In April 2017, DBRS re-affirmed the long-term credit rating on OPG's debt at 'A (low)' and the commercial paper rating at 'R-1 (low)', each with a stable outlook. In July 2017, S&P re-affirmed OPG's long-term credit rating at BBB+ with a stable outlook. On July 7, 2015, S&P lowered OPG's long-term corporate credit rating from 'A-' to 'BBB+' with a stable outlook. S&P's rating action followed its July 6, 2015 downgrade to the Province's rating from 'AA-' to 'A+'. The link between the Province and OPG through ownership and financial support may impact OPG's credit rating. S&P's commercial paper rating for OPG is 'A-1 (low)'.

Long-term debt instruments that are rated in the 'A' category by DBRS are considered to be of good credit quality. The capacity for the payment of financial obligations by the obligor of such instruments is considered to be substantial, but of lesser credit quality than higher-rated entities. Entities in the 'A' category may be vulnerable to future events, but qualifying negative factors are considered manageable. The addition of a "high" or "low" modifier indicates relative standing within the rating category.

A ‘BBB’ rating category by S&P for long-term debt instruments means that the obligor has adequate capacity to meet its financial commitments, but is considered more subject to adverse economic conditions than higher-rated entities. The addition of a plus ‘+’ or minus ‘-’ designation after a rating indicates the relative standing within a particular rating category.

DBRS’s commercial paper credit rating scale ranges from ‘R-1(high)’ to ‘D’, which represents the highest to lowest quality of such securities rated. The rating of ‘R-1(low)’ is the third highest and is considered to be of good credit quality. S&P’s Canadian commercial paper rating scale ranges from ‘A-1 (high)’ to ‘D’, which represents the highest to lowest quality of such securities rated. The rating of ‘A-1 (low)’ is the third highest and is considered to be satisfactory.
There can be no assurance that a credit rating will remain in effect for any given period of time or that a credit rating will not be lowered, withdrawn or revised by either or both rating agencies if, in their judgment, circumstances so warrant. The rating of any securities is not a recommendation to buy, sell or hold such securities, and such ratings do not comment as to market price or suitability for a particular investor.

During the past two years, OPG has made payments to DBRS and S&P’s credit rating agencies for their credit rating services and for other services. OPG reasonably expects such payments will continue in the future for the services acquired.

MARKET FOR SECURITIES

In October 2017, OPG issued Series 1 Notes with a coupon rate of 3.315 percent for a principal amount of $500 million are currently outstanding and are not listed on any exchange or similar market for securities. The Notes are due in 2027.

CORPORATE GOVERNANCE

National Instrument 58-101 *Disclosure of Corporate Governance Practices* (NI 58-101), has been implemented by Canadian securities regulatory authorities to provide greater transparency for the marketplace regarding issuers' corporate governance practices. OPG’s corporate governance practices align with NI 58-101 and National Policy 58-201 *Corporate Governance Guidelines.* In addition, OPG has reviewed its governance practices against the principles discussed in the 2013 Report on Building High Performance Boards issued by the Canadian Coalition for Good Governance and concluded that OPG compares favourably to those principles that apply to OPG.

Information with respect to OPG’s Board of Directors is as follows:

Board of Directors

OPG’s Board of Directors (Board) is made up of 14 individuals with the following capabilities:

- managing large businesses;
- managing and operating nuclear stations;
- understanding of the Canadian nuclear environment;
- engineering and/or project management, including large infrastructure project management;
- managing capital intensive companies;
- knowledge and expertise in mergers and acquisitions;
- overseeing regulatory, government and public relations;
- human resources management;
- financial, investment, legal and corporate governance expertise;
- knowledge of information technology/cybersecurity;
- knowledge of Indigenous communities; and
- stakeholder management.

The Board exercises its independent supervision over management as follows: the majority of members of the Board are independent of the Company; meetings of the Board are held at least five times a year; a formal Charter for the Board and for each Board committee has been adopted and the charters are reviewed annually; the Board and each Board committee is chaired by an independent Director; and a portion of each Board and Board committee meeting is reserved for independent Directors to meet without management present.

OPG has a written position description for the Chief Executive Officer (CEO). This position is accountable to the Board for: ensuring a culture of integrity and ethical conduct; increasing Shareholder value; defining and executing a corporate strategy, including a sustainable business model that will service the long-term power generation needs of the province; and providing a standard of leadership that will achieve operational excellence with respect to matters of safety, stakeholder relationships, financial performance, asset reliability, and health, environmental and regulatory compliance. In addition, the Board delineates the President and CEO role and responsibilities through the By-laws, the Board Charter, the Board policies, and the corporate and CEO annual goals and objectives. The Board sets, and monitors performance against, annual corporate and CEO targets and objectives.

Director Independence

On an annual basis, the Compensation, Leadership and Governance Committee of the Board reviews the disclosures made by Directors in the annual Director Questionnaire and reviews each disclosed affiliation's relationship with OPG in order to determine whether the Director is (or remains) independent. The Compensation, Leadership and Governance Committee reports on its review to the Board.

Based on the meaning of Independence in Section 1.4 of National Instrument 52-110 *Audit Committees* (NI 52-110) and a review of the applicable factual circumstances against this standard, the Compensation, Leadership and Governance Committee has determined that all Directors listed are independent, except for Jeffrey Lyash, who is considered to have a material relationship with OPG by virtue of his position as President and CEO of OPG.

The Board has a Board of Directors Conflict of Interest Policy and Procedure that governs the disclosure and mitigation of Director conflicts or potential conflicts of interest and has adopted an annual process of written disclosure by Directors in order to:

(i) identify potential conflicts of interest for the purposes of complying with the Board of Directors Conflict of Interest Policy and the OBCA;
(ii) validate the Directors' independence and financial literacy for the purposes of complying with securities regulations related to boards of directors and audit committees; and
(iii) satisfy other disclosures and regulatory filings.

To further minimize potential conflicts of interest, the Board has a policy on interlocking directorships. This policy states that no more than two OPG Directors may sit on a board of directors of another reporting issuer at the same time. Directors must confirm that they are in compliance with OPG's policy on interlocking directorships when disclosing to the Board Chair appointments to other boards of directors.

Strategic Planning

OPG's Board holds an annual strategy session and devotes a significant portion of each regular Board meeting to discussion of strategic matters. Management is responsible for developing the strategy and presenting it to the Board for discussion.

In 2017, the Board received reports on key strategic issues, risks, competitive developments, and corporate opportunities facing the Company. Management ensures that the key strategic elements are incorporated into OPG's annual budget and business plan, which are reviewed and approved by the Board. The Board also periodically receives briefings from external advisors on broad energy industry developments and/or special strategic matters.

Overseeing the Management of Risk

The Board oversees OPG's approach of identifying, reporting and mitigating the risks that could significantly impact the Company's capacity to achieve its long-term strategic objectives, as well as specific business plan objectives. To fulfill its risk oversight responsibilities, the Board has established an Enterprise Risk Management Policy and an Audit and Risk Committee, comprised of independent Directors. The committee's mandate includes oversight of the Enterprise Risk Management (ERM) framework that management uses to manage the Company's risk profile. The ERM framework assists the Board in understanding how risks may affect the Company and how they are being addressed by management. The Audit and Risk Committee receives quarterly reports from OPG's Chief Risk and Audit Executive (CRAE) on enterprise-wide risks.

Through the Compensation, Leadership and Governance Committee, the Board also monitors the risks associated with the executive compensation program, to preclude the Company's decision-makers from taking excessive risk in order to achieve incentives under the compensation plans. The CRAE and Senior Vice President, People & Culture and Chief Ethics Officer jointly review the executive compensation framework on an annual basis to identify any potential for unintended risk-taking. The CRAE and Senior Vice President, People & Culture and Chief Ethics Officer provide an annual joint report to the Compensation, Leadership and Governance Committee on the results of their review.

Directors

The following tables set forth the name, age, municipality of residence, position with the Company and principal occupation of each of the Directors of the Company as of March 8, 2018. Each Director holds office until he or she resigns or a successor is elected or appointed. For a discussion of the Board Committee structure, refer to the heading, *Committees of the Board of Directors*.

Bernard Lord
Age: 52
Moncton, New Brunswick, Canada

Bernard Lord was appointed Board Chair for Ontario Power Generation on April 1, 2014. Mr. Lord is the CEO of Médavie, a not-for-profit Canadian medical care insurance company headquartered in Moncton, New Brunswick.

Mr. Lord earned a bachelor's degree with a major in economics as well as a bachelor's degree in common law from l'Université de Moncton. He has also received honorary doctorate degrees from University of New Brunswick, l'Université de Moncton and Saint Thomas University. He was admitted to the New Brunswick Law Society in 1993 and was appointed as Queen's Counsel in 2011.

Mr. Lord was the CEO of the Canadian Wireless and Telecommunications Association from October 2008 until August 2016. He also served on several other boards of directors.

In 1999, Mr. Lord became one of Canada's youngest Premiers at the age of 33. His majority government was re-elected in 2003 and he served as Premier of New Brunswick until October 2006. He was elected four times as a Member of the New Brunswick Legislative Assembly.

Mr. Lord's government introduced several new initiatives to support the development of natural resources while also protecting the environment, including a new energy policy that lead to the restructuring of NB Power and the refurbishment of the Point Lepreau nuclear generating station.

During Mr. Lord's terms as Premier, New Brunswick saw the lowest unemployment rate in 30 years and tax cuts each year, combined with balanced budgets and debt reduction. His government made record investments in health care and education while strengthening local democracy and modernizing the Official Languages Act.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since November 2013) *****	8 of 8	100%
Special Committee (since March 2017)	14 of 15	93%
The Board Chair is not a member of any standing Committee. The Board Chair attends all Committee meetings.	18 of 18	100%

Principal Occupation: CEO of Médavie

Board Memberships for other Reporting Issuers: None

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

*Chair

Jeffrey Lyash
Age: 56
Toronto, Ontario, Canada

Jeff Lyash is the President and CEO of OPG. Mr. Lyash was formerly the president of CB&I Power, a position he held from 2013 to 2015, where he was responsible for a full range of engineering, procurement and construction of multi-billion dollar electrical generation projects in both domestic and international markets. He also provided operating plant services for nuclear, coal, gas, oil and renewable generation.

Prior to joining CB&I in 2013, Mr. Lyash served as Executive Vice President of Energy Supply for Duke/Progress Energy from 2008 to 2012. With Duke Energy, he led engineering, maintenance and operations of the company's 42,000-megawatt generation fleet, fuel procurement, power trading, major projects and construction, environmental programs, and health and safety programs.

Before the merger of Progress Energy and Duke Energy, Mr. Lyash served as Executive Vice President of Energy Supply for Progress Energy. In this role, he oversaw Progress Energy's diverse 22,000-megawatt fleet of generating resources including nuclear, coal, oil, natural gas and hydroelectric stations. In addition, he was responsible for generating fleet fuel procurement and power trading operations.

Mr. Lyash began his career in the utility industry in 1981, joining Progress Energy in 1993. Before assuming the role of Executive Vice President of Energy Supply, he served as Executive Vice President of Corporate Development, President and Chief Executive Officer of Progress Energy Florida, Senior Vice President of Energy Delivery Florida, and Vice President of Transmission. He also held a wide range of management and executive roles in Progress Energy's nuclear program, including Operations Manager, Engineering Manager, Plant Manager, and Director of Site Operations.

Before joining Progress Energy, Mr. Lyash worked for the U.S. Nuclear Regulatory Commission (NRC) in a number of senior technical and management positions throughout the northeast United States and in Washington, D.C, receiving the NRC Meritorious Service Award in 1987.

Mr. Lyash earned a Bachelor's Degree in Mechanical Engineering from Drexel University, and was honored with the Drexel University Distinguished Alumnus Award in 2009. He has held a Senior Reactor Operator License from the NRC, and is a graduate of the U.S. Office of Personnel Management Executive Training Program and the Duke Fuqua School of Business Advanced Management Program.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since August 2015)	8 of 8	100%
The President and CEO attends all Committee meetings, excluding independent Director in-camera meetings/sessions.	18 of 18	100%

Principal Occupation: President & Chief Executive Officer, Ontario Power Generation Inc.

Board Memberships for other Reporting Issuers: None

Independence from OPG: Not Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

William Coley
Age: 74
Charlotte, North Carolina, U.S.A

Bill Coley served as Chief Executive of British Energy from 2005 to 2009 when he retired following the successful combination of British Energy and EDF Energy. He was President of Duke Power from 1997 until his retirement in February 2003, holding various officer level positions in engineering, operations and senior management during his 37-year career with the company.

Mr. Coley is a director of E.R. Jahna Industries. He also served on the WANO Fukushima Commission

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since January 2013)	8 of 8	100%
Compensation, Leadership and Governance Committee (since February 2016)	5 of 5	100%
Generation Oversight Committee (since February 2016)	4 of 4	100%
Darlington Refurbishment Committee (since May 2015)	4 of 4	100%
Special Committee (since March 2017)	15 of 15	100%

Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: None

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

Elisabeth (Lisa) DeMarco
Age: 50
Toronto, Ontario Canada

Lisa DeMarco is a senior partner at DeMarco Allan LLP with over two decades of experience in law, regulation, policy, and advocacy relating to energy and climate change. Ms. DeMarco was previously a partner at Macleod Dixon LLP from 2002 to 2012, partner at Norton Rose Canada LLP from 2012 to 2013 and partner at Norton Rose Fulbright LLP from 2013 to 2014. She represents several governments and leading energy companies in a wide variety of natural gas, electricity, pipeline and energy storage matters before various regulatory agencies, including the OEB and the National Energy Board. She has been an adjunct professor at Osgoode Hall Law School, is a guest lecturer at a number of law schools and presents regularly.

Ms. DeMarco also assists leading Canadian energy companies and Indigenous business organizations on domestic and overseas power project development, renewable power projects, alternative fuel projects, cleantech development and finance, energy storage, carbon capture and storage, corporate social responsibility, environmental disclosure, clean energy finance, and sustainable business strategy.

She is ranked by Chambers Global as one of the world's leading climate change lawyers and regularly attends and advises on related United Nations negotiations. She is ranked and repeatedly recommended by LEXpert, Expert Guide, International Who's Who, and Chambers Canada as a leading energy (oil, gas, and electricity) and environment lawyer. Ms. DeMarco has worked for multilateral development banks and energy companies on deals and projects in India, Brazil, Sri Lanka, Thailand, Argentina, Chile, Ireland, Africa, Mexico, China, Russia, California, Alberta, Ontario, Nova Scotia, British Columbia, Saskatchewan, Prince Edward Island and Québec. She plays an ongoing and active role in the development and drafting of energy and greenhouse gas emissions policy, regulation, and law throughout Canada, and in various countries around the world. She was also lead counsel on all aspects of the successful sale of an Ontario power distribution company to Hydro One. Lisa was an appointed member of Ontario Premier's Clean Energy Task Force and Climate Action Group.

Ms. DeMarco is a member of theBoard of Directors of the Advanced Energy Centre at MaRS, and Ontario Power Generation. She is a graduate of the University of Western Ontario (BSc Hon. – 1990), the University of Toronto (MSc. – 1992), Osgoode Hall Law School, York University (LLB – 1995) and the Vermont Law School (MSEL, summa cum laude – 1995) and is called to the bar in England and Ontario.

2017 Board/Committee Membership:	**2017 Attendance**	
Board (since April 2014)	8 of 8	100%
Audit and Risk Committee (since February 2016)	5 of 5	100%
Generation Oversight Committee (since February 2016)	4 of 4	100%
Special Committee (since March 2017)	15 of 15	100%

Principal Occupation: Senior Partner, DeMarco Allan LLP

Board Memberships for other Reporting Issuers: None

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

Jean Paul (JP) Gladu
Age: 44
Toronto, Ontario, Canada

JP Gladu is currently the President and CEO of the Canadian Council for Aboriginal Business (CCAB) based in Toronto. Anishinaabe from Thunder Bay, Mr. Gladu is a member of Bingwi Neyaashi Anishinaabek located on the eastern shores of Lake Nipigon. Mr. Gladu has over two decades of experience in the natural resource sector including work with Aboriginal communities and organizations, environmental non-government organizations, industry and governments from across Canada, including involvement in business development for the Bingwi Neyaashi Anishinaabek Nation from 2009 to 2012. He has produced a number of publications related to Aboriginal issues including: forest certification, Native values collection, biofuel opportunities, First Nation community land use plans, criteria and indicators for sustainable forestry, and cedar product development.

Mr. Gladu holds a Forest Technician Diploma from the Sault College of Applied Arts and Technology, a Bachelor of Science degree in forestry from Northern Arizona University, and an Executive Masters of Business Administration from Queens University in Kingston. In 2014, he was a recipient of the Community Service Award – Transformation Awards from Diversity Magazine. Mr. Gladu was nominated for the 2013 Premier's Award for Outstanding Ontario College Graduates, was recognized as one of five Northern Leaders in 2012 by Northern Ontario Business and was elected Class President of the 2012 Queens Executive Masters of Business Administration.

Mr. Gladu currently serves on the Canadian Electricity Associations' Public Advisory Panel, Noront Resources and Chancellor of St, Paul's University Board of Governors. He has also held previous board positions with Colleges and Institutes Canada (previously the Association of Canadian Community Colleges), Northern Policy Institute, Canadian Foundation for Economic Education boards of directors, Centre for Research and Innovation in the Bio-Economy, Papasay Management Corporation, and a board member of the Canadian Bioenergy Association. He also held advisory positions with the Canadian Association of Petroleum Producers Renewable Clean Energy Committee and the Ontario Provincial Forest Policy Committee.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since November 2015)	6 of 8	75%
Compensation, Leadership and Governance Committee (since February 2016)	5 of 5	100%
Generation Oversight Committee (since February 2016)	3 of 4	75%

Principal Occupation: President and CEO, Canadian Council for Aboriginal Business

Board Memberships for other Reporting Issuers: Noront Resources Ltd. *(TSX)*

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

John Herron
Age: 64
Punta Gorda, Florida, U.S.A.

John Herron retired from Entergy in April 2013 where he was the President, CEO and Chief Nuclear Officer of Entergy Nuclear, with responsibility for Entergy's nuclear plants located in New York, Massachusetts, Vermont, Michigan, Louisiana, Mississippi and Arkansas as well as the company's management service to the Cooper Nuclear Station for the state of Nebraska.

He previously served as Entergy's Senior Vice President for Nuclear Operations handling the operational side of fleet management. Mr. Herron joined Entergy in February 2001 as Vice President, Operations at the Waterford 3 Nuclear Station in Killona, Louisiana. He then moved to New York as the Senior Vice President of the Indian Point Energy Center in February 2002.

Mr. Herron began his career in nuclear operations in 1979 at Vermont Yankee Nuclear Power Corporation. His positions there included technical services superintendent, operations manager, technical programs manager, shift supervisor, and supervisory control room operator. In 1994, he moved to Brownville, Nebraska to become plant manager at Nebraska Public Power District's Cooper Nuclear Station.

Mr. Herron then joined the Tennessee Valley Authority as plant manager at Sequoyah Nuclear Plant in Soddy-Daisy, Tennessee, from October 1996 through July 1999. From July 1999 to February 2001, Mr. Herron served as site Vice President at TVA's Browns Ferry Nuclear Plant.

Prior to his career in utilities, Mr. Herron served in the U.S. Navy from 1972 to 1978. He was attached to the USS Tullibee and the S1C NPTU Windsor, where he was an instructor at the Nuclear Submarine Prototype School.

Mr. Herron holds a bachelor's degree in Business Management from Franklin Pierce College in Rindge, New Hampshire. He also attended the Advanced Management Program at the Harvard Business School in May 2005.

Mr. Herron currently serves on the board of directors for Duke Energy. He also served on the board of directors for the Institute of Nuclear Power Operations and on the Nuclear Strategic Issues Advisory Committee of the Nuclear Energy Institute. In the aftermath of Japan's 2011 earthquake, he was named to the WANO Post-Fukushima Commission and the U.S. nuclear industry's Fukushima response steering committee.

2017 Board/Committee Membership:	**2017 Attendance**	
Board (since November 2013)	8 of 8	100%
Generation Oversight Committee* (since February 2016)	4 of 4	100%
Darlington Refurbishment Committee (since May 2015)	4 of 4	100%

Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: Duke Energy (NYSE)

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

* Chair of Committee

Ani Hotoyan-Joly
Age: 56
Markham, Ontario, Canada

Ani Hotoyan-Joly is currently Chief Financial Officer and Corporate Secretary of Coventree Inc. Prior to Coventree, she was V.P. Finance and Chief Financial Officer at Swiss Reinsurance Company Canada (P&C) and prior to that held senior positions at Zurich Canada. Ms. Hotoyan-Joly is a member of the Board of Directors of Women's College Hospital and is a member of the Executive Committee and Chair of the Governance and Nominations Committee. She is currently a member of the Executive Board of Armenian Relief Society's Roubina (Toronto) Chapter and was the Past Chair of A.R.S. Armenian Private School's Board of Trustees.

Ms. Hotoyan-Joly is a Chartered Professional Accountant and Chartered Accountant and holds a Bachelor of Commerce degree from the University of Toronto and the ICD.D designation from the Institute of Corporate Directors. She was elected as a 2016 Diversity 50 Candidate by the Canadian Board Diversity Council.

2017 Board/Committee Membership:	**2017 Attendance**	
Board (since March 2017)	6 of 6	100%
Audit and Risk Committee (since March 2017)	4 of 4	100%
Compensation, Leadership and Governance Committee (since March 2017)	4 of 4	100%

Principal Occupation: Chief Financial Officer and Corporate Secretary, Coventree Inc.

Board Memberships for other Reporting Issuers: None

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

Wendy Kei
Age: 50
Toronto, Ontario, Canada

Ms. Wendy Kei currently serves on the Board of Guyana Goldfields, Inc., as the Chair of the Audit Committee, a member of the Human Resources & Compensation Committee and a member of the Corporate Governance & Nominating Committee. She is an accomplished Finance Executive with over 25 years of business experience in a variety of industries. For the past 14 years, Ms. Kei has been working within the mining industry and brings a strong focus on corporate governance, financial and risk management and a strong expertise in executing complex mergers and acquisitions.

Ms. Kei is a Chartered Professional Accountant and Chartered Accountant and previously served as Chief Financial Officer of Dominion Diamond Corporation (formerly Harry Winston Diamond Corporation and Aber Diamond Corporation).

Ms. Kei is a member of the Chartered Professional Accountants of Ontario, and holds a Bachelor of Mathematics from the University of Waterloo. Ms. Kei was selected as a Diversity 50 2016 Candidate by the Canadian Board Diversity Council.

2017 Board/Committee Membership:	**2017 Attendance**	
Board (since March 2017)	6 of 6	100%
Audit and Risk Committee (since March 2017)	4 of 4	100%
Generation Oversight Committee (since March 2017)	3 of 3	100%

Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: Guyana Goldfields Inc. *(TSX)*

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

M. George Lewis
Age: 57
Toronto, Ontario, Canada

From February 2007 until November 2015, George Lewis was a member of RBC's Group Executive, one of eight executives responsible for setting the overall strategic direction for Royal Bank of Canada, Canada's largest bank. In that capacity, he served as Group Head of RBC Wealth Management from 2007 and RBC Insurance from 2012. As Group Head, Wealth Management, Mr. Lewis led the RBC businesses that serve the wealth management needs of affluent clients globally, and units that provide asset management and trust products. He was also Chairman of RBC Global Asset Management Inc.

From July 2000 to May 2008, Mr. Lewis was Chief Executive Officer of RBC Global Asset Management, which under his leadership became Canada's largest single mutual-fund family (RBC Funds) and one of Canada's largest asset management firms. He previously served as Head of Wealth Management for the Canadian Personal and Business segment and, from 2003 to 2006, was Head of all banking and investment products for RBC's Canadian Business.

From 1998 to 2000, Mr. Lewis was Managing Director, Head of Institutional Equity with RBC Capital Markets, responsible for global institutional-equity sales, trading and research. He was previously a top-rated equity analyst and Director of Research. He began his career with RBC in 1986, in the investment banking division of RBC Capital Markets.

Mr. Lewis has extensive experience in the investment industry, has a Masters of Business Administration degree with distinction from Harvard University and a Bachelor of Commerce degree with high distinction from Trinity College at the University of Toronto. He is also a Chartered Financial Analyst and an FCA/FCPA and has been certified by the Institute of Corporate Directors.

Mr. Lewis serves on the board of directors of Enbridge Income Fund Holdings Inc., the Canadian Film Centre and the Anglican Diocese of Toronto Foundation. He is a current member and past chair of the Bishop's Company of the Anglican Diocese of Toronto, as well as a patron and member of the Cabinet of the United Way of Toronto and York Region. Mr. Lewis also serves as the Honorary Colonel Commandant of the Royal Canadian Chaplain Service of the Canadian Armed Forces.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since February 2005)	8 of 8	100%
Audit and Risk Committee* (since February 2016)	5 of 5	100%
Compensation, Leadership and Governance Committee (since February 2016)	5 of 5	100%
Special Committee* (since March 2017)	15 of 15	100%

Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: Enbridge Income Fund Holdings Inc. *(TSX)*

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

* Chair of Committee

Margaret (Peggy) Mulligan
Age: 59
Cameron, Ontario, Canada

Peggy Mulligan was the Executive Vice President and Chief Financial Officer, Valeant Pharmaceuticals International, Inc. until December 2010. Prior to this, she was a Principal at Priiva Consulting, and before that she served as Executive Vice President and Chief Financial Officer of Linamar Corporation. Prior to Linamar, Mrs. Mulligan was with the Bank of Nova Scotia for eleven years as Executive Vice President, Systems and Operations and Senior Vice President, Audit and Chief Inspector. Before joining Scotiabank, she was an Audit Partner with PricewaterhouseCoopers in Toronto. She holds a B. Math (Honours) from the University of Waterloo and was named a Fellow of the Institute of Chartered Professional Accountants of Ontario in 2003.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since December 2005)	7 of 8	88%
Compensation and Leadership and Governance Committee* (since February 2016)	5 of 5	100%
Darlington Refurbishment Committee (since May 2015)	4 of 4	100%
Special Committee (since March 2017)	14 of 15	93%

Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: Canadian Western Bank (*TSX),* ClearStream Energy Services Inc. *(TSX)* (*previously Tuckamore Capital*)

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

* Chair of Committee

Yezdi Pavri
Age: 68
North York, Ontario, Canada

Yezdi Pavri retired as Vice Chairman of Deloitte Canada in June 2012 after a career of more than 30 years. Prior to being named Vice Chairman, Mr. Pavri was a member of the firm's national Management Committee for over ten years and was the Managing Partner of the Toronto practice since June 2004. He founded Deloitte's national Enterprise Risk Services practice in 1990 and led it for 15 years. He was a founding member of the global firm's India Steering Committee and co-chaired the firm's first Diversity and Inclusion Committee.

Mr. Pavri holds a Bachelor's degree in Aeronautical Engineering from the Indian Institute of Technology in Bombay and a Master's degree in Thermal Power Engineering from Imperial College in London. He is a Fellow of the Chartered Professional Accountants of Ontario.

Mr. Pavri currently serves on the boards of ICICI Bank of Canada, Enterra Holdings Limited (the global parent of Golder Associates) and MD Financial Services, and is a past member of the board of directors of Hydro One. Mr. Pavri is also the immediate past chairman of the board of trustees of United Way Toronto.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since September 2015)	8 of 8	100%
Audit and Risk Committee (February 2016)	5 of 5	100%
Compensation, Leadership and Governance Committee (since February 2016)	5 of 5	100%
Special Committee (since March 2017)	15 of 15	100%

Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: None

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

Gerry Phillips
Age: 77
Ajax, Ontario, Canada

Gerry Phillips was the Member of Provincial Parliament in the Legislative Assembly of Ontario for the east Toronto riding of Scarborough-Agincourt from 1987 to 2011. He served in six cabinet portfolios, including twice as Ontario Minister of Energy, where he was OPG's Shareholder from 2007 to 2008 and again on an interim basis from November 2009 to January 2010, as well as, Minister responsible for Securities Regulation in Ontario. He was also the Chair of the Management Board of Cabinet from 2008 to 2011 and the Chair of the Select Committee on the TMX Transaction in 2011.

Before entering public life, Mr. Phillips graduated from the University of Western Ontario's School of Business and worked in the marketing department of Procter and Gamble. In 1970, he joined the consulting firm of Canadian Marketing Associates and became President in 1977. He later founded two successful spin-off companies – the Sales Development Group in 1979 and the Retail Resource Group in 1982. By 1987, he was Chair of all three companies, with a combined workforce of approximately 300.

Mr. Phillips has an Honours B.A. from the Western School of Business.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since January 2013)	8 of 8	100%
Audit and Risk Committee (since February 2016)	5 of 5	100%
Darlington Refurbishment Committee (since May 2015)	4 of 4	100%

Principal Occupation: Retired

Board Memberships for other Reporting Issuers: None

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

Jim Reinsch
Age: 74
Frederick, Maryland, U.S.A.

Jim Reinsch retired from the Bechtel Group where he was Senior Vice President and Partner, and past President of Bechtel Nuclear. In this role, he was responsible for the global profit/loss, customer relations, operations, project management, marketing and business development of Bechtel's three nuclear business segments: nuclear operating plant services, steam generator replacement, and operations of Bechtel's global nuclear activities. During his 40 years with Bechtel, he also presided over Bechtel Canada, and managed large regions in the United States and Asia. He served as the President of the American Nuclear Society, and was a member of the Nuclear Energy Institute as well as a member of their Executive Committee. Mr. Reinsch is also a member of several international nuclear energy organizations, including the WANO and the World Nuclear Association.

Mr. Reinsch holds a Bachelor of Science degree from the University of Maryland.

Mr. Reinsch currently serves on the board of directors for Frederick Memorial Hospital and the Hood College Board of Trustees, and is a past board member of Duke Energy and the Smithsonian National Portrait Gallery. Additionally, he serves on the Emirate Nuclear Energy Corporation's committee on nuclear power which reports to the board of directors, and is a member of the international advisory board of Terrestrial Power.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since August 2015)	7 of 8	88%
Generation Oversight Committee (since February 2016)	4 of 4	100%
Darlington Refurbishment Committee* (since August 2015)	4 of 4	100%

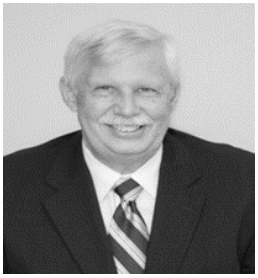
Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: None

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

*Chair of Committee



James Sheppard
Age: 69
Toronto, Ontario, Canada

Mr. Sheppard serves as an Independent Consultant. Mr. Sheppard served as Interim Senior Vice President for Southern California Edison Company and served as its Interim Chief Nuclear Officer from September 2010 to December 9, 2010. From 1993 to 2009, he held several senior positions associated with the South Texas Project nuclear power plant, including Chairman, President and Chief Executive Officer of STP Nuclear Operating Company, which operated the facility for its three owners. He served as Executive Officer of South Texas Project Electric Generating Station. He served as an executive at STP for ten years, he held the positions of Vice President and Assistant to the President and Chief Executive Officer; Vice President of Engineering and Technical Services; Vice President of Business Systems; Assistant to the executive vice president; and General Manager of Licensing. He has been an Independent Director at Xcel Energy Inc. since March 2011.

Mr. Sheppard holds a bachelor of science degree in aerospace engineering from the U.S. Naval Academy and a master's degree in business administration from the Duke University.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since March 2017)	6 of 6	100%
Darlington Refurbishment Committee (since March 2017)	3 of 3	100%
Generation Oversight Committee (since March 2017)	3 of 3	100%

Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: Xcel Energy Inc. *(NYSE)*

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

Nicole Boivin served as a Director from April 2014 to March 2017 and was a member of the Compensation, Leadership and Governance Committee and the Darlington Refurbishment Committee. Brendan Hawley was a Director from April 2014 to March 2017 and was a member of the Audit and Risk Committee and Darlington Refurbishment Committee. Ira Kagan was a Director from April 2014 to March 2017 and served as a member of the Audit and Risk Committee and the Generation Oversight Committee.

Orientation and Continuing Education

The Compensation, Leadership and Governance Committee is responsible for reviewing and recommending appropriate orientation programs for new Directors. New directors are provided relevant documentation relating to OPG's governance practices and policies and to its business. Directors attend plant tours of OPG generating facilities, where they also receive comprehensive introductory briefings from OPG senior executives on OPG's operations and business activities.

The Board supports and sponsors the continuing education of OPG Directors, both in the business of OPG and in their duties as Directors. This includes plant tours of OPG's major facilities, site visits to projects with OPG's Indigenous business partners, and special presentations by internal and external experts on topical business-related issues or on specific aspects of OPG's operations. In 2017, such topics included pension plan governance, the cap and trade program and OPG's dam safety program. Directors also are provided with articles and publications on current topics of interest. Board members have full access to all Board and Board committee materials and records. OPG has developed a Director Governance Handbook, which provides Directors with information necessary to fulfill their roles, including director duties and obligations under the OBCA, and relevant corporate policies and procedures. OPG also sponsors Director attendance at the Institute of Corporate Directors' Director Education Program, or equivalent, and sponsors attendance at the Goizueta Director program for members of Board committees responsible for oversight of nuclear operations.

Ethical Business Conduct

The Board has adopted a policy for ethical business behaviour and a Code of Business Conduct. The mandate of the Audit and Risk Committee requires that it receive regular reports throughout the year on the Code of Business Conduct in order to satisfy itself that appropriate code of conduct and compliance programs are in place and are being enforced, and remedial action is being taken. The Audit and Risk Committee receives quarterly reports from management on the Code of Business Conduct (including reports on any substantiated cases of fraud) and the disposition of cases including disciplinary action, as well as an annual report on the Code of Business Conduct and a report on the annual review of the Board policy. A copy of the Code of Business Conduct can be found on SEDAR at www.sedar.com and also is available on the Company's website at www.opg.com. The Audit and Risk Committee has procedures for the receipt, retention and treatment of complaints received pertaining to accounting, internal controls or auditing matters, and for the confidential anonymous submission by employees concerning such matters.

Nomination of Directors

The Compensation, Leadership and Governance Committee, which is comprised of six independent Directors within the meaning of NI 52-110, is responsible for conducting an annual review of the OPG Board's principles and systems of governance, and oversight of annual Board, Board committee and Director evaluations. The Compensation, Leadership and Governance Committee recommends candidates to the Shareholder. Nominations of Directors by the Shareholder also may be considered by the Compensation, Leadership and Governance Committee. When considering a potential candidate, the committee considers the qualities, experience, and skills that the Board, as a whole, should have in light of the business opportunities and risks facing OPG. The attributes the Compensation, Leadership and Governance Committee considers in a candidate include integrity, business judgment and experience, diversity, professional expertise, independence from management, financial literacy, and communication skills, as well as sufficient time available to fulfill his or her obligations as a Board member. The Board's policy on diversity is to interview a diverse candidate for every vacancy on the Board. OPG defines

diversity to include: women, aboriginal peoples, people with disabilities, and visible minorities. These four enumerated groups mirror the four enumerated groups in the definition of "designated groups" in the federal *Employment Equity Act*.

From time to time, the Compensation, Leadership and Governance Committee may engage outside advisors to assist in identifying potential candidates.

Director Tenure/Board Renewal

The OPG Board Charter guideline for board tenure is 10 to 15 years. When considering board renewal, the Compensation, Leadership and Governance Committee regularly reviews the OPG Board skills profile. The Board maintains an "evergreen list" of potential Board candidates. From time to time, the committee makes recommendations to add skills to the Board that reflect OPG's business opportunities and risks.

Diversity in Leadership

Board of Directors

As noted under the heading, *Nomination of Directors*, the Compensation, Leadership and Governance Committee interviews a diverse candidate for every vacancy on the Board, where diversity is defined as: women, aboriginal peoples, people with disabilities, and visible minorities. The Board has signed on to the Catalyst Accord, set a target for "diverse" representation on the Board of 50 percent, including 40 percent women by 2019 and adopted a target of 25 percent women on the Board by 2017. In 2017, three members were added to the Board, two of whom meet the diversity definition. As of the date of this AIF, overall diversity of the Board is at 50 percent. Representation of women on the Board is 29 percent (four Directors) as of the date of this AIF.

Senior Management

OPG strives to create a workforce that reflects diverse populations of the communities in which it operates. As of December 31, 2017, women filled 25 percent of Corporate Officer roles and 26 percent of senior management (senior managers and above) positions. In total, there were three women in Corporate Officer roles and 153 women in senior management positions. OPG tracks and monitors diversity succession planning metrics and strives to have a diverse candidates list for senior management positions.

Compensation

Executive Compensation Framework

In September 2016, the Government of Ontario introduced *Regulation 304/16: Executive Compensation Framework*. The regulation sets out how all employers, including OPG, designated under the *Broader Public Sector Executive Compensation Act, 2014* must establish and post compensation programs for executives. The regulation requires all designated employers to have a written Executive Compensation Program that describes the compensation they may provide to executives. The program must include the compensation philosophy, salary and performance-related pay caps, comparative analysis details, and a description of other elements of compensation. The regulation also requires that designated employers post their program on their website and provide a reasonable opportunity for members of the public to provide comments. OPG met the requirements of *Ontario Regulation 304/16* and posted its Executive Compensation Framework on the Company's website for public comment on November 30, 2016. OPG reviewed the comments received through the public consultation process and determined that there was no need to alter its Executive Compensation Program, which became effective on January 1, 2017. OPG's Executive Compensation Program applies to employees at the Vice President level and higher. A copy of OPG's Executive Compensation Program can be found on SEDAR at www.sedar.com and is also available on the Company's website at www.opg.com.

Director Compensation

As at March 8, 2018, OPG's Director compensation framework provides each Director who is not an employee of OPG with an annual retainer of $25,000. Directors also receive a $3,000 retainer for each Board committee of which they are a member. There are four standing committees of the Board and Directors serve on at least two committees. Directors receive an additional retainer for serving as committee chairs. The retainer for the chair of the Audit and Risk Committee is $8,000. The chairs of the other three committees receive retainers of $5,000.

In addition to the above, Directors are compensated for each regular and/or special meeting that they attend and receive a fee of $2,000 or $1,000 for a long or short meeting, respectively. The Board Chair may also determine that no fee is warranted.

In order to retain national and international expertise, non-resident Directors are compensated in U.S. dollars and Directors who travel over certain distances receive a travel fee to cover travel time related to Board and Board committee meetings they attend.

Since 2004, the Chair of the Board, in his role as non-executive Chair, receives an all-inclusive annual fee of $150,000 and is reimbursed for out-of-pocket expenses including travel and other expenses.

CEO Compensation

Among its other responsibilities, the Compensation, Leadership and Governance Committee oversees, on behalf of the Board, the setting of the CEO's annual goals and objectives and the annual review of CEO performance, and makes recommendations to the Board with respect to CEO compensation. The Committee may seek input from an independent advisor with regard to monitoring and benchmarking compensation trends.

In August 2015, when the current CEO was appointed, the CEO compensation terms were established based on the benchmarks recommended in the 2007 Report of the Agency Review Panel on Phase 1 of its Review of Ontario's Provincially Owned Electricity Agencies. The CEO's base pay and incentives compensation are compliant with *Ontario Regulation 304/16*. Other elements of the CEO's compensation will be compliant within the three-year period provided in the regulation to bring all elements of compensation into compliance.

For details regarding compensation paid to Directors and executive officers during the financial year ended December 31, 2017, see OPG's Statement of Executive Compensation (Form 51-102F6), which is available on SEDAR at www.sedar.com and incorporated by reference herein.

Committees of the Board of Directors

The following are the current standing Board committees as at March 8, 2018:

Audit and Risk Committee

This committee is responsible for the integrity, quality, and transparency of OPG's financial information, the adequacy of the financial reporting process, the systems of internal controls, and related principles, policies and procedures established by management. The Committee is responsible for the oversight of the Company's regulatory filings, financial statements, MD&A and press releases prior to their disclosures to the public, including approval of quarterly financial statements and recommending approval of the annual financial statements and various other annual disclosures to the Board. The committee is also responsible for recommending the appointment and compensation of the external auditor to the Board and for oversight of the external auditor.

The committee also provides oversight of OPG's corporate financing strategies including:

- policies related to financial exposure management;
- processes for identifying major financial risks;
- performance of the OPG Pension Fund, the Used Fuel Segregated Fund and the Decommissioning Segregated Fund;
- review and approval of the audited financial statements of the OPG Pension Fund, the Used Fuel Segregated Fund and the Decommissioning Segregated Fund; and
- review and approval of the statements of investment policies and procedures for the OPG Pension Fund and the Decommissioning Segregated Fund.

The Audit and Risk Committee also oversees risk and associated risk management activities, including the review of management's assessment of significant risks to achieving OPG's business plan objectives. The committee also is responsible for ensuring that an effective Code of Business Conduct is in place at OPG and monitors compliance with this code.

As of November 22, 2017, the Audit and Risk Committee assumed oversight of OPG's role as Financial Services Manager of the Fair Hydro Trust.

As of the date of this AIF, the Audit and Risk Committee consists of George Lewis (Chair), Elisabeth (Lisa) DeMarco, Ani Hotoyan-Joly, Wendy Kei, Yezdi Pavri, and Gerry Phillips.

For further details regarding the Audit and Risk Committee, see *Audit and Risk Committee Information*.

Compensation, Leadership and Governance Committee

This committee provides oversight of OPG's human resources and compensation policies and practices, including CEO objectives and compensation, disclosure on compensation and human resources matters, leadership talent review, succession planning, and collective bargaining negotiations. The committee also provides oversight of the design of OPG's benefit and pension plans.

The Compensation, Leadership and Governance Committee oversees the Board's governance program and practices to ensure that they are consistent with high standards of corporate governance, including annually reviewing and assessing the Board's system of corporate governance with a view to maintaining these high standards. The committee also is responsible for overseeing OPG's reputation management plan, and for identifying and recommending to the Board candidates for nomination to the Shareholder. Finally, the committee oversees OPG's processes for Board, Board committee, and Director assessments, as well as Director compensation and new Director orientation.

As of the date of this AIF, the Compensation, Leadership and Governance Committee consists of Margaret (Peggy) Mulligan (Chair), Bill Coley, JP Gladu, Ani Hotoyan-Joly, George Lewis and Yezdi Pavri.

Darlington Refurbishment Committee

The Darlington Refurbishment Committee is responsible for the oversight of the execution of the Darlington Refurbishment Program, including retaining external independent oversight advisors. The committee was also responsible for making a recommendation to the Board with respect to a final budget and schedule for the Darlington Refurbishment Program, which was subsequently approved by the Board of Directors in November 2015. The committee monitors and reports on the progress of the refurbishment program against the approved budget and schedule. The committee will make a recommendation to the Board with respect to the refurbishment of subsequent Darlington units, and other recommendations for approvals related to the refurbishment program as may be required from time to time.

As of the date of this AIF, the Darlington Refurbishment Committee consists of Jim Reinsch (Chair), Bill Coley, John Herron, Margaret (Peggy) Mulligan, Gerry Phillips, and James Sheppard.

Generation Oversight Committee

This committee is responsible for the oversight of safe, secure and efficient operations of OPG's generating facilities. Additionally, the committee is responsible for the development, risk management, financing, and execution of the Company's major generation projects including those related to nuclear waste management, other than the Darlington Refurbishment Program. The committee also is responsible for the oversight of OPG's environment and dam safety management systems and OPG's Indigenous relations. The committee reviews reports of internal and external advisors/assessors in respect of OPG's generation operations and management's response to the findings from such assessments. The committee provides oversight to ensure that OPG's generating facilities are in compliance with nuclear safety, industrial and occupational health and safety, and environmental laws and regulations.

As of the date of this AIF, the Generation Oversight Committee consists of John Herron (Chair), Bill Coley, Elisabeth (Lisa) DeMarco, JP Gladu, Wendy Kei, Jim Reinsch, and James Sheppard.

Special Committee of the Board

This Special Committee of the Board was established on March 10, 2017. The Special Committee was responsible for providing timely strategic and other guidance to OPG management in connection with the Province's announcement of Ontario's Fair Hydro Plan on March 2, 2017, which includes refinancing a portion of the Global Adjustment. The Committee was also responsible for making recommendations to the Board with respect to OPG's participation in the Province's implementation of the refinancing proposal. The mandate of the Special Committee concluded on November 22, 2017 and the Audit and Rick Committee will be responsible for the oversight of this process.

Assessments

The Compensation, Leadership and Governance Committee is responsible for the annual process for evaluating the performance of the Board, its committees and individual Directors. The Board and committee evaluations are based upon the completion of confidential questionnaires regarding assessment of performance and compliance with the Board and Committee Charters. The individual Director evaluations are based on self-assessment questionnaires, which are submitted in confidence to the Board Chair and the Chair of the Compensation, Leadership and Governance Committee. In addition, the process includes a follow-up one-on-one meeting between each Director and the Board Chair. The Compensation, Leadership and Governance Committee reports the results of the evaluations to the Board and the results are discussed amongst the Board. The Compensation, Leadership and Governance Committee makes recommendations to the Board for enhancing the Board's governance and effectiveness.

Further Information on OPG Governance

OPG provides additional information on the Company's governance on its website (www.opg.com) including:

- Memorandum of Agreement with the Shareholder
- Shareholder Directives
- List of Corporate Officers
- Board and Committee Charters
- Board and Committee Chair Position Descriptions
- Board of Directors Conflict of Interest Policy
- Indigenous Relations Policy

- Code of Business Conduct
- Disclosure Policy
- Environmental Policy
- Employee Health and Safety Policy
- Nuclear Safety Policy
- Safe Operations Policy
- Cyber Security Policy

Unless otherwise specifically stated, none of the information contained on, or connected to the Company's website nor any of the contents of the aforementioned additional information on OPG's governance are incorporated by reference herein.

EXECUTIVE OFFICERS

The following table sets forth the name, municipality of residence, position with the Company, and the date of commencement for each of the executive officers of the Company as of March 8, 2018:

Name and Municipality of Residence	**Current Position Held**	**Executive Officer Since**
Bernard Lord *Moncton, New Brunswick*	Board Chair	April 2014
Jeff Lyash *Toronto, Ontario*	President and Chief Executive Officer	August 2015
Carlo Crozzoli *Toronto, Ontario*	Senior Vice President, Corporate Business Development and Strategy	December 2011
Chris Ginther *Newmarket, Ontario*	Chief Administrative Officer	July 2012
Ken Hartwick *Milton, Ontario*	Chief Financial Officer & Senior Vice President – Finance	March 2016
Glenn Jager *Clarington, Ontario*	President, OPG Nuclear and Chief Nuclear Officer	November 2013
David Kaposi *Toronto, Ontario*	Vice President, Chief Investment Officer	November 2013
Barb Keenan *Toronto, Ontario*	Senior Vice President, People & Culture and Chief Ethics Officer	March 2010
Catriona King *Richmond Hill, Ontario*	Vice President, Corporate Secretary	February 2005
John Lee *Toronto, Ontario*	Vice President, Treasurer	July 2011
Mike Martelli *Etobicoke, Ontario*	President, Renewable Generation **[CONFIRM]**	July 2013

Name and Municipality of Residence	Current Position Held	Executive Officer Since
Dietmar Reiner *Clarington, Ontario*	Senior Vice President, Nuclear Projects	June 2014
Jennifer Rowe *Toronto, Ontario*	Senior Vice President, Corporate Affairs	January 2017

All of the executive officers of the Company have been engaged for more than five years in their current principal occupations, except as set out below:

- Mr. Lyash was Executive Vice President at Duke Energy from May 2008 to January 2012 and President at CB&I Power from July 2013 to July 2015.
- Mr. Crozzoli was Senior Vice President, Corporate Business Development and Chief Risk Officer at OPG from December 2011 to November 2015, Acting Senior Vice President, Finance, Strategy & Risk and Chief Financial Officer at OPG from November 2015 to March 2016 and Senior Vice-President, Corporate Business Development and Chief Risk Officer at OPG from March 2016 to August 2016.
- Mr. Ginther was Senior Vice President, Law and General Counsel and Chief Ethics Officer at OPG from July 2012 to January 2016 and Senior Vice President, Legal, Ethics and Compliance at OPG from January 2016 to February 2017.
- Mr. Hartwick was President and CEO at Just Energy Corp. from February 2008 to April 2014, Interim President and CEO at Atlantic Power Corporation from September 2014 to January 2015, Chief Financial Officer at Wellspring Financial Corporation from February 2015 to March 2016 and Senior Vice President, Finance, Strategy, Risk and Chief Financial Officer at OPG from March 2016 to February 2017.
- Mr. Jager was Senior Vice President, Pickering Nuclear Generating Station at OPG from January 2010 to November 2013 and Chief Nuclear Officer at OPG from November 2014 to March 2015.
- Mr. Kaposi was Global Head of Alternatives for Mercer (Canada) Inc. from November 2007 to June 2012 and Partner, Investor Relations at Bastion Infrastructure Group Inc. from July 2012 to September 2013.
- Ms. Keenan was Senior Vice President, People and Culture at OPG from March 2012 to January 2016 and Senior Vice President, People, Culture and Communications from January 2016 to February 2017.
- Ms. King was Vice President, Corporate Secretary at OPG from June 2005 to May 2012, Vice President, Corporate Secretary & Executive Operations from May 2012 to March 2017.
- Mr. Martelli was Plant Manager for the Niagara Plant Group at OPG from June 2010 to July 2013 and Senior Vice President, Hydro-Thermal Operations at OPG from July 2013 to January 2016.
- Mr. Reiner was Senior Vice President, Nuclear Refurbishment at OPG from March 2010 to April 2014.
- Ms. Rowe was Senior Managing Director – Marketing and Communications and VP Corporate Affairs at Manulife from January 2010 to October 2012 and Senior Vice President and Chief Marketing Officer at Meridan Credit Union from October 2012 to April 2016.

INDEBTEDNESS OF DIRECTORS AND EXECUTIVE OFFICERS

As of the date of this AIF, no director or executive officer of the Company or any of its subsidiaries had any outstanding indebtedness to the Company or any of its subsidiaries except routine indebtedness or had any indebtedness that was the subject of a guarantee, support agreement, letter of credit or other similar arrangement or understanding provided by the Company or any of its subsidiaries.

CEASE TRADE ORDERS, BANKRUPTCIES, PENALTIES OR SANCTIONS

To the knowledge of OPG, no director or executive officer is, at the date of the AIF, or was within 10 years before the date of the AIF, a director, chief executive officer, or chief financial officer of any company, that (a) was subject to an order that was issued while the director or executive officer was acting in the capacity as director, chief executive officer, or chief financial officer, or (b) was subject to an order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer, or chief financial officer, except for:

- Ani Hotoyan-Joly was the Chief Financial Officer of Coventree Inc. on November 8, 2011, when the Ontario Securities Commission issued an order that trading in any securities by Coventree cease and any exemptions contained in Ontario Securities law do not apply to Coventree until such time as Coventree completes it winding up. The order was made on the basis that Coventree had contravened Ontario Securities law by failing to issue and file certain news releases and material change reports in 2007.

- The events in question occurred before she became CFO of Coventree Inc. in May 2009. Coventree Inc. continues in the process of a court-supervised winding up and the order is still in effect.

To the knowledge of OPG, no director or executive officer of OPG, or a shareholder holding a sufficient number of securities of OPG to affect materially the control of OPG (a) is, as at the date of the AIF, or has been within the 10 years before the date of the AIF, a director or executive officer of any company (including OPG) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (b) has, within the 10 years before the date of the AIF, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager, or trustee appointed to hold the assets of the director, executive officer, or shareholder, except for:

- Bernard Lord was a director of AEA Technology from the fall of 2010 until the fall of 2012 when it became insolvent.
- Ani Hotoyan-Joly is currently the CFO and Corporate Secretary of Coventree Inc. from May 2009. On February 15, 2012 Coventree Inc. announced that the winding up of the Company will commence and that Duff & Phelpe Canada Restructuring Inc. (now known as KSV Advisory Inc.) was appointed the liquidator of the Company for the purpose of winding up its affairs.
- Peggy Mulligan was a director of MethylGene Inc. from May 2012 to June 2014. On May 9, 2013, MethylGene announced a plan of arrangement that was successfully completed on June 28, 2013.
- Bernard Lord, was a director of Clean Air Power, during September 2015 while it was subject to liquidation proceedings under the laws of Bermuda. Mr. Lord is no longer a director of Clean Air Power.
- William Coley is a director of Peabody Energy Corporation which declared voluntary Chapter 11 bankruptcy protection in April 2016 for most of its U.S. entities and is currently restructuring. As of April 13, 2017, Mr. Coley is no longer a director of the entity.

AUDIT AND RISK COMMITTEE INFORMATION

NI 52-110 has been implemented by Canadian securities regulatory authorities to encourage reporting issuers to establish and maintain strong, effective, and independent audit committees, to enhance the quality of financial disclosure, and to foster increased investor confidence in Canada's capital markets. The Audit and Risk Committee's Charter is attached to this AIF as Appendix A. Information on OPG's Audit and Risk Committee is as follows:

Composition of the Audit and Risk Committee

As at March 8, 2018, the members of the Audit and Risk Committee were George Lewis (Chair), Elisabeth (Lisa) DeMarco, Ani Hotoyan-Joly, Wendy Kei, Yezdi Pavri and Gerry Phillips. All members are independent within the meaning of NI 52-110 and have experience in business and financial matters. Each member has an understanding of internal controls and procedures for financial reporting. As part of OPG's Continuing Education Program for Directors, Audit and Risk Committee members are provided with access to both internal and external educational resources, including seminars and courses, in order to maintain or enhance their financial literacy.

Activities of the Audit and Risk Committee

The Chartered Professional Accountants of Canada (CPA Canada) and the Canadian Public Accountability Board have recommended that audit committees perform a comprehensive review of the external audit firm at least once every five years. CPA Canada issued guidelines in early 2014 to assist audit committees in implementing these recommendations. The Audit and Finance Committee of the Board conducted its first comprehensive review of the Company's external auditor, Ernst & Young LLP (EY) in 2014, for the period from 2009 to 2013, using the guidelines and format recommended by CPA Canada. EY has been OPG's external auditor since the Company's inception in 1999. EY provides audit and audit related services to OPG, including the audit of OPG's annual consolidated financial statements, reviews of OPG's quarterly financial statements, and audits of the financial statements of OPG's consolidated subsidiaries and other financial information.

In conducting the 2017 review of EY's performance, the Audit and Risk Committee considered input from management, EY, and OPG's internal audit function. The Committee performed this review taking into consideration the information submitted by these parties, as well as their individual experience. The results of the 2017 annual review were discussed at the Audit and Risk Committee meeting in August 2017. As part of the review, the Committee considered factors such as the auditor's independence, engagement team quality including the Committee's involvement in the selection of EY's lead engagement partner, and communication effectiveness between EY and OPG. Upon completion of the review, the Committee was satisfied with the performance of EY, concluded that their reappointment was in the best interests of OPG, and, in November 2017, recommended that the Board reappoint EY as the Company's auditor for the 2018 fiscal year. The Board reappointed EY as the Company's auditor for the 2018 fiscal year in November 2017.

External Auditor Service Fees [UPDATE]

The following fees were accrued by EY:

(thousands of dollars)	**2017**	**2016**
Audit fees		1,959
Audit-related fees		554
All other fees [1]		17

[1] Comprised of fees related to the subscription of an online accounting research tool and training.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Relationship with the Province and the OEFC

Relationship with the Shareholder

As a corporation created under and governed by the OBCA, OPG's management is supervised by its Board of Directors, which is obligated by law to act in the best interests of the Company. The Company's

sole Shareholder, the Province, owns all of the Company's issued and outstanding common shares and thereby has the power to determine the composition of the Company's Board of Directors.

As one of several wholly-owned government business enterprises of the Province, OPG has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

Memorandum of Agreement

On August 17, 2005, OPG entered into the MOA with the Shareholder regarding OPG's role and responsibility as a power producer in Ontario. In July 2015, the MOA was revised. The MOA serves as the basis of agreement between OPG and the Shareholder regarding OPG's mandate, governance, performance, reporting and communications, and establishes the accountabilities between OPG and the Province. OPG's strategic imperatives are based on the Company's mandate as set out in the MOA. The MOA was reaffirmed for continuance by both the Ontario Minister of Energy and the OPG Board of Directors' Chair in the fourth quarter of 2016, as required by the MOA following a change in the Minister of Energy.

A copy of the MOA can be found on the Company's website at www.opg.com. ***Unless otherwise specifically stated, none of the information contained on, or connected to the Company's website nor any of the contents of the MOA are incorporated by reference herein.***

Shareholder Directives

The Shareholder may at times direct OPG to undertake special initiatives. A Shareholder directive is issued when the Shareholder finds it necessary to assume decision-making power and authority over certain aspects of the business operations of the Corporation. Under a Shareholder directive, the Shareholder assumes all the rights, powers, duties and liabilities of the Directors to manage or supervise the management of the business and the Directors are relieved of their duties and liabilities. Shareholder directives are communicated as written pursuant to section 108 of the OBCA. Copies of each Shareholder directive can be found on the Company's website at www.opg.com. ***Unless otherwise specifically stated, none of the information contained on, or connected to the Company's website nor any of the contents of the Shareholder directives are incorporated by reference herein.*** The Shareholder directives issued by the Shareholder to date are listed below in reverse chronological order:

- Sale of the Corporation's Lakeview site (June 9, 2016);
- Sale of the Corporation's Head Office (December 14, 2015);
- Bruce Power L.P. Lease Agreement and Used Fuel Agreement (November 30, 2015) – For further details, see *General Development of Business – Nuclear Business Development – Bruce Power Refurbishment and Bruce Lease Agreement*;
- Bruce Power L.P. Amended and Restated Heavy Water and Associated Services Agreement (November 30, 2015) – For further details, see *General Development of Business – Nuclear Business Development – Bruce Power Refurbishment and Bruce Lease Agreement*;
- Conversion of One Unit of Thunder Bay Generating Station to Advanced Biomass (May 1, 2014);
- Thunder Bay Generating Station Conversion (December 16, 2013);
- Early Closure of Ontario Power Generation's Lambton and Nanticoke Coal-Fired Generation Stations (March 7, 2013);
- First Nation Directive (April 1, 2011) – OPG was directed to pay a part of the Shareholder's portion of the settlement liability with a First Nation on its behalf;
- Atikokan Generating Station Conversion (March 8, 2011);
- Addressing Carbon Dioxide Emissions from the Use of Coal at Coal-Fired Generating Stations (May 20, 2010);

- Request for Indicative Prices for the Supply of Wood Pellet Fuel Declaration (Atikokan) (March 18, 2010);
- Request for Expressions of Interest for Supply and Transportation of Solid Biomass Fuel Declaration (January 13, 2009);
- Addressing Carbon Dioxide Emissions from the Use of Coal at Coal-Fired Generating Stations (May 15, 2008);
- Thunder Bay Gas Conversion Cancellation (July 12, 2006);
- Nuclear Directive (June 16, 2006) – OPG was directed to begin feasibility studies on refurbishing existing nuclear units, an environmental assessment on refurbishing Pickering B units, and federal approvals processes (including environmental assessment) for new nuclear units;
- Lower Mattagami River Agreement (May 23, 2006);
- Bruce Power Lease Agreement (October 14, 2005); and
- Thunder Bay Gas Conversion Declaration (October 6, 2005).

Ontario Nuclear Funds Agreement

The ONFA between OPG and the Province sets out the responsibility for funding the liabilities for the decommissioning of OPG's nuclear facilities and the long-term management of OPG's used nuclear fuel and other nuclear waste. Pursuant to the ONFA, the Company has established a Used Fuel Segregated Fund and a Decommissioning Segregated Fund to fund the future costs of these activities. Additional details can be found in the section, *Description of the Business* under the heading, *Regulated – Nuclear Waste Management Segment – Funding Mechanisms*.

OPG Debt Held by the OEFC

OPG's long-term debt has been financed predominantly by the OEFC. As at December 31, 2017, the OEFC held approximately $3.2 billion of OPG's long-term debt with maturities ranging from one month to 30 years. For additional details, see Note 6 to the Company's audited annual financial statements as at and for the year ended December 31, 2017.

Payments-In-Lieu of Corporate Income Taxes and Property Taxes

OPG and its wholly-owned subsidiaries are exempt from tax under the *Income Tax Act* (Canada) and *Taxation Act, 2007* (Ontario). However, under the *Electricity Act, 1998*, OPG is required to make proxy tax payments to the OEFC. These payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by the *Electricity Act, 1998* and related regulations. This results in OPG paying taxes similar to those imposed under the federal and Ontario tax acts.

OPG is subject to income tax audits by the Ontario Ministry of Finance. As of the date of this AIF, income tax audits up to and including the 2013 taxation year have been completed.

The *Electricity Act, 1998* also provides that OPG and certain of its subsidiaries are required to make payments in lieu of property tax to the OEFC on their non-hydroelectric generating station buildings and structures. These payments generally equal the difference between property taxes that would be otherwise payable if these assets were privately owned, and the amount payable to municipalities in respect of these assets as determined under the *Assessment Act, 1990* (Ontario). As with other hydroelectric generators in Ontario, OPG's hydroelectric generation operations are not subject to payments in lieu of property taxes because they are subject to the GRC regime. Additional details on the GRC regime can be found in the section, *Description of the Business* under the heading, *Generation Operations – Hydroelectric (Regulated – Hydroelectric and Contracted Generation Portfolio segments)*.

Stranded Debt

One of the OEFC's purposes under the *Electricity Act, 1998* is to manage "stranded debt," which was not transferred to any of Ontario Hydro's successor entities. The *Electricity Act, 1998* defines stranded debt as the amount of the debt and other liabilities of the OEFC that, in the opinion of the Minister of Finance, cannot reasonably be serviced and retired in a competitive electricity market. Although OPG has no obligations in connection with the stranded debt, the *Electricity Act, 1998* does provide for participants in the electricity sector, including OPG, Hydro One, and the municipal electricity utilities, to make payments to the OEFC, which the OEFC uses in managing the debt and other obligations. These payments include proxy taxes, payments in lieu of property tax, the Debt Retirement Charge levied on certain electricity consumers, and certain amounts that may be payable by municipal electricity utilities on the transfer of their electricity business.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Legal Proceedings

OPG is potentially the subject of various legal proceedings and claims that arise in the ordinary course of business. The outcome of these proceedings and claims is uncertain. Based on information available as of the date of this AIF, management believes that none of the proceedings and claims, individually and in the aggregate, are expected to have a material impact on OPG.

British Energy Claim

On August 9, 2006, a Notice of Action and Statement of Claim filed with the Ontario Superior Court of Justice in the amount of $500 million was served against OPG and Bruce Power by British Energy Limited and British Energy International Holdings Limited (together British Energy). The action is for contribution and indemnity of any amounts British Energy was liable for in an arbitration against it by some of the owners of Bruce Power regarding an alleged breach of British Energy's representations and warranties to the claimants when they purchased British Energy's interest in Bruce Power (the Arbitration). Both the action and the Arbitration relate to corrosion to a steam generator unit discovered after OPG leased the Bruce nuclear generating stations to Bruce Power.

In 2012, the arbitrator found that British Energy was liable to the claimants for some of the damages they claimed. The final settlement amount was valued by British Energy at $71 million. In September 2014, British Energy amended its Statement of Claim (Amended Claim) to reduce the claim amount to $100 million to reflect that the purchasers of British Energy's interest in Bruce Power did not receive the full damages they originally claimed in the Arbitration. British Energy also added an allegation to its Amended Claim that OPG breached a covenant to maintain the steam generator between the time of the initial agreement to lease and the effective date of the lease in accordance with "Good Utility Practices".

In November 2016, British Energy obtained consent to a timetable for the remaining steps in the litigation, pursuant to which the matter must be set down for trial by December 31, 2018. OPG has delivered a statement of defence in accordance with an extension of the original June 30, 2017 delivery deadline set out in the timetable.

Regulatory Actions

OPG is not aware of any penalties or sanctions imposed by a court or securities regulatory authority or other regulatory body against the Company, nor has the Company entered into any settlement agreements before a court or with a securities regulatory authority.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business (unless otherwise required by applicable securities requirements to be disclosed), there were no material contracts entered into by the

Company or its subsidiaries during the most recently completed financial year, or before the most recently completed financial year that are still in effect.

INTERESTS OF EXPERTS

The external auditor of the Company is Ernst & Young LLP, Chartered Professional Accountants, 100 Adelaide Street West, P.O. Box 1, Toronto, Ontario M5H 0B3. Ernst & Young LLP has been the Company's auditors since OPG was formed in 1999, and is independent in accordance with the Rules of Professional Conduct of the Chartered Professional Accountants of Ontario.

GLOSSARY

ancillary service	a service necessary to maintain the reliability of the IESO-controlled grid.
availability	when used in reference to a generating unit, a measure of mechanical reliability represented by the percentage of time a generating unit is capable of providing service, whether or not it is actually in-service, relative to the total time for the period.
baseload facilities	electricity generation facilities that produce a constant supply of energy. In Ontario, baseload facilities are made up of nuclear, run-of-the-river hydroelectric and variable generation facilities such as wind and solar.
bilateral contract	a contract for the purchase and sale of notional electricity usually entered into directly between a generator and an end-user, or between a generator or end-user and a market intermediary.
biomass	plant material from agricultural and forest sources that can be used to produce energy, including beneficiated biomass, which includes torrefied, carbonized, and steam exploded biomass.
CANDU	an acronym for CANada Deuterium Uranium, a family of nuclear fission reactors developed in Canada which use pressurized heavy water coolant or deuterium oxide as a moderating agent and natural uranium (uranium dioxide) as fuel.
capacity factor	the ratio (usually specified as a percentage) of the amount of energy that a generating asset actually generated over a period of time divided by the amount of energy that the generating asset would have produced over the same period of time if it had operated continuously at full capacity.
decommissioning	actions taken in the interest of health, safety, security and protection of the environment to retire a facility permanently from service and render it to a predetermined end-state condition.
detritiation	the removal of tritium from heavy water.
deuterium oxide	see heavy water.
equivalent forced outage rate	the hours of unit failure given as a percentage of the total hours of the availability of that unit.
government business enterprises	Government organizations that are separate legal entities with the power to contract in their own name, have the financial and operating authority to carry on a business, are principally focused on the selling of goods and services to individuals and non-government organizations, and are able to maintain their operations and meet their obligations through revenues generated outside the government reporting entity.
heavy water (deuterium oxide)	water containing significantly more than the natural proportion of heavy hydrogen (deuterium) atoms to ordinary hydrogen atoms, used as a moderator in CANDU reactors.
in-service capacity	the portion of installed capacity (the highest level of output which a generating unit is designed to maintain indefinitely without damage to the unit) that has not been removed from service.

interconnection	a transmission line which carries power across the service area boundary of geographically adjacent jurisdictions.
kWh	a kilowatt hour, the commercial unit of electric energy (the amount of electricity consumed by ten 100 watt light bulbs burning for one hour).
load	the quantity of electricity consumption measured as either the energy consumed over a given period of time or the rate of energy consumption at a given time by a particular customer or group of customers.
MW	a megawatt, equal to 1,000,000 watts or 1,000 kilowatts.
MWh	a megawatt hour, equal to 1,000 kWh.
OEFC	an acronym for the Ontario Electricity Financial Corporation, the legal continuation of the former Ontario Hydro. The OEFC is responsible for managing the debt and certain other obligations not transferred to other successor companies of Ontario Hydro.
ONFA	an acronym for the Ontario Nuclear Funds Agreement between OPG and the Province that sets out the responsibility for funding the liabilities for the decommissioning of OPG's nuclear stations and the long-term management of OPG's used nuclear fuel and other nuclear waste.
Ontario NFWA Trust	a trust established by OPG pursuant to the *Nuclear Fuel Waste Act* (Canada) for the purpose of funding the implementation of Canada's long-term nuclear fuel waste management plan.
operating reserve	the capacity that can be called upon on short notice by the IESO to replace scheduled energy supply that is unavailable as a result of an unexpected outage or to augment scheduled energy as a result of unexpected demand or other contingencies.
reactive support	the control and maintenance of prescribed voltages on the IESO-controlled grid.
refurbishment	the work needed to extend the life of a reactor unit by replacing the major life-limiting components (such as pressure tubes, steam generators, etc).
Shareholder	the sole shareholder of OPG, the Province of Ontario.
surplus baseload generation	a condition that occurs when electricity generation from baseload facilities is greater than the electricity market demand.
tonne	1,000 kilograms or 2,204.6 pounds.
tritium	a radioactive substance that is created within CANDU reactors as a result of heavy water in the reactor moderator and heat transport systems.
TWh	a terawatt hour, equal to 1,000,000 MWh.
unit	an electrical generator, together with its driving turbine and auxiliary equipment.
watt	a scientific unit of electric power representing the rate of work of one joule per second.

APPENDIX A

ONTARIO POWER GENERATION INC.

AUDIT AND RISK COMMITTEE CHARTER

Audit and Risk Committee Charter

Purpose

The function and purpose of the Audit and Risk Committee is to assist the Board of Directors in their responsibility for oversight of matters relating to:

1. The integrity of OPG's financial statements and reporting
2. The integrity and adequacy of internal controls and standards of Codes of Conduct and ethics
3. The performance of OPG's internal audit function
4. The performance and independence of OPG's external auditors
5. Business and financial planning
6. The performance of OPG's pension, nuclear decommissioning, and used fuel investment funds
7. OPG's Enterprise Risk Management
8. Assessment of committee performance and board policies.

Management is responsible for the preparation, presentation and integrity of OPG's interim and annual financial statements and related disclosure documents. Management is responsible for maintaining appropriate accounting and financial reporting principles and policies and systems of internal and disclosure controls and procedures to comply with accounting standards and applicable laws and regulations which provide reasonable assurance that the assets of the Company are safeguarded and transactions are authorized, executed, recorded and properly reported.

Management is also responsible for the identification, assessment, monitoring, and management of the risks to achieving OPG's strategic and business plan objectives and the development and implementation of policies and procedures to respond to such risks.

The Committee's role is to provide oversight that ensures the Company's assets are protected and safeguarded within reasonable business limits and report such to the Board.

Committee Responsibilities and Duties

The Committee shall perform the duties set out in this Charter and shall perform such other duties as may be necessary or appropriate under applicable law or securities rules, or as may be delegated to the Committee by the Board from time to time.

1. *The integrity of OPG's financial statements and reporting*

   The Committee reviews and makes recommendations to the Board with respect to:

   a) appointment or replacement of the Chief Financial Officer.

   b) OPG's annual financial statements and external audit report, including financial statements, MD&A, related footnotes and any documentation required by the Securities Act to be prepared and filed by OPG or that OPG otherwise files with securities regulators.

   c) OPG's Annual Information Form, if required, prior to filing with securities regulators.

   The Committee reviews and approves:

   d) OPG's quarterly financial statements and interim financial information and disclosures in the Management Discussion and Analysis (MD&A) and earnings press release, prior to filing.

   In carrying out its responsibilities for oversight of the integrity of OPG's financial statements and reporting the Committee will include in its review:

e) Adequacy of procedures in place for the review of OPG's public disclosure of financial information extracted or derived from OPG's financial statements.

f) significant accounting principles and reporting issues and impact on the financial statements, including complex or unusual transactions, highly judgmental areas, major issues regarding or changes to OPG's selection/application of accounting principles, financial presentations, the effect of regulatory and accounting initiatives, as well as off-balance sheet arrangements on OPG's financial statements.

g) analysis prepared by Management and/or the external auditor detailing financial reporting issues and judgments made in connection with the preparation of financial information, including analysis of the effects of alternative generally accepted accounting principles methods.

h) whether any other matters related to conduct have come to the Committee's attention that causes it to believe that the financial statements contain an untrue statement of material fact or omit to state a necessary material fact.

2. *Integrity and adequacy of Internal Controls and standards of Codes of Conduct and ethics*

In carrying out its responsibilities for the integrity and adequacy of internal controls, including compliance with legal and regulatory requirements and standards of codes of conduct and ethics, the Committee reviews:

a) legal, tax, or regulatory matters that may have a material impact on OPG's operations and the financial statements, including, but not limited to, violations of securities law or breaches of fiduciary duty.

b) the scope of review of internal control over financial reporting, significant findings, recommendations and Management's responses for implementation of actions to correct weaknesses in internal controls.

c) disclosures made by the Chief Executive Officer and Chief Financial Officer during the certification process regarding significant deficiencies in the design or operation of internal controls or any fraud that involves Management or other employees who have a significant role in OPG's internal controls.

d) procedures for the receipt, recording and treatment of complaints received by OPG regarding accounting, internal accounting controls, or auditing matters, and procedures for the confidential and anonymous submission by OPG employees of concerns regarding accounting or auditing matters.

e) expenses of the Board Chair, Board of Directors, President/CEO and the President/CEO's direct reports on an annual basis, and of any other senior officers and employees the Committee considers appropriate.

f) reports from the Chief Ethics Officer on independent reviews and investigations of fraud allegations, matters that may involve fraud and/or Codes of Conduct violations and compliance.

3. *Performance of OPG's internal audit function*

The Committee reviews and makes recommendations to the Board with respect to:

a) Appointment or replacement of the Chief Risk and Audit Executive.

The Committee reviews and approves:

b) The annual internal audit plan and all major changes to the plan, including the organizational structure, budget and the adequacy of resources.

c) the charter of the internal audit function triennially.

In carrying out its responsibilities for the performance of OPG's internal audit function the Committee reviews:

d) results of Internal audit reports, including: significant findings, the adequacy of the control processes, Management's response and the timetable for implementation of Management actions to correct weaknesses, any difficulties encountered in the course of their work (such as restrictions on the scope of their work or access to information).

e) Internal Audit's confirmation of organizational independence and disclosure of any conflict of interest.

f) Internal Audit performance relative to the annual internal audit plan.

4. *Performance and Independence of External Auditor*

The Committee reviews and makes recommendations to the Board with respect to:

a) the external auditor to be annually appointed on behalf of the Shareholder and related compensation, including results of a cyclical performance review, and a comprehensive review of the external audit firm at least once every five years.

The Committee reviews and approves:

b) pre-approval of additional audit services and fees to be provided by the external auditors if such services are required further to the annual compensation approved by the Board. The Committee may delegate such pre-approval authority to the Committee Chair up to a limit of $250,000. Any decisions of the Committee Chair to whom pre-approval authority is delegated must be presented to the full Audit and Risk Committee at its next scheduled meeting.

In carrying out its responsibilities for the performance and independence of OPG's external audit function the Committee reviews:

c) the work and report of the external auditor engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for OPG, including the resolution of disagreements between Management and the external auditor regarding financial reporting.

d) the independence and qualifications of the external auditor.

e) the annual report by the external auditor describing the auditing firm's internal quality control procedures, any material issues raised by the most recent internal quality-control review or peer review of the auditing firm or by any inquiry or investigation by governmental or professional authorities within the preceding five years respecting one or more independent audits carried out by the external auditor and any steps taken to deal with any such issues and all relationships between the external auditors and OPG.

f) scope and approach of the annual audit plan with the external auditors.

g) quality and acceptability of OPG's accounting principles including all critical accounting policies and practices used, any alternative treatments that have been discussed with Management as well as any other material communications with Management.

h) external auditor's process for identifying and responding to key audit and internal control risks.

i) rotation of the lead audit partner and other audit partners every seven years, and consider regular rotation of the audit firm.

j) all related-party transactions.

k) OPG's hiring policies regarding partners, employees and former partners and employees of the present and former external auditor of OPG.

5. *Business and Financial Planning*

The Committee reviews and makes recommendations to the Board on:

a) OPG's business plan, including overall financing plan in support of the Company's capital expenditures and medium – long term forecast.

b) OPG's rate applications to the Ontario Energy Board, including proposed payment amounts and any agreement arising from a Settlement Conference with intervenors.

c) corporate financing vehicles, credit facilities, including any plans to access capital debt markets and other related financing activities. The Board may delegate to an officer of the company authority to enter into such financing activities in such a manner as the Board shall determine at the time of such delegation. Any decisions of the officer to whom authority is delegated must be presented to the full Audit and Risk Committee at its next scheduled meeting.

6. *Pension, Nuclear Decommissioning and Used Fuel Investment Funds*

The Committee reviews and makes recommendations to the Board on:

a) the appointment or replacement of the Chief Investment Officer.

b) the appointment of the auditor for the OPG Pension Fund and the Used Fuel Segregated Fund and Decommissioning Segregated Fund.

c) the broad objectives, governance frameworks and risk posture for the OPG Pension Fund and the Used Fuel Segregated Fund and Decommissioning Segregated Fund and annual status report on these Funds.

d) the tri-ennial valuation of the Pension Fund and annual valuation of the Supplementary Employee Retirement Pension Plans. (The Committee provides advice to the Compensation, Leadership and Governance Committee on the affordability of proposed pension benefit changes.)

The Committee reviews and approves:

e) the appointment of the members of OPG's Pension Committee. In addition, the Committee may, at any time, remove or replace any member of the Pension Committee or fill a vacancy on the Pension Committee. The Pension Committee Chair may temporarily appoint a senior management employee to fill a vacancy on the Pension Committee until the next regularly scheduled Audit and Risk Committee meeting.

f) the annual audited financial statements for the OPG Pension Fund, the Used Fuel Segregated Fund and the Decommissioning Segregated Fund.

g) the investment policies and procedures, including the design of modifications, for the OPG Pension Fund, as required by the Ontario Pension Benefits Act and its regulations, and for the Decommissioning Segregated Funds, as required by the Ontario Nuclear Funds Agreement.

h) the appointment of the Pension Plan actuary.

In carrying out its responsibilities for the oversight of financial planning and investment funds the Committee reviews:

i) reports on a quarterly, annual or by exception basis, on compliance with and appropriateness of the asset mix policy; total fund and asset class returns relative to benchmarks; material compliance with breaches of policies or procedures; and work conducted by the plan actuary.

j) periodic reports on the calculation of OPG's nuclear waste liability.

7. *OPG's Enterprise Risk Management*

The Committee reviews and makes recommendations to the Board on:

a) the appointment or replacement of the Chief Risk and Audit Executive.

b) the Company's enterprise risk policy, framework, overall risk appetite and targets.

In carrying out its responsibilities for oversight of OPG's Enterprise Risk Management the Committee reviews:

c) the processes employed by Management for identifying and assessing the Company's principal risks.

d) periodic reports on Management's assessment of the principal risks to achieving the Company's strategic and business plan objectives, and the strategies for monitoring, managing and responding to those risks.

e) periodic reports on significant emerging and evolving risks and relevant external events that could potentially impact OPG's risk profile.

f) compliance metrics related to OPG's commercial operations trading, treasury, and fuels management.

g) regular reports on OPG's cyber security position and programs.

h) periodic reports on OPG's Insurance Program.

8. *Assessment of committee performance and board policies*

In carrying out its responsibilities for assessment of committee performance and board policies the Committee shall:

a) Review and assess Committee performance, including a review of the adequacy of and its compliance with this Charter, in accordance with the evaluation process approved by the Board and taking into account all legislative and regulatory requirements applicable to the Committee as

well as any best practice guidelines recommended by regulators with whom OPG has a reporting relationship.

b) Provide oversight of the implementation of the following Board of Directors' policies, and review these policies at least annually (or as otherwise noted below) to ensure their continuing adequacy:

   i. Delegation and Exercise of Authority Policy
   ii. Disclosure Policy
   iii. Code of Business Conduct and Supplier Code of Conduct, including anti-bribery and corruption
   iv. Enterprise Risk Management Policy (reviewed every three years)
   v. Cyber Security Policy

c) Provide oversight of the development of any new policies deemed necessary by the Committee.

Organization

Members

The Audit and Risk Committee shall consist of three or more Directors as determined by the Board of Directors. All members of the Committee shall be independent as defined by the Ontario Securities Commission, and not "affiliated" with OPG.

The Board shall appoint the members of the Committee and the Chair of the Committee annually. The Board may appoint a member to fill a vacancy which occurs in the Committee between annual elections of Directors. Any member of the Committee may be removed or replaced at any time by the Board.

If a member of the Committee becomes "affiliated" with OPG, the member may continue as a member of the Committee with the approval of the Board Chair, in consultation with the Corporate Secretary.

As a "venture issuer", OPG is exempt from the statutory requirements of National Instrument 52-110 requiring members of Audit Committees be independent and financially literate. However, OPG considers such independence and financial literacy to be "best practice" and therefore each of the members of the Audit and Risk Committee shall satisfy the applicable independence and financial literacy requirements of the laws and regulations governing Audit Committees.

The Board of Directors shall confirm that each member of the Audit and Risk Committee is financially literate; as such qualification is interpreted by the Board of Directors in its business judgment, and in compliance with National Instrument 52-110 and its Companion Policy.

Meetings

The Committee shall meet as frequently as it determines but not less than quarterly. During quarterly meetings, the Committee will hold separate in camera sessions with the external auditors, the Chief Internal Audit Executive, the Chief Risk Officer and Management to discuss any matters that the Committee believes should be discussed and to provide a forum for any relevant issues to be raised.

Notice of the time and place of each meeting of the Committee must be given to each member of the Committee not less than 48 hours before the time of the meeting.

A quorum of the Committee shall be a majority of its members, but not less than two. The powers of the Committee may be exercised at a meeting at which a quorum of the Committee is present in person or by telephone or other electronic means, or by a resolution signed by all members entitled to vote on that resolution at a meeting of the Committee. Each member is entitled to one vote in Committee proceedings.

The Chair shall preside at all meetings of the Committee at which he or she is present (or if not able to be present designate another member of the Committee to chair the meeting) and shall develop the agenda for each Committee meeting. The agenda for each meeting of the committee shall be delivered to each member of the Committee at least 48 hours prior to any meeting of the Committee, together with such other materials as the chair determines necessary.

Minutes shall be kept of all meetings of the Committee and shall be maintained by OPG's Corporate Secretary. The procedure at meetings is to be determined by the Committee unless otherwise determined by the by-laws of OPG, by a resolution of the Board or by this Charter.

The Committee may meet in camera (without management present) at any time during the meeting consistent with the Board guideline on the conduct of in camera sessions and the keeping of minutes from in camera sessions.

The Committee may invite any Director, officer or employee of OPG or OPG's counsel or any other person to attend meetings of the Committee to assist in the discussion and examination of the matters under consideration by the Committee.

Reports

The Committee will report its activities and actions to the Board of Directors with recommendations, as the Committee deems appropriate.

The Committee will provide for inclusion in OPG's financial information or regulatory filings any report from the Audit and Risk Committee required by applicable laws and regulations and stating among other things whether the Committee has:

i. Reviewed and discussed the audited financial statements with Management.
ii. Discussed pertinent matters with the internal and external auditors.
iii. Received disclosures from the external auditors regarding the auditors' independence and discussed with the auditors their independence.
iv. Recommended to the Board of Directors that the audited financial statements be included in OPG's Annual Report.

Authority

The Audit and Risk Committee shall have the authority to:

a) conduct or authorize investigations into any matters within the Committee's scope of responsibilities.

b) set and pay the compensation for any advisors employed by the Committee.

c) to communicate directly with the internal and external auditors.

While the Audit and Risk Committee has the responsibilities and powers set forth in this Charter, it is not the duty of the Audit and Risk Committee to plan or conduct audits or risk assessments, or to determine that OPG's financial statements and disclosures are complete and accurate and are in accordance with generally accepted accounting principles and applicable rules and regulations. These are the responsibility of Management and, as appropriate, the external auditor.

Delegation of Authority

The Committee may not delegate its oversight responsibilities. The Committee may delegate to a sub-committee, the Chief Executive Officer or any employee of OPG the authority to exercise any right, power or responsibility that the Committee may have on such terms and conditions and within such limits as the

Committee deems appropriate provided that the sub-committee, Chief Executive Officer or employee subsequently advises the Committee of any right, power or responsibility so exercised.

Access to Management and Outside Advisors

The Audit and Risk Committee shall have unrestricted access to members of Management and relevant information.

The Audit and Risk Committee has the authority to retain legal counsel, accountants or other advisors to assist it in the conduct of any investigation, as it determines necessary to carry out its duties.

ONTARIO POWER GENERATION INC.

CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2017

[DRAFT]

STATEMENT OF MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL INFORMATION

Ontario Power Generation Inc.'s (OPG) management is responsible for the presentation and preparation of the annual consolidated financial statements and Management's Discussion and Analysis (MD&A).

The consolidated financial statements have been prepared in accordance with United States generally accepted accounting principles (US GAAP). The MD&A has been prepared in accordance with the requirements of securities regulators, including National Instrument 51-102 of the Canadian Securities Administrators and its related published requirements.

The consolidated financial statements and information in the MD&A necessarily include amounts based on informed judgments and estimates of the expected effects of current events and transactions with appropriate consideration to materiality. Something is considered material if it is reasonably expected to have a significant impact on the Company's earnings, cash flow, value of an asset or liability, or reputation. In addition, in preparing the financial information, we must interpret the requirements described above, make determinations as to the relevancy of information to be included, and make estimates and assumptions that affect the reported information. The MD&A also includes information regarding the impact of current transactions and events, sources of liquidity and capital resources, operating trends, and risks and uncertainties. Actual results in the future may differ materially from our present assessment of this information because future events and circumstances may not occur as expected.

In meeting our responsibility for the reliability of the financial information, we maintain and rely on a comprehensive system of internal controls and internal audits, including organizational and procedural controls and internal controls over financial reporting. Our system of internal controls includes: written communication of our policies and procedures governing corporate conduct and risk management; comprehensive business planning; effective segregation of duties; delegation of authority and personal accountability; careful selection and training of personnel; and accounting policies, which we regularly update. This structure ensures appropriate internal controls over transactions, assets and records. We also regularly test internal controls. These controls and testing are designed to provide us with reasonable assurance that the financial records are reliable for preparing financial statements and other financial information, assets are safeguarded against unauthorized use or disposition, liabilities are recognized, and we are in compliance with all regulatory requirements.

Management, including the President and Chief Executive Officer (CEO) and the Chief Financial Officer (CFO), is responsible for maintaining disclosure controls and procedures (DC&P) and internal controls over financial reporting (ICOFR). DC&P is designed to provide reasonable assurance that all relevant information is gathered and reported to senior management, including the President and CEO and the CFO, on a timely basis so that appropriate decisions can be made regarding public disclosure. ICOFR is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements in accordance with US GAAP.

An evaluation of the effectiveness of the design and operation of OPG's DC&P and ICOFR was conducted as of December 31, 2017. Accordingly, we, as OPG's President and CEO and CFO, will certify OPG's annual disclosure documents filed with the Ontario Securities Commission, which includes attesting to the design and effectiveness of OPG's DC&P and ICOFR.

The Board of Directors, based on recommendations from its Audit and Risk Committee, reviews and approves the consolidated financial statements and the MD&A, and oversees management's responsibilities for the presentation and preparation of financial information, maintenance of appropriate internal controls, management and control of major areas of financial risk, and assessment of significant and related party transactions.

The consolidated financial statements have been audited by Ernst & Young LLP, independent external auditors appointed by the Board of Directors. The Independent Auditors' Report outlines the auditors' responsibilities and the scope of their examination and their opinion on OPG's consolidated financial statements. The independent external auditors, as confirmed by the Audit and Risk Committee, had direct and full access to the Audit and Risk Committee, with and without the presence of management, to discuss their audit and their findings therefrom, as to the integrity of OPG's financial reporting and the effectiveness of the system of internal controls.

Jeff Lyash
President and Chief Executive Officer

Ken Hartwick
Chief Financial Officer and Senior Vice President – Finance

March 8, 2018

INDEPENDENT
AUDITORS' REPORT

To the Shareholder of Ontario Power Generation Inc.

We have audited the accompanying consolidated financial statements of Ontario Power Generation Inc., which comprise the consolidated balance sheets as at December 31, 2017 and 2016, and the consolidated statements of income, comprehensive income, cash flows and changes in shareholder's equity for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with United States generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Ontario Power Generation Inc. as at December 31, 2017 and 2016, and the results of its operations and its cash flows for the years then ended in accordance with United States generally accepted accounting principles.

Toronto, Canada

March 8, 2018

Ernst & Young LLP

Chartered Professional Accountants,
Licensed Public Accountants

CONSOLIDATED STATEMENTS OF INCOME

Years Ended December 31 *(millions of dollars except where noted)*	**2017**	**2016**
Revenue *(Note 17)*	**5,158**	5,653
Fuel expense *(Note 17)*	**689**	727
Gross margin	**4,469**	4,926
Operations, maintenance and administration *(Note 17)*	**2,824**	2,747
Depreciation and amortization *(Note 4)*	**679**	1,257
Accretion on fixed asset removal and nuclear waste management liabilities *(Note 8)*	**960**	929
Earnings on nuclear fixed asset removal and nuclear waste management funds *(Note 8)*	**(801)**	(746)
Earnings from Fair Hydro Trust *(Note 17)*	**(1)**	-
Income from investments subject to significant influence	**(38)**	(37)
Property taxes	**40**	46
Restructuring	**-**	6
	3,663	4,202
Income before other gains, interest and income taxes	**806**	724
Other gains *(Note 17)*	**379**	17
Income before interest and income taxes	**1,185**	741
Net interest expense *(Note 6)*	**95**	120
Income before income taxes	**1,090**	621
Income tax expense *(Note 9)*	**209**	168
Net income	**881**	453
Net income attributable to the Shareholder	**860**	436
Net income attributable to non-controlling interest	**21**	17
Basic and diluted net income per common share *(dollars) (Note 15)*	**3.35**	1.70

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Years Ended December 31 *(millions of dollars)*	**2017**	**2016**
Net income	**881**	453
Other comprehensive income, net of income taxes *(Note 10)*		
Actuarial loss on re-measurement of liabilities for pension and other post-employment benefits [1]	**(23)**	(6)
Reclassification to income of amounts related to pension and other post-employment benefits [2]	**10**	12
Reclassification to income of losses on derivatives designated as cash flow hedges [3]	**18**	19
Unrealized loss on available-for-sale securities [4]	**(8)**	(1)
Other comprehensive (loss) income for the year	**(3)**	24
Comprehensive income	**878**	477
Comprehensive income attributable to the Shareholder	**857**	460
Comprehensive income attributable to non-controlling interest	**21**	17

[1] Net of income tax recovery of $7 million and $2 million for 2017 and 2016, respectively.

[2] Net of income tax expenses of $3 million and $4 million for 2017 and 2016, respectively.

[3] Net of income tax expenses of $2 million for each of 2017 and 2016.

[4] Net of income tax recovery of $2 million and nil for 2017 and 2016, respectively.

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31 *(millions of dollars)*	**2017**	**2016**
Operating activities		
Net income	**881**	453
Adjust for non-cash items:		
Depreciation and amortization *(Note 4)*	**679**	1,257
Accretion on fixed asset removal and nuclear waste management liabilities	**960**	929
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(801)**	(746)
Pension and other post-employment benefit costs *(Note 11)*	**412**	464
Deferred income taxes	**19**	(36)
Mark-to-market on derivative instruments	**(3)**	3
Provision for used nuclear fuel and low and intermediate level nuclear waste	**116**	118
Regulatory assets and liabilities	**(558)**	(170)
Provision for materials and supplies	**33**	42
Other gains	**(371)**	-
Other	**1**	(25)
	1,368	2,289
Contributions to nuclear fixed asset removal and nuclear waste management funds	**-**	(150)
Expenditures on fixed asset removal and nuclear waste management	**(313)**	(275)
Reimbursement of eligible expenditures on nuclear fixed asset removal and nuclear waste management	**79**	70
Contributions to pension funds and expenditures on other post-employment benefits and supplementary pension plans	**(322)**	(363)
Expenditures on restructuring	**(4)**	(6)
Distributions received from investments subject to significant influence	**50**	52
Net changes to other long-term assets and liabilities	**32**	20
Net changes to non-cash working capital balances *(Note 18)*	**54**	180
Cash flow provided by operating activities	**944**	1,817
Investing activities		
Acquisition of Fair Hydro Trust financing receivables *(Notes 3 and 19)*	**(1,179)**	-
Purchase of available-for-sale securities	**-**	(213)
Proceeds from deposit note	**70**	110
Net proceeds from sale of property, plant and equipment	**484**	-
Investment in property, plant and equipment and intangible assets	**(1,853)**	(1,816)
Cash flow used in investing activities	**(2,478)**	(1,919)
Financing activities		
Issuance of Class A shares *(Note 14)*	**519**	-
Issuance of long-term debt *(Note 6)*	**1,301**	334
Repayment of long-term debt	**(1,103)**	(273)
Issuance of long-term debt by Fair Hydro Trust *(Note 6)*	**601**	-
Distribution to non-controlling interest	**(15)**	(14)
Capital contribution from non-controlling interest	**19**	-
Issuance of short-term notes	**1,960**	3,108
Repayment of short-term debt	**(1,700)**	(3,331)
Cash flow provided by (used in) financing activities	**1,582**	(176)
Net increase (decrease) in cash and cash equivalents	**48**	(278)
Cash and cash equivalents, beginning of year	**186**	464
Cash and cash equivalents, end of year	**234**	186

See accompanying notes to the consolidated financial statements

CONSOLIDATED BALANCE SHEETS

As at December 31 *(millions of dollars)*	2017	2016
Assets		
Current assets		
Cash and cash equivalents [1]	**234**	186
Available-for-sale securities	**188**	212
Receivables from related parties *(Note 19)*	**369**	429
Nuclear fixed asset removal and nuclear waste management funds *(Notes 8 and 17)*	**23**	24
Fuel inventory *(Note 17)*	**309**	310
Materials and supplies *(Note 17)*	**103**	100
Prepaid expenses	**192**	198
Other current assets	**146**	298
	1,564	1,757
Property, plant and equipment *(Notes 4 and 17)*	**29,950**	29,315
Less: accumulated depreciation	**8,628**	9,317
	21,322	19,998
Intangible assets *(Notes 4 and 17)*	**565**	503
Less: accumulated amortization	**432**	404
	133	99
Other assets		
Nuclear fixed asset removal and nuclear waste management funds *(Notes 8 and 17)*	**16,701**	15,960
Financing receivables *(Note 19)*	**1,179**	-
Long-term materials and supplies *(Note 17)*	**355**	345
Regulatory assets *(Note 5)*	**7,231**	5,855
Investments subject to significant influence *(Note 20)*	**309**	321
Other long-term assets	**28**	37
	25,803	22,518
	48,822	44,372

[1] Includes $4 million restricted for Fair Hydro Trust purposes.

See accompanying notes to the consolidated financial statements

CONSOLIDATED BALANCE SHEETS

As at December 31 *(millions of dollars)*	2017	2016
Liabilities		
Current liabilities		
Accounts payable and accrued charges *(Note 19)*	**1,228**	1,164
Short-term debt *(Note 7)*	**260**	2
Deferred revenue due within one year	**12**	12
Long-term debt due within one year *(Note 6)*	**398**	1,103
Income taxes payable	**80**	123
	1,978	2,404
Long-term debt *(Notes 6 and 17)*	**5,921**	4,417
Other liabilities		
Fixed asset removal and nuclear waste management liabilities *(Notes 8 and 17)*	**20,421**	19,484
Pension liabilities *(Note 11)*	**3,423**	3,012
Other post-employment benefit liabilities *(Note 11)*	**3,092**	2,897
Long-term accounts payable and accrued charges	**252**	213
Deferred revenue	**351**	298
Deferred income taxes *(Note 9)*	**879**	829
Regulatory liabilities *(Note 5)*	**594**	310
	29,012	27,043
Equity		
Common shares [1] *(Note 14)*	**5,126**	5,126
Class A shares [2] *(Note 14)*	**519**	-
Retained earnings	**6,396**	5,534
Accumulated other comprehensive loss *(Note 10)*	**(295)**	(295)
Equity attributable to the Shareholder	**11,746**	10,365
Equity attributable to non-controlling interest *(Note 22)*	**165**	143
Total equity	**11,911**	10,508
	48,822	44,372

[1] 256,300,010 common shares outstanding at a stated value of $5,126 million as at December 31, 2017 and December 31, 2016.

[2] 12,217,616 Class A shares outstanding at a stated value of $519 million as at December 31, 2017.

Commitments and Contingencies *(Notes 6, 9, 11 and 16)*

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY

Years Ended December 31 *(millions of dollars)*	**2017**	**2016**
Common shares	**5,126**	5,126
Class A shares *(Note 14)*	**519**	-
Retained earnings		
Balance at beginning of year	**5,534**	5,098
Net income attributable to the Shareholder	**860**	436
Reclassification of non-controlling interest on change in ownership interest *(Note 22)*	**2**	-
Balance at end of year	**6,396**	5,534
Accumulated other comprehensive loss, net of income taxes		
Balance at beginning of year	**(295)**	(319)
Other comprehensive (loss) income	**(3)**	24
Reclassification of non-controlling interest on change in ownership interest *(Note 22)*	**3**	-
Balance at end of year	**(295)**	(295)
Equity attributable to the Shareholder	**11,746**	10,365
Equity attributable to non-controlling interest		
Balance at beginning of year	**143**	140
Equity contribution from non-controlling interest *(Note 22)*	**21**	-
Reclassification of non-controlling interest on change in ownership interest *(Note 22)*	**(5)**	-
Distribution to non-controlling interest	**(15)**	(14)
Income attributable to non-controlling interest	**21**	17
Balance at end of year	**165**	143
Total equity	**11,911**	10,508

See accompanying notes to the consolidated financial statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the years ended December 31, 2017 and 2016

1. DESCRIPTION OF BUSINESS

Ontario Power Generation Inc. (OPG or the Company) was incorporated on December 1, 1998 pursuant to the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the Province or the Shareholder). OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario.

2. BASIS OF PRESENTATION

These consolidated financial statements have been prepared and presented in accordance with United States generally accepted accounting principles (US GAAP).

As required by *Ontario Regulation 395/11,* as amended, under the *Financial Administration Act* (Ontario), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. Since January 1, 2012, OPG also has received exemptive relief from the Ontario Securities Commission (OSC) from the requirements of section 3.2 of National Instrument 52-107, *Acceptable Accounting Policies and Auditing Standards*. The exemption allows OPG to file consolidated financial statements based on US GAAP, rather than International Financial Reporting Standards (IFRS), without becoming a US Securities and Exchange Commission registrant, or issuing public debt.

The current OSC exemption, received in 2014, will terminate on the earliest of the following:

- January 1, 2019
- The financial year that commences after OPG ceases to have activities subject to rate regulation
- The effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within IFRS specific to entities with rate-regulated activities.

All dollar amounts are presented in Canadian dollars, except in tabular format where noted. Certain of the 2016 comparative amounts have been reclassified from financial statements previously presented to conform to the 2017 consolidated financial statement presentation.

3. SIGNIFICANT ACCOUNTING POLICIES AND ESTIMATES

Consolidation

The consolidated financial statements of the Company include the accounts of OPG and its majority-owned subsidiaries, and variable interest entities (VIEs) where OPG is the primary beneficiary. All significant intercompany balances and intercompany transactions have been eliminated on consolidation.

Where OPG does not control an investment, but has significant influence over operating and financing policies of the investee, the investment is accounted for under the equity method. OPG co-owns the Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS) with TransCanada Energy Ltd. and co-owns the Brighton Beach gas-fired combined cycle GS (Brighton Beach) with ATCO Power Canada Ltd. OPG accounts for its 50 percent ownership interest in each of these jointly controlled entities using the equity method.

Variable Interest Entities

OPG performs ongoing analysis to assess whether it holds any VIEs. VIEs of which OPG is deemed to be the primary beneficiary are consolidated. The primary beneficiary of a VIE has both the power to direct the activities of the entity that most significantly impact its economic performance and the obligation to absorb losses of the entity that could potentially be significant to the Company. In circumstances where OPG is not deemed to be the primary beneficiary, the VIE is not recorded in OPG's consolidated financial statements.

Nuclear Waste Management Organization (NWMO)

In 2002, OPG and other Canadian nuclear waste producers established a separately incorporated NWMO in accordance with the *Nuclear Fuel Waste Act* (Canada) (NFWA). The primary long-term mandate of the NWMO is to implement an approach to address the long-term management of used nuclear fuel in Canada. In addition to the above mandate, the NWMO currently provides project management services for OPG's proposed Deep Geologic Repository (DGR) for the long-term management of low and intermediate level waste (L&ILW) and certain other nuclear life cycle liability management services. OPG has the majority of voting rights at the NWMO Board of Directors' and members' level. The NFWA requires the nuclear fuel waste owners to establish and make payments into trust funds for the purpose of funding the implementation of the long-term nuclear used fuel management plan in accordance with the NFWA. OPG provides over 90 percent of NWMO's funding, primarily towards the design and implementation of Canada's Adaptive Phased Management plan for the long-term management of nuclear used fuel. As a result, OPG is expected to absorb a majority of the NWMO's expected losses through future funding in the event of any shortfall. Therefore, OPG holds a variable interest in the NWMO, of which it is the primary beneficiary. Accordingly, the applicable amounts in the accounts of the NWMO, after elimination of all significant intercompany transactions, are consolidated.

Fair Hydro Trust

On March 2, 2017, the Province announced Ontario's Fair Hydro Plan (the Fair Hydro Plan) aimed at reducing electricity bills for all residential, farm, small businesses and other eligible consumers (Specified Consumers) in the province on average by 25 percent. The rate reduction is inclusive of an eight percent rebate equivalent to the provincial portion of the harmonized sales tax granted by the Ontario government in January 2017. As part of the Fair Hydro Plan, a portion of the Global Adjustment costs resulting from the Fair Hydro Plan shortfall will be refinanced over a longer time period. The Global Adjustment includes the difference between Ontario's electricity market clearing price used to dispatch generation and the prices paid to contracted and regulated generators in the province, and the cost of conservation and demand management programs. On June 1, 2017, the *Ontario Fair Hydro Plan Act, 2017* (the Fair Hydro Act or the Act) received Royal Assent and the associated general regulation came into force in June 2017. Effective May 1, 2017, the Independent Electricity System Operator (IESO) began to defer a portion of the Global Adjustment costs. The Act allows for the IESO to transfer a portion of the balance in the variance account to a financing entity that will fund the deferral in exchange for the right to recover the balance and associated financing and other costs from Specified Consumers in the future (Investment Interest).

In December 2017, the Fair Hydro Trust (the Trust) was established as the financing entity contemplated by the Fair Hydro Act. Immediately after the establishment, OPG entered into a management agreement with the Trust which conveys to OPG all of the powers and duties of managing the Trust, including determining whether to acquire Investment Interests from the IESO related to the shortfall from the rate reduction mandated by the Fair Hydro Act, negotiating and executing all agreements, fulfilling all reporting requirements, and administering all of its day-to-day activities. In addition to the powers and duties delegated to OPG as manager under the management agreement, OPG is also required to comply with its duties as Financial Services Manager under the Fair Hydro Act and the regulations.

The Trust is essentially all debt funded and has minimal equity at risk to finance its activities. As part of the funding structure of the Trust, concurrent with every issuance of senior debt, it is expected that OPG will purchase

subordinated debt of the Trust in an aggregate amount equal to, but no more than 49 percent of all of the required funding. The subordination level may vary over time, but must at least equal to, or be greater than 35 percent of all outstanding debt. Approximately 90 percent of such amount is expected to be funded through equity investments in OPG by the Province, with the remainder being funded from OPG's available funds, including all or a portion of the proceeds from OPG's medium term notes program. Based on management's assessment, it is concluded that OPG holds a variable interest in the Trust through its ownership of the most subordinated debt, of which it is the primary beneficiary. Accordingly, the applicable amounts in the accounts of the Trust, after elimination of all significant intercompany transactions, have been consolidated by OPG.

PSS Generating Station Limited Partnership (PSS or the Partnership)

As at December 31, 2017, PSS has recognized sufficient level of income and has eliminated deficits within the partnership. Hence, the Partnership has met the criteria of having sufficient equity at risk to finance its activities, and ceased being classified as a variable interest entity. Since OPG is the primary beneficiary of PSS, it continues to consolidate the Partnership.

Use of Management Estimates

The preparation of consolidated financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the consolidated financial statements, and the reported amounts of revenues and expenses for the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in the period incurred. Significant estimates are included in the determination of pension and other post-employment benefit (OPEB) balances, asset retirement obligations (AROs) and associated asset retirement costs capitalized as part of property, plant and equipment (PP&E), income taxes (including deferred income taxes), contingencies, regulatory assets and liabilities, valuation of investments in segregated funds, depreciation and amortization expenses. Actual results may differ significantly from these estimates.

Cash and Cash Equivalents and Short-Term Investments

Cash and cash equivalents include cash on deposit and money market securities with a maturity of less than 90 days on the date of purchase. All other money market securities with a maturity on the date of purchase that is greater than 90 days, but less than one year, are recorded as short-term investments and classified as current assets. These securities are valued at the lower of cost and market.

Inventories

Inventories, consisting of fuel and materials and supplies, are measured at the lower of cost and net realizable value. Cost is determined as weighted average cost for fuel inventory and average cost for materials and supplies.

Property, Plant and Equipment, Intangible Assets and Depreciation and Amortization

PP&E and intangible assets are recorded at cost. Interest costs incurred during construction and development are capitalized as part of the cost of the asset based on the interest rates on OPG's long-term debt. Expenditures for replacements of major components are capitalized.

Depreciation and amortization rates for the various classes of assets are based on their estimated service lives. Asset removal costs that have not been specifically provided for in current or previous periods are charged to operations, maintenance and administration (OM&A) expenses when incurred. Repairs and maintenance costs also are expensed when incurred.

PP&E are depreciated on a straight-line basis, except for computers, which are depreciated on a declining balance basis. Intangible assets, which consist of major application software, are amortized on a straight-line basis.

As at December 31, 2017, the amortization periods of PP&E and intangible assets are as follows:

Nuclear generating stations and major components	15 to 74 years [1]
Thermal generating stations and major components	5 to 50 years
Hydroelectric generating stations and major components	10 to 100 years
Administration and service facilities	10 to 50 years
Computers – declining balance	12% to 40% per year
Major application software	5 years
Service equipment	5 to 10 years

[1] As at December 31, 2017, the end of station life for depreciation purposes for the Darlington, Pickering, Bruce A and Bruce B nuclear generating stations ranged between 2022 and 2061. Major components are depreciated over the lesser of the station life and the life of the components.

Asset Impairment

Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. The review is based on the presence of impairment indicators such as the future economic benefit of the assets and external market conditions. The net carrying amount of assets is considered impaired if it exceeds the sum of the estimated undiscounted cash flows expected to result from the asset's use and eventual disposition. In cases where the sum of the undiscounted expected future cash flows is less than the carrying amount, an impairment loss is recognized. This loss equals the amount by which the carrying amount exceeds the fair value. Fair value is determined using expected discounted cash flows when quoted market prices are not available. The impairment is recognized in income in the period in which it is identified.

The carrying values of investments accounted for under the equity method are reviewed annually for the presence of any indicators of impairment. If an impairment exists and is determined to be other-than-temporary, an impairment charge is recognized. This charge equals the amount by which the carrying value exceeds the investment's fair value.

Rate Regulated Accounting

The *Ontario Energy Board Act, 1998* and *Ontario Regulation 53/05* provide that OPG receives regulated prices for electricity generated from the Sir Adam Beck 1, 2 and Pump hydroelectric generating stations, the DeCew Falls 1 and 2 hydroelectric generating stations, the R.H. Saunders Hydroelectric GS, the 48 hydroelectric generating stations prescribed for rate regulation effective in 2014, and the Pickering and Darlington nuclear generating stations (collectively, prescribed facilities or regulated facilities). OPG's regulated prices for these facilities are determined by the Ontario Energy Board (OEB).

The OEB is a self-funding Crown corporation. Its mandate and authority come from the *Ontario Energy Board Act, 1998,* the *Electricity Act, 1998*, and a number of other provincial statutes. The OEB is an independent, quasi-judicial tribunal that reports to the Legislature of the Province through the Ontario Ministry of Energy. It regulates market participants in Ontario's natural gas and electricity industries. The OEB carries out its regulatory functions through public hearings and other more informal processes such as consultations.

US GAAP recognizes that rate regulation can create economic benefits and obligations that are required by the regulator to be obtained from, or settled with, the customers. When the Company assesses that there is sufficient assurance that incurred costs in respect of the regulated facilities will be recovered in the future, those costs are deferred and reported as a regulatory asset. When the Company is required to refund amounts to customers in the future in respect of the regulated facilities, including amounts related to costs that have not been incurred but for which the OEB has provided recovery through regulated prices, the Company records a regulatory liability.

Certain of the regulatory assets and liabilities recognized by the Company relate to variance and deferral accounts authorized by the OEB, including those authorized pursuant to *Ontario Regulation 53/05*. Variance and deferral accounts typically capture differences between actual costs and revenues and the corresponding forecast amounts

approved by the OEB in setting regulated prices, or record the impact of items not reflected in the approved regulated prices. The measurement of these regulatory assets and liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of *Ontario Regulation 53/05* and the OEB's decisions. The estimates and assumptions made in the interpretation of the regulation and the OEB's decisions are reviewed as part of the OEB's regulatory process.

Regulatory assets and liabilities for variance and deferral account balances approved by the OEB for inclusion in regulated prices are amortized based on approved recovery or repayment periods. Disallowed balances are charged to operations in the period that the corresponding OEB decision is issued.

Regulatory assets and liabilities for variance and deferral account balances approved by the OEB are classified as current if they are expected to be recovered from, or refunded to, customers within 12 months of the end of the reporting period, based on recovery or repayment periods authorized by the OEB. All other regulatory asset and liability balances are classified as non-current on the consolidated balance sheets.

In addition to regulatory assets and liabilities for variance and deferral accounts, OPG recognizes regulatory assets and liabilities for unamortized amounts recorded in accumulated other comprehensive income (AOCI) in respect of pension and OPEB obligations, and deferred income taxes, in order to reflect the expected recovery or repayment of these amounts through future regulated prices charged to customers. There are measurement uncertainties related to these balances due to the assumptions made in the determination of pension and OPEB obligations and deferred income taxes that are attributed to rate regulated business segments.

The regulatory asset for unamortized pension and OPEB amounts recorded in AOCI has reflected the OEB's use, since April 1, 2008, of the accrual basis of accounting for including pension and OPEB amounts in approved regulated prices for OPG. This is also the manner in which these costs are recognized in OPG's consolidated financial statements. Therefore, unamortized amounts in respect of OPG's pension and OPEB plans recognized in AOCI generally would not be reflected in regulated prices until they have been reclassified from AOCI and recognized as amortization components of the benefit costs for these plans. The regulatory asset is reversed as underlying unamortized balances are amortized as components of the benefit cost.

In setting OPG's regulated prices effective November 1, 2014, the OEB limited amounts for pension and OPEB costs allowed in the approved revenue requirements to the regulated business portion of the Company's cash expenditures on its pension and OPEB plans. It is the Company's position that this decision by the OEB does not constitute a change in the basis of rate recovery for OPG's pension and OPEB costs. This position is based on the OEB's establishment of the Pension & OPEB Cash Versus Accrual Differential Deferral Account pursuant to its November 2014 decision, and the expectation expressed by the OEB in that decision that a transition from the accrual basis of recovery for OPG, if required, would be addressed in a future OPG rate proceeding, informed by the outcome of an OEB generic proceeding related to the regulatory treatment and recovery of pension and OPEB costs. Effective November 1, 2014, the Pension & OPEB Cash Versus Accrual Differential Deferral Account records the difference between OPG's actual pension and OPEB costs for the regulated business determined using the accrual method applied in OPG's audited consolidated financial statements and OPG's corresponding actual cash expenditures for these plans. The OEB's November 2014 decision indicated that the future recovery, if any, of amounts recorded in the deferral account would be subject to the outcome of an OEB generic proceeding on the regulatory treatment and recovery of pension and OPEB costs. In May 2015, the OEB began a consultation process to develop standard principles to guide its future review of pension and OPEB costs of rate regulated utilities in the electricity and natural gas sectors, including establishing appropriate regulatory mechanisms for cost recovery. The consultation is continuing. On September 14, 2017, the OEB issued its final report on the guiding principles and the policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the Ontario electricity and natural gas sectors. The report establishes the accrual basis of accounting as the method of determining pension and OPEB amounts for rate-setting purposes, unless the OEB finds that this method does not result in just and reasonable rates in the circumstances of a particular utility.

In consideration of the above factors, the Company continues to believe that there is sufficient likelihood that unamortized pension and OPEB amounts that have not yet been reclassified from AOCI will be included in future regulated prices or in an OEB-authorized deferral or variance account for future recovery, as they are recognized in benefit costs. Therefore, the Company continues to recognize a regulatory asset for these unamortized amounts and also has recognized a regulatory asset for the balance of the Pension & OPEB Cash Versus Accrual Differential Deferral Account discussed in Note 5.

See Notes 5, 8, 9, and 11 for additional disclosures related to the OEB's decisions, regulatory assets and liabilities, and rate regulated accounting.

Revenue Recognition

All of OPG's electricity generation is offered into the real-time energy spot market administered by the IESO. Revenue is recognized as electricity is generated and metered to the IESO.

Revenue Recognition – Regulated Generation

Energy revenue generated from OPG's regulated facilities is based on regulated prices determined by the OEB that include a base regulated price and, as applicable, rate riders for the recovery or repayment of approved variance and deferral account balances.

The base regulated prices in effect during 2016 were established by the OEB's November 2014 decision and December 2014 order, using a forecast cost-of-service rate-setting methodology based on the OEB-approved revenue requirements, taking into account the OEB-approved forecasts of production and operating costs for the regulated facilities for 2014 and 2015 and a return on rate base. Rate base is a regulatory construct that, for OPG, represents the average net level of investment in regulated fixed and intangible assets in-service and an allowance for working capital. The revenues from the regulated hydroelectric facilities are also subject to the OEB-approved hydroelectric incentive mechanism. This mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers.

The rate riders in effect during 2016 were established by the OEB in its October 2015 order on OPG's application to recover balances in most of the Company's authorized variance and deferral accounts as at December 31, 2014. The OEB-authorized variance and deferral accounts are discussed in Note 5.

The OEB's decision and order on OPG's May 2016 five-year application for new regulated prices for its nuclear and regulated hydroelectric generation was issued on December 28, 2017, following a public hearing process. The OEB set an effective date for OPG's new regulated prices of June 1, 2017. OPG had requested an effective date of January 1, 2017 and has filed a motion with the OEB in January 2018 to review and vary this aspect of the OEB's December 2017 decision. [**MONITOR**] See Note 5 for further information on OPG's May 2016 application.

Revenue Recognition – Non-regulated Generation and Other Revenue

The electricity generation from OPG's non-regulated assets receives the Ontario electricity spot market price, except where an energy supply agreement (ESA) with the IESO or another contractual agreement is in place. As at December 31, 2017, most of OPG's operating non-regulated assets are subject to an ESA. Revenue from the generating stations subject to an ESA is recognized in accordance with the terms of the agreement.

OPG also sells into, and purchases from, interconnected markets of other provinces and the northeast and midwest regions of the US. All contracts that are not designated as hedges are recorded on the consolidated balance sheets at market value, with gains or losses recorded in the consolidated statements of income. Gains and losses on energy trading contracts (including those to be physically settled) are recorded on a net basis in the consolidated statements of income. Accordingly, power purchases of $15 million were netted against revenue in 2017 (2016 – $19 million).

OPG derives non-energy revenue under the terms of a lease arrangement and associated agreements with Bruce Power L.P. (Bruce Power) related to the Bruce nuclear generating stations. This includes lease revenue and revenue from heavy water sales, detritiation services and waste management services. OPG's net revenues from the lease of these stations and related agreements, including a portion of heavy water sales, are credited to customers and therefore have reduced regulated prices for the generation from the nuclear facilities owned and operated by OPG. The minimum lease payments are recognized in revenue on a straight-line basis over the term of the lease.

In addition, non-energy revenue includes isotope sales, real estate rentals and other service revenues. Revenues from these activities are recognized as services are provided, or as products are delivered, in accordance with the terms stipulated in the respective contracts.

Fixed Asset Removal and Nuclear Waste Management Liabilities

OPG recognizes AROs for fixed asset removal and nuclear waste management, discounted for the time value of money. OPG estimates both the amount and timing of future cash expenditures based on the plans for fixed asset removal and nuclear waste management. The liabilities are initially recorded at their estimated fair value, which is based on a discounted value of the expected costs to be paid.

On an ongoing basis, the liabilities for nuclear fixed asset removal and nuclear waste management (Nuclear Liabilities) are increased by the present value of the incremental (variable) cost portion for the nuclear waste generated each year, with the corresponding amounts charged to OM&A expenses. Variable expenses relating to L&ILW are charged to OM&A expenses. Variable expenses relating to the management and storage of nuclear used fuel are charged to fuel expense. The liabilities may also be adjusted due to changes in the estimated amount or timing of the underlying future cash flows, with resulting changes in the related asset retirement costs capitalized as part of the carrying amount of the related fixed assets in service. A comprehensive reassessment of all underlying assumptions and baseline cost estimates for the Nuclear Liabilities is performed periodically. Changes in the Nuclear Liabilities resulting from changes in assumptions or estimates that impact the amount or timing of the originally estimated undiscounted future cash flows are recorded as an adjustment to the liabilities. Upward revisions in the Nuclear Liabilities represent the present value of increases in future undiscounted cash flows determined using a current credit-adjusted risk-free rate. Downward revisions in the Nuclear Liabilities represent the present value of decreases in future undiscounted cash flows determined using the weighted average discount rate reflected in the existing liability. Upon settlement of the liabilities, a gain or loss would be recorded.

Accretion arises because the fixed asset removal and nuclear waste management liabilities are reported on a net present value basis. Accretion expense is the increase in the carrying amount of the liabilities due to the passage of time.

The asset retirement cost is capitalized by increasing the carrying value of the related fixed assets in service. The capitalized cost is depreciated over the remaining service life of the related fixed assets and is included in depreciation and amortization expenses.

OPG has no legal obligation associated with the decommissioning of its hydroelectric generating facilities and the costs cannot be reasonably estimated because of the long service life of these assets. With either maintenance efforts or rebuilding, the water control structures are assumed to be used for the foreseeable future. Accordingly, OPG has not recognized a liability for the decommissioning of its hydroelectric generating facilities.

Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

Pursuant to the Ontario Nuclear Funds Agreement (ONFA) between OPG and the Province, OPG has established and sets aside funds in a Used Fuel Segregated Fund and a Decommissioning Segregated Fund (together the Nuclear Segregated Funds). The Used Fuel Segregated Fund is intended to fund expenditures associated with the long-term management of radioactive used nuclear fuel bundles and certain costs of used fuel storage incurred after the nuclear stations are shut down, while the Decommissioning Segregated Fund was established to fund the costs

of nuclear fixed asset removal and long-term L&ILW management, and certain costs of used fuel storage incurred after the nuclear stations are shut down. OPG's funding obligations and resulting contributions to the Nuclear Segregated Funds are determined based on periodically updated reference plans approved by the Province under the ONFA. OPG maintains the Nuclear Segregated Funds in third-party custodial and trust accounts that are segregated from the rest of OPG's assets.

OPG's investments in the Nuclear Segregated Funds and the corresponding amounts payable to/receivable from the Province are classified as held-for-trading. The Nuclear Segregated Funds are measured at fair value based on the bid prices of the underlying equity and fixed income securities, and, in the case of the alternative investment portfolio, using appropriate valuation techniques as outlined in Note 13, with realized and unrealized gains and losses recognized in OPG's consolidated statements of income.

Financing Receivables

Financing receivables consist of the current and irrevocable right of the Fair Hydro Trust to collect payments from Specified Consumers in the future in accordance with the Fair Hydro Act and associated general regulation. These amounts are measured at the transaction price entered into with the IESO on market terms upon acquisition and subsequently measured on an amortized cost basis. The basis of amortization follows the effective interest method.

Derivatives

All derivatives, including embedded derivatives that must be separately accounted for, generally are classified as held-for-trading and recorded at fair value in the consolidated balance sheets. Transaction costs are expensed as incurred for financial instruments classified or designated as held-for-trading.

Derivatives qualify for hedge accounting if they meet stringent documentation requirements, and if the derivative instrument that is designated as a hedge is expected to effectively hedge the identified risk throughout the life of the hedged item. At the inception of a hedging relationship, OPG documents the relationship between the hedging instrument and the hedged item, its risk management objective, and its strategy for undertaking the hedge. A documented assessment is made, both at the inception of a hedge and on an ongoing basis, of whether or not the derivatives that are used in hedging transactions are highly effective in offsetting the changes attributable to the hedged risks in the fair values or cash flows of the hedged items.

All derivative contracts not designated as hedges are recorded on the consolidated balance sheets as derivative assets or liabilities at fair value, with changes in the fair value recorded in the revenue of the Services, Trading, and Other Non-Generation segment. Refer to Note 12 for a discussion of OPG's risk exposures and the derivative instruments used to manage these risks.

Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly arm's-length transaction between market participants at the measurement date. Fair value measurements are required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model. OPG uses a fair value hierarchy, grouping assets and liabilities into three levels based on the relative objectivity of the inputs used to measure fair value, with Level 1 representing the most objective. Refer to Note 13 for a discussion of fair value measurements and the fair value hierarchy.

Available-for-Sale Securities

Available-for-sale (AFS) securities are measured at fair value, with unrealized gains and losses due to changes in fair value recognized in other comprehensive income (OCI). Gains and losses are realized and included in net income when the securities are sold or awarded. Related transaction costs are expensed as incurred, and dividend income

is included in net income in the period dividends are declared. Equity securities are initially measured at the transaction price.

Research and Development

Research and development costs are expensed as incurred. Research and development costs incurred to discharge long-term obligations for which specific provisions have already been made, such as the Nuclear Liabilities, are charged to the related liability.

Leases

Leases are evaluated and classified as either operating or capital leases for financial reporting purposes. Capital leases, which transfer substantially all of the risks and benefits incidental to ownership of the leased item, are capitalized at the inception of the lease at the fair value of the leased property or, if lower, at the present value of the minimum lease payments. Capital leases are depreciated over the shorter of the estimated useful life of the asset and the lease term.

Leases where the lessor retains substantially all the risks and benefits incidental to ownership of the asset are classified as operating leases. Operating lease payments, other than contingent rentals, are recognized as an expense in the consolidated statements of income on a straight-line basis over the lease term. Where the amount of rent expense recognized is different from the actual operating lease payment, other than contingent rentals, the difference is deferred and included as assets or liabilities on the consolidated balance sheets.

Pension and Other Post-Employment Benefits

OPG's post-employment benefit programs consist of a contributory defined benefit registered pension plan, a defined benefit supplementary pension plan, and other post-retirement benefits (OPRB) including group life insurance and health care benefits, and long-term disability (LTD) benefits. Post-employment benefit programs are also provided by the NWMO, which is consolidated into OPG's financial results. Unless otherwise noted, information on the Company's post-employment benefit programs is presented on a consolidated basis.

OPG accrues its obligations under pension and OPEB plans in accordance with US GAAP. The obligations for pension and OPRB are determined using the projected benefit method pro-rated on service. The obligation for LTD benefits is determined using the projected benefit method on a terminal basis. Pension and OPEB obligations are impacted by factors including interest rates, adjustments arising from plan amendments, demographic assumptions, experience gains or losses, salary levels, inflation, and health care cost escalation assumptions. Pension and OPEB costs and obligations are determined annually by independent actuaries using management's best estimate assumptions.

Assumptions are significant inputs to actuarial models that measure pension and OPEB obligations and related effects on operations. Discount rate, inflation rate, and changes in salary levels are three critical assumptions in the determination of benefit costs and obligations. In addition, the expected long-term rate of return on plan assets is a critical assumption in the determination of registered pension plan cost and the health care cost trend rate is a critical assumption in the determination of OPEB cost and obligations. These assumptions, as well as other assumptions involving demographic factors such as retirement age, mortality, and employee turnover, are evaluated periodically by management in consultation with independent actuaries. During the evaluation process, the assumptions are updated to reflect past experience and expectations for the future. Actual results in any given year will often differ from actuarial assumptions because of economic and other factors giving rise to actuarial gains and losses. In accordance with US GAAP, for pension and OPRB, the impact of these updates and differences on the respective benefit obligations is accumulated and amortized over future periods. For LTD benefits, the impact of these updates and differences is immediately recognized as OPEB costs in the period incurred.

The discount rates, which are representative of AA corporate bond yields, are used to calculate the present value of the expected future cash flows on the measurement date in order to determine the projected benefit obligations for the Company's employee benefit plans. A lower discount rate increases the benefit obligations and increases benefit costs. The expected rate of return on plan assets is based on the pension fund's asset allocation and the expected return considering long-term risks and returns associated with each asset class within the plan portfolio. A lower expected rate of return on plan assets increases pension cost.

Pension fund assets include equity securities, corporate and government debt securities, pooled funds, real estate, infrastructure, and other investments. These assets are managed by professional investment managers. The pension fund does not invest in equity or debt securities issued by OPG. Pension fund assets are valued using market-related values for purposes of determining the amortization of actuarial gains or losses and the expected return on plan assets. The market-related value recognizes gains and losses on equity assets relative to a six percent assumed real return over a five-year period.

Pension and OPEB costs include current service costs, interest costs on the obligations, the expected return on pension plan assets, adjustments for plan amendments, and adjustments for actuarial gains or losses, which result from changes in assumptions and experience gains and losses. Past service costs or credits arising from pension and OPRB plan amendments are amortized on a straight-line basis over the expected average remaining service life to full eligibility of the employees covered by the corresponding plan. Past service costs or credits arising from amendments to LTD benefits are immediately recognized as OPEB costs in the period incurred. Due to the long-term nature of pension and OPRB liabilities, the excess of the net cumulative unamortized gain or loss, over 10 percent of the greater of the benefit obligation and the market-related value of the plan assets (the corridor), is amortized over the expected average remaining service life of the employees, which represents the period during which the associated economic benefits are expected to be realized by the Company. Actuarial gains or losses for LTD benefits are immediately recognized as OPEB costs in the period incurred.

OPG recognizes the funded status of its defined benefit plans on the consolidated balance sheets. The funded status is measured as the difference between the fair value of plan assets and the benefit obligation, on a plan-by-plan basis.

Actuarial gains or losses and past service costs or credits arising during the year that are not recognized immediately as components of benefit costs are recognized as increases or decreases in OCI, net of income taxes. These unamortized amounts in AOCI are subsequently reclassified and recognized as components of pension and OPRB costs as described above.

OPG records an offsetting regulatory asset or liability for the portion of the adjustments to AOCI that is attributable to the regulated operations in order to reflect the expected recovery or refund of these amounts through future regulated prices charged to customers. For the recoverable or refundable portion attributable to regulated operations, OPG records a corresponding change in this regulatory asset or liability for the amount of the increases or decreases in OCI and for the amounts reclassified from AOCI into benefit costs during the period.

When the recognition of the transfer of employees and employee-related benefits gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement. A curtailment is the loss by employees of the right to earn future benefits under the plan. A settlement is the discharge of a plan's liability.

Income Taxes and Investment Tax Credits

OPG is exempt from income taxes under the *Income Tax Act* (Canada). However, under the *Electricity Act, 1998*, OPG is required to make payments in lieu of corporate income taxes to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by the *Electricity Act, 1998* and related regulations. This results in OPG paying taxes similar to those imposed under the federal and Ontario tax acts.

OPG's operations are complex and the computation of the provision for income taxes involves interpretation of the various tax statutes and regulations. OPG has taken certain filing positions in calculating the amount of its income tax provision. These filing positions may be challenged on audit by the Ontario Ministry of Finance and some of them possibly disallowed, resulting in a potential significant change in OPG's tax provision upon reassessment. A change in the tax provision upon reassessment impacting regulated operations may be recoverable from or refundable to customers through the Income and Other Taxes Variance Account authorized by the OEB.

OPG follows the liability method of accounting for income taxes. Under the liability method, deferred income tax assets and liabilities are determined based on differences between the accounting and tax bases of assets and liabilities. Deferred amounts are measured using the enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect of a change in tax rates on deferred income tax assets and liabilities is included in income in the period the change is enacted.

If management determines that it is more likely than not that some, or all, of a deferred income tax asset will not be realized, a valuation allowance is recorded to report the balance at the amount expected to be realized.

OPG recognizes deferred income taxes associated with its regulated operations and records an offsetting regulatory asset or liability for the deferred income taxes that are expected to be recovered or refunded through future regulated prices charged to customers.

Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return and investment tax credits are recorded only when the more likely than not recognition threshold is satisfied. Tax benefits and investment tax credits recognized are measured at the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement.

Investment tax credits are recorded as a reduction to income tax expense. OPG classifies interest and penalties associated with unrecognized income tax benefits as income tax expense.

Change in Accounting Estimates

Change in Nuclear Liabilities Estimate

In the fourth quarter of 2017, OPG achieved sufficient confidence in the Company's plans to pursue the continued safe and reliable operation of two units at the Pickering GS to 2022 and the four remaining units to 2024. This resulted in a change to the useful lives for the Pickering GS, for the purposes of calculating depreciation. Effective December 31, 2017, the change to the estimated service live of the Pickering GS has been reflected in an increase to the estimate of the Nuclear Liabilities of $188 million, and a corresponding changes in the carrying value of the nuclear generating stations to which the liabilities relate. The increase in the liabilities is primarily due to higher fixed costs associated with the Used Fuel Disposal and L&ILW Storage programs, discounted using the current credit-adjusted risk-free rate of 2.94 percent.

OPG filed an application with the OEB (EB-2018-0002) on December 29, 2017 to seek approval to establish a deferral account to record, from January 1, 2018 until the effective date of the OEB's next payment amounts order, the revenue requirement impact of changes to nuclear liabilities and depreciation and amortization expense resulting from changes to station end-of-life dates for OPG's Pickering prescribed nuclear facilities that were effective December 31, 2017. On January 31, 2018 the OEB issued an interim order (EB-2018-0002) for the establishment of the Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account, pending the outcome of the proceeding.

Pension and Other Post-Employment Benefits

Effective January 1, 2017, OPG changed the method used to estimate the service and interest cost components of pension and OPEB costs. OPG adopted a full yield curve approach to the estimation of these cost components, by applying the specific spot rates along the yield curve used in the determination of the projected benefit obligations to the relevant projected cash flows. Under the previous method, these components of pension and OPEB costs were calculated using the same single weighted-average discount rates as reflected in the calculation of the benefit obligations. This change in the method was accounted for prospectively, as a change in estimate. The resulting reduction in pension and OPEB costs is estimated at approximately $135 million in 2017. Approximately 90 percent of this reduction in pension and OPEB costs was attributed to the Company's regulated business segments and therefore was offset by the impact of regulatory variance and deferral accounts authorized by the OEB. This change does not affect the measurement of the total benefit obligation as the change in the current service and interest cost components from the previous method will be offset by a corresponding change in the actuarial gain and loss recorded in AOCI.

Pension Plan Actuarial Valuation

A new actuarial valuation of the OPG registered pension plan was filed with the Financial Services Commission of Ontario in September 2017 with an effective date of January 1, 2017. The annual funding requirements in accordance with the new actuarial valuation are $212 million for 2017, $215 million for 2018, and $219 million for 2019.

Recent Accounting Pronouncements Not Yet Adopted

Revenue from Contracts with Customers

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09, *Revenue from Contracts with Customers* (Topic 606), which supersedes nearly all existing revenue recognition guidance, including industry-specific guidance, under US GAAP. The core principle of Topic 606 is to recognize revenues when promised goods or services are transferred to customers in an amount that reflects the consideration to which an entity expects to be entitled for those goods or services. Either a full retrospective application or a modified retrospective application is required for annual periods beginning on or after January 1, 2018, including interim periods within that year. Early adoption is permitted.

OPG has assessed the impact of the standard on accounting for the Company's revenue streams and consolidated financial statements. OPG's major revenue streams include regulated generation revenue from base regulated prices and rate riders established by the OEB, as well as revenue from generation assets under long-term contractual arrangements with the IESO. OPG has completed its analyses of the impact of Topic 606 on all of its revenue streams, and has not identified any material differences in the timing or amount of revenue recognition for these streams.

The Company will apply the new revenue standard in its 2018 first quarter interim financial statements and is in the process of evaluating the additional disclosures required under the new standard.

Lease Accounting

In February 2016, the FASB issued ASU No. 2016-02, *Leases* (Topic 842). The update includes comprehensive changes to existing guidance for lease accounting, particularly for lessees, and aims to increase transparency and comparability among organizations by requiring the recognition of lease assets and lease liabilities on the balance sheet. The standard is effective for annual periods beginning after December 15, 2018, including interim periods within that year.

Under the current guidance, entities are required to use a modified retrospective approach for leases that exist, or are entered into, after the beginning of the earliest comparative period presented in the financial statements of the period of adoption. Under this method, Topic 842 would effectively be implemented by recognizing any adjustments stemming from the transition, as of beginning of the earliest comparative period presented in the entities' financial statements. Full retrospective application is prohibited. In January 2018, the FASB issued a proposed ASU wherein entities would be able to utilize an additional optional transition method of recording the cumulative impact of adopting the new lease standard to the opening balance in the initial period of adoption; with comparative periods continuing to be presented in accordance with the existing leasing standard, Topic 840 - *Leases*, including disclosures. [**MONITOR**] The Company will continue to monitor the status of this proposed ASU.

The FASB also issued ASU No. 2018-01, *Land Easement Practical Expedient for Transition to Topic 842* in January 2018. The amendments therein allows an entity to choose not to evaluate under Topic 842 land easements that exist or expired before the entity's adoption of the new leasing standard and that were not previously accounted for as leases under Topic 840.

The Company continues to implement and execute a comprehensive project governance framework, which comprises a Steering Committee, Implementation & Stakeholder Committee, Project Management Office, and various working groups in order to evaluate the implement the new standard. The working groups are represented by cross functional finance and non-finance stakeholders who will support the financial and operational implementation of the standard. The Company continues to evaluate the impact of the new leasing standard on its consolidated financial statements.

Recognition and Measurement of Financial Assets and Financial Liabilities

In January 2016, the FASB issued ASU No. 2016-01, *Financial Instruments – Overall: Recognition and Measurement of Financial Assets and Financial Liabilities*. Under the updated guidance, entities will have to measure equity investments at fair value and recognize any changes in fair value in net income. The update will be effective for OPG's 2018 fiscal year, including interim periods. As a result of this update, effective January 1, 2018, the AFS classification for securities will no longer be available, with any unrealized gains and losses related to such securities recognized in net income instead of OCI. Any unrealized gains and losses for AFS securities reported by OPG in AOCI as of the end of 2017 will be reclassified to retained earnings as of January 1, 2018. OPG's Hydro One share holdings are currently the Company's only AFS securities. As at December 31, 2017, these shares are valued on the consolidated balance sheet at $188 million (December 31, 2016 − $212 million), for which a loss of $8 million (2016 − $1 million) has been recorded in AOCI. OPG continues to evaluate whether the new standard will have any further impact on its consolidated financial statements.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost

In March 2017, the FASB issued ASU No. 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. Under the new guidance, employers that sponsor defined benefit plans for pensions and/or other postretirement benefits are required to present the service cost component of net periodic benefit cost in the same statement of income line item as other employee compensation costs arising from services rendered during the period. The other components of the net periodic benefit cost are to be presented separately from the line item that includes the service cost and outside of any subtotal of income from operations, if such a subtotal is presented. In addition, the new guidance requires that only the service cost component of net benefit cost be eligible for capitalization.

This guidance is effective for fiscal years beginning after December 15, 2017, including interim periods of those years. The guidance is not expected to have a material impact on OPG's consolidated financial statements, as OPG currently capitalizes only the service cost component of post-retirement benefits costs. Additionally, OPG already includes the service cost component of post-retirement benefit costs with other compensation costs, within the OM&A expenses line item in the consolidated statements of income, and does not show a subtotal of income from operations. As such, the new guidance is not expected to affect the presentation of OPG's consolidated financial statements.

4. PROPERTY, PLANT AND EQUIPMENT, INTANGIBLE ASSETS AND DEPRECIATION AND AMORTIZATION

PP&E as at December 31 consist of the following:

(millions of dollars)	**2017**	**2016**
Nuclear generating stations	**11,985**	11,057
Regulated hydroelectric generating stations	**9,566**	9,430
Contracted generation portfolio generating stations	**3,935**	3,751
Other property, plant and equipment	**372**	1,595
Construction in progress	**4,092**	3,482
	29,950	29,315
Less: accumulated depreciation		
Generating stations	**8,480**	7,948
Other property, plant and equipment	**148**	1,369
	8,628	9,317
	21,322	19,998

Construction in progress as at December 31 consists of the following:

(millions of dollars)	**2017**	**2016**
Darlington Refurbishment	**3,507**	2,563
Peter Sutherland Sr. GS	**17**	236
Other	**568**	683
	4,092	3,482

Intangible assets as at December 31 consist of the following:

(millions of dollars)	**2017**	**2016**
Nuclear generating stations	**122**	122
Regulated hydroelectric generating stations	**6**	7
Contracted generation portfolio generating stations	**5**	4
Computer software and other intangible assets	**393**	350
Development in progress	**39**	20
	565	503
Less: accumulated amortization		
Generating stations	**123**	120
Computer software and other intangible assets	**309**	284
	432	404
	133	99

Depreciation and amortization expenses, including amounts recognized in regulatory variance and deferral accounts authorized by the OEB, for the years ended December 31 consist of the following:

(millions of dollars)	**2017**	**2016**
Depreciation	**649**	602
Amortization of intangible assets	**30**	27
Amounts recognized in regulatory variance and deferral accounts	**-**	26
Amortization of regulatory assets and liabilities *(Note 5)*	**-**	602
	679	1,257

Interest capitalized to construction in progress during 2017 was $162 million (2016 – $141 million), at an average rate of five percent (2016 – five percent).

5. REGULATORY ASSETS AND LIABILITIES

OPG's May 2016 application with the OEB for new regulated prices included a request for new rate riders to recover or repay the December 31, 2015 balances in all of the Company's OEB-authorized variance and deferral accounts, with the exception of the Pension & OPEB Cash Versus Accrual Differential Deferral Account, less amounts previously approved for recovery or repayment for these accounts in 2016. The application also requested the continuation of all applicable existing variance and deferral accounts. In March 2017, the OEB approved a settlement agreement reached by OPG and intervenors on a limited set of issues in the application (Settlement Agreement). Among the settled issues, the agreement provided for the continuation of all applicable existing variance and deferral accounts and accepted a number of variance and deferral account balances for recovery, as requested in OPG's application. The periods of recovery or repayment for the accepted variance and deferral account balances were excluded from the scope of the Settlement Agreement.

In the OEB's December 2017 Decision and Order, the OEB accepted all applicable variance and deferral account balances for recovery that were not already accepted as part of the partial Settlement Agreement that was reached by OPG and intervenors. That OEB-approved Settlement Agreement also provided for the continuation of all applicable existing variance and deferral accounts effective June 1, 2017. The December 2017 decision and order allows for recovery of $305 million recorded in certain variance and deferral accounts as at December 31, 2015, without adjustments. OPG's draft Payment Amounts Order proposed the recovery period to be January 1, 2019 to December 31, 2021.

Consistent with the effective date of the OEB's December 2017 decision and order, for the period from January 1, 2017 to May 31, 2017, OPG continued to record additions to the existing variance and deferral accounts for the nuclear and regulated hydroelectric facilities pursuant to the OEB's previous decisions and orders. These additions reflected differences between actual and forecast amounts embedded in the regulated prices in effect prior to June 1, 2017.

In its December 2017 decision and order on OPG's rate application, the OEB granted OPG approval to request disposal of applicable audited deferral and variance account balances, including the Pension & OPEB Cash Versus Accrual Differential Account, in calendar year 2018. Under the requirements of US GAAP, the period of deferring amounts recorded in the Pension & OPEB Cash Versus Accrual Differential Deferral Account must not exceed five years from the time that they were incurred. Accordingly, such amounts recorded during November 2014 must begin to be recovered no later than November 2019 and must be fully recovered within 20 years of November 2014 or OPG will be required to write off the regulatory asset for these amounts.

The regulatory assets and liabilities recorded as at December 31 are as follows:

(millions of dollars)	**2017**	**2016**
Regulatory assets		
Variance and deferral accounts authorized by the OEB		
Pension and OPEB Cost Variance Account	**716**	716
Pension & OPEB Cash Versus Accrual Differential Deferral Account *(Note 11)*	**614**	497
Hydroelectric Surplus Baseload Generation Variance Account	**360**	210
Bruce Lease Net Revenues Variance Account	**121**	95
Other variance and deferral accounts	**124**	107
	1,935	1,625
Interim Period Revenue Shortfall Account	**544**	-
Pension and OPEB Regulatory Asset *(Note 11)*	**3,855**	3,392
Deferred Income Taxes	**897**	838
Total regulatory assets	**7,231**	5,855
Regulatory liabilities		
Variance and deferral accounts authorized by the OEB		
Hydroelectric Water Conditions Variance Account	**150**	51
Pension & OPEB Cash Variance Account	**140**	58
Impacts Resulting from Changes in Station End-of-Life Dates Deferral Account	**103**	71
Rate Smoothing Deferral Account	**63**	-
Other variance and deferral accounts	**138**	130
Total regulatory liabilities	**594**	310

The changes in the regulatory assets and liabilities during 2017 and 2016 are as follows:

(millions of dollars)	Pension and OPEB Cost Vari-ance	Pension & OPEB Cash vs Accrual Differen-tial Deferral	Hydro-electric Surplus Baseload Genera-tion Variance	Bruce Lease Net Reve-nues Variance	Water Condit-ions variance	Pension & OPEB Cash	Impact Resulting from Changes in Station End-of-Life Dates Deferral Account	Rate Smooth-ing Deferral Account	Other Vari-ance and Deferral (net)	Interim Period Revenue Shortfall Account	Pension and OPEB Regula-tory Asset	Deferred Income Taxes
Net regulatory assets (liabilities) January 1, 2016	865	315	114	95	(23)	28	-	-	260	-	3,362	792
Increase (decrease)	-	182	126	143	(33)	(86)	(71)	-	-	-	30	46
Interest	-	-	2	-	(1)	-	0	-	1	-	-	-
Amortization	(149)	-	(32)	(143)	6	-	0	-	(284)	-	-	-
Net regulatory assets (liabilities) December 31, 2016	716	497	210	95	(51)	(58)	(71)	-	(23)	-	3,392	838
Increase (decrease)	**-**	**117**	**146**	**25**	**(98)**	**(81)**	**(32)**	**(62)**	**10**	**544**	**463**	**59**
Interest	**-**	**-**	**4**	**1**	**(1)**	**(1)**	**0**	**(1)**	**(1)**	**-**	**-**	**-**
Net regulatory assets (liabilities) December 31, 2017	**716**	**614**	**360**	**121**	**(150)**	**(140)**	**(103)**	**(63)**	**(14)**	**544**	**3,855**	**897**

Pension and OPEB Cost Variance Account

As authorized by the OEB, for the period from March 1, 2011 to October 30, 2014, the Pension and OPEB Cost Variance Account recorded the differences between OPG's actual pension and OPEB costs for the regulated business determined on an accrual basis and related tax impacts, and corresponding forecast amounts reflected in the regulated prices then in effect. In its November 2014 decision, the OEB determined that the pension and OPEB amounts reflected in OPG's regulated prices established by that decision effective November 1, 2014 would be limited to the Company's estimated minimum contributions to its registered pension plan and a forecast of OPG's expenditures on the OPEB and supplementary pension plans. As such, the OEB ordered the Pension and OPEB Cost Variance Account to record only amortization beginning on November 1, 2014.

In its October 2015 order, the OEB approved the continuation of the previously authorized recovery of 10/12 of the account balance as at December 31, 2012 over a 144-month period to December 31, 2024. Amounts recorded in the account in 2013 and 2014 were approved for recovery over a 72-month period to June 30, 2021 by the OEB's October 2015 order. In OPG's draft payment amounts order, the recovery period was adjusted to extend beyond June 30, 2021 and December 31, 2024 to account for the break in recovery of the account in the 2017 and 2018 periods as proposed by OPG.

Pension & OPEB Cash Versus Accrual Differential Deferral Account

In its November 2014 decision and December 2014 order, the OEB established the Pension & OPEB Cash Versus Accrual Differential Deferral Account. Effective November 1, 2014, this deferral account records the difference between OPG's actual pension and OPEB costs for the regulated business determined on an accrual basis under US GAAP and OPG's corresponding actual cash expenditures for these plans. The balance in the account as at

December 31, 2017 represents the excess of costs calculated using the accrual basis over the cash basis for the period from November 1, 2014 to December 31, 2017. The Company has recognized the amount set aside in the deferral account as a regulatory asset.

The OEB's November 2014 decision indicated that the future recovery, if any, of amounts recorded in the deferral account would be subject to the outcome of the OEB generic proceeding on the regulatory treatment and recovery of pension and OPEB costs. On September 14, 2017, the OEB issued its final report on the guiding principles and the policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the Ontario electricity and natural gas sectors. The report establishes the accrual basis of accounting as the method of determining pension and OPEB amounts for rate-setting purposes, unless the OEB finds that this method does not result in just and reasonable rates in the circumstances of a particular utility. The OEB's September 2017 report and the OEB's December 2017 decision on OPG's application for new regulated prices require OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the Pension & OPEB Cash to Accrual Differential Deferral Account in effect since November 1, 2014, until such time as the OEB approves resumption of the accrual basis of recovery.

Consistent with the expectations set out in the OEB's December 2017 decision, in 2018, OPG plans to file an application with the OEB requesting disposition of the Pension & OPEB Cash Versus Accrual Differential Deferral Account balance.

Hydroelectric Surplus Baseload Generation Variance Account

The Hydroelectric Surplus Baseload Generation Variance Account records the impact of forgone production at OPG's regulated hydroelectric facilities due to surplus baseload generation conditions.

In its December 2017 Decision and Order, the OEB approved the disposition of the Hydroelectric Surplus Baseload Generation Variance Account balance as at December 31, 2015, as proposed. OPG has proposed a recovery period of January 1, 2019 to December 31, 2021.

Bruce Lease Net Revenues Variance Account

In accordance with *Ontario Regulation 53/05*, the OEB is required to include the difference between OPG's revenues and costs associated with the two nuclear generating stations on lease to Bruce Power in the determination of the regulated prices for production from OPG's regulated nuclear facilities. Based on *Ontario Regulation 53/05* requirements, the OEB has established a variance account that captures differences between OPG's actual revenues and costs related to these stations and the corresponding forecasts included in approved nuclear regulated prices, including the costs associated with OPG's Nuclear Liabilities and the earnings from the portion of the Nuclear Segregated Funds related to the Bruce stations.

In 2013, the OEB ordered the portion of the balance in the Bruce Lease Net Revenues Variance Account related to the impact of the derivative liability embedded in the terms of the lease agreement between OPG and Bruce Power related to the Bruce nuclear generating stations (Bruce Lease) in effect prior to December 2015 to be recovered on the basis of OPG's expected rent rebate payments to Bruce Power and associated income tax impacts. The OEB's October 2015 order reaffirmed this approach and included, in amounts authorized for recovery over the period to the end of 2016, amounts for the derivative liability. In December 2015, as a result of amendments to the Bruce Lease, OPG reversed the derivative liability, with a corresponding reduction to the regulatory asset for the Bruce Lease Net Revenue Variance Account. Amounts collected from customers for the derivative liability for periods after its reversal are subject to refund in the future and have been recognized as a regulatory liability as part of the variance account balance.

The regulatory asset balance for the Bruce Lease Net Revenues Variance Account as at December 31, 2017 reflects a net amount of $190 million recoverable from customers for non-derivative variances recorded in 2015 through 2017, which is partially offset by a liability of $69 million to customers for amounts recovered for the derivative liability

since its reversal in December 2015. Non-derivative amounts recorded during 2017 included those arising from the adjustment to the Nuclear Liabilities and related changes to the estimated service lives of OPG's nuclear stations, for accounting purposes, effective December 31, 2015 and the updated 2017 ONFA reference plan approved by the province.

In its December 2017 Decision and Order, the OEB approved the disposition of the Bruce Lease Net Revenues Account balance as at December 31, 2015, as proposed. OPG has proposed a recovery period of January 1, 2019 to December 31, 2021.

Interim Period Revenue Shortfall Account

The Interim Period Revenue Shortfall regulatory asset records the revenue shortfall between proposed Nuclear and Regulated Hydroelectric rates and existing Nuclear and Regulated Hydroelectric rates from June 1, 2017 through December 31 2017 based on actual production. The recovery of this account is expected to begin January 1, 2019 through to December 31, 2021. [**UPDATE**]

Pension and OPEB Regulatory Asset

The Pension and OPEB Regulatory Asset represents unamortized amounts in respect of OPG's pension and OPEB plans that have been recognized in OCI and not yet reclassified into the amortization component of the benefit costs in respect of these plans. These amounts are expected to be recovered from customers through future regulated prices. The regulatory asset is reversed as underlying unamortized balances are amortized as components of benefit costs. For further details, refer to Note 3 under the heading, *Rate Regulated Accounting*. The AOCI amounts related to pension and OPEB plans are presented in Note 11.

Deferred Income Taxes

OPG is required to record a regulatory asset or liability for the deferred income taxes that are expected to be recovered or refunded through future regulated prices charged to customers for generation from OPG's regulated facilities. In addition, OPG is required to recognize a deferred income tax liability or asset for the regulatory asset or liability for the amount of deferred income taxes expected to be included in future regulated prices and paid to, or recovered, from customers. Income taxes are discussed in Note 9.

Hydroelectric Water Conditions Variance Account

The Hydroelectric Water Conditions Variance Account captures the impact of differences in regulated hydroelectric electricity production due to differences between forecast water conditions underlying the production forecast approved by the OEB in setting regulated hydroelectric prices, and the actual water conditions.

In its December 2017 Decision and Order, the OEB approved the disposition of the Hydroelectric Water Conditions Variance Account balance as at December 31, 2015, as proposed. OPG has proposed a recovery period of January 1, 2019 to December 31, 2021.

Pension & OPEB Cash Payment Variance Account

The Pension & OPEB Cash Payment Variance Account was approved in EB-2013-0321 and continued in EB-2014-0370. The account records the difference between OPG's actual registered pension plan contributions and OPEB plan payments (including the long-term disability benefit plan) attributed to the prescribed generating facilities, and such forecast amounts reflected in the revenue requirement approved by the OEB.

In its December 2017 Decision and Order, the OEB approved the disposition of the Pension & OPEB Cash Payment Variance Account balance as at December 31, 2015, as proposed. OPG has proposed a recovery period of January 1, 2019 to December 31, 2021.

Impact Resulting from Changes in Station End-of-Life Dates Deferral Account

In December 2015, as required by the OEB's previous decisions and orders, OPG applied to the OEB for an accounting order to establish a new deferral account to record the revenue requirement impact on the Pickering and Darlington nuclear generating stations of changes to the Nuclear Liabilities and depreciation expense arising from extensions in the estimated useful lives of OPG's nuclear stations, for accounting purposes, effective December 31, 2015. These impacts were not reflected in the existing regulated prices. In March 2016, the OEB issued its final decision and order establishing the requested account, the Impact Resulting from Changes in Station End-of-Life Dates Deferral Account, effective January 1, 2016. The deferral account recorded these impacts until new regulated prices reflecting the above changes came into effect on June 1, 2017.

The extensions to the estimated useful lives of OPG's nuclear generating stations effective December 31, 2015, for accounting purposes, included those of the Bruce A GS and the Bruce B GS to reflect the estimated end-of-life dates per the updated refurbishment agreement between the IESO and Bruce Power announced in December 2015, a one-year extension for the Darlington GS to reflect the approval of the refurbishment schedule in 2015, and an extension of less than one year for the Pickering GS. To reflect these changes, OPG recognized a total increase of $2,330 million in the Nuclear Liabilities and a corresponding increase in the related asset retirement costs capitalized to PP&E, effective December 31, 2015.

Rate Smoothing Deferral Account

In accordance with section 5.5 of *Ontario Regulation 53/05*, OPG shall establish a Rate Smoothing Deferral Account. This account shall record, for each respective year, the difference between: (i) the total annual revenue requirement for the prescribed nuclear facilities approved by the OEB; and, (ii) the portion of that revenue requirement in (i) that is used in connection with setting the approved nuclear payment amounts in each year.

Consistent with the requirements of *Ontario Regulation 53/05*, OPG's overall production weighted payment amounts will be smoothed, with a resulting portion of the approved annual nuclear revenue requirements for the 2017-2021 period deferred in the Rate Smoothing Deferral Account for future collection. The non-deferred portion of each year's nuclear revenue requirement will be divided by the OEB-approved forecast of OPG's nuclear electricity generation for the corresponding year to determine the base nuclear regulated price. Per the regulation, the deferral account records interest at a long-term debt rate reflecting OPG's cost of long-term borrowing approved by the OEB, compounded annually. The regulation also requires the OEB to authorize recovery of the balance in the account on a straight line basis over a period not to exceed ten years following the end of the Darlington Refurbishment project. OPG recognizes positive amounts deferred under rate smoothing as an increase in net regulatory assets and an increase in revenue in the period to which the underlying approved revenue requirement relates. Negative amounts determined under rate smoothing are correspondingly recorded as a decrease in net regulatory assets and a decrease to revenue.

On January 17, 2018, OPG submitted a draft payment amounts order to the OEB that proposed nuclear base regulated prices for each year of the 2017-2021 period. The proposed regulated prices reflected the December 2017 decision's findings in calculating the 2017-2021 nuclear revenue requirements and reflected a rate smoothing proposal developed by OPG in accordance with *Ontario Regulation 53/05* and OEB's direction. As at December 31, 2017 OPG recorded a liability of $63 million and is expected to have a regulatory asset balance of approximately $750 million by 2021.

Other Variance and Deferral Accounts

Regulatory assets

As at December 31, 2017 and 2016, regulatory assets for Other variance and deferral accounts included amounts for the Nuclear Liability Deferral Account, the Nuclear and Hydroelectric Deferral and Variance Over/Under Recovery Variance Account, the Nuclear Development Account, and the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account and the Fitness for Duty Deferral Account.

Pursuant to *Ontario Regulation 53/05*, the Nuclear Liability Deferral Account has been authorized by the OEB in connection with changes to OPG's liabilities for nuclear used fuel management and nuclear decommissioning and L&ILW management associated with the nuclear facilities owned and operated by OPG, which are comprised of the Pickering and Darlington nuclear generating stations. The deferral account records the revenue requirement impact associated with the changes in these liabilities arising from an approved reference plan, in accordance with the terms of the ONFA.

The Nuclear and Hydroelectric Deferral and Variance Over/Under Recovery Variance Accounts records any shortfall or over-recovery of the approved variance and deferral account balances due to differences between actual and forecast nuclear and hydroelectric production respectively.

The Nuclear Development Variance Account records variances between the actual non-capital costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities and the corresponding forecasts reflected in the regulated prices approved by the OEB.

The Fitness for Duty Deferral Account was approved by the OEB in the EB-2016-0152 Decision and order, effective June 1, 2017. The account shall record the costs related to implementing the Canadian Nuclear Safety Commission (CNSC) Fitness for Duty program. The Fitness for Duty program is a drug, alcohol, psychological and physical testing program for employees in nuclear facilities, which is anticipated to be a license requirement of the CNSC.

Regulatory liabilities

As at December 31, 2017 and 2016, regulatory liabilities for Other variance and deferral accounts included amounts for the Ancillary Services Net Revenue Variance Account, the Income and Other Taxes Variance Account, the Hydroelectric Incentive Mechanism Variance Account, the SR&ED ITC Variance Account and the Capacity Refurbishment Variance Account.

The Ancillary Services Net Revenue Variance Account has been authorized by the OEB to capture differences between actual nuclear and regulated hydroelectric ancillary services net revenue and the forecast amounts of such revenue approved by the OEB in setting regulated prices.

The Income and Other Taxes Variance Account includes deviations in income taxes for the regulated business, from those approved by the OEB in setting regulated prices, caused by changes in tax rates and rules, as well as reassessments.

The Hydroelectric Incentive Mechanism Variance Account records a credit to customers equal to 50 percent of OPG's hydroelectric incentive mechanism revenues above a specified threshold for the regulated hydroelectric facilities.

As at December 31, 2017, regulatory liabilities for Other variance and deferral accounts also included the SR&ED ITC Variance Account and the Capacity Refurbishment Variance Account. The SR&ED ITC Variance Account was approved by the OEB in its EB-2016-0152 Decision, effective June 1, 2017. This account will record the tax expense impact for the nuclear facilities as a result of the difference between actual SR&ED ITCs (attributed to the nuclear facilities) as determined after any tax audits and the forecast SR&ED ITCs included in the nuclear revenue requirement approved by the OEB. Pursuant to *Ontario Regulation 53/05*, the OEB has authorized the Capacity Refurbishment Variance Account. The account captures variances from the forecasts reflected in the regulated prices for capital and non-capital costs incurred to increase the output of, refurbish, or add operating capacity to one or more of the regulated facilities. The balance in the account as at December 31, 2017 includes variances related to

the refurbishment of the Darlington nuclear generating station, life extension initiatives at the Pickering nuclear generation station, and other projects.

6. LONG-TERM DEBT AND NET INTEREST EXPENSE

Long-term debt consists of the following as at December 31: [1]

(millions of dollars)	**2017**	**2016**
Notes payable to the OEFC [2]		
Senior Notes		
bear interest at rates ranging from 3.12% to 5.44%; maturity dates ranging from 2018 to 2047	**3,195**	3,295
Medium Term Note Program [3]		
Senior Notes		
3.32% due 2027	**500**	-
UMH Energy Partnership [4]		
Senior Notes		
7.86% due 2041	**181**	184
PSS Generating Station Limited Partnership [5]		
Senior Notes		
4.90% due 2067	**245**	245
Lower Mattagami Energy Limited Partnership [6]		
Senior Notes		
bear interest at rates ranging from 2.4% to 5.26%; maturity dates ranging from 2021 to 2052	**1,595**	1,795
Fair Hydro Trust [7]		
Senior notes		
2.32% due 2019	**601**	-
Other	**19**	15
	6,336	5,534
Less: bond issuance fees	**(17)**	(14)
Less: due within one year	**(398)**	(1,103)
Long-term debt	**5,921**	4,417

[1] The interest rates disclosed reflect the effective interest rate of the debt, except for the Fair Hydro Trust notes which reflect the weighted average interest rate during the period the notes were outstanding from December 21 to December 31, 2017.

[2] OEFC is entitled to receive in full amounts owing in respect of the senior debt.

[3] These notes are direct unsecured obligations of OPG and rank *pari passu* with all other OPG's unsubordinated and unsecured obligations.

[4] These notes are secured by the assets of the Upper Mattagami and Hound Chute project. Principal repayments of $3 million per year are made on a semi-annual basis until maturity in 2041, at which time the remaining principal balance of $116 million becomes due.

[5] These notes are secured by the assets of the Peter Sutherland Sr. GS project. The notes have an interest-only feature until 2025 and will be amortized with blended semi-annual principal and interest payments thereafter until maturity in 2067, at which time the remaining principal balance of $49 million becomes due.

[6] These notes are secured by the assets of the Lower Mattagami River project, including existing and new operating facilities.

[7] The notes were issued under an $800 million two-year revolving warehouse facility discussed below and are secured by the assets of the Fair Hydro Trust.

In June 2016, OPG entered into a $700 million general corporate credit facility agreement with the OEFC, which expired on December 31, 2017. In September 2017, the agreement was amended, with the credit facility increased to $2,350 million and the expiry date extended to December 31, 2018. As of December 31, 2017, $800 million were outstanding from the credit facility.

In February 2017, OPG issued senior notes payable to the OEFC totalling $200 million and maturing in February 2047. The effective interest rate and coupon interest rate of these notes was 4.12 percent. In June 2017,

OPG issued senior notes payable to the OEFC totalling $100 million and maturing in June 2047. The effective interest rate and coupon interest rate of these notes was 3.65 percent. In August 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in August 2047. The effective interest rate and coupon interest rate of these notes was 3.86 percent. In September 2017, OPG issued senior notes payable to the OEFC totalling
$400 million and maturing in September 2047. The effective interest rate and coupon interest rate of these notes was 4.07 percent.

In October 2017, OPG issued $500 million of senior notes payable under a Medium Term Note Program. The notes bear a coupon interest rate of 3.32 percent and an effective rate of 3.43 percent, payable semi-annually until maturity in October 2027. The offering was made under OPG's $2 billion short form base shelf prospectus filed in September 2017.

In 2015, PSS, a subsidiary of OPG, issued long-term debt totalling $245 million in support of the Peter Sutherland Sr. Generating Station (GS) project. The majority of the debt proceeds, totalling $180 million, were invested in a structured deposit note with staggered maturity dates ranging from January 2016 to April 2017. As at December 31, 2017, the deposit note had matured.

In October 2016, Lower Mattagami Energy Limited Partnership (LME) issued senior notes totalling $220 million maturing in October 2026. The effective interest rate and coupon interest rate of these notes were 2.40 percent and 2.31 percent, respectively.

In December 2017, the Trust entered into an $800 million revolving warehouse facility agreement with an expiry date of December 21, 2019. As at December 31, 2017, there were outstanding senior notes of $601 million under this credit facility, which were used to finance 51 percent of the Trust's funding requirement for the acquisition of the first tranche of Investment Interest from the IESO in December 2017. The outstanding balance has been classified as long-term debt to reflect the terms and substance of the facility agreement. The interest incurred on this debt is recorded within Earnings from Fair Hydro Trust on the consolidated statements of income. Please refer to Note 17 for additional information on Fair Hydro Trust's financial information.

In February 2018, the Trust issued $500 million of senior notes payable with a coupon interest rate of 3.36 percent and an effective interest rate of 3.42 percent, payable semi-annually until maturity on May 15, 2033. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility issued by the Trust in December 2017. By the end of the first quarter of 2018, the Trust is expected to acquire another tranche of Investment Interest from the IESO, which it expects to fund using its revolving warehouse facility. **[MONITOR]**

The following table summarizes the net interest expense:

	December 31	
(millions of dollars)	**2017**	**2016**
Interest on long-term debt	**289**	290
Interest on short-term debt	**7**	8
Interest income	**(9)**	(7)
Interest capitalized to property, plant and equipment and intangible assets	**(162)**	(141)
Interest related to regulatory assets and liabilities [1]	**(30)**	(30)
Net interest expense	**95**	120

[1] Includes interest to recognize the cost of financing related to regulatory variance and deferral accounts, as authorized by the OEB, and interest deferred in the Bruce Lease Net Revenues Variance Account, the Capacity Refurbishment Variance Account, and the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account.

Interest paid in 2017 was $258 million (2016 – $269 million), of which $ 251 million (2016 – $261 million) relates to interest paid on long-term debt.

The net book value of the pledged assets of PSS, UMH, LME, and Lower Mattagami Limited Partnership against their debt as at December 31, 2017 was $3,645 million (2016 – $3,510 million).

7. SHORT-TERM DEBT

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. During 2017, OPG renewed and extended the expiry date of both tranches to May 2022. There were no amounts outstanding under the bank credit facility. There was $100 million of commercial paper outstanding under OPG's commercial paper program as at December 31, 2017. The Commercial paper program is used to provide short-term funding requirement for the Company, at rates of approximately one percent and are less than one year in duration.

As at December 31, 2017, the LME maintained a $400 million bank credit facility to support the funding requirements for the Lower Mattagami River project including support for LME's commercial paper program. The facility consists of a $300 million tranche maturing in August 2022 and a $100 million tranche maturing in August 2018. As at December 31, 2017, there was $160 million commercial paper outstanding under LME's commercial paper program (December 31, 2016 – nil). A letter of credit of $55 million was issued in July 2017 and remains outstanding as at December 31, 2017 under the first tranche of LME's credit facility.

As at December 31, 2017, OPG maintained $25 million of short-term, uncommitted overdraft facilities and $468 million of short-term, uncommitted credit facilities, which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other general corporate purposes. As at December 31, 2017, a total of $390 million of Letters of Credit had been issued under these facilities. This included $353 million for the supplementary pension plans, $36 million for general corporate purposes, and $1 million related to the operation of the PEC.

The Company has an agreement to sell an undivided co-ownership interest in its current and future accounts receivable to an independent trust. The maximum amount of co-ownership interest that can be sold under this agreement is $150 million, expiring on November 30, 2018. As at December 31, 2017, there were Letters of Credit outstanding under this agreement of $150 million (December 31, 2016 – $150 million), which were issued in support of OPG's supplementary pension plans.

UMH Energy Partnership has entered into an $8 million short-term, uncommitted overdraft facility and $16 million of irrevocable, standby Letters of Credit facilities in support of its operations. As at December 31, 2017, total Letters of Credit of $15 million had been issued under these facilities.

8. NUCLEAR FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT FUND AND FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT LIABILITIES

The liabilities for fixed asset removal and nuclear waste management on a present value basis as December 31, consist of the following:

(millions of dollars)	**2017**	**2016**
Liability for nuclear used fuel management	**11,970**	11,292
Liability for nuclear decommissioning and nuclear low and intermediate level waste management	**8,107**	7,811
Liability for non-nuclear fixed asset removal	**344**	381
Fixed asset removal and nuclear waste management liabilities	**20,421**	19,484

The changes in the fixed asset removal and nuclear waste management liabilities for the years ended December 31 are as follows:

(millions of dollars)	**2017**	**2016**
Liabilities, beginning of year	**19,484**	20,169
Increase in liabilities due to accretion [1]	**974**	1,024
Decrease in liabilities resulting from the ONFA reference plan update process	**-**	(1,567)
Net change in liabilities reflecting changes to the estimated useful lives *(Note 3)*	**158**	-
Increase in liabilities due to changes in estimates of nuclear used fuel and nuclear waste management expenses and other expenses [1]	**118**	133
Liabilities settled by expenditures on fixed asset removal and nuclear waste management	**(313)**	(275)
Liabilities, end of year	**20,421**	19,484

[1] Amounts shown exclude the impact of regulatory variance and deferral accounts.

OPG's fixed asset removal and nuclear waste management liabilities are comprised of expected costs to be incurred up to and beyond termination of operations and the closure of nuclear and thermal generating facilities, and other facilities. Costs will be incurred for activities such as preparation for safe storage and safe storage of the nuclear stations, dismantlement, demolition and disposal of facilities and equipment, remediation and restoration of sites, and the ongoing and long-term management of nuclear used fuel and L&ILW material.

The determination of the accrual for fixed asset removal and nuclear waste management costs requires significant assumptions since these programs are long-term in nature. The most recent comprehensive update of the cost estimates for the Nuclear Liabilities is contained in the 2017−2021 ONFA reference plan, which was finalized and approved by the Province in the fourth quarter of 2016 (2017 ONFA Reference Plan).

For the purposes of calculating OPG's Nuclear Liabilities, as at December 31, 2017, consistent with the current accounting end-of-life assumptions, nuclear station decommissioning activities are projected to occur over approximately the next 80 years. The estimates for the Nuclear Liabilities include cash flow estimates for decommissioning the nuclear stations for approximately 40 years after stations are shut down and to 2088 for placement of used fuel into the assumed long-term disposal repository, followed by extended monitoring.

The significant assumptions underlying operational, technical, and economic factors used in the calculation of the accrued Nuclear Liabilities are subject to periodic review. Changes to these assumptions, including changes to assumptions on the timing of the nuclear waste programs including construction of waste disposal facilities, station end-of-life dates, waste disposal methods, financial indicators, or the technology employed, may result in significant changes to the value of the accrued liabilities. With programs of this long-term duration and the evolving technology to handle the nuclear waste, there is a significant degree of inherent uncertainty surrounding the measurement of the costs for these programs. These costs may increase or decrease over time.

Liability for Nuclear Used Fuel Management Costs

The liability for nuclear used fuel management represents the cost of managing the highly radioactive used nuclear fuel bundles. The federal NFWA, proclaimed into force in 2002, required that Canada's nuclear fuel waste owners form a nuclear waste management organization, and that each waste owner establish a trust fund for used fuel management costs as specified in the NFWA. This organization, the NWMO, is responsible for the design and implementation of Canada's plan for the long-term management of nuclear used fuel waste. To estimate its liability for nuclear used fuel management costs, OPG has adopted an approach consistent with the Adaptive Phased Management concept approved by the Government of Canada, which assumes a deep geologic repository as part of the long-term management of nuclear used fuel, with an in-service date of 2043 at the earliest.

Liability for Nuclear Decommissioning and L&ILW Management Costs

The liability for nuclear decommissioning and L&ILW management represents the estimated costs of decommissioning the nuclear generating stations after the end of their service lives, as well as the cost of managing L&ILW generated by the stations. The significant assumptions used in estimating future nuclear fixed asset removal costs include a deferred dismantlement basis for decommissioning of the stations, whereby the reactors will be de-watered and de-fueled immediately after the station has ceased operations and thereafter will remain in a safe state condition for a 30-year period, prior to an approximate 10-year dismantlement period.

The life cycle costs of L&ILW management include the costs of processing and storage of such radioactive wastes during and following the operation of the nuclear stations, as well as the costs of the ultimate long-term management of these wastes. The current assumptions used to establish the accrued costs for the management of L&ILW include an L&ILW DGR to be owned and operated by OPG. Agreement was previously reached with local municipalities for OPG to develop a deep geologic repository for the long-term management of L&ILW adjacent to OPG's Western Waste Management Facility in Kincardine, Ontario.

Liability for Non-Nuclear Fixed Asset Removal Costs

The liability for non-nuclear fixed asset removal primarily represents the estimated costs of decommissioning OPG's thermal generating stations at the end of their services lives. The liability is based on third-party cost estimates following an in-depth review of plant sites and an assessment of required clean-up and restoration activities completed in 2017.

OPG performed a revaluation of the liability for non-nuclear fixed asset removal as at December 31, 2017. OPG recognized a decrease in the non-nuclear fixed asset removal liabilities of approximately $30 million, resulting in an decrease in asset retirement costs of $18 million capitalized as part of the carrying value of PP&E, and a gain of $12 million recorded to net income in 2017.

Ontario Nuclear Funds Agreement

In accordance with the ONFA, OPG sets aside and invests funds that are held in segregated custodian and trustee accounts specifically for discharging its life cycle obligation for nuclear decommissioning and long-term nuclear waste management. The Used Fuel Segregated Fund and the Decommissioning Segregated Fund were established under the ONFA for this purpose. OPG makes contributions to the Nuclear Segregated Funds based on the approved ONFA reference plan in effect. ONFA reference plans are subject to approval by the Province.

Since inception, OPG has been making quarterly payments to the Used Fuel Segregated Fund over the assumed lives of its nuclear generating stations, as specified in the ONFA, including contributions to the NFWA Trust established by OPG pursuant to the NFWA. The NFWA Trust forms part of the Used Fuel Segregated Fund, with any OPG contributions to the Used Fuel Segregated Fund, as well as any portion of the fund currently not in the trust, being able to be applied towards the NFWA Trust's annual contribution requirements pursuant to the NFWA. As a result, required funding of the Used Fuel Segregated Fund for 2017 was nil (2016 – $150 million). ONFA

requirements have resulted in the majority of the underlying used fuel management obligation being funded through OPG contributions over the initial estimated useful lives of the nuclear generating stations assumed in the ONFA, which did not reflect subsequent extensions to the nuclear station lives to reflect refurbishment and life extension decisions.

OPG has not been required to make contributions to the Decommissioning Segregated Fund, which was fully funded at its inception through an initial contribution made by the Province and, taking into account asset performance and changes in underlying funding obligation over time, at the time of every subsequent approved ONFA reference plan.

The 2017 ONFA Reference Plan was approved by the Province in December 2016, with an effective date of January 1, 2017. Based on the funded status of the Used Fuel Segregated Fund and the Decommissioning Segregated Fund reflecting the life cycle liability estimates per the 2017 ONFA Reference Plan, no overall contributions to either fund are currently required starting in 2017. Contributions may be required in the future should either or both of the funds be in an underfunded position when a new reference plan is prepared.

The *Nuclear Safety and Control Act* (Canada) requires OPG to have sufficient funds available to discharge its existing nuclear waste management and nuclear facilities decommissioning obligations. As required by the terms of the ONFA, the Province has provided a Provincial Guarantee to the CNSC since 2003, on behalf of OPG. The Provincial Guarantee provides for any shortfall between the CNSC consolidated financial guarantee requirement and the value of the Nuclear Segregated Funds. OPG pays the Province an annual guarantee fee of 0.5 percent of the amount of the Provincial Guarantee. The value of the Provincial Guarantee amount in effect through to the end of 2017 was $1,551 million. Based on this guarantee amount, OPG paid a guarantee fee of $8 million to the Province for each of 2017 and 2016.

The investments in the Nuclear Segregated Funds include a diversified portfolio of equities and fixed income securities that are invested across geographic markets, as well as investments in infrastructure, real estate, and agriculture. The Nuclear Segregated Funds are invested to fund long-term liability requirements and, as such, the portfolio asset mix is structured to achieve the required return over a long-term horizon. While short-term fluctuations in market value will occur, managing the long-term return of the Nuclear Segregated Funds remains the primary goal. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

Decommissioning Segregated Fund

Under the ONFA, OPG is wholly responsible for cost estimate changes and investment returns in the Decommissioning Segregated Fund. As at December 31, 2017 and 2016, the Decommissioning Segregated Fund was in an overfunded position.

Upon termination of the ONFA, the Province has the sole right to any excess funds in the Decommissioning Segregated Fund, which is the excess of the fair market value of the fund's assets over the underlying estimated future costs, as per the most recently approved ONFA reference plan. Accordingly, when the Decommissioning Segregated Fund is overfunded, OPG limits the fund earnings recognized in the consolidated financial statements by recording an amount due to the Province, such that the asset recognized for the fund on the consolidated balance sheet is equal to the cost estimate of the liability based on the most recently approved ONFA reference plan. Additionally, OPG recognizes the portion of the surplus that it may direct to the Used Fuel Segregated Fund, which is possible when the surplus in the Decommissioning Segregated Fund is such that the underlying liabilities, as defined by the most recently approved ONFA reference plan, are at least 120 percent funded. In those circumstances, OPG may direct, at the time a new reference plan is approved, up to 50 percent of the surplus over 120 percent to the Used Fuel Segregated Fund, with the OEFC entitled to a distribution of an equal amount. Therefore, when the Decommissioning Segregated Fund is at least 120 percent funded, OPG recognizes 50 percent of the excess greater than 120 percent in income, up to the amount by which the Used Fuel Segregated Fund is underfunded. Based on the 2017 ONFA Reference Plan, the Used Fuel Segregated Fund was in a marginally overfunded position as at December 31, 2016, for the first time since inception. As a result, OPG recognized a due to the Province amount

such that the Decommissioning Segregated Fund asset on the consolidated balance sheet as at December 31, 2017 and 2016 was limited to the value of the underlying liability per the 2017 ONFA Reference Plan. The payable to the Province may be reduced in subsequent periods in the event that the Decommissioning Segregated Fund earns less than its target rate of return, a new ONFA reference plan is approved with a higher underlying funding liability, or the Used Fuel Segregated Fund changes to an underfunded status. When the Decommissioning Segregated Fund is underfunded, the earnings on the fund reflect actual fund returns based on the market value of the assets.

When the Decommissioning Segregated Fund is in an overfunded status at less than 120 percent, OPG recognized its annual earnings on the fund at 3.25 percent plus the long-term Ontario Consumer Price Index (CPI) specified in the most recently approved ONFA reference plan, which is the rate of growth in the underlying funding liability. The same treatment is applied to the Decommissioning Segregated Fund when it is in an overfunded status at greater than 120 percent, if the Used Fuel Segregated Fund is fully funded.

Used Fuel Segregated Fund

OPG is responsible for cost increases in the funding liability for used fuel waste management under the ONFA, subject to specified graduated liability thresholds, pursuant to which the Province limits OPG's total financial exposure for the first 2.23 million nuclear used fuel bundles at approximately $15.7 billion in present value dollars as at December 31, 2017. The graduated liability thresholds do not apply to used fuel bundles beyond the 2.23 million threshold.

Under the ONFA, the Province guarantees OPG's annual return in the Used Fuel Segregated Fund at 3.25 percent plus the change in the Ontario CPI, as defined by ONFA, for funding related to the first 2.23 million used fuel bundles, (committed return). OPG recognizes the committed return on the Used Fuel Segregated Fund as Earnings on the Nuclear Segregated Funds. The difference between the committed return and the actual market return determined based on the fair value of the fund assets related to the first 2.23 million used fuel bundles is recorded as due to or due from the Province. This amount due to or due from the Province represents the amount that would be paid to or received from the Province if the committed return were to be settled as at the consolidated balance sheets date. The 2.23 million threshold represents the estimated total life cycle fuel bundles based on the initial estimated useful lives of the nuclear stations assumed in the ONFA.

As prescribed under the ONFA, OPG's contributions for fuel bundles in excess of 2.23 million are not subject to the rate of return guaranteed by the Province, and earn a return based on changes in the market value of the assets of the Used Fuel Segregated Fund.

If there is a surplus in the Used Fuel Segregated Fund such that the liabilities, as defined by the most recently approved ONFA reference plan, are at least 110 percent funded, the Province, has the right, at any time, to access the excess amount greater than 110 percent. Upon termination of the ONFA, the Province is entitled to any surplus in the fund, which is the excess of the fair market value of the Used Fuel Segregated Fund assets over the estimated future costs, as per the most recently approved ONFA reference plan. Neither OPG nor the Province has a right to direct any amounts from the Used Fuel Segregated Fund to the Decommissioning Segregated Fund. Therefore, when the Used Fuel Fund is overfunded, OPG limits the earnings it recognizes by recording an amount due to the Province, such that the asset recognized for the fund on the consolidated balance sheets is equal to the cost estimate of the liability per the most recently approved ONFA reference plan. This results in OPG recognizing annual earnings on the fund at 3.25 percent plus the long-term Ontario CPI specified in the most recently approved ONFA reference plan, which is the rate of growth in the underlying funding liability, when the fund is overfunded.

As at December 31, 2017, the Used Fuel Segregated Fund was marginally overfunded in accordance with the 2017 ONFA Reference Plan, and OPG recognized a due to the Province amount of $55 million such that the asset recognized for the fund was limited to the value of the underlying funding liability. This payable to the Province may be reduced in subsequent periods in the event that the Used Fuel Segregated Fund earns less than its target rate of return or in the event that a new ONFA reference plan is approved with a higher underlying funding liability.

Nuclear Segregated Funds

The nuclear fixed asset removal and nuclear waste management funds as at December 31 consist of the following:

(millions of dollars)	Fair Value 2017	2016
Decommissioning Segregated Fund	**9,099**	8,317
Due to Province – Decommissioning Segregated Fund	**(1,933)**	(1,477)
	7,166	6,840
Used Fuel Segregated Fund [1]	**12,087**	11,082
Due to Province – Used Fuel Segregated Fund	**(2,529)**	(1,938)
	9,558	9,144
Total Nuclear Segregated Funds	**16,724**	15,984
Less: current portion	**23**	24
Non-current Nuclear Segregated Funds	**16,701**	15,960

[1] The Ontario NFWA Trust represents $3,882 million as at December 31, 2017 (2016 – $3,688 million) of the Used Fuel Segregated Fund on a fair value basis.

The fair value of the securities invested in the Nuclear Segregated Funds as at December 31 is as follows:

(millions of dollars)	Fair Value 2017	2016
Cash and cash equivalents and short-term investments	**227**	354
Alternative investments	**2,357**	1,989
Pooled funds	**1,713**	1,329
Marketable equity securities	**10,457**	9,503
Fixed income securities	**6,405**	6,181
Net receivables/payables	**27**	43
	21,186	19,399
Due to Province	**(4,462)**	(3,415)
	16,724	15,984

The historical cost, gross unrealized aggregate appreciation and depreciation of investment, gross unrealized foreign exchange gains, and fair value of the Nuclear Segregated Funds as at December 31, 2017 and 2016 are summarized as follows:

(millions of dollars)	**Decommissioning Segregated Fund**	**2017 Used Fuel Segregated Fund**	**Total**
Historical cost	**7,327**	**9,902**	**17,229**
Gross unrealized gains (losses)			
Aggregate appreciation	**1,789**	**2,188**	**3,977**
Aggregate depreciation	**(134)**	**(180)**	**(314)**
Foreign exchange	**117**	**177**	**294**
	9,099	**12,087**	**21,186**
Due to Province	**(1,933)**	**(2,529)**	**(4,462)**
Total fair value	**7,166**	**9,558**	**16,724**
Less: current portion	**5**	**18**	**23**
Non-current fair value	**7,161**	**9,540**	**16,701**

(millions of dollars)	**Decommissioning Segregated Fund**	**2016 Used Fuel Segregated Fund**	**Total**
Historical cost	6,896	9,385	16,281
Gross unrealized gains (losses)			
Aggregate appreciation	1,326	1,564	2,890
Aggregate depreciation	(165)	(222)	(387)
Foreign exchange	260	355	615
	8,317	11,082	19,399
Due to Province	(1,477)	(1,938)	(3,415)
Total fair value	6,840	9,144	15,984
Less: current portion	8	16	24
Non-current fair value	6,832	9,128	15,960

Net realized and unrealized gains or losses from investments for the years ended December 31, 2017 and 2016 are summarized as follows:

(millions of dollars)	2017 Decommissioning Segregated Fund	2017 Used Fuel Segregated Fund	2017 Total
Net realized gains			
Realized gains excluding foreign exchange	**198**	**245**	**443**
Realized foreign exchange gains	**54**	**65**	**119**
Net realized gains	**252**	**310**	**562**
Net unrealized gains			
Unrealized gains excluding foreign exchange	**494**	**666**	**1,160**
Unrealized foreign exchange losses	**(143)**	**(178)**	**(321)**
Net unrealized gains	**351**	**488**	**839**

(millions of dollars)	2016 Decommissioning Segregated Fund	2016 Used Fuel Segregated Fund	2016 Total
Net realized gains			
Realized gains excluding foreign exchange	84	180	264
Realized foreign exchange gains	30	41	71
Net realized gains	114	221	335
Net unrealized gains			
Unrealized gains excluding foreign exchange	360	442	802
Unrealized foreign exchange losses	(165)	(216)	(381)
Net unrealized gains	195	226	421

The change in the Nuclear Segregated Funds for the years ended December 31 is as follows:

(millions of dollars)	Fair Value 2017	Fair Value 2016
Decommissioning Segregated Fund, beginning of year	**6,840**	6,549
Increase in fund due to return on investments	**807**	505
Decrease in fund due to reimbursement of eligible expenditures	**(25)**	(22)
Increase in due to Province	**(456)**	(192)
Decommissioning Segregated Fund, end of year	**7,166**	6,840
Used Fuel Segregated Fund, beginning of year	**9,144**	8,587
Increase in fund due to contributions made	**-**	150
Increase in fund due to return on investments	**1,059**	690
Decrease in fund due to reimbursement of eligible expenditures	**(54)**	(48)
Increase in due to Province	**(591)**	(235)
Used Fuel Segregated Fund, end of year	**9,558**	9,144

The earnings from the Nuclear Segregated Funds during 2017 and 2016 were impacted by the Bruce Lease Net Revenues Variance Account authorized by the OEB. The earnings on the Nuclear Segregated Funds for the years ended December 31 are as follows:

(millions of dollars)	**2017**	**2016**
Decommissioning Segregated Fund	**351**	313
Used Fuel Segregated Fund	**468**	455
Bruce Lease Net Revenues Variance Account	**(18)**	(22)
Total earnings	**801**	746

9. INCOME TAXES

OPG follows the liability method of accounting for income taxes. The Company records an offsetting regulatory asset or liability for the deferred income taxes that are expected to be recovered or refunded through future regulated prices charged to customers for generation from OPG's regulated facilities.

A reconciliation between the statutory and the effective rate of income taxes is as follows:

(millions of dollars)	**2017**	**2016**
Income before income taxes	**1,090**	621
Combined Canadian federal and provincial statutory enacted income tax rates	**26.5%**	26.5%
Statutory income tax rates applied to accounting income	**289**	165
(Decrease) increase in income taxes resulting from:		
Income tax (recovery) expense deferred in regulatory assets and liabilities	**(20)**	65
Scientific Research and Experimental Development investment tax credits	**(47)**	(48)
Manufacturing and processing credit	**(16)**	(9)
Other	**3**	(5)
	(80)	3
Income tax expense	**209**	168
Effective rate of income taxes	**19.1%**	27.0%

Significant components of the income tax expense are presented in the table below:

(millions of dollars)	**2017**	**2016**
Current income tax expense	**190**	204
Deferred income tax expense (recovery)	**19**	(36)
Income tax expense	**209**	168

The income tax effects of temporary differences that give rise to deferred income tax assets and liabilities as at December 31 are as follows:

(millions of dollars)	**2017**	**2016**
Deferred income tax assets:		
Fixed asset removal and nuclear waste management liabilities	**5,096**	4,861
Other assets and liabilities	**2,057**	1,813
	7,153	6,674
Deferred income tax liabilities:		
Property, plant and equipment and intangible assets	**(1,923)**	(1,807)
Nuclear fixed asset removal and nuclear waste management funds	**(4,181)**	(3,996)
Other assets and liabilities	**(1,928)**	(1,700)
	(8,032)	(7,503)
Net deferred income tax liabilities	**(879)**	(829)

During 2017, OPG recorded an increase in the deferred income tax liability for the income taxes that are expected to be recovered or refunded through regulated prices charged to customers of $59 million (2016 – $46 million). Since these deferred income taxes are expected to be refunded through future regulated prices, OPG recorded a corresponding increase to the regulatory asset for deferred income taxes. As a result, the deferred income tax expense for 2017 and 2016 was not impacted.

The following table summarizes the deferred income tax liabilities recorded for the rate regulated operations that are expected to be recovered through future regulated prices:

(millions of dollars)	**2017**	**2016**
January 1:		
Deferred income tax liabilities on temporary differences related to regulated operations	**627**	592
Deferred income tax liabilities on temporary differences related to the regulatory asset for the deferred income tax liabilities	**211**	200
	838	792
Changes during the year:		
Increase in deferred income tax liabilities on temporary differences related to regulated operations	**44**	35
Increase in deferred income tax liabilities on temporary differences related to the regulatory asset for the deferred income tax liabilities	**15**	11
Balance as at December 31	**897**	838

The tax benefit associated with an income tax position is recognized only when it is more likely than not that such a position will be sustained upon examination by the taxing authorities based on the technical merits of the position. The current and deferred income tax benefit is equal to the largest amount, considering possible settlement outcomes, that is greater than 50 percent likely of being realized upon settlement with the taxing authorities.

A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

(millions of dollars)	**2017**	**2016**
Unrecognized tax benefits, beginning of year	**77**	72
Additions based on tax positions related to the current year	**21**	19
Additions for tax positions of prior years	**-**	2
Reductions for tax positions of prior years	**(20)**	(16)
Unrecognized tax benefits, end of year	**78**	77

As at December 31, 2017, OPG's unrecognized tax benefits were $78 million (2016 – $77 million), excluding interest and penalties, all of which, if recognized, would affect OPG's effective tax rate. Changes in unrecognized tax benefits over the next 12 months cannot be predicted with certainty.

OPG recognizes interest and penalties related to unrecognized tax benefits as income tax expense. As at December 31, 2017, OPG had recorded interest on unrecognized tax benefits of $8 million (2016 – $8 million). OPG considers its significant tax jurisdiction to be Canada. OPG remains subject to income tax examination for years after 2013.

OPG paid $195 million in income taxes (net of tax refunds) during 2017 (2016 – $98 million).

10. ACCUMULATED OTHER COMPREHENSIVE LOSS

The changes in the balance of each component of accumulated other comprehensive loss (AOCL), net of income taxes, are as follows:

	2017			
(millions of dollars)	**Unrealized Gains and Losses on Cash Flow Hedges [1]**	**Pension and OPEB [1]**	**Available-for-sale Securities [1]**	**Total [1]**
AOCL, beginning of year	**(87)**	**(207)**	**(1)**	**(295)**
Actuarial loss on re-measurement of liabilities for pension and OPEB	**-**	**(23)**	**-**	**(23)**
Unrealized loss on available-for-sale securities	**-**	**-**	**(8)**	**(8)**
Amounts reclassified from AOCL	**18**	**10**	**-**	**28**
Other comprehensive income (loss) for the year	**18**	**(13)**	**(8)**	**(3)**
Reclassification of non-controlling interest on change in ownership interest *(Note 22)*	**3**	**-**	**-**	**3**
AOCL, end of year	**(66)**	**(220)**	**(9)**	**(295)**

[1] All amounts are net of income taxes.

	2016			
(millions of dollars)	**Unrealized Gains and Losses on Cash Flow Hedges [1]**	**Pension and OPEB [1]**	**Available-for-sale Securities [1]**	**Total [1]**
AOCL, beginning of year	(106)	(213)	-	(319)
Actuarial loss on re-measurement of liabilities for pension and OPEB	-	(6)	-	(6)
Unrealized loss on available-for-sale securities	-	-	(1)	(1)
Amounts reclassified from AOCL	19	12	-	31
Other comprehensive income (loss) for the year	19	6	(1)	24
AOCL, end of year	(87)	(207)	(1)	(295)

[1] All amounts are net of income taxes.

The significant amounts reclassified out of each component of AOCL, net of income taxes, during December 31, 2017 and 2016 are as follows:

(millions of dollars)	Amount Reclassified from AOCL 2017	2016	Statement of Income Line Item
Amortization of losses from cash flow hedges			
Losses	**20**	21	Net interest expense
Income tax recovery	**(2)**	(2)	Income tax expense
	18	19	
Amortization of amounts related to pension and OPEB			
Actuarial losses and past service costs	**13**	16	See (1) below
Income tax recovery	**(3)**	(4)	Income tax expense
	10	12	
Total reclassifications for the year	**28**	31	

[1] These AOCL components are included in the computation of pension and OPEB costs (see Note 11 for additional details).

11. PENSION AND OTHER POST-EMPLOYMENT BENEFITS

Fund Assets

The OPG registered pension fund investment guidelines are stated in an approved Statement of Investment Policies and Procedures (SIPP). The SIPP is reviewed and approved by the Audit and Risk Committee of OPG's Board of Directors at least annually and includes a discussion of investment objectives and expectations, asset mix and rebalancing, and the basis for measuring the performance of the pension fund assets.

In accordance with the SIPP, investment allocation decisions are made with a view to achieve OPG's objective of meeting obligations of the plan as they come due. The pension fund assets are invested in four categories of asset classes. The first category is liability hedging assets, which are intended to hedge the inflation and interest rate sensitivity of the plan liabilities. The second category is return enhancing assets, which are intended to obtain higher investment returns compared to the returns expected for liability hedging assets. The third category is real assets, which offer exposure to the combined characteristics of liability hedging and return enhancing assets. The fourth category is return diversifying strategies, which are intended to improve the overall return of the pension fund while mitigating the downside market risk.

To achieve the above objective, OPG has adopted the following target strategic asset allocation:

	Target
Asset Class	
Liability Hedging Assets	34%
Return Enhancing Assets	31%
Real Assets	20%
Return Diversifying Assets	15%

The plan may use derivatives for risk management or strategic purposes, where such activity is consistent with the plan's investment objectives.

Significant Concentrations of Risk in Fund Assets

The assets of the pension fund are diversified to limit the impact of any individual investment. The pension fund is diversified across multiple asset classes. Fixed income securities are diversified among Canadian government bonds, government agency bonds, real return bonds, and corporate bonds. Equity securities are diversified across

Canadian, US, and Global stocks. There are also real estate, infrastructure, and agriculture portfolios that represent approximately 12 percent of the total pension fund assets as at December 31, 2017. Investments in the above asset classes are further diversified across funds, investment managers, strategies, vintages, sectors and geographies, depending on the specific characteristics of each asset class.

Credit risk with respect to the pension fund's fixed income securities is managed by risk tolerance guidelines, which requires that fixed income securities comply with various investment constraints that ensure prudent diversification and prescribed minimum required credit rating quality. Credit risk, as it relates to the pension fund's derivatives, is managed through the use of International Swap and Derivatives Association documentation and counterparty management performed by the fund's investment managers.

Risk Management

Risk management oversight with respect to the pension fund includes, but is not limited to, the following activities:

- Periodic asset/liability management and strategic asset allocation studies
- Monitoring of funding levels and funding ratios
- Monitoring compliance with asset allocation guidelines and investment management agreements
- Monitoring asset class performance against asset class benchmarks
- Monitoring investment manager performance against benchmarks
- Monitoring of risk tolerance guidelines

Expected Rate of Return on Plan Assets

The expected rate of return on plan assets is based on the fund's asset allocation, as well as the return expectations considering long-term risks and returns associated with each asset class within the plan portfolio. The asset management decisions consider the economic liabilities of the plan.

Fair Value Measurements

OPG is required to classify fair value measurements using a fair value hierarchy. This hierarchy groups financial instruments into three levels, based on the significance of inputs used in measuring the fair value of the assets and liabilities. Refer to Note 13 for a detailed discussion of fair value measurements and the fair value hierarchy.

The following tables present pension plan assets measured at fair value in accordance with the fair value hierarchy:

	December 31, 2017			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Cash and cash equivalents	**377**	**-**	**-**	**377**
Short-term investments	**-**	**9**	**-**	**9**
Fixed income				
Corporate debt securities	**-**	**521**	**-**	**521**
Government bonds	**-**	**3,476**	**-**	**3,476**
Equities				
Canadian	**1,441**	**329**	**-**	**1,770**
US	**1,551**	**-**	**-**	**1,551**
Global	**1,681**	**-**	**-**	**1,681**
Pooled funds	**459**	**105**	**-**	**564**
Other	**15**	**-**	**-**	**15**
	5,524	**4,440**	**-**	**9,964**
Investments measured at NAV [1]				**4,221**
				14,185 [2]

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to the total fair value of plan assets presented in tables following.

[2] The table above excludes pension fund receivables and payables.

	December 31, 2016			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Cash and cash equivalents	690	-	-	690
Fixed income				
Corporate debt securities	-	407	-	407
Government bonds	-	3,483	-	3,483
Equities				
Canadian	1,449	291	-	1,740
US	1,495	-	-	1,495
Global	1,643	-	-	1,643
Pooled funds	118	413	-	531
	5,395	4,594	-	9,989
Investments measured at NAV [1]				3,504
				13,493 [2]

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to the total fair value of plan assets presented in tables following.

[2] The table above excludes pension fund receivables and payables.

Plan Costs and Liabilities

Details of OPG's pension and OPEB obligations, pension fund assets and costs are presented in the following tables:

	Registered and Supplementary Pension Plans		Other Post-Employment Benefits	
	2017	**2016**	**2017**	**2016**
Weighted Average Assumptions – Benefit Obligations at Year-End				
Discount rate for projected benefit obligation	**3.57 %**	3.90 %	**3.60 %**	3.94 %
Salary schedule escalation rate - initial rate [1]	**1.90 %**	1.80 %	**1.90 %**	1.80 %
- thereafter	**2.50 %**	2.50 %	**2.50 %**	2.50 %
Rate of cost of living increase to pensions	**2.00 %**	2.00 %	**n/a**	n/a
Initial health care trend rate	**n/a**	n/a	**5.80 %**	5.90 %
Ultimate health care trend rate	**n/a**	n/a	**4.32 %**	4.32 %
Year ultimate health care trend rate reached	**n/a**	n/a	**2030**	2030
Rate of increase in disability benefits	**n/a**	n/a	**2.00 %**	2.00 %

[1] Per year to December 31, 2021.

	Registered and Supplementary Pension Plans		Other Post-Employment Benefits	
	2017	**2016**	**2017**	**2016**
Weighted Average Assumptions – Costs for the Year				
Expected return on plan assets, net of expenses	**6.00 %**	6.00 %	**n/a**	n/a
Discount rate for projected benefit obligation	**3.90 %**	4.10 %	**3.94 %**	4.13 %
Discount rate for current service cost	**4.15 %**	4.10 %	**4.03 %**	4.13 %
Discount rate for interest on projected benefit obligation	**3.37 %**	4.10 %	**3.53 %**	4.13 %
Discount rate for interest on current service cost	**3.95 %**	4.10 %	**3.85 %**	4.13 %
Salary schedule escalation rate - initial rate [1]	**1.80 %**	1.60 %	**1.80 %**	1.60 %
- thereafter	**2.50 %**	2.50 %	**2.50 %**	2.50 %
Rate of cost of living increase to pensions	**2.00 %**	2.00 %	**n/a**	n/a
Initial health care trend rate	**n/a**	n/a	**5.90 %**	6.00 %
Ultimate health care trend rate	**n/a**	n/a	**4.32 %**	4.33 %
Year ultimate health care trend rate reached	**n/a**	n/a	**2030**	2030
Rate of increase in disability benefits	**n/a**	n/a	**2.00 %**	2.00 %
Expected average remaining service life for employees (years)	**12**	12	**13**	13

[1] Per year to December 31, 2021.

(millions of dollars)	Registered Pension Plans 2017	2016	Supplementary Pension Plans 2017	2016	Other Post-Employment Benefits 2017	2016
Components of Cost Recognized for the year						
Current service costs	**274**	277	**7**	7	**67**	67
Interest on projected benefit obligation	**548**	634	**11**	12	**106**	133
Expected return on plan assets, net of expenses	**(766)**	(734)	**-**	-	**-**	-
Amortization of past service costs [1]	**-**	-	**-**	-	**1**	1
Amortization of net actuarial loss [1]	**183**	192	**6**	4	**-**	19
Recognition of LTD net actuarial loss (gain)	**-**	**-**	**-**	**-**	**11**	(52)
Costs recognized [2]	**239**	369	**24**	23	**185**	168

[1] The amortization of past service costs and net actuarial loss was recognized as an increase to OCI. This increase was partially offset by the impact of the Pension and OPEB Regulatory Asset discussed in Note 5.

[2] Excludes the impact of regulatory variance and deferral accounts discussed in Note 5.

Total benefit costs, including the impact of the Pension & OPEB Cash Payment Variance Account and the Pension & OPEB Cash Versus Accrual Differential Deferral Account, for the years ended December 31 are as follows:

(millions of dollars)	2017	2016
Registered pension plans	**239**	369
Supplementary pension plans	**24**	23
Other post-employment benefits	**185**	168
Pension & OPEB Cash Payment Variance Account *(Note 5)*	**81**	86
Pension & OPEB Cash Versus Accrual Differential Deferral Account *(Note 5)*	**(117)**	(182)
Pension and other post-employment benefit costs	**412**	464

The pension and OPEB obligations and the pension fund assets measured as at December 31 are as follows:

(millions of dollars)	Registered Pension Plans 2017	Registered Pension Plans 2016	Supplementary Pension Plans 2017	Supplementary Pension Plans 2016	Other Post-Employment Benefits 2017	Other Post-Employment Benefits 2016
Change in Plan Assets						
Fair value of plan assets at beginning of year	**13,506**	13,160	**-**	-	**-**	-
Contributions by employer	**214**	255	**14**	15	**94**	93
Contributions by employees	**97**	85	**-**	-	**-**	-
Actual return on plan assets, net of expenses	**1,207**	714	**-**	-	**-**	-
Benefit payments	**(761)**	(708)	**(14)**	(15)	**(94)**	(93)
Fair value of plan assets at end of year	**14,263**	13,506	**-**	-	**-**	-
Change in Projected Benefit Obligations						
Projected benefit obligations at beginning of year	**16,199**	15,475	**336**	299	**2,992**	3,188
Employer current service costs	**274**	277	**7**	7	**67**	67
Contributions by employees	**97**	85	**-**	-	**-**	-
Interest on projected benefit obligation	**548**	634	**11**	12	**106**	133
Benefit payments	**(761)**	(708)	**(14)**	(15)	**(94)**	(93)
Net actuarial loss (gain)	**987**	436	**16**	33	**119**	(303)
Projected benefit obligations at end of year	**17,344**	16,199	**356**	336	**3,190**	2,992
Funded status – deficit at end of year	**(3,081)**	(2,693)	**(356)**	(336)	**(3,190)**	(2,992)

The following table provides the pension and OPEB liabilities and their classification on the consolidated balance sheets as at December 31:

(millions of dollars)	Registered Pension Plans 2017	Registered Pension Plans 2016	Supplementary Pension Plans 2017	Supplementary Pension Plans 2016	Other Post-Employment Benefits 2017	Other Post-Employment Benefits 2016
Current liabilities	**-**	-	**(14)**	(17)	**(98)**	(95)
Non-current liabilities	**(3,081)**	(2,693)	**(342)**	(319)	**(3,092)**	(2,897)
Total liabilities	**(3,081)**	(2,693)	**(356)**	(336)	**(3,190)**	(2,992)

The accumulated benefit obligations for the registered pension plans and supplementary pension plans as at December 31, 2017 are $16,005 million and $333 million, respectively (2016 – $14,909 million and $293 million, respectively). The accumulated benefit obligation differs from the projected benefit obligation in that the accumulated benefit obligation includes no assumption about future compensation levels.

The following table provides the components of OPG's OCI related to pension and OPEB plans and the offsetting Pension and OPEB Regulatory Asset, discussed in Note 5, for the years ended December 31, on a pre-tax basis:

(millions of dollars)	Registered Pension Plans 2017	Registered Pension Plans 2016	Supplementary Pension Plans 2017	Supplementary Pension Plans 2016	Other Post-Employment Benefits 2017	Other Post-Employment Benefits 2016
Changes in plan assets and benefit obligations recognized in OCI						
Current year net actuarial loss (gain)	**546**	456	**16**	33	**108**	(251)
Amortization of net actuarial loss	**(183)**	(192)	**(6)**	(4)	**-**	(19)
Amortization of past service costs	**-**	-	**-**	-	**(1)**	(1)
Total decrease (increase) in OCI	**363**	264	**10**	29	**107**	(271)
Less: increase (decrease) in Pension and OPEB Regulatory Asset *(Note 5)*	**352**	253	**9**	27	**102**	(250)
Net decrease (increase) in OCI (pre-tax)	**11**	11	**1**	2	**5**	(21)

The following table provides the components of OPG's AOCL and the offsetting Pension and OPEB Regulatory Asset that have not yet been recognized as components of benefit costs as at December 31, on a pre-tax basis:

(millions of dollars)	Registered Pension Plans 2017	Registered Pension Plans 2016	Supplementary Pension Plans 2017	Supplementary Pension Plans 2016	Other Post-Employment Benefits 2017	Other Post-Employment Benefits 2016
Unamortized amounts recognized in AOCL						
Past service costs	**-**	-	**-**	-	**4**	5
Net actuarial loss	**3,650**	3,287	**116**	106	**378**	270
Total recognized in AOCL	**3,650**	3,287	**116**	106	**382**	275
Less: Pension and OPEB Regulatory Asset *(Note 5)*	**3,391**	3,039	**109**	100	**355**	253
Net recognized in AOCL (pre-tax)	**259**	248	**7**	6	**27**	22

The following table provides the components of OPG's AOCL and the offsetting Pension and OPEB Regulatory Asset as at December 31 (included in the table above) that are expected to be amortized as components of benefit costs and recognized as increases to OCI and reductions in the Pension and OPEB Regulatory Asset in 2018, on a pre-tax basis:

(millions of dollars)	Registered Pension Plans	Supplementary Pension Plans	Other Post-Employment Benefits
Past service costs	**-**	**-**	**1**
Net actuarial loss	**198**	**7**	**6**
Total increase in OCI	**198**	**7**	**7**
Less: estimated decrease in Pension and OPEB Regulatory Asset	**184**	**6**	**6**
Net increase in OCI (pre-tax)	**14**	**1**	**1**

The most recently filed actuarial valuation, for funding purposes, of the OPG registered pension plan, as at January 1, 2017, was filed with the FSCO in September 2017. The next filed funding valuation must have an effective date no later than January 1, 2020. For 2018, OPG's required contribution to its registered pension plan is expected to be $215 million. The amount of OPG's additional, voluntary contribution, if any, is revisited from time to time. OPG will continue to assess the requirements for contributions to the pension plan.

The supplementary pension plans are not funded, but are secured by Letters of Credit totalling $353 million as at December 31, 2017 (2016 – $349 million).

Estimated future benefit payments to participants in the pension and OPEB plans based on the assumptions used to measure the benefit obligations as at December 31, 2017 are as follows:

(millions of dollars)	**Registered Pension Plans**	**Supplementary Pension Plans**	**Other Post-Employment Benefits**
2018	676	15	98
2019	696	15	101
2020	722	15	105
2021	747	16	108
2022	764	16	111
2023 through 2027	4,397	86	633

A one percent increase or decrease in the health care trend rate would result in an increase in the current service and interest components of the 2017 OPEB costs of $40 million (2016 – $45 million) or a decrease in the service and interest components of the 2017 OPEB costs of $29 million (2016 – $33 million). A one percent increase or decrease in the health care trend rate would result in an increase in the projected OPEB obligation as at December 31, 2017 of $592 million (2016 – $560 million) or a decrease in the projected OPEB obligation as at December 31, 2017 of $451 million (2016 – $426 million).

12. RISK MANAGEMENT AND DERIVATIVES

OPG is exposed to risks related to changes in market interest rates on debt expected to be issued in the future and movements in foreign currency that affect the Company's assets, liabilities, and forecasted transactions. Select derivative instruments are used to manage such risks. Derivatives are used as hedging instruments, as well as for trading purposes.

Interest rate risk is the risk that the value of assets and liabilities can change due to movements in related interest rates. Interest rate risk for OPG arises with the need to refinance existing debt and/or undertake new financing. The management of these risks includes using derivatives to hedge the exposure in accordance with corporate risk management policies. OPG periodically uses interest rate swap agreements to mitigate elements of interest rate risk exposure associated with anticipated financing.

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are denominated in, or tied to, US dollars. OPG enters into foreign exchange derivatives and agreements with major financial institutions, when appropriate, in order to manage the Company's exposure to foreign currency movements.

The majority of OPG's revenues are derived from sales through the IESO administered spot market. Market participants in the IESO spot market provide collateral in accordance with the IESO prudential support requirements to cover funds that they might owe to the market. Although the credit exposure to the IESO represents a significant portion of OPG's accounts receivable, the Company's management accepts this risk due to the IESO's primary role in the Ontario electricity market. The remaining receivables exposure is to a diverse group of generally high quality counterparties. OPG's allowance for doubtful accounts as at December 31, 2017 was less than $1 million. OPG's fair value derivatives totalled a net liability of $20 million as at December 31, 2017 (December 31, 2016 − $24 million).

The following table shows the pre-tax amounts related to derivatives recorded in AOCL and net income for the years ended December 31:

(millions of dollars)	**2017**	**2016**
Cash flow hedges (recorded in AOCL)		
Reclassification of losses to net interest expense	**19**	21
Commodity derivatives (recorded in net income)		
Realized losses in revenue	**(9)**	(12)
Unrealized gains (losses) in revenue	**3**	(3)

Existing pre-tax net losses of $19 million deferred in AOCL as at December 31, 2017 are expected to be reclassified to net income within the next 12 months.

13. FAIR VALUE MEASUREMENTS

OPG is required to classify fair value measurements using a fair value hierarchy. This hierarchy groups financial assets and liabilities into three levels, based on the inputs used in measuring the fair value of the financial assets and liabilities. The fair value hierarchy has the following levels:

- Level 1: Valuation of inputs is based on unadjusted quoted market prices observed in active markets for identical assets or liabilities.
- Level 2: Valuation is based on inputs other than quoted prices under Level 1 that are observable for the asset or liability, either directly or indirectly.
- Level 3: Valuation is based on inputs for the asset or liability that are not based on observable market data.

The fair value of financial instruments traded in active markets is based on quoted market prices as at the consolidated balance sheet dates. A market is regarded as active if quoted prices are readily and regularly available from an exchange, dealer, broker, industry group, pricing service, or regulatory agency, and those prices represent actual and regularly occurring market transactions on an arm's length basis. The quoted market price used for financial assets held by OPG is the current bid price. These instruments are included in Level 1 and are comprised primarily of equity investments and fund investments.

For financial instruments for which quoted market prices are not directly available, fair values are estimated using forward price curves developed from observable market prices or rates. The estimation of fair value may include the use of valuation techniques or models, based wherever possible on assumptions supported by observable market prices or rates prevailing as at the consolidated balance sheet dates. This is the case for over-the-counter derivatives and securities, which include energy commodity derivatives, foreign exchange derivatives, interest rate swap derivatives, and fund investments. Pooled fund investments are valued at the unit values supplied by the pooled fund administrators. The unit values represent the underlying net assets at fair values, determined using closing market prices. Valuation models use general assumptions and market data and therefore do not reflect the specific risks and other factors that would affect a particular instrument's fair value. The methodologies used for calculating the fair value adjustments are reviewed on an ongoing basis to ensure that they remain appropriate. If all significant inputs required to fair value an instrument are observable, the instrument is included in Level 2.

The following is a summary of OPG's financial instruments and their fair value as at December 31, 2017 and December 31, 2016:

	Fair Value		Carrying Value [1]		
(millions of dollars)	**2017**	**2016**	**2017**	**2016**	**Balance Sheet Line Item**
Nuclear Segregated Funds (includes current portion) [2]	**16,724**	15,984	**16,724**	15,984	Nuclear fixed asset removal and nuclear waste management funds
Financing receivables	**1,179**	-	**1,179**	-	Financing receivables
Investment in Hydro One shares	**188**	212	**188**	212	Available-for-sale securities
Payable related to cash flow hedges	**(40)**	(48)	**(40)**	(48)	Long-term accounts payable and accrued charges
Long-term debt (includes current portion and medium) term notes)	**(6,835)**	(6,033)	**(5,735)**	(5,520)	Long-term debt
Long-term debt – Fair Hydro Trust	**(601)**	-	**(601)**	-	Long-term debt
Other financial instruments	**(16)**	(18)	**(16)**	(18)	Various

[1] The carrying values of other financial instruments included in cash and cash equivalents, receivables from related parties, other current assets, short-term debt, and accounts payable and accrued charges approximate their fair values due to the immediate or short-term maturity of these financial instruments.

[2] The Nuclear Segregated Funds are comprised of the Decommissioning Segregated Fund and the Used Fuel Segregated Fund.

The fair value of long-term debt instruments is determined based on a conventional pricing model, which is a function of future cash flows, the current market yield curve and term to maturity. These inputs are considered Level 2 inputs.

The fair value of the Trust debt and Medium Term Note Program debt (included in the Long-term debt line above) are based on unadjusted quoted active market prices, which are considered Level 1 inputs. All other long-term debt instruments is determined based on a conventional pricing model, which is a function of future cash flows, the current market yield curve and term to maturity. These inputs are considered Level 2 inputs. For the financing receivables related to the Investment Interest acquired from the IESO, fair value is estimated to equal the fair value of the underlying debt due to the direct relationship of the asset, and the debt instruments that financed the acquisition. The financing receivables are funded by both the senior and subordinated debt issued by the Trust. The long-term debt ranks as senior notes and has inputs that are based on unadjusted quoted active market prices, which are considered Level 1 inputs, while the portion funded by the subordinated debt has inputs that are based on indicative pricing from the market, which are considered Level 2 inputs.

If one or more of the significant inputs is not based on observable market data, the instrument is included in Level 3. Specific valuation techniques are used to value these instruments. Significant Level 3 inputs include: recent comparable transactions, comparable benchmark information, bid/ask spread of similar transactions, and other relevant factors.

Transfers into, out of, or between levels are deemed to have occurred on the date of the event or change in circumstances that caused the transfer to occur.

The following tables present financial assets and financial liabilities measured at fair value in accordance with the fair value hierarchy as at December 31, 2017 and December 31, 2016:

	December 31, 2017			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Used Fuel Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	**6,090**	**4,705**	**-**	**10,795**
Investments measured at NAV [1]				**1,292**
				12,087
Due to Province				**(2,529)**
Used Fuel Segregated Fund, net				**9,558**
Decommissioning Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	**4,547**	**3,487**	**-**	**8,034**
Investments measured at NAV [1]				**1,065**
				9,099
Due to Province				**(1,933)**
Decommissioning Segregated Fund, net				**7,166**
Investment in available-for-sale securities	**188**	**-**	**-**	**188**
Other financial assets	**5**	**3**	**6**	**14**
Liabilities				
Other financial liabilities	**(28)**	**(2)**	**-**	**(30)**

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to amounts presented on the consolidated balance sheets.

(millions of dollars)	December 31, 2016 Level 1	Level 2	Level 3	Total
Assets				
Used Fuel Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	5,602	4,394	-	9,996
Investments measured at NAV [1]				1,086
				11,082
Due to Province				(1,938)
Used Fuel Segregated Fund, net				9,144
Decommissioning Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	4,171	3,243	-	7,414
Investments measured at NAV [1]				903
				8,317
Due to Province				(1,477)
Decommissioning Segregated Fund, net				6,840
Investments in available-for-sale securities	212	-	-	212
Other financial assets	6	2	9	17
Liabilities				
Other financial liabilities	(29)	(6)	-	(35)

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to amounts presented on the consolidated balance sheets.

During the year ended December 31, 2017, there were no transfers between Level 1 and Level 2. In addition, there were no transfers into or out of Level 3.

The following table presents the changes in OPG's net assets measured at fair value that are classified as Level 3 financial instruments.

(millions of dollars)	Other financial instruments
Opening balance, January 1 2017	**9**
Unrealized losses included in revenue	**(3)**
Realized losses included in revenue	**(9)**
Purchases	**9**
Closing balance, December 31, 2017	**6**

Nuclear Segregated Funds

The fair value of the investments within the Nuclear Segregated Funds' alternative investment portfolio is determined using appropriate valuation techniques, such as recent arm's length market transactions, references to current fair values of other instruments that are substantially the same, discounted cash flow analyses, third-party independent appraisals, valuation multiples, or other valuation methods. Any control, size, liquidity or other discount premiums on the investments are considered in the determination of fair value. Alternative investments are measured at fair value using NAV as a practical expedient.

The process of valuing investments for which no published market price exists is based on inherent uncertainties and the resulting values may differ from values that would have been used had a ready market existed for these investments. The values may also differ from the prices at which the investments may be sold.

The following are the classes of investments within the Nuclear Segregated Funds that are reported on the basis of NAV as at December 31, 2017:

(millions of dollars except where noted)	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice
Alternative Investments				
Infrastructure	**1,330**	**798**	**n/a**	**n/a**
Real Estate	**936**	**440**	**n/a**	**n/a**
Agriculture	**90**	**97**	**n/a**	**n/a**
Pooled Funds				
Short-term Investments	**32**	**n/a**	**Daily**	**1 - 5 Days**
Fixed Income	**729**	**n/a**	**Daily**	**1 - 5 Days**
Equity	**952**	**n/a**	**Daily**	**1 - 5 Days**
Total	**4,069**	**1,335**		

The fair value of the pooled funds is classified as Level 2. Infrastructure, real estate and agriculture investments are measured using NAV as a practical expedient for determining their fair value.

Infrastructure

This asset class includes investments in funds and assets with an objective to generate a combination of long-term capital appreciation and current income, generally through private investments in sectors such as energy, transportation, communication and utilities. The fair values of investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in these investments. The investments in its respective funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests/shares to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Distributions from each infrastructure fund will be received based on the operations of the underlying investments and/or as the underlying investments of the infrastructure funds are liquidated. It is not possible to estimate when the underlying assets in this asset class will be liquidated.

Real Estate

This asset class includes investments in funds and assets with an objective is to generate a combination of long-term capital appreciation and current income, generally through investments in institutional-grade real estate property. The fair values of the investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in these investments. The investments in its respective funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Distributions from each real estate fund will be received based on the operations of the underlying investments and/or as the underlying investments of the real estate funds are liquidated. For investments in private real estate corporations, shares may be redeemed through a pre-established redemption process. It is not possible to estimate when the underlying assets in this asset class will be liquidated.

Agriculture

This asset class includes investments in funds and assets with an objective to provide a differentiated return source, income yield, and inflation protection, generally through private investments inglobal farmland and timberland. The fair values of the investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in these investments. The investments in its respective funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests/shares to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Distributions from each fund will be received based on the operations of the underlying investments and/or as the underlying investments of the funds are liquidated. It is not possible to estimate when the underlying assets in this asset class will be liquidated.

Pooled Funds

This asset class represents investments in pooled funds, which primarily include a diversified portfolio of fixed income securities, issued mainly by Canadian corporations, and diversified portfolios of Emerging Market listed equity. The investment objective of the pooled funds is to achieve capital appreciation and income through professionally managed portfolios. The fair value of the investments in this class has been estimated using NAV per share of the investments. There are no significant restrictions on the ability to sell the investments in this class.

14. SHARE CAPITAL

Common Shares

As at December 31, 2017 and 2016, OPG had 256,300,010 common shares issued and outstanding at a stated value of $5,126 million. OPG is authorized to issue an unlimited number of common shares without nominal or par value. Any issue of new shares is subject to the consent of OPG's shareholder.

Class A Shares

The Company's Articles of Amalgamation were amended effective December 1, 2017 to allow for the creation and issuance of non-voting Class A shares to the Province in exchange for its equity injections in OPG to be used solely for its investment in the Trust. All of the outstanding shares are owned directly by the Province and OPG is authorized to issue an unlimited number of Class A shares without nominal or par value. The Class A and common shares rank equally as to dividends on a share for share basis, and all dividends declared by OPG shall be declared in equal amounts per share on all outstanding shares without preference or distinction. Upon the liquidation, dissolution or wind-up of OPG, whether voluntary or involuntary, the holders of Class A shares and common shares are entitled to share equally, on a share for share basis, in all distributions of property and assets without preference or distinction. Any issue of new shares is subject to the consent of the Province. OPG is entitled to redeem outstanding shares in connection with the repayment of the Trust's debt or other purposes as may be approved by OPG's Board of Directors.

In December 2017, OPG issued 12,217,616 Class A shares at a price of $42.46 per share to the Province for its equity injection in OPG, generating proceeds of $519 million, which was used to fund 44 percent of the total funding requirement of the Trust's acquisition of Investment Interest from the IESO.

15. EARNINGS PER COMMON SHARE

Basic and diluted earnings per common share is calculated by dividing net income attributable to the Shareholder of OPG by the weighted average number of common shares outstanding.

Class A shares are included in the weighted average number of common shares outstanding. The weighted average number of shares outstanding as at December 31, 2017 was 256.7 million (2016 – 256.3 million). There were no dilutive securities during the years ended December 31, 2017 and 2016.

16. COMMITMENTS AND CONTINGENCIES

Litigation

On August 9, 2006, a Notice of Action and Statement of Claim filed with the Ontario Superior Court of Justice in the amount of $500 million was served against OPG and Bruce Power by British Energy Limited and British Energy International Holdings Limited (together British Energy). The action is for contribution and indemnity of any amounts British Energy was liable for in an arbitration against it by some of the owners of Bruce Power regarding an alleged breach of British Energy's representations and warranties to the claimants when they purchased British Energy's interest in Bruce Power (the Arbitration). Both the action and the Arbitration relate to corrosion to a steam generator unit discovered after OPG leased the Bruce nuclear generating stations to Bruce Power.

In 2012, the arbitrator found that British Energy was liable to the claimants for some of the damages they claimed. The final settlement amount was valued by British Energy at $71 million. In September 2014, British Energy amended its Statement of Claim (Amended Claim) to reduce the claim amount to $100 million to reflect that the purchasers of British Energy's interest in Bruce Power did not receive the full damages they originally claimed in the Arbitration. British Energy also added an allegation to its Amended Claim that OPG breached a covenant to maintain the steam generator between the time of the initial agreement to lease and the effective date of the lease in accordance with "Good Utility Practices".

In November 2016, British Energy obtained consent from Ontario Superior Court of Justice to a timetable for the remaining steps in the litigation, pursuant to which the matter must be set down for trial by December 31, 2018. OPG has delivered a statement of defence in accordance with an extension of the original June 30, 2017 delivery deadline set up in the timetable. [**MONITOR**]

Various other legal proceedings are pending against OPG or its subsidiaries covering a wide range of matters that arise in the ordinary course of business activities.

Each of these matters is subject to various uncertainties. Some of these matters may be resolved unfavourably. While it is not possible to determine the ultimate outcome of the various pending actions, it is the Company's belief that their resolution is not likely to have a material adverse impact on its financial position.

Guarantees

The Company and its joint venture partners have jointly guaranteed the financial performance of jointly owned entities related primarily to the payment of liabilities. As at December 31, 2017, the total amount of guarantees OPG provided to these entities was $82 million (December 31, 2016 − $83 million). OPG may terminate some of these guarantees within a short time frame by providing written notice to the counterparties at any time. Other guarantees have terms ending between 2019 and 2029. As at December 31, 2017, the potential impact of the fair value of these guarantees to income has been estimated to be negligible and OPG does not expect to make any payments associated with these guarantees.

Contractual Obligations

OPG's contractual obligations as at December 31, 2017, are as follows:

(millions of dollars)	2018	2019	2020	2021	2022	Thereafter	Total
Fuel supply agreements	158	125	115	88	67	67	620
Contributions to the OPG registered pension plan [1]	215	219	-	-	-	-	434
OPG long-term debt repayment	398	368	663	413	172	3,721	5,735
Interest on OPG long-term debt	244	226	204	175	161	3,006	4,016
Fair Hydro Trust senior debt repayment [2]	-	601	-	-	-	-	601
Interest on Fair Hydro Trust senior debt	15	15	-	-	-	-	30
Commitments related to Darlington Refurbishment project [3]	473	-	-	-	-	-	473
Commitments related to Ranney Falls GS project	29	5	-	-	-	-	34
Operating licences	40	41	24	28	28	87	248
Operating lease obligations	28	24	24	22	22	79	199
Unconditional purchase obligations	59	58	56	5	-	-	178
Accounts payable and accrued charges	957	8	-	-	-	16	981
Other	57	30	2	1	1	64	155
Total	2,673	1,720	1,088	732	451	7,040	13,704

[1] The pension contributions include ongoing funding requirements and additional funding requirements towards the deficit, in accordance with the actuarial valuation of the OPG registered pension plan as at January 1, 2017. The next actuarial valuation of the OPG registered pension plan must have an effective date no later than January 1, 2020. The pension contributions are affected by various factors including market performance, changes in actuarial assumptions, plan experience, changes in the pension regulatory environment, and the timing of funding valuations. Funding requirements after 2019 are excluded due to significant variability in the assumptions required to project the timing of future cash flows. The amount of OPG's additional, voluntary contribution, if any, is revisited from time to time.

[2] The notes were issued by the Fair Hydro Trust under an $800 million two-year revolving warehouse facility in December 2017. In February 2018, the Trust issued $500 million of senior notes payable to repay the majority of the outstanding balance of the revolving warehouse facility.

[3] Represents estimated currently committed costs to close the project, including accruals for completed work, demobilization of project staff and cancellation of existing contracts and material orders.

Other Commitments

Collective Agreements

As of December 31, 2017, OPG had approximately 9,212 regular employees. Most of OPG's regular employees are represented by two unions:

- **The PWU** – This union represents approximately 4,849 OPG employees or approximately 53 percent of OPG's regular workforce as at December 31, 2017. Union membership includes operators, technicians, skilled trades, clerical, and security personnel. The current collective agreement between OPG and the PWU has a three-year term, expiring on March 31, 2018.
- **The Society** – This union represents approximately 3,259 OPG employees or approximately 35 percent of OPG's regular workforce as at December 31, 2017. Union membership includes supervisors, professional engineers, scientists, and other professionals. The current collective agreement between OPG and The Society has a three-year term, expiring on December 31, 2018.

In addition to the regular workforce, construction work is performed through 19 craft unions with established bargaining rights at OPG facilities. These bargaining rights are established either through the Electrical Power Systems Construction Association or directly with OPG. Collective agreements between the Company and its construction unions are negotiated either directly or through EPSCA. All of these collective agreements currently have multi-year terms, expiring on April 30, 2020.

17. BUSINESS SEGMENTS

Effective in the fourth quarter of 2017, OPG has the following six reportable business segments:

- Regulated – Nuclear Generation
- Regulated – Nuclear Waste Management
- Regulated – Hydroelectric
- Contracted Generation Portfolio
- Services, Trading, and Other Non-Generation
- Fair Hydro Trust

Regulated – Nuclear Generation Segment

The Regulated – Nuclear Generation business segment operates in Ontario, generating and selling electricity from the Pickering GS and the Darlington GS, both owned and operated by OPG. The business segment also includes revenue under the terms of a long-term lease arrangement and related agreements with Bruce Power related to the Bruce nuclear generating stations. This revenue includes lease revenue, fees for nuclear waste management, and revenue from heavy water sales and detritiation services. The segment also earns revenue from isotope sales and ancillary services supplied by OPG-operated nuclear stations. Ancillary revenues are earned through voltage control and reactive support. Revenues under the agreements with Bruce Power, including a portion of heavy water sales, and from isotope sales and ancillary services are included by the OEB as a credit to customers in the determination of the regulated prices for production from OPG's nuclear facilities, which has had the effect of reducing these prices.

Regulated – Nuclear Waste Management Segment

OPG's Regulated – Nuclear Waste Management segment reports the results of the Company's operations associated with the management of nuclear used fuel and L&ILW, the decommissioning of OPG's nuclear generating stations including the stations on lease to Bruce Power and other waste management facilities, the management of the Nuclear Segregated Funds, and related activities including the inspection and maintenance of the waste storage facilities. Accordingly, accretion expense, which is the increase in the Nuclear Liabilities carried on the consolidated balance sheets in present value terms due to passage of time, and earnings from the Nuclear Segregated Funds are reported under this segment.

As the nuclear generating stations operate over time, OPG incurs incremental costs related to used nuclear fuel and low and intermediate level wastes, which increase the Nuclear Liabilities. OPG charges these incremental costs to current operations in the Regulated – Nuclear Generation segment to reflect the cost of producing energy from the Pickering and Darlington nuclear generating stations and earning revenue under the Bruce Lease and related agreements. Since the incremental costs increase the Nuclear Liabilities in the Regulated – Nuclear Waste Management segment, OPG records an inter-segment charge between the Regulated – Nuclear Generation and the Regulated – Nuclear Waste Management segments. The impact of the inter-segment charge is eliminated in the consolidated statements of income and balance sheets.

The Regulated – Nuclear Waste Management segment is considered rate regulated because OPG's costs associated with the Nuclear Liabilities have been included in the determination of regulated prices for production from the Pickering and Darlington nuclear generating stations, in accordance with the methodology applied by the OEB since its 2008 decision on OPG's first application for regulated prices.

Regulated – Hydroelectric Segment

OPG's Regulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from most of the Company's hydroelectric generating stations. The business segment includes the results of the Sir Adam Beck 1, 2 and Pump generating stations, the DeCew Falls 1 and 2 generating stations, and the R.H. Saunders GS

that were prescribed for rate regulation prior to 2014, and the 48 hydroelectric stations prescribed for rate regulation effective in 2014.

In addition, the business segment includes ancillary and other revenues from OPG's regulated hydroelectric stations. Ancillary revenues are earned through offering available generating capacity as operating reserve and through the supply of other ancillary services including voltage control and reactive support, certified black start facilities, regulation service, and other services. These ancillary revenues and other revenues are included by the OEB as a credit to ratepayers in the determination of the regulated prices for production from OPG's prescribed hydroelectric facilities, which has had the effect of reducing these prices.

Contracted Generation Portfolio Segment

The Contracted Generation Portfolio business segment operates in Ontario, generating and selling electricity from the Company's generating stations that are not prescribed for rate regulation. The segment primarily includes generating facilities that are under an ESA with the IESO or other long-term contracts.

The Contracted Generation Portfolio segment also includes OPG's share of equity income from its 50 percent ownership interests in the PEC and Brighton Beach stations.

The business segment also includes ancillary revenues and other revenues from the stations included in the segment, which are earned through offering available generating capacity as operating reserve, and the supply of other ancillary services including voltage control and reactive support, certified black start facilities, regulation service, and other services.

Services, Trading, and Other Non-Generation Segment

The Services, Trading, and Other Non-Generation segment is a non-generation segment that is not subject to rate regulation. It includes the revenue and expenses related to OPG's trading and other non-hedging activities. As part of these activities, OPG transacts with counterparties in Ontario and neighbouring energy markets in predominantly short-term trading activities of typically one year or less in duration. These activities relate to electricity that is purchased and sold at the Ontario border, financial energy trades, financial risk management energy product revenues, and sales of energy-related products. In addition, OPG has a wholly owned trading subsidiary that transacts solely in the US market. The results of this subsidiary are reported in this segment. All contracts that are not designated as hedges are recorded as assets or liabilities at fair value on the consolidated balance sheets with changes in fair value recorded in the revenue of this segment. In addition, the segment includes revenue from real estate rentals and non-regulated services, non-regulated business development activities, and, prior to OPG's decision to decommission the stations, preservation costs related to the former coal-fired Lambton GS and the Nanticoke GS sites.

OM&A expenses of the generation business segments include an inter-segment service fee for the use of certain PP&E and intangible assets held within Service, Trading, and Other Non-Generation segment. The total service fee is recorded as a reduction to the segment's OM&A expenses.

The service fee included in OM&A expenses by segment in 2017 and 2016 was as follows:

(millions of dollars)	**2017**	**2016**
Regulated – Nuclear Generation	**36**	34
Regulated – Hydroelectric	**7**	7
Contracted Generation Portfolio	**4**	4
Reduction to Services, Trading, and Other Non-Generation	**47**	45

Fair Hydro Trust Segment

The Trust was established on December 20, 2017 and was established as a non-generation segment that is not subject to rate regulation. It includes OPG's earnings from the Trust, which includes the financial results of the Trust, as well as revenues and expenses related to OPG's role as Financial Services Manager of the Fair Hydro Trust and holder of subordinated debt issued by the Trust. Revenues include recovery of related to third-party costs and fees for financial management and ongoing administration services. OM&A expenses include incurred third-party and other recoverable incurred costs related to the management and administration of the Trust. Net interest expense (income) include interest income from OPG's investment in subordinated debt of the Trust of up to 49 percent of the Trust's total outstanding debt, partially offset by interest costs on debt issued by OPG to fund five percent of the subordinated investment in the Trust.

The earnings from the Trust is comprised of the following:

For the year ended December 31 *(millions of dollars)*	**2017**
Revenues	**(8)**
OM&A expenses	**8**
Net interest expense (income)	**(1)**
Earnings from Fair Hydro Trust	**(1)**

Segment Income (Loss) for the Year Ended December 31, 2017 *(millions of dollars)*	Nuclear Generation	Regulated Nuclear Waste Management	Hydro-Electric	Unregulated Contracted Generation Portfolio	Unregulated Services, Trading, and Other Non-Generation	Fair Hydro Trust	Elimination	Total
Revenue	**3,095**	**121**	**1,436**	**579**	**43**	**-**	**(116)**	**5,158**
Fuel expense	**284**	**-**	**351**	**53**	**1**	**-**	**-**	**689**
Gross margin	**2,811**	**121**	**1,085**	**526**	**42**	**-**	**(116)**	**4,469**
Operations, maintenance and administration	**2,293**	**129**	**330**	**169**	**18**	**1**	**(116)**	**2,824**
Depreciation and amortization	**431**	**-**	**139**	**79**	**30**	**-**	**-**	**679**
Accretion on fixed asset removal and nuclear waste management liabilities	**-**	**943**	**-**	**9**	**8**	**-**	**-**	**960**
Earnings on nuclear fixed asset removal and nuclear waste management funds	**-**	**(801)**	**-**	**-**	**-**	**-**	**-**	**(801)**
Earnings from Fair Hydro Trust						**(1)**		**(1)**
Income from investments subject to significant influence	**-**	**-**	**-**	**(38)**	**-**	**-**	**-**	**(38)**
Property taxes	**26**	**-**	**1**	**7**	**6**	**-**	**-**	**40**
Other (gains) losses	**4**	**-**	**1**	**-**	**(384)**	**-**	**-**	**(379)**
Income (loss) before interest and income taxes	**57**	**(150)**	**614**	**300**	**364**	**-**	**-**	**1,185**
Net interest expense								**95**
Income before income taxes								**1,090**
Income tax expense								**209**
Net income								**881**

Segment Income (Loss) for the Year Ended December 31, 2016 *(millions of dollars)*	Nuclear Generation	Regulated Nuclear Waste Management	Hydroelectric	Unregulated Contracted Generation Portfolio	Unregulated Services, Trading, and Other Non-Generation	Elimination	Total
Revenue	3,481	138	1,527	573	68	(134)	5,653
Fuel expense	315	-	353	58	1	-	727
Gross margin	3,166	138	1,174	515	67	(134)	4,926
Operations, maintenance and administration	2,210	146	325	178	22	(134)	2,747
Depreciation and amortization	925	-	225	75	32	-	1,257
Accretion on fixed asset removal and nuclear waste management liabilities	-	912	-	9	8	-	929
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(746)	-	-	-	-	(746)
Income from investments to significant influence	-	-	-	(37)	-	-	(37)
Property taxes	26	-	1	7	12	-	46
Restructuring	-	-	-	-	6	-	6
Other (gains) losses	1	-	(19)	1	-	-	(17)
Income (loss) before interest and taxes	4	(174)	642	282	(13)	-	741
Net interest expense							120
Income before income taxes							621
Income tax expense							168
Net income							453

Selected Consolidated Balance Sheet information as at December 31, 2017 *(millions of dollars)*	Regulated		Unregulated				
	Nuclear Gener-ation	Nuclear Waste Manage-ment	Hydro-electric	Contracted Generation Portfolio	Services, Trading, and Other Non-Generation	Fair Hydro Trust	Total
Segment property, plant and equipment in-service, net	**6,167**	**-**	**7,359**	**3,480**	**224**	**-**	**17,230**
Segment construction in progress	**3,839**	**-**	**157**	**78**	**18**	**-**	**4,092**
Segment property, plant and equipment, net	**10,006**	**-**	**7,516**	**3,558**	**242**	**-**	**21,322**
Segment intangible assets in-service, net	**4**	**-**	**1**	**5**	**84**	**-**	**94**
Segment development in progress	**16**	**-**	**-**	**-**	**23**	**-**	**39**
Segment intangible assets, net	**20**	**-**	**1**	**5**	**107**	**-**	**133**
Segment fuel inventory	**265**	**-**	**-**	**44**	**-**	**-**	**309**
Segment materials and supplies inventory, net:							
Current	**102**	**-**	**-**	**1**	**-**	**-**	**103**
Long-term	**351**	**-**	**-**	**4**	**-**	**-**	**355**
Nuclear fixed asset removal and nuclear waste management funds (current and non-current portions)	**-**	**16,724**	**-**	**-**	**-**	**-**	**16,724**
Financing receivables Fair Hydro Trust	**-**	**-**	**-**	**-**	**-**	**1,179**	**1,179**
Fixed asset removal and nuclear waste liabilities	**-**	**(20,077)**	**-**	**(151)**	**(193)**	**-**	**(20,421)**

Selected Consolidated Balance Sheet Information as at December 31, 2016 *(millions of dollars)*	Nuclear Generation	Regulated Nuclear Waste Management	Hydro-electric	Unregulated Contracted Generation Portfolio	Unregulated Services, Trading, and Other Non-Generation	Total
Segment property, plant and equipment in-service, net	5,653	-	7,355	3,282	226	16,516
Segment construction in progress	2,988	-	166	301	27	3,482
Segment property, plant and equipment, net	8,641	-	7,521	3,583	253	19,998
Segment intangible assets in-service, net	7	-	2	4	66	79
Segment development in progress	3	-	-	1	16	20
Segment intangible assets, net	10	-	2	5	82	99
Segment fuel inventory	276	-	-	34	-	310
Segment materials and supplies inventory, net:						
Current	99	-	-	1	-	100
Long-term	340	-	1	4	-	345
Nuclear fixed asset removal and nuclear waste management funds (current and non-current portions)	-	15,984	-	-	-	15,984
Fixed asset removal and nuclear waste management liabilities	-	(19,103)	-	(160)	(221)	(19,484)

Selected Capital Expenditure Information	Regulated			Unregulated			
(millions of dollars)	**Nuclear Generation**	**Nuclear Waste Management**	**Hydro-electric**	**Contracted Generation Portfolio**	**Services, Trading, and Other Non-Generation**	**Fair Hydro Trust**	**Total**
Year ended December 31, 2017							
Investment in property, plant and equipment, and intangible assets	**1,631**	**-**	**148**	**73**	**74**	**-**	**1,926**
Year ended December 31, 2016							
Investment in property, plant and equipment, and intangible assets	1,338	-	132	198	36	-	1,704

Shareholder Declarations and Shareholder Resolutions to Sell Certain Non-Core Real Estate Properties

In December 2015, OPG received a Shareholder Declaration and a Shareholder Resolution requiring the Company to sell its head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street in Toronto, Ontario. The sale was completed in April 2017 with a gain on sale of $283 million, which is net of tax effects of $95 million, recognized in net income during the year ended December 31, 2017. The pre-tax gain on sale was recorded as an item of Other gains in the consolidated statement of income in the Services, Trading and Other Non-Generation segment. Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. The amount of designated proceeds transferred into the Consolidated Revenue Fund will be equal to the after-tax gain on sale. [**MONITOR**] The transfer is expected to take place as early as in the first quarter of 2018, through a special dividend authorized by OPG's Board of Directors in March 2018. **[MONITOR]**

In June 2016, OPG received a Shareholder Declaration and a Shareholder Resolution that requires the Company to sell its former Lakeview GS site located in Mississauga, Ontario. The Lakeview GS site assets were fully depreciated prior to June 2017. OPG entered into a purchase and sale agreement with a purchaser with the sale scheduled to close in March 2018. An estimated after-tax gain on sale of approximately $200 million will be recognized in net income upon completion of the transaction in the first quarter of 2018. **[MONITOR]** Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. In accordance with the Shareholder Resolution, approximately one-third of the site is to be transferred to the City of Mississauga, by the purchaser, for parkland, institutional, and cultural uses. **[MONITOR]**

18. NET CHANGES IN NON-CASH WORKING CAPITAL BALANCES

(millions of dollars)	December 31 2017	2016
Receivables from related parties	**60**	116
Prepaid expenses	**(14)**	(6)
Other current assets [1]	**(28)**	(32)
Fuel inventory	**1**	34
Materials and supplies	**(3)**	(4)
Income taxes payable	**2**	57
Accounts payable and accrued charges	**36**	15
	54	180

[1] Represents other accounts receivable.

19. RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One, the IESO and the OEFC. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly-owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions for the years ended December 31 are summarized below:

(millions of dollars)	2017 Revenue	2017 Expense	2016 Revenue	2016 Expense
Hydro One				
Electricity sales	**8**	**-**	6	-
Services	**1**	**10**	1	5
Dividends	**7**	**-**	6	-
Province of Ontario				
Change in Decommissioning Segregated Fund amount due to Province [1]	**-**	**456**	-	192
Change in Used Fuel Segregated Fund amount due to Province [1]	**-**	**591**	-	235
Hydroelectric gross revenue charge	**-**	**110**	-	120
ONFA guarantee fee	**-**	**8**	-	8
Other	**-**	**2**	-	-
OEFC				
Hydroelectric gross revenue charge	**-**	**216**	-	203
Interest expense on long-term notes	**-**	**158**	-	169
Income taxes, net of investment tax credits	**-**	**246**	-	104
IESO				
Electricity related revenue	**4,802**	**-**	5,082	-
Fair Hydro Trust	**4**	**3**	-	-
	4,822	**1,800**	5,095	1,036

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at December 31, 2017 and December 31, 2016, the Nuclear Segregated Funds were reported net of amounts due to the Province of $4,462 million and $3,415 million, respectively.

The receivable, AFS securities, payable and long-term debt balances between OPG and its related parties are summarized below:

(millions of dollars)	December 31 2017	December 31 2016
Receivables from related parties		
Hydro One	**1**	1
IESO − Electricity related receivables	**354**	421
IESO − Fair Hydro Trust [1]	**7**	-
OEFC	**-**	1
PEC	**4**	4
Province of Ontario	**3**	2
Financing receivables		
IESO − Fair Hydro Trust	**1,179**	-
Available-for-sale securities		
Hydro One shares	**188**	212
Accounts payable and accrued charges		
Hydro One	**1**	-
OEFC	**52**	61
Province of Ontario	**9**	2
IESO − Electricity-related payables	**5**	2
IESO − Fair Hydro Trust	**3**	-
Long-term debt (including current portion)		
Notes payable to OEFC	**3,195**	3,295

[1] Balance consists of unbilled revenue.

OPG holds interest-bearing Province of Ontario bonds in the Nuclear Segregated Funds and the OPG registered pension fund. As at December 31, 2017, the Nuclear Segregated Funds held $1,503 million of interest-bearing Province of Ontario bonds. As at December 31, 2016, the Nuclear Segregated Funds and the registered pension fund held $1,652 million and $284 million of interest-bearing Province of Ontario bonds, respectively. These bonds are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

In December 2017, the Trust purchased its first tranche of Investment Interest from the IESO for an exchange amount of $1.18 billion, which has been classified as a financing receivable on OPG's consolidated balance sheet. The transaction was settled in cash using proceeds from the Trust's issuance of senior and subordinated debt. Pursuant to the general regulation of the Act, the IESO is required to pay and remit carrying costs of the Trust, excluding repayment of principal on any debt obligations, up to July 31, 2021. Commencing May 1, 2021, Specified Consumers will be invoiced by their local distribution company for the Clean Energy Adjustment to pay financing and other costs of the Trust. These funds will be remitted to the Trust through the IESO and will be used to settle all funding and other related expenses of the Trust that underlie the financing receivable.

As at December 31, 2017, OPG's consolidated balance sheet included approximately $7 million of unbilled revenue from the IESO primarily for OPG's general fee for 2017 as Financial Services Manager relating to incurred third-party and certain direct labour costs. In February 2018, OPG submitted to the OEB its proposed general fee for 2017 in the amount of approximately $6 million for review pursuant to the requirements of the general regulation of the Fair Hydro Act. Once approved, the fees will be remitted to the Trust by the IESO and the Trust will pay OPG's fees as Financial Services Manager.

20. INVESTMENTS SUBJECT TO SIGNIFICANT INFLUENCE

Investments subject to significant influence consist of OPG's 50 percent ownership interest in the jointly controlled entities of the PEC gas-fired combined cycle generating station and the Brighton Beach, which are accounted for using the equity method. Details of the balances as at December 31, 2017 and December 31, 2016 are as follows:

(millions of dollars)	**2017**	**2016**
PEC		
Current assets	**20**	18
Long-term assets	**240**	256
Current liabilities	**(10)**	(8)
Long-term liabilities	**(6)**	(5)
Brighton Beach		
Current assets	**5**	5
Long-term assets	**160**	168
Current liabilities	**(17)**	(16)
Long-term liabilities	**(9)**	(7)
Long-term debt	**(74)**	(90)
Investments subject to significant influence	**309**	321

21. RESEARCH AND DEVELOPMENT

For the year ended December 31, 2017, research and development expenses of $106 million (2016 – $95 million) were charged to operations.

22. NON-CONTROLLING INTEREST

PSS Generating Station LP

PSS is a limited partnership between OPG, Coral Rapids Power Corporation (CRP) and PSS Generating Station Inc. (PSS GS Inc.). The principal business of the partnership is the development, construction, ownership, operation and maintenance of the 28 Megawatt (MW) Peter Sutherland Sr. hydroelectric GS on the New Post Creek. OPG and PSS GS Inc. are general partners and CRP is a limited partner in the partnership. CRP is a wholly owned subsidiary of the Taykwa Tagamou Nation.

The Peter Sutherland Sr. GS was placed in-service in March 2017 and, in April 2017, CRP increased its interest in PSS to 33 percent under the partnership agreement, by making contributions of $21 million, reducing OPG's interest to 67 percent. CRP's 33 percent interest in PSS is reported as non-controlling interest. As a result of CRP increasing its interest in the partnership, PSS's AOCL and partner's deficit were proportionately allocated to CRP as a reduction to its non-controlling interest.

Nanticoke Solar LP

In March 2016, Nanticoke Solar LP (NSLP), a partnership between OPG, SunEdison Canadian Construction LP (SECCLP) and a subsidiary of the Six Nations of the Grand River Development Corporation, was selected through IESO's Large Renewal Procurement program to construct a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands. In the first quarter of 2017, OPG acquired all of SECCLP's interests in NSLP, which represented 25 percent of the equity interest in NSLP. Subsequent to the acquisition, OPG owns 90 percent of the equity interest in NSLP, with an approximate value of $2 million. OPG consolidates the results of the NSLP in its consolidated financial statements and reports the equity interest of the other partner as non-controlling interest.

From:	John Kim
To:	Mike Manning; Ken Kandeepan
Cc:	Ronald Kwan; Malle Hanslep (MOF); Tobias P. Whitfield (MOF); Carlos Yep; John Psinas; Shajee Kathirgamanathan
Subject:	OPG Q4 reporting - relevant excerpts for FHP
Date:	Monday, February 26, 2018 11:03:59 AM
Attachments:	Q4 2017 OPG MD&A - DRAFT - Feb 25_230PM_RPT excerpt for Prov.docx Q4 2017 OPG FS Feb 25_230PM_RPT excerpt for Prov.docx

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Hi Mike, Ken,

We have the attached excerpts from OPG's draft Q4. Let me know if you have any comments on the draft wording, as highlighted.

I had shared these with Toby and Malle earlier this morning.

Thanks,

John

Y. John Kim
Director, Electricity Finance Branch
Ontario Financing Authority
e-mail: john.kim@ofina.on.ca
Ph: 416-212-6996

ONTARIO POWER GENERATION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

DECEMBER 31, 2017

[DRAFT]

RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One, the IESO and the OEFC. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly-owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions for the years ended December 31 are summarized below:

	2017		2016	
(millions of dollars)	**Income**	**Expense**	**Income**	**Expense**
Hydro One				
Electricity sales	**8**	**-**	6	-
Services	**1**	**10**	1	5
Dividends	**7**	**-**	6	-
Province of Ontario				
Change in Decommissioning Segregated Fund amount due to Province [1]	**-**	**456**	-	192
Change in Used Fuel Segregated Fund amount due to Province [1]	**-**	**591**	-	235
Hydroelectric gross revenue charge	**-**	**110**	-	120
ONFA guarantee fee	**-**	**8**	-	8
Other	**-**	**2**	-	-
OEFC				
Hydroelectric gross revenue charge	**-**	**216**	-	203
Interest expense on long-term notes	**-**	**158**	-	169
Income taxes, net of investment tax credits	**-**	**246**	-	104
IESO				
Electricity related revenue	**4,802**	**-**	5,082	-
Earnings from Fair Hydro Trust	**1**	**-**	-	-
	4,819	**1,797**	5,095	1,036

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at December 31, 2017 and December 31, 2016, the Nuclear Segregated Funds were reported net of amounts due to the Province of $4,462 million and $3,415 million, respectively.

The receivable, AFS securities, payable and long-term debt balances between OPG and its related parties are summarized below:

(millions of dollars)	December 31 2017	December 31 2016
Receivables from related parties		
Hydro One	**1**	1
IESO – Electricity related receivables	**354**	421
IESO – Fair Hydro Trust [1]	**7**	-
OEFC	**-**	1
PEC	**4**	4
Province of Ontario	**3**	2
Financing receivables		
IESO – Fair Hydro Trust	**1,179**	-
Available-for-sale securities		
Hydro One shares	**188**	212
Accounts payable and accrued charges		
Hydro One	**1**	-
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IESO – Electricity-related payables	**5**	2
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Long-term debt (including current portion)		
Notes payable to OEFC	**3,195**	3,295

[1] Balance consists of unbilled revenue.

OPG holds interest-bearing Province of Ontario bonds in the Nuclear Segregated Funds and the OPG registered pension fund. As at December 31, 2017, the Nuclear Segregated Funds held $1,503 million of interest-bearing Province of Ontario bonds, while the registered pension fund had no such holdings. As at December 31, 2016, the Nuclear Segregated Funds and the registered pension fund held $1,652 million and $284 million of interest-bearing Province of Ontario bonds, respectively. These bonds are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

In December 2017, the Fair Hydro Trust purchased its first tranche of Investment Interest from the IESO for an exchange amount of $1.18 billion, which has been classified as a financing receivable on OPG's consolidated balance sheet. The transaction was settled in cash using proceeds from the Trust's issuance of senior and subordinated debt. Pursuant to the general regulation of the Fair Hydro Act, the IESO is required to pay and remit carrying costs of the Trust, excluding repayment of principal on any debt obligations, up to July 31, 2021. Commencing May 1, 2021, Specified Consumers will be invoiced by their local distribution company for the Clean Energy Adjustment to pay the carrying costs of the Trust. These funds will be remitted to the Trust through the IESO and will be used to settle all funding and other related expenses of the Trust that underlie the financing receivable.

As at December 31, 2017, OPG's consolidated balance sheet included approximately $7 million of unbilled revenue from the IESO, primarily for OPG's general fee for 2017 as the Financial Services Manager under the Act relating to incurred third-party and certain direct labour costs.

Under one of the Trust's program agreements, the Province has provided a limited guarantee to specified creditors in the event that the Trust's ability to receive amounts in respect of its Investment Interest to pay for certain funding obligations is adversely affected due to the occurrence of any one of the following: the Province changes the Fair

Hydro Act or any other legislation or regulation; Ontario's electricity market significantly changes due to actions undertaken by the Province; or the Act is declared invalid or unconstitutional.

ONTARIO POWER GENERATION INC.

CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2017

[DRAFT]

19. RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

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Under one of the Trust's program agreements, the Province has provided a limited guarantee to specified creditors in the event that the Trust's ability to receive amounts in respect of its Investment Interest to pay for certain funding obligations is adversely affected due to the occurrence of any one of the following: the Province changes the Fair

Hydro Act or any other legislation or regulation; Ontario's electricity market significantly changes due to actions undertaken by the Province; or the Act is declared invalid or unconstitutional.

From: Bruno Amara
To: Ronald Kwan
Cc: John Kim
Subject: OPG changes
Date: Thursday, February 15, 2018 7:17:08 PM
Attachments: OPG Comparisons.xlsx

Hi Ron

For what it's worth, I put these tables together to help make more clear the changes in OPG's Outlook when comparing OPG's current 2018-2021 BP to a) 2017 Budget and b) our previous January 2018 Outlook distribution.

Bruno

Bruno Amara
Sr. Manager, Financial and Regulatory Analysis
Electricity Finance Branch
Corporate and Electricity Finance Division
Ontario Financing Authority

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OPG Business Plan 2018-2021

	$ Millions				2017 Budg $ Millions
	2017-18	**2018-19**	**2019-20**	**2020-21**	**2017-18**
Net Income	712	795	1,053	877	480
OPG Headquarters**	283				
OPG Lakeview**	200				
Sub-total	**1,195**	**795**	**1,053**	**877**	**480**
OPG Fair Hydro Plan Amounts	10	80	150	225	17
Sub-total	**1,205**	**875**	**1,203**	**1,102**	**497**
IFRS Adjustment	(400)	(475)	(700)	(750)	(400)
Sub-total	**805**	**400**	**503**	**352**	**97**
PILs					
GRC to OEFC	206	209	212	212	205
Property Tax to OEFC	13	14	14	13	18
Sub-total	**219**	**223**	**226**	**225**	**223**
Income Tax PLs	58	54	175	169	92
OPG Headquarters**	93				74
OPG Lakeview**	70				-
Sub-total	**221**	**54**	**175**	**169**	**166**
Total OPG	**1,245**	**677**	**904**	**746**	**486**

* 2017 Budget is based on OPG 2017-2019 Business Plan. 2020-21 is EFB estimate

** OPG Headquarters and Lakeview amonts were reported in Sales and Rentals at the time of the 2017 Budget

get*

2018-19	2019-20	2020-21
678	726	913
678	**726**	**913**
54	99	153
732	**825**	**1,066**
	(200)	
732	**625**	**1,066**
212	219	220
19	19	19
231	**238**	**239**
135	170	298
135	**170**	**298**
1,098	**1,033**	**1,603**

$ Millions

2017-18	2018-19	2019-20	2020-21
232	117	327	(36)
283	-	-	-
200	-	-	-
715	**117**	**327**	**(36)**
(7)	26	51	72
708	**143**	**378**	**36**
-	(475)	(500)	(750)
708	**(332)**	**(122)**	**(714)**
1	(3)	(7)	(8)
(5)	(5)	(5)	(6)
(4)	**(8)**	**(12)**	**(14)**
(34)	(81)	5	(129)
19	-	-	-
70	-	-	-
55	**(81)**	**5**	**(129)**
759	**(421)**	**(129)**	**(857)**

see change table line 7

OPG Business Plan 2018-2021

	$ Millions					$ Millions
	2017-18	**2018-19**	**2019-20**	**2020-21**		**2017-18**
Net Income	1,037	795	1,053	877		574
OEB Impact*	(325)	na	na	na		(320)
OPG Headquarters**	283					283
OPG Lakeview**	200					
Sub-total	**1,195**	**795**	**1,053**	**877**		**537**
OPG Fair Hydro Plan Amounts	10	80	150	225		12
Sub-total	**1,205**	**875**	**1,203**	**1,102**		**549**
IFRS Adjustment	(400)	(475)	(700)	(750)		(400)
Sub-total	**805**	**400**	**503**	**352**	-	**149**
PILs						
GRC to OEFC	206	209	212	212		214
Property Tax to OEFC	13	14	14	13		18
Sub-total	**219**	**223**	**226**	**225**		**232**
Income Tax PLs	58	54	175	169		67
OPG Headquarters**	-	na	na	na		(107)
OPG Lakeview**	93					95
OPG Lakeview	70					
Sub-total	**221**	**54**	**175**	**169**		**55**
Total OPG	**1,245**	**677**	**904**	**746**		**436**

* OPG Business Plan noted that impavct of deferred effective date was $325M (impact note separated out in pre

** OPG Headquarters and Lakeview amonts were reported in Sales and Rentals at the time of the 2017 Budget.c

lectricty Outlook Distribution

2018-19	2019-20	2020-21
678	726	913
(109)	(115)	(136)
569	**611**	**777**
42	82	128
612	**693**	**906**
(475)	(700)	(750)
137	**(7)**	**156**
224	222	222
19	19	19
243	**241**	**241**
135	170	298
135	**170**	**298**
515	**404**	**695**

$ Millions

2017-18	2018-19	2019-20	2020-21
463	117	327	(36)
(5)			
-	-	-	-
200	-	-	-
658	**226**	**442**	**100**
(2)	38	68	97
656	**263**	**510**	**196**
-	-	-	-
656	**263**	**510**	**196**
(8)	(15)	(10)	(10)
(5)	(5)	(5)	(6)
(13)	**(20)**	**(15)**	**(16)**
(9)	(81)	5	(129)
107			
(2)	-	-	-
70	-	-	-
166	**(81)**	**5**	**(129)**
809	**162**	**500**	**51**

see change table line 7

evious table)

distribution included OPG Headquarters but not Lakeview.

7

From: Bruno Amara
To: Ronald Kwan
Cc: John Kim; Esther Jeon
Subject: OPG results
Date: Tuesday, May 15, 2018 5:47:46 PM
Attachments: OPG Quarterly Update Q1_v6.docx
OPG Quarterly Update Q1_v6-clean.docx

Hi Ron

OPG released Q1 late this afternoon. Attached is the quarterly summary note. Results were unchanged from the draft provided by OPG earlier. We will review again tomorrow morning.

S:\Users\CEF\Hydro 2018\OPG\Financials\Q1\Summary Update

Hydro One files saved

S:\Users\CEF\Hydro 2018\Hydro One\Financials\Financial Statements\Q1 - 2018
S:\Users\CEF\Hydro 2018\CINs\Hydro One Financials Q1 2018 update

Bruno

Bruno Amara
Sr. Manager, Financial and Regulatory Analysis
Electricity Finance Branch
Corporate and Electricity Finance Division
Ontario Financing Authority

Tel: 416-325-1489
Email: bruno.amara@ofina.on.ca

ONTARIO POWER GENERATION INC: First Quarter 2018 Update

OPG QUARTERLY NET INCOME: 2017-18 AND 2016-17~~YEAR-OVER-YEAR CHANGES~~

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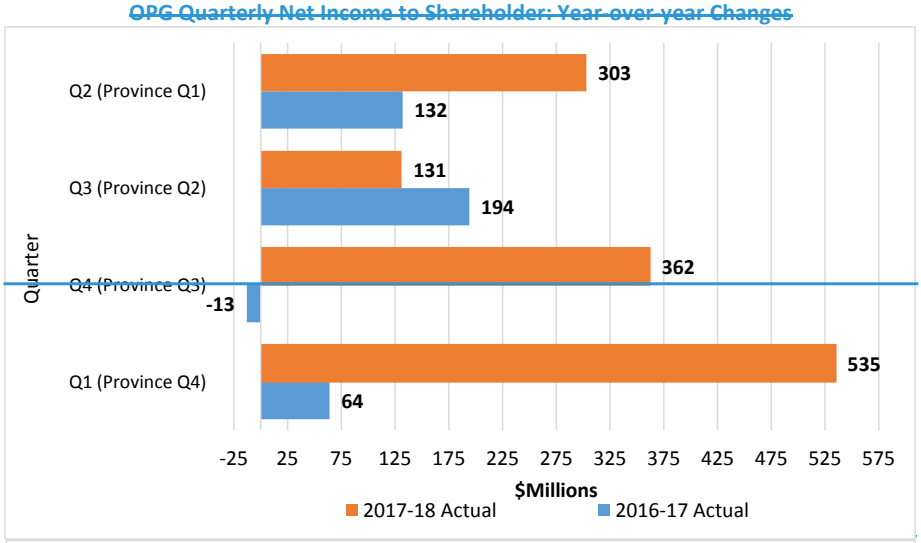
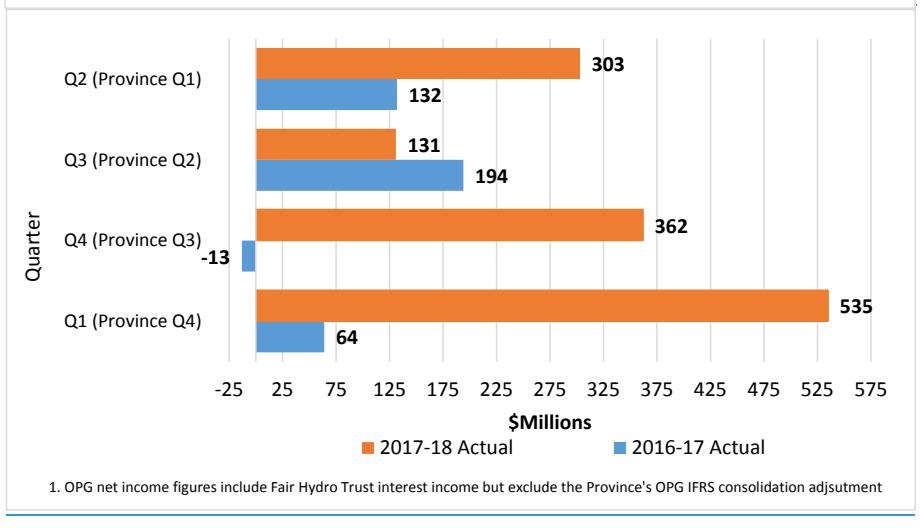
~~OPG Quarterly Net Income to Shareholder: Year-over-year Changes~~





1. OPG net income figures include Fair Hydro Trust interest income but exclude the Province's OPG IFRS consolidation adjsutment

FIRST QUARTER (PROVINCE Q4): YEAR-OVER-YEAR CHANGES

Net income attributable to the Shareholder for the first quarter was $535 million, which is an increase of

$471 million for the same quarter in 2017.

SIGNIFICANT FACTORS THAT INCREASED NET INCOME

- A pre-tax gain of $273 million on the sale of the former Lakeview GS site.
- Higher revenue from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments (approximately $210 million) recorded in the first quarter of 2018 reflecting the impact of the OEB's December 2017 decision and March 2018 payment amounts order on OPG's application for new regulated prices.
- Higher revenues due to higher electricity generation from the Regulated – Nuclear Generation segment
- Higher earnings from the Regulated – Nuclear Waste Management segment (approximately $14 million), primarily due to higher earnings from the Nuclear Segregated Funds, partially offset by an increase in accretion expense on the Nuclear Liabilities.

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SIGNIFICANT FACTORS THAT REDUCED NET INCOME

- Higher depreciation and amortization expense, due to higher amount of depreciation expense deffeerred in regulatory variance and deferral accounts in Q1 of 2017
- Higher OM&A expenses mainly in the Regulated – Nuclear Generation segment, due to higher services and materials costs associated with planned outages at the nuclear stations.

PROVINCIAL FISCAL YEAR ~~TO DATE~~: 2017-18 Actual vs. 2018 Budget Interim and 2017 Budget Plan~~YEAR-OVER-YEAR CHANGES~~

OPG net income increased by $954 million in the Province's 2017-18 fiscal year, from $377 millio~~0~~n in 2016-17 to $1,331 million in 2017-18.

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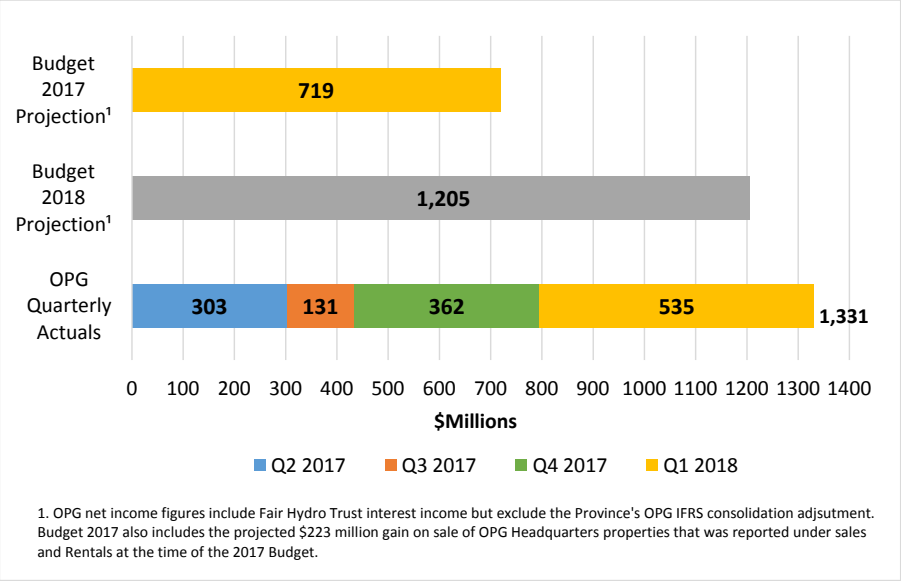
Factors contributing to the year-over-year increase included:

- ~~compared to the same period a year ago.~~
- Gains T~~Increase was also largely due to the higher than projected gain~~ on sale of OPG's head office and parking facilities during Q2 2017 and ~~the sale of their~~ Lakeview GS property in the first quarter of 2018 boosted net income by $488 million.
- H~~he increase was due to h~~igher revenue from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments which reflecteds~~d~~ the OEB's decision on OPG's application for new regulated rates issued in December 2017 with a retrospective effective date of June 1, 2017~~.~~
- ~~Increase was also largely due to the higher than projected gain on sale of OPG's head office and parking facilities during Q2 2017 and the sale of their Lakeview GS property in the first quarter of 2018~~
- Higher earnings ~~were also obtained~~ from the Regulated – Nuclear Waste Management segment, due to higher earnings from the n~~nuclear fixed asset removal and nuclear waste management funds (N~~uclear s~~S~~egregated f~~F~~unds~~)~~, partially offset by an increase in accretion expense on the ~~nuclear fixed asset removal and nuclear waste management liabilities (n~~Nuclear l~~L~~iabilities).

OPG ACTUALS VS. 2018 ~~and~~ & 2017 BUDGETS



1. OPG net income figures include Fair Hydro Trust interest income but exclude the Province's OPG IFRS consolidation adjsutment. Budget 2017 also includes the projected $223 million gain on sale of OPG Headquarters properties that was reported under sales and Rentals at the time of the 2017 Budget.

1. This number is not the adjusted net income value which takes into account of 'Extraordinary Gains', 'GA-OPG Trust Interest Revenue', and 'OPG IFRS consolidation risk picked up in Fiscal Plan~~.~~.

OPG's 2017-18 net income of $1,331 million is $126 million above the Interim Actual projection at the time of the 2017 Budget.

Factors contributing to the increase over Interim Actual include:

- higher nuclear generation performance than plan in the first quarter of 2018 (approx. 1 TWh), lower OM&A costs mainly due to timing of expenditures, and increased electricity trading margins in January 2018.

OPG's ~~has a~~ 2017-18 net income ~~attributable to shareholder~~ of $1,331 million ~~which~~ is $6122~~9~~ million above the ~~projection at the time of the~~ 2017 Budget Plan projection of $719 million.

Factors contributing to the increase over the Budget 2017 Plan include:

- H~~The increase is largely due to the h~~igher-than-projected gain on sale of OPG's head office and parking facilities during Q2 2017 and the sale of their Lakeview GS property during Q1 of 2018 increased net income by $265 million
- ~~The increase is also due to higher revenues from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments reflecting the impact of the OEB's December 2017 decision and March 2018 payment amounts order on OPG's application for new regulated prices.~~
- Higher than actual production in 2017 compared to Plan

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Commented [BA1]: $50.7/Mwh actual vs %$54.7/Mwh Plan.
(+ provisional expense)

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Commented [BA2]: This is correct for YOY, but Budget 2017 would have reflected OPG's submission, so OEB decision if anything would have a negative impact.

Commented [BA3]: ($73.8 Twh actual vs $72.5 Twh Plan

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- Lower expense in 2017 compared to plan, including lower total generating costs per megawatt hour.

Commented [BA4]: $50.7/Mwh actual vs %$54.7/Mwh Plan.
(+ provisional expense)

GENERATION DEVELOPMENT PROJECT UPDATES

Project	Important Updates
Darlington Refurbishment	• The Unit 2 refurbishment has transitioned into the third major segment, the installation and reassembly of reactor components, including new feeder tubes and fuel channel assemblies. • Construction activities on the Heavy Water Storage and Drum Handling Facility are also continuing. • In February 2018, the Province confirmed its commitment to proceed with Darlington's Unit 3 refurbishment in 2020. • In March 2018, OPG's Board of Directors approved the funding to complete planning and prerequisite activities for the Unit 3 refurbishment. • Planning activities for the Unit 3 refurbishment are progressing in accordance with the overall project schedule. • Prerequisite activities for Unit 3 refurbishment have commenced, with the Unit 3 refurbishment execution expected to commence upon the return to service of Unit 2. As of March 31, 2018, $137 million has been invested in planning and prerequisite activities related to the Unit 3 refurbishment. • Overall Darlington Refurbishment project continues to track on budget
Ranney Falls Hydroelectric GS	• Project is tracking on schedule and on budget • Expected in-service date to be fourth quarter of 2019, with a budget of $77 million.
Nanticoke Solar Facility	• Significant contracts for equipment and engineering construction services were executed in the first quarter of 2018 • Expected to be completed in first quarter of 2019, with a budget of $107 million.

FINANCING ACTIVITIES

As at March 31, 2018, OPG's long-term debt outstanding was $6,896 million, including $263 million due within one year and including the Fair Hydro Trust's senior debt reported on OPG's interim consolidated balance sheets. This included $1,400 million outstanding under OPG's $2,350 million general corporate credit facility agreement with the OEFC that expires on December 31, 2018. The Fair Hydro Trust's senior debt outstanding was $836 million as at March 31, 2018.	
Relevant to OEFC	• In June 2016, OPG entered into a $700 million general corporate credit facility agreement with the OEFC, which expires on December 31, 2017. • In the third quarter of 2017, the agreement was amended to increase the credit facility to $2,350 million and to extend its expiry date to December 31, 2018. • As at December 31, 2017, there were outstanding long-term borrowings of $800 million under this credit facility. • During the first quarter of 2018, OPG issued a total of $600 million senior notes payable to OEFC maturing in 2048.
Fair Hydro Trust (for Fair Hydro Plan)	• In December 2017, the Fair Hydro Trust entered into an $800 million revolving warehouse facility agreement with an expiry date of December 21, 2019. As at December 31, 2017, there were outstanding senior notes of $601 million under this credit facility, which were used to finance 51% of the Trust's funding requirement for the acquisition of the first tranche of Investment Interest from the IESO. The Province provided an additional $519 million for this acquisition through an equity injection in OPG. • As at March 31, 2018, there were outstanding senior notes of $336 million under this credit facility, $235 million of which was used to finance 51 percent of the Trust's funding requirement for the acquisition of the Investment Interest from the IESO in March 2018 in the amount of $460 million. • An additional $76 million was issued under the credit facility in April 2018 to finance fifty-one percent of the Trust's funding requirement for the acquisition of the Investment Interest from the IESO in April 2018 in the amount of $149 million. • In February 2018, the Trust issued $500 million of senior notes payable with a coupon interest rate of 3.36% and an effective interest rate of 3.44%, payable semi-annually until maturity on May 15, 2033. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility issued by the Trust in December 2017.

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	• In April 2018, the Trust issued $400 million of senior notes payable with a coupon interest rate of 3.52 percent and an effective interest rate of 3.60 percent, payable semi-annually until maturity in May 2038. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility after the Investment Interest acquisition in April 2018. Following this repayment, the facility had $12 million outstanding.

ADDITIONAL ~~IMPORTANT~~ INFORMATION

OPG Motion to Review OEB ~~'s~~ December 28, 2017 decision with respect to June 1, 2017 effective date ~~Payment Amounts Order on OPG's Application for New Regulated Prices~~

- The OEB's decision on OPG's May 2016 five-year application for new regulated prices for nuclear and regulated hydroelectric generation was issued on December 28, 2017, with an effective date for the new regulated prices of June 1, 2017 rather than January 1, 2017 as requested in OPG's rate application.
- The impact to net income of the later effective date is estimated at $300 million.
- OEB's main reasons for not approving this were:
    1. OEB stated OPG should have filed their application earlier knowing how complex the application would be, and
    2. OEB wished to balance the revenue requirement needs of OPG with rate certainty expected by ratepayers.
- On January 17, 2018 OPG filed a Notice of Motion to Review and Vary the OEB decision arguing that there were material errors in OEB's findings on the effective date for the decision. OPG presented four main arguments:
    1. Final payment amounts for January 1 to May 31, 2017 are not just and reasonable
    2. It is incorrect to balance revenue requirement with ratepayer expectation of rate certainty
    3. The procedural standard applied to OPG's application was not previously articulated and is impossible to meet
    4. The attribution of fault to OPG for procedural delays is contrary to facts in the proceeding
- On March 16, 2018 OEB staff made a submission regarding OPG's Notice of Motion to Review. This was followed by an OPG oral hearing on April 10, 2018 in which they responded to OEB staff comments and restated their arguments of material errors in OEB's findings on the effective date for the decision
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~~-~~

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A decision on OPG's Motion to Review is expected is by Fall 2018.

- To reflect management's best estimate of the impact of the OEB's decision, in the fourth quarter of 2017, OPG recorded incremental net revenue for the June 1, 2017 to December 31, 2017 interim period based on the draft payment amounts order.
- The revenue was recorded as an increase in regulatory assets for the June 1, 2017 to December 31, 2017 interim period revenue shortfall based on proposed new regulated prices, net of a regulatory liability for the Rate Smoothing Deferral Account.
- On March 29, 2018, the OEB issued the final payment amounts order establishing new regulated prices for OPG's regulated facilities, with an implementation date of March 1, 2018. For the regulated hydroelectric facilities, the OEB approved the base regulated prices as calculated by OPG in the draft payment amounts order it submitted to the OEB on January 17, 2018.
- For the nuclear facilities, the OEB approved the 2017-2021 revenue requirements as submitted by OPG in the draft payment amounts order, with minor adjustments.
- The OEB's adjustments to OPG's rate smoothing proposal and resulting nuclear base regulated prices in the final payment amounts order resulted in a partial reversal of the regulatory asset for the June 1, 2017 to December 31, 2017 interim period revenue shortfall recorded in the fourth quarter of 2017, largely offset by the reversal of the regulatory liability for the Rate Smoothing Deferral Account recorded in the fourth quarter of 2017. Taken together, these reversals did not have a material impact on the results of operations for the first quarter of 2018.
- In addition, for the period from March 1, 2018 to December 31, 2020, the final payment amounts order authorized interim period shortfall riders to collect the revenue shortfall for the June 1, 2017 to February 28, 2018 period based on the newly approved base regulated prices.
- As the interim period shortfall riders and the variance and deferral account riders will collect amounts previously recorded as regulatory assets, they will contribute to improved cash flow from operations but are not expected to have a material impact on net income.

Ontario's Fair Hydro Plan (Fair Hydro Trust)

- Pursuant to the Fair Hydro Act, effective May 1, 2017, the IESO began to defer a portion of the Global Adjustment costs. The Act allows the IESO to transfer a portion of the deferred balance to a financing entity that would fund the deferral in exchange for an irrevocable right to recover the balance and associated financing and other costs from Specified Consumers in the future ("Investment Interest").
- OPG as the Financial Services Manager under the Act created one or more financing entities that may acquire the Investment Interests from the IESO.
- In November 2017, OPG's Board of Directors provided its final approval regarding OPG's involvement with the Fair Hydro Trust on commercial terms. The Fair Hydro Trust was established as the financing entity contemplated by the Act in December 2017. The majority unitholder and beneficiary of the Trust is a wholly owned subsidiary of OPG.
- The Trust is structured to be bankruptcy remote and ring fenced from OPG to protect the Company's assets and operations. [Note: A bankruptcy remote company is a company within a corporate group whose bankruptcy has as little economic impact as possible on other entities within the group. A bankruptcy

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Commented [BA5]: Do we need background material in a current update product?

~~remote company is often a single-purpose entity. A **ring fence** is meant to protect the assets from inclusion in an investor's calculable net worth or to lower tax consequences.]~~

- ~~In order for the Trust to finance the Investment Interest acquired from the IESO, it will incur senior debt from capital markets and subordinated debt from OPG.~~
- ~~With every issuance of the Trust's senior notes, it is expected that OPG will purchase subordinated debt of the Trust in an aggregate amount not to exceed 49% of the Trust's total outstanding debt, with 44% of the funding to be provided by the Province through equity injections and 5% to be provided by OPG. The subordination level may vary over time, but must at least equal to, or be greater than 35% of all outstanding debt.~~

~~FHP Financing Activities in the First Quarter of 2018~~

Commented [BA6]: is this not covered in financing box above?

- ~~In March 2018 and April 2018, the Trust purchased Investment Interests from the IESO in the amount of $460 million and $149 million, respectively.~~
- ~~51% of the funding requirements for each acquisition (approximately $311M) was financed by the Trust through a revolving warehouse facility ranked as senior notes, and the remaining 49% totalling approximately ($298M) was funded through the following sources:~~
  - ~~the Province provided 44% of the funding requirements for each acquisition (total of $268M), through an equity injection in OPG in exchange for approximately 6.1 million non-voting Class A shares at a price of $43.74/share~~
  - ~~OPG provided 5% of the funding requirements, or $30M.~~
- ~~Earnings from Fair Hydro Trust were $4M during the Q1 of 2018, primarily due to net interest income for the period.~~

Regulatory Treatment of Pension and OPEB Costs (Regulatory Risk Factor)

- On September 14, 2017, the OEB issued its final report on the guiding principles and the policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the electricity and natural gas sectors.
- The report requires OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the Pension & OPEB Cash Versus Accrual Differential Deferral Account that has been in effect since November 1, 2014, until such time as the OEB approves the resumption of the accrual basis of recovery. The future recovery of amounts recorded in the account will be subject to this approval.
- The OEB's September 2017 report and the OEB's December 2017 decision on OPG's application for new regulated prices require OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the Pension & OPEB Cash to Accrual Differential Deferral Account in effect since November 1, 2014, until such time as the OEB approves resumption of the accrual basis of recovery for OPG. The future recovery of amounts recorded in the account will be subject to this approval. The OEB's report did not impact OPG's financial results for the year ended December 31, 2017.
- The Company recognizes the amount set aside in the Pension & OPEB Cash Versus Accrual Differential Deferral Account as a regulatory asset. As at December 31, 2017, the regulatory asset had a balance of $614 million.
- Consistent with the OEB's December 2017 decision, later in 2018, OPG plans to file an application with the OEB requesting disposition of the Pension & OPEB Cash Versus Accrual Differential Deferral Account balance as at December 31, 2017 and the balances accumulated between December 31, 2015 and December 31, 2017 in other variance and deferral account balances. If approved by the OEB, recovery of these balances would contribute to improved cash flow from operations.

~~Shareholder Declarations and Shareholder Resolutions to~~ Sale of ~~all Certain~~ Non-Core Real Estate Properties

Head Office Sale Update

- In April 2017, OPG completed the sale of its head office and had a gain on sale of $283 million, which is net of tax effects of $95 million.
- OPG was required to transfer the proceeds from this disposition, net of prescribed deductions under the Trillium Trust Act, into the Province's Consolidated Revenue Fund
- In accordance with these requirements, a special dividend of $283 million was authorized by OPG's Board of Directors and transferred into the Consolidated Revenue Fund in March 2018.

Lakeview Site Sale Update

- ~~In June 2016, OPG received a Shareholder Declaration and a Shareholder Resolution that requires the Company to sell its former Lakeview GS site located in Mississauga, Ontario.~~
- In March 2018, OPG completed the sale of its former Lakeview GS site property located in Mississauga, Ontario, with an after-tax gain on sale of $205 million recognized in net income in the first quarter of 2018.
- OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Trillium Trust Act, into the Province's Consolidated Revenue Fund.
- OPG expects that the amount of designated proceeds to be transferred into the Consolidated Revenue Fund will be largely consistent with the after-tax gain on sale, and is working with the Ontario Ministry of Finance to finalize the amount.

Canadian Nuclear Safety Commission Safety Rating for the Pickering GS

- A Notice of Public Hearing was released by the CNSC in September 2017, to consider OPG's application to renew their "Nuclear Power Reactor Operating License for the Pickering Nuclear Generating Station" license. The hearing will be in two parts where Part 1 was on April 4, 2018 and Part 2 is in June 26-28, 2018
- Based on the evidence and documentation submitted to the CNSC, OPG is confident in obtaining a licence renewal that would support its extended operations plan for Pickering GS.
- OPG's current five-year operating licence for the Pickering GS was approved by the CNSC in 2013 and expires on August 31, 2018. This current licence was issued assuming that the station would shut down in 2020.
- The 2017 Long Term Energy Plan (LTEP) also recognized the value to customers of continuing to operate the Pickering GS until 2024, as planned.
- In 2016, OPG submitted applications with the CNSC seeking a ten-year licence renewal for the Pickering Waste Management Facility (PWMF) to August 31, 2028. On February 7, 2018, following public hearings in April 2017, the CNSC announced that the PWMF licence was renewed for a ten-year period and will be valid until August 31, 2028.

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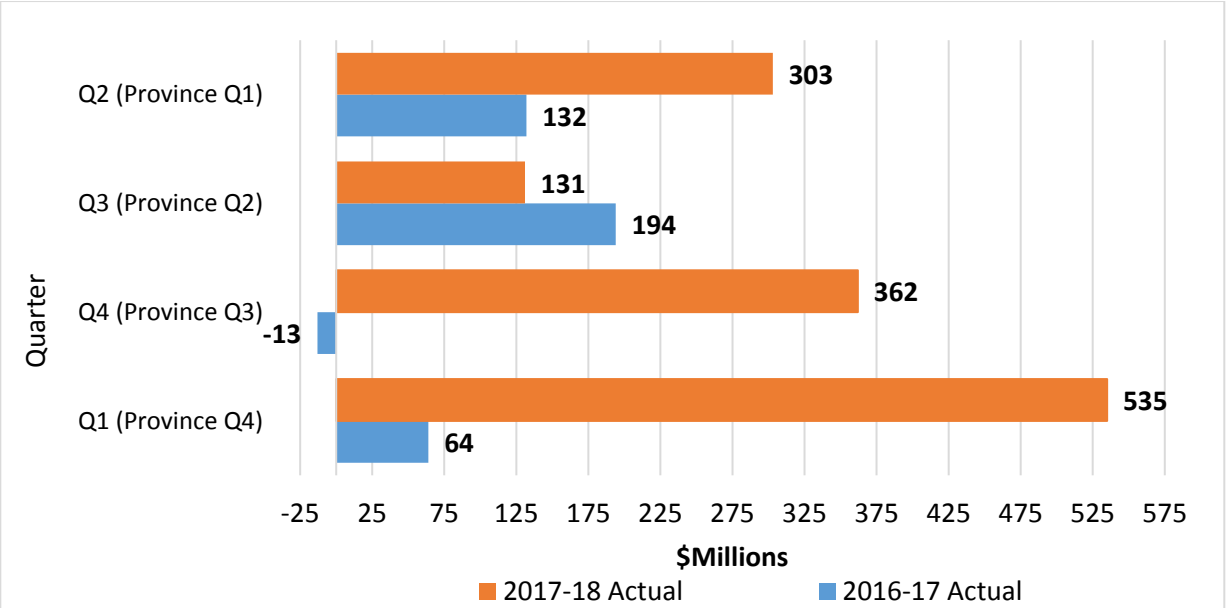
Electricity Finance Branch
Corporate Electricity Finance Division
May 15, 2018

ONTARIO POWER GENERATION INC: First Quarter 2018 Update

OPG QUARTERLY NET INCOME: 2017-18 AND 2016-17



1. OPG net income figures include Fair Hydro Trust interest income but exclude the Province's OPG IFRS consolidation adjsutment

FIRST QUARTER (PROVINCE Q4): YEAR-OVER-YEAR CHANGES

Net income attributable to the Shareholder for the first quarter was $535 million, which is an increase of $471 million for the same quarter in 2017.

SIGNIFICANT FACTORS THAT INCREASED NET INCOME

- A pre-tax gain of $273 million on the sale of the former Lakeview GS site.
- Higher revenue from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments (approximately $210 million) recorded in the first quarter of 2018 reflecting the impact of the OEB's December 2017 decision and March 2018 payment amounts order on OPG's application for new regulated prices.
- Higher revenues due to higher electricity generation from the Regulated – Nuclear Generation segment
- Higher earnings from the Regulated – Nuclear Waste Management segment (approximately $14 million), primarily due to higher earnings from the Nuclear Segregated Funds, partially offset by an increase in accretion expense on the Nuclear Liabilities.

SIGNIFICANT FACTORS THAT REDUCED NET INCOME

- Higher depreciation and amortization expense, due to higher amount of depreciation expense deferred in regulatory variance and deferral accounts in Q1 of 2017
- Higher OM&A expenses mainly in the Regulated – Nuclear Generation segment, due to higher services and materials costs associated with planned outages at the nuclear stations.

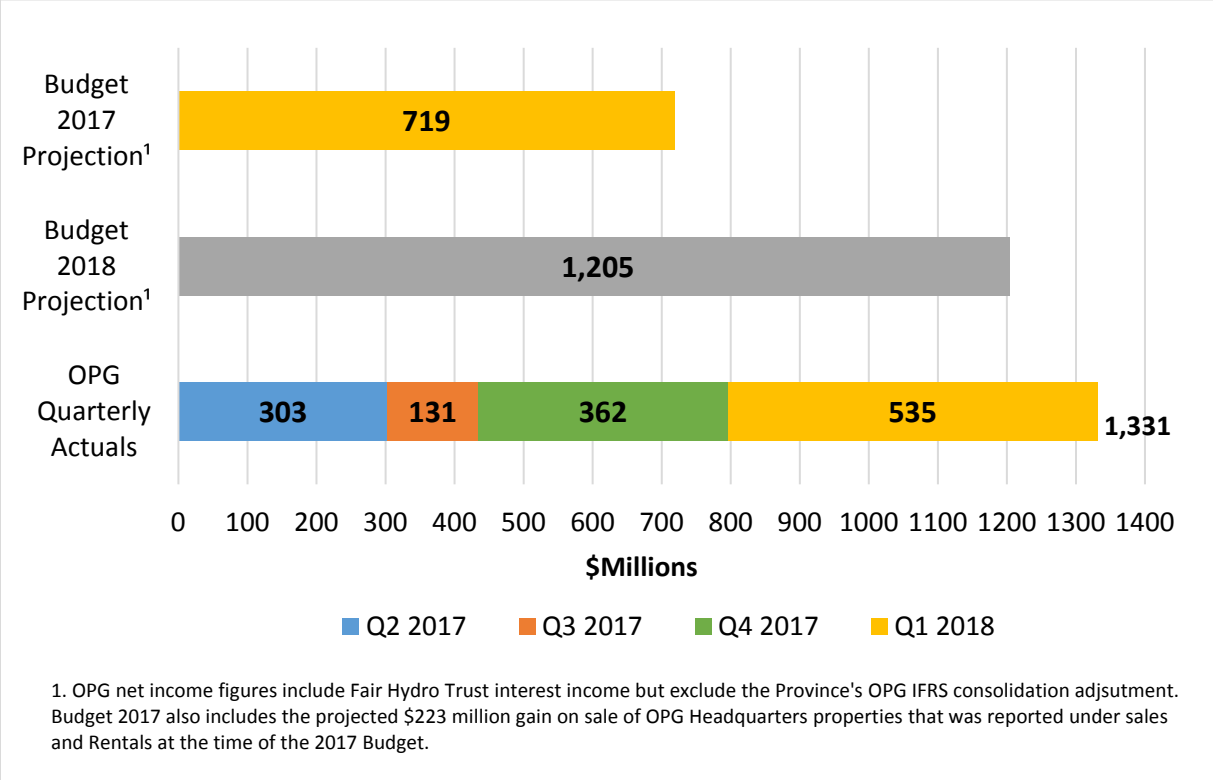
PROVINCIAL FISCAL YEAR: 2017-18 Actual vs. 2018 Budget Interim and 2017 Budget Plan

OPG net income increased by $954 million in the Province's 2017-18 fiscal year, from $377 million in 2016-17 to $1,331 million in 2017-18.

Factors contributing to the year-over-year increase included:

- Gains on sale of OPG's head office and parking facilities during Q2 2017 and Lakeview GS property in the first quarter of 2018 boosted net income by $488 million.
- Higher revenue from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments which reflected the OEB's decision on OPG's application for new regulated rates issued in December 2017 with a retrospective effective date of June 1, 2017
- Higher earnings from the Regulated – Nuclear Waste Management segment, due to higher earnings from the nuclear segregated funds, partially offset by an increase in accretion expense on the nuclear liabilities).

OPG ACTUALS VS. 2018 & 2017 BUDGETS



1. OPG net income figures include Fair Hydro Trust interest income but exclude the Province's OPG IFRS consolidation adjsutment. Budget 2017 also includes the projected $223 million gain on sale of OPG Headquarters properties that was reported under sales and Rentals at the time of the 2017 Budget.

OPG's 2017-18 net income of $1,331 million is $126 million above the Interim Actual projection at the time of the 2017 Budget.

Factors contributing to the increase over Interim Actual include:

- higher nuclear generation performance than plan in the first quarter of 2018 (approx. 1 TWh), lower OM&A costs mainly due to timing of expenditures, and increased electricity trading margins in January 2018.

OPG's 2017-18 net income of $1,331 million is $612 million above the 2017 Budget Plan projection of $719 million.

Factors contributing to the increase over the Budget 2017 Plan include:

- Higher-than-projected gain on sale of OPG's head office and parking facilities during Q2 2017 and the sale of their Lakeview GS property during Q1 of 2018 increased net income by $265 million
- Higher than actual production in 2017 compared to Plan
- Lower expense in 2017 compared to plan, including lower total generating costs per megawatt hour.

GENERATION DEVELOPMENT PROJECT UPDATES

Project	Important Updates
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ADDITIONAL INFORMATION

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2017 in other variance and deferral account balances. If approved by the OEB, recovery of these balances would contribute to improved cash flow from operations.

Sale of Non-Core Real Estate Properties

Head Office Sale Update

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Canadian Nuclear Safety Commission Safety Rating for the Pickering GS

- A Notice of Public Hearing was released by the CNSC in September 2017, to consider OPG's application to renew their "Nuclear Power Reactor Operating License for the Pickering Nuclear Generating Station" license. The hearing will be in two parts where Part 1 was on April 4, 2018 and Part 2 is in June 26-28, 2018
- Based on the evidence and documentation submitted to the CNSC, OPG is confident in obtaining a licence renewal that would support its extended operations plan for Pickering GS.
- OPG's current five-year operating licence for the Pickering GS was approved by the CNSC in 2013 and expires on August 31, 2018. This current licence was issued assuming that the station would shut down in 2020.
- The 2017 Long Term Energy Plan (LTEP) also recognized the value to customers of continuing to operate the Pickering GS until 2024, as planned.
- In 2016, OPG submitted applications with the CNSC seeking a ten-year licence renewal for the Pickering Waste Management Facility (PWMF) to August 31, 2028. On February 7, 2018, following public hearings in April 2017, the CNSC announced that the PWMF licence was renewed for a ten-year period and will be valid until August 31, 2028.

Electricity Finance Branch
Corporate Electricity Finance Division
May 15, 2018

From:	Bruno Amara
To:	Ronald Kwan; John Kim
Subject:	Outlook and PRRT
Date:	Thursday, February 22, 2018 5:42:34 PM
Attachments:	Electricity Sector Outlook (2018 02 22)_v03.xlsm Revised_2018-19 PRRT - Program Note_EFB_ Wrap Up 2 update 2018022 (CPFB edit).docx

Hi Ron, John

We revised the Electricity Outlook based on the updated IFRS impacts. Versus previous this revised IFRS increased OPG net income and ESDI by $100M, 100, 225, 325 starting in (Added a vs Previous panel to the Cover Sheet line 97). The explanation for OPG changes from Budget is also updated.

CQSD had also requested that we updated the PRRT note to be consistent with the electricity update. We had already sent a DRAFT to CQSD to review. This is also attached.

The only further update now would be NUGs. TBS/OB had asked for numbers (not just electricity) to be finalized as of tomorrow to prepare for weekend meetings.

Thanks
Bruno

Bruno Amara
Sr. Manager, Financial and Regulatory Analysis
Electricity Finance Branch
Corporate and Electricity Finance Division
Ontario Financing Authority

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Electricity Sector Outlook
February 2018

Disclosure:

All information contained in this workbook is confidential and commercially sensitive

All projected numbers are estimates and subjected to change

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Please consult with OFA before sharing of information.

Commercially Sensitive and Confidential Advice to Cabinet for Consideration of Options for Discussion Purposes Only

Commercially Sensitive and Confidential Advice to Cabinet for Consideration of Options for Discussion Purposes Only

Electricity Sector Outlook
Including Line Items for Consolidation

Electricity Summary - On Deck

February 2018

			MOF Expense Items (consolidated)	**Current Outlook**			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**38**	Power Supply Contract Costs	(182)	(183)	(134)	(103)
Expense	**MOF (OEFC)**	**40**	Demand Management Support Costs	(10)	-	-	-
Expense	**MOF (OEFC)**	**41**	Provision for Electricity Sector	797	449	736	711
Expense	**MOF**	**17**	Provision for Electricity Sector	(797)	(449)	(736)	(711)
Expense	**MOF (OEFC)**	**42**	Other (Finance)	(6)	(7)	(7)	(7)
			Total MOF Expense	**(198)**	**(190)**	**(141)**	**(110)**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**7**	OPG Income	905	500	728	677
Revenue	**ENE**	**8**	OPG - ONFA and other Fair Value Adjustments	194	-	-	-
Revenue	**ENE**	**10**	HOI Income	346	353	412	438
Revenue		**11**	Brampton Income	-	-	-	-
Revenue	**MOF (OEFC)**	**26**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	499	387	531	535
Revenue	**MOF (OEFC)**	**29**	Electricity Debt Retirement Charge	604	-	-	-
Revenue	**MOF (OEFC)**	**30**	Power Supply Contract Recoveries	182	183	134	103
Revenue	**MOF (OEFC)**	**31**	Net Reduction of Power Purchase Contracts	74	41	30	28
Revenue	**MOF (OEFC)**	**34**	Miscellaneous	-	-	-	-
			Total MOF Revenue	**2,804**	**1,463**	**1,835**	**1,781**
			OFA IOD Expense				
			Public Debt Interest - Electricity Sector	(454)	(404)	(404)	(404)
			Interest on Debt	(477)	(484)	(473)	(402)
			Total OFA IOD Expense	**(931)**	**(888)**	**(877)**	**(806)**
			Impact on Surplus/Deficit	**1,675**	**386**	**817**	**865**
			check	***(0)***	***(0)***	***(0)***	***(0)***

Electricity Summary - Budget 17

For Discussion			MOF Expense Items (consolidated)	Plan			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**38**	Power Supply Contract Costs	(292)	(325)	(301)	(273)
Expense	**MOF (OEFC)**	**40**	Demand Management Support Costs	(10)	0	0	0
Expense	**MOF (OEFC)**	**41**	Provision for Electricity Sector	125	0	0	0
Expense	**MOF**	**17**	Provision for Electricity Sector	(125)	0	0	0
Expense	**MOF (OEFC)**	**42**	Other (Finance)	(6)	(6)	(6)	(6)
			Total MOF Expense	**(308)**	**(331)**	**(307)**	**(279)**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**7**	OPG Income	97	732	625	1,066
Revenue	**ENE**	**8**	OPG - ONFA and other Fair Value Adjustments	0	0	0	0
Revenue	**ENE**	**10**	HOI Income	520	562	603	652
			Brampton Income				
Revenue	**MOF (OEFC)**	**25**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	405	476	538	679
Revenue	**MOF (OEFC)**	**29**	Electricity Debt Retirement Charge	623	0	0	0
Revenue	**MOF (OEFC)**	**30**	Power Supply Contract Recoveries	292	325	301	273
Revenue	**MOF (OEFC)**	**31**	Net Reduction of Power Purchase Contracts	74	41	30	28
Revenue	**MOF (OEFC)**	**34**	Miscellaneous	0	0	0	0
			Total MOF Revenue	**2,011**	**2,136**	**2,098**	**2,697**
			OFA IOD Expense				
		17	Public Debt Interest - Electricity Sector	(492)	(492)	(492)	(492)
		36	Interest on Debt	(422)	(374)	(342)	(250)
			Total OFA IOD Expense	**(914)**	**(866)**	**(834)**	**(742)**
			Impact on Surplus/Deficit	**789**	**939**	**957**	**1,676**
			check	**-**	**-**	**-**	**-**

Electricity Summary - Change

			MOF Expense Items (consolidated)	Variance from Plan			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**69**	Power Supply Contract Costs	110	142	167	170
Expense	**MOF (OEFC)**	**71**	Demand Management Support Costs	0	0	0	0
Expense	**MOF (OEFC)**	**72**	Provision for Electricity Sector	672	449	736	711
Expense	**MOF**	**48**	Provision for Electricity Sector	(672)	(449)	(736)	(711)
Expense	**MOF (OEFC)**	**73**	Other (Finance)	0	(1)	(1)	(1)
			Total MOF Expense	**110**	**141**	**166**	**169**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**38**	OPG Income	808	(232)	103	(389)
Revenue	**ENE**	**39**	OPG - ONFA and other Fair Value Adjustments	194	0	0	0
Revenue	**ENE**	**41**	HOI Income	(173)	(209)	(191)	(214)
			Brampton Income	0	0	0	0
Revenue	**MOF (OEFC)**	**25**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	93	(89)	(7)	(143)
Revenue	**MOF (OEFC)**	**60**	Electricity Debt Retirement Charge	(19)	0	0	0
Revenue	**MOF (OEFC)**	**61**	Power Supply Contract Recoveries	(110)	(142)	(167)	(170)
Revenue	**MOF (OEFC)**	**62**	Net Reduction of Power Purchase Contracts	(0)	(0)	(0)	(0)
Revenue	**MOF (OEFC)**	**65**	Miscellaneous	0	0	0	0
			Total MOF Revenue	**793**	**(672)**	**(262)**	**(916)**
			OFA IOD Expense				
		17	Public Debt Interest - Electricity Sector	38	88	88	88
		36	Interest on Debt	(55)	(110)	(131)	(152)
			Total OFA IOD Expense	**(17)**	**(22)**	**(43)**	**(64)**
			Impact on Surplus/Deficit	**886**	**(553)**	**(139)**	**(811)**
			check	***(0)***	***(0)***	***(0)***	***(0)***

Track Changes in Surplus/Deficit

Date	Change ID#	Source	Tab
5/1/2017	20170501-1	Link	ONFA
5/1/2017	20170501-2	Link	Hydro One
5/1/2017	20170501-3	Link	Hydro One
5/1/2017	20170501-4	Link	Other Data
5/2/2017	20170502-1	Link	OPG
5/9/2017	20170509-1	Link	OPG
5/10/2017	20170510-1	Link	Hydro One
5/10/2017	20170510-2	Link	Other Data
5/12/2017	20170512-1	Link	Hydro One
5/15/2017	20170515-1	Link?	
5/15/2017	20170515-2	Link	OPG
5/17/2017	20170517-1	Link	Hydro One
5/17/2017	20170517-2	Link	ONFA
5/17/2017	20170517-3		
5/18/2017	20170518-1	Link	OPG
5/18/2017	20170518-2	Link	OPG
5/18/2017	20170518-3		
6/15/2017	20170615-1	Link	OPG
6/22/2017	20170622-1	Link	Hydro One
6/22/2017	20170622-2	Link	Hydro One
6/26/2017	20170626-1		
6/29/2017	20170629-1		

7/6/2017	20170706-1		
7/11/2017	20170711-1		
7/13/2017	20170713-1	Link	Provision
7/17/2017	20170717-1	Link	Revenue (Risks)
7/24/2017	20170724-1	Link	Revenue (Risks)
7/25/2017	20170725-1	Link	Revenue (Risks)
7/26/2017	20170726-1	Link	Revenue (Risks)
7/27/2017	20170727-1	Link	Revenue (Risks)
7/27/2017	20170727-2	Link	Revenue (Risks)
7/31/2017	20170731-1		
7/31/2017	20170731-2	Link	Hydro One
7/31/2017	20170731-3	Link	Other Data
8/11/2017	20170811-1	Link	OPG
8/15/2017	20170815-1		
8/15/2017	20170815-2		
8/15/2017	20170815-3		
8/15/2017	20170815-4		
8/15/2017	20170815-5		Other Data
8/15/2017	20170815-6		Other Data
8/15/2017	20170815-7		Other Data
8/15/2017	20170815-8		Other Data
8/15/2017	20170815-9		Other Data
8/15/2017	20170815-10		Other Data
8/17/2017	20170817-1	Link	Provision
8/17/2017	20170817-2	Link	Hydro One
8/18/2017	20170818-1	Link	Revenue (Risks)
8/22/2017	20170822-1	Link	OPG
8/25/2017	20170825-1		Hydro One
8/29/2017	20170829-1		Revenue (Risks)
8/31/2017	20170831-1		Revenue (Risks)
9/5/2017	20170905-1		Other Data
9/5/2017	20170905-2		Other Data
9/5/2017	20170905-3	Link	OPG

9/6/2017	20170906-1	Link	Other Data
9/6/2017	20170906-2	Link	Revenue (Risks)
9/8/2017	20170908-1	Link	Hydro One
9/8/2017	20170908-2	Link	OPG
9/11/2017			
9/12/2017			
9/13/2017			
9/21/2017			
9/22/2017			
10/2/2017			Hydro One
10/2/2017			
10/2/2017			
10/2/2017			
10/4/2017	20171004-1		OPG
10/4/2017	20171004-2		OPG
10/4/2017			
10/4/2017			
10/5/2017			
10/6/2017			
10/7/2017			
10/8/2017			
10/10/2017	20171010-1		Hydro One
10/10/2017			
10/10/2017			
10/11/2017	20171011-1		OPG
10/11/2017			
10/11/2017			
10/12/2017			OPG
10/12/2017			
10/12/2017			
10/12/2017			
10/18/2017	20171018-1		Hydro One
10/18/2017	20171018-1		Hydro One
10/18/2017	20171018-1		Hydro One
10/19/2017	20171019-1		Revenue (Risks)
10/19/2017	20171019-2		Revenue (Risks)
10/20/2017	20171020-1		Revenue (Risks)
10/20/2017	20171020-2		
10/20/2017	20171020-2		
10/20/2017	20171020-2		
10/20/2017	20171020-3		Revenue (Risks)
10/20/2017	20171020-4		OPG
10/20/2017	20171020-4		OPG
10/20/2017	20171020-4		OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017	20171114-1		Hydro One

11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017		Hydro One
11/14/2017		Hydro One
11/14/2017		Hydro One
11/30/2017	20171130-1	Revenue (Risks)
12/8/2017		Hydro One
12/11/2017	20171211-1	Other Data
12/11/2017	20171211-1	Other Data
12/22/2017	20171222-1	OPG
1/2/2018		Hydro One
1/2/2018		Hydro One
1/2/2018		Hydro One
1/2/2018	20180102-1	OPG
1/2/2018	20180102-1	OPG
1/2/2018	20180102-1	OPG
1/2/2018	20180102-2	OPG
1/2/2018	20180102-3	OPG
1/2/2018	20180102-3	Revenue (Risks)
1/2/2018	20180102-4	Revenue (Risks)
1/2/2018	20180102-5	Revenue (Risks)
1/2/2018	20180102-6	Revenue (Risks)
1/2/2018	20180102-7	Revenue (Risks)
1/2/2018	20180102-8	Revenue (Risks)
1/2/2018	20180102-9	OPG
1/2/2018	20180102-9	OPG
1/2/2018	20180102-9	OPG
1/2/2018	20180102-9	OPG
1/3/2018		OPG
1/3/2018		OPG
1/3/2018		OPG
1/3/2018		OPG
1/3/2018		Hydro One
1/3/2018		Hydro One
1/3/2018		Hydro One
1/4/2018	20180104-1	OPG
1/4/2018	20180104-1	OPG
1/4/2018	20180104-1	OPG
1/4/2018	20180104-1	OPG
1/4/2018	20180104-2	Other Data
1/4/2018	20180104-2	Other Data
1/5/2018		
1/5/2018		
1/5/2018		
1/5/2018		
1/5/2018		
1/5/2018		
1/5/2018		
1/8/2018		
1/8/2018		
1/8/2018		
1/16/2018		Other Data

1/23/2018		OPG
2/2/2018	20180202-1	OPG
		OPG
		OPG
	20180202-1	OPG
	20180202-1	OPG
	20180202-1	OPG
	20180202-1	OPG
		OPG
		OPG
		OPG
		OPG
		OPG
		OPG
2/13/2018		
2/13/2018		
2/13/2018		
2/13/2018		
2/13/2018		
2/13/2018		
2/15/2018	20180215-1	Hydro One
2/15/2018		
2/15/2018		
2/22/2018	20180222-1	OPG
		OPG
		OPG

FOR EFB USE ONLY

Budget 2017 Outlook
Current Outlook
Change Since Budget

Description of Update
ONFA Update as of March 31 2017
s. 50.3 Update for 2016-17
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Debt Interest
OPG IFRS Risk in 2019-20
Revised OPG 2016-17 Net Income
Revised OPG 2016-17 Net Income
Revised OPG 2016-17 Net Income
tech change: slight update to assumed Prov share 70.05% from 70%
tech change: slight update to assumed Prov share 70.05% from 70%
tech change: slight update to assumed Prov share 70.05% from 70%
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
Updating H1 2016-17 Net Income for ESDI
Updating H1 2016-17 Net Income for ESDI
Updating H1 2016-17 Net Income for ESDI
Power Purchase Supply
H1 Model Forecasts - No Fiscal Update Resaving Data
Update Budget 2017 Tabs to reflect fiscal plan
Update OPG forecasted PILS to reflect sources
Update H1 2016-17 CIT
Re-inputting ONFA updates
Updating H1 Net Income to include Pref Shares in 16-17
Updating OPG Income Tax Expense for 2016-17
Updating OPG non-income tax PILs
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2017
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2018
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2019
Updating with actual OPG IFRS Adjustment 2016-17
Updating with actual OPG IFRS Adjustment 2016-17
Updating with actual OPG IFRS Adjustment 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
[NOT APPLIED] Updating H1 Brampton (Interim Adjustments)
Shifted H1 Brampton 2016-17 NI to the 2017-18
Removed H1 Brampton for 2016-17 (pending finals)
Removed H1 Brampton for 2016-17 (pending finals)
Removed H1 Brampton for 2016-17 (pending finals)

add prior-year adjustment for 2016-17

add prior-year adjustment for 2016-18
Reconfigured calculation of ESDI and MOF ESDI Expense
Reconfigured calculation of OPG 2017-18 Net Income
Backup for the Provincial Interest cost
Linking source for Revenue Risks Tab
New source for Revenue Risks Tab
Revenue Risks Tab - ROE Risks
Updating OEB Risk for OPG
OEB Staff Report - H1 Tx - Revenue Risks
OPG Pensions - Cash vs Accrual Deferral Accounts
Updating Links in Electricity Summary Change and OEFC Change
Preliminary estimate for Hydro One Brampton
Preliminary estimate for Hydro One Brampton
Preliminary estimate for Hydro One Brampton

Updating DRC for Actuals 2016-17 (Based on draft FS)
Updating PILs for 2016-17 Baced on Actuals
OPG: Non-ONFA Fair Value Adjustment
Round all Hydro One ownership assumptions to two decimal places
H1 Equity Adjustment rounding.
Round all Hydro One ownership assumptions to two decimal places
Round all Hydro One ownership assumptions to two decimal places
Revising source of ESDI, Dedicated Electricity Earnings
2016-17 - Update Power Supply Recoveries to actuals
2016-17 - Update Power Supply Recoveries to actuals
2016-17 - Updating Miscellaneous OEFC Revenue to Actuals
Adj: Exclude Bramton $15m add prior year adjustment +$3M
Adj: Exclude Bramton $15m add prior year adjustment +$3M
Public Accts: Updated IESO debt interest Interest On Debt, 2016-17
Public Accts: 2016-17 - Demand Management Support Costs Update
2017-18 - Demand Management Support Costs (no change)
Public Accts: 2016-17 - Updating Operating Expense in OEFC
Sourcing Provision for Electricity Sector from Actual Public Accounts
Revised 2016-17 Brampton Amount for Public Accounts
OPG Pensions - Cash vs Accrual Deferral Accounts (Revenue Risks Tab)
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
Reclassification
Reclassification
Reverting H1 Ownership change (undoing 20170518-3)
Reverting H1 Ownership change (undoing 20170518-3)
Reverting H1 Ownership change (undoing 20170518-3)
Updating Risks based on Hydro One Q2 Results Model
Avista Acquisition Risks
NUG Amortization Liability (sourcing amortization schedule)
2016-17 Actuals - Debt Guarantee Fee
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results

Interest Revenue for IESO and "Other"
OPG Revenue Risks from OEB Filings
Net income corrected for Preferred Shares
Net income corrected for Preferred Shares
Net income corrected for Preferred Shares
Made link edits to OPG sheet so that the "Net Income Before Tax" 2017-18 number is not a hardc
Updated PILs to include OPCD public accounts adjustment
Provision tab fix to pick up Hydro One preferred share net income
Provision tab fix to pick up Hydro One preferred share net income
FTD Update to OEFC Outlook (Sep 19, 2017) OPG Interest
FTD Update to OEFC Outlook (Sep 19, 2017) Other Interest
Update to Hydro One PILs from information in Transmission rate application material
OEB September 28, 2017 Hydro One decision and order impact - incl. rebasing
OEB September 28, 2017 Hydro One decision and order impact - incl. rebasing
OEB September 28, 2017 Hydro One decision and order impact - incl. rebasing
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Debenture Interest Costs - Removing from Revenue (Risks) and adding it ot H1 Model
Debenture Interest Costs - Removing from Revenue (Risks) and adding it ot H1 Model
Debenture Interest Costs - Removing from Revenue (Risks) and adding it ot H1 Model
Updated OPG Net Income and PILs based on monthly report (August 2017 results)
Updated OPG Net Income and PILs based on monthly report (August 2017 results)
Updated OPG Net Income and PILs based on monthly report (August 2017 results)
Correction to PILs on OPG sheet
Correction to PILs on OPG sheet
Correction to PILs on OPG sheet
Correction to PILs on OPG sheet
Switch to Direct from Model
Switch to Direct from Model
Switch to Direct from Model
Updating ROE Risks
Updating H1 Load Risks based on model output
Updating ONFA Risks for September 2017
Adjust OEB decision/rebasing to ~50% provincial ownership
Adjust OEB decision/rebasing to ~50% provincial ownership
Adjust OEB decision/rebasing to ~50% provincial ownership
Updating OPG
OPG IOD impact from GA Financing, FHP
OPG IOD impact from GA Financing, FHP
OPG IOD impact from GA Financing, FHP
Unpacking updated OPG Gain on sale (net income)
Unpacking updated OPG Gain on sale (net income)
Unpacking updated OPG Gain on sale (net income)
Unpack PILs related to HQ gain on sale
Updating IFRS Risk
Adjustment for lower Provincial share (from 70.1% to 50.9 2017-18 & 47.4% after)
Adjustment for lower Provincial share (from 70.1% to 50.9 2017-18 & 47.4% after)
Adjustment for lower Provincial share (from 70.1% to 50.9 2017-18 & 47.4% after)
November 1 and November 7 Hydro One model updates

November 1 and November 7 Hydro One model updates
November 1 and November 7 Hydro One model updates
Revise Hydro Model to reverse OEB tax decision ongoing annual impact
Revise Hydro Model to reverse OEB tax decision ongoing annual impact
Revise Hydro Model to reverse OEB tax decision ongoing annual impact
Undo allocation adjustment in H1 tab (now that provincial shares are updated)
Undo allocation adjustment in H1 tab (now that provincial shares are updated)
Undo allocation adjustment in H1 tab (now that provincial shares are updated)
Updating OPG Revenue Risks from rate application
Update Hydro One PILs (reverses update on line 119 whuich did not account fro Dx side)
Updating Debt Guarantee Fee
Updating OEFC Operating Expense
small changes - linking the net income numbers
Updated number of shares sold for First Nations (Dec 2017) sale
Updated number of shares sold for First Nations (Dec 2017) sale
Updated number of shares sold for First Nations (Dec 2017) sale
Implemented OEB's Dec 2017 payment amounts decision for OPG (CEFD Analysis)
Implemented OEB's Dec 2017 payment amounts decision for OPG (CEFD Analysis)
Implemented OEB's Dec 2017 payment amounts decision for OPG (CEFD Analysis)
Updated OPG Net Income (based on their Q3 update, Sep 30, 2017)
Updated OPG ONFA adjustment (up to Sep 30, 2017) in OPG tab (removed it from Risks table)
Removal of OPG ONFA Sep 2017 adjustment in Risks table
Included possible range (-50M to 50M) of impact for future OPG ONFA adjustment in the negative
Removal of negative regulatory risk: "OPG Switch from accrual based to cash based accounting f
Removal of negative regulatory risk: "Timing of OPG Rate Decision" from Risks table
Removal of negative regulatory risk: "OEB Staff Recommendations wrt OPG rate application(May
Removal of negative regulatory risk: "Nuclear Liabilities Cash vs. Accrual" from Risks table
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month
Updated estimates of NUG costs.
Updated estimates of NUG costs.
Unpacking OPG (Head Office sale)
Unpacking OPG (Head Office sale)
Unpacking OPG (Head Office sale)
Unpacking OPG (Head Office sale)
Unpacking Hydro One for AO (from 70.1% ownership to as of January 2018)
Unpacking Hydro One for AO (from 70.1% ownership to as of January 2018)
Unpacking Hydro One for AO (from 70.1% ownership to as of January 2018)
Update H1 allocations for additional shares (SIFB edits)
Update H1 allocations for additional shares (SIFB edits)
Update H1 allocations for additional shares (SIFB edits)
Updated (latest IOD) Debt Interest Expense line (OEFC on-deck tab) and OPG, IESO, and Other

ONFA consolidation adjustment for Dec 2017
OPG 2018-2021 BP preliminary net income update
OPG 2018-2021 BP preliminary net income update
OPG 2018-2021 BP preliminary net income update
OPG 2018-2021 BP preliminary Income Tax PILs
OPG 2018-2021 BP preliminary GRC payable to OEFC update
OPG 2018-21 BP preliminary Property Tax Payable to OEFC update
Removal of net income from estimated gain from Lakeview sale, as it has not been realized yet
Removal of PILs from estimated gain from Lakeview sale, as it has not been realized yet
Removal of net income from estimated gain from Lakeview sale, as it has not been realized yet
Removal of net income from estimated gain from Lakeview sale, as it has not been realized yet
Remove EFB OEB impact estimate
Remove EFB OEB impact estimate
Remove EFB OEB impact estimate
Update with Board-approved net income
Update with Board-approved net income
Update with Board-approved net income
Remove reversal of Lakeview proceeds on net income (now included)
Remove reversal of Lakeview proceeds on net income (now included)
Remove reversal of Lakeview proceeds on net income (now included)
Remove reversal of Lakeview proceeds on PILs (now included)
Update with Board-approved PILs
Update OPG Fair Hydro Plan amounts from OPG Busdiness Plan 2018-2021
Update OPG Fair Hydro Plan amounts from OPG Busdiness Plan 2018-2022
Update OPG Fair Hydro Plan amounts from OPG Busdiness Plan 2018-2023
Remove Hydro One Debenture Cost from Outlook (now in Model)
Remove Hydro One Debenture Cost from Outlook (now in Model)
Remove Hydro One Debenture Cost from Outlook (now in Model)
Annual Report 2017 Hydro One Net Income Updates
Annual Report 2017 Hydro One Net Income Updates
Annual Report 2017 Hydro One Net Income Updates
Adjustment from using quarterly actuals
Adjustment from using quarterly actuals
Adjustment from using quarterly actuals
Updating Hydro One debt interest Costs
Updating Hydro One debt interest Costs
February 15, 2018 FTD Update\
Update based on January 31, 2018 BSC material for OEFC YTD
Update from Hydro One Feb 16 (email to Gavin)
Update based on January 31, 2018 BSC material for OEFC YTD and Siva email
Updated OPG IFRS Impact
Updated OPG IFRS Impact
Updated OPG IFRS Impact
Rounding adjustment

This line show net impact of latest change. READ COMMENT

$ Millions

		2016-17	2017-18	2018-19	2019-20
		930	789	939	957
	File	915	1,675	386	817
		-15	886	-553	-139
	check	*0*	*0*	*0*	*0*
		Impacts by FY →			
Outlook line affected	**Expense / Rever**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
ONFA and other Fair Value Adjustments	Revenue	41.0	0.0	0.0	0.0
N/A		0.0	0.0	0.0	0.0
?		0.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		38.1		
Provision for Electricity Sector (MOF)	Expense		(38.1)		
Public Debt Interest - Electricity Sector	Expense	0.0	38.1	38.1	38.1
Interest on Debt	Expense	0.0	(69.1)	(79.1)	(75.1)
OPG Income	Expense	0.0	0.0	0.0	
OPG Income	Revenue	(2.0)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**(2.0)**			
Provision for Electricity Sector (MOF)	Expense	2.0			
HOI Income	Revenue	0.4			
Provision for Electricity Sector (OEFC)	Expense	0.4			
Provision for Electricity Sector (MOF)	Expense	(0.4)			
Public Debt Interest - Electricity Sector	Expense	1.7			
Provision for Electricity Sector (OEFC)	Expense	(1.7)			
Provision for Electricity Sector (MOF)	Expense	1.7			
Interest on Debt	Expense	(1.7)			
HOI Income	Revenue	(39.8)	0.0	0.0	(0.0)
Provision for Electricity Sector (OEFC)	Expense	**(39.8)**			
Provision for Electricity Sector (MOF)	Expense	39.8			
	Revenue	-	-	-	-
	Revenue	-	-	-	-
	n/a	-	-	-	-
		-	-	-	-
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	4.7	0.0	0.0	0.0
	Revenue	0.0	0.0	0.0	0.0
HOI Income	Revenue	18.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	7.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	8.0	9.0	12.0	3.5
HOI Income	Revenue	0.0	(141.5)	(181.4)	(194.9)
Provision for Electricity Sector (OEFC)	Expense		(141.5)		
Provision for Electricity Sector (MOF)	Expense		141.5		
OPG Income	Revenue	(3.0)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**(3.0)**			
Provision for Electricity Sector (MOF)	Expense	3.0			
HOI Income	Revenue	7.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**7.0**			
Provision for Electricity Sector (MOF)	Expense	(7.0)			
	Revenue	-	-	-	-
	Revenue	0.0	0.0	0.0	0.0
Brampton Income	Revenue	(14.7)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**(14.7)**			
Provision for Electricity Sector (MOF)	Expense	14.7			

Provision for Electricity Sector (OEFC)	Expense		3.2			
Provision for Electricity Sector (MOF)	Expense		(3.2)			
	Revenue	-	-	-	-	
		-	-	-	-	
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
Brampton Income	Revenue		15.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		**15.0**			
Provision for Electricity Sector (MOF)	Expense		(15.0)			
Provision for Electricity Sector (OEFC)	Expense		3.2			
Provision for Electricity Sector (MOF)	Expense		(3.2)			
Electricity Debt Retirement Charge	Revenue		(4.0)	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue		(29.0)	0.0	0.0	0.0
OPG Income	Revenue		(6.0)	0.0	0.0	0.0
HOI Income	Revenue		(0.0)	(0.0)	0.0	0.0
HOI Income	Revenue		(1.7)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense			(0.0)		
Provision for Electricity Sector (MOF)	Expense			0.0		
	Revenue		0.0	0.0	0.0	0.0
Power Supply Contract Recoveries	Revenue		99.0	0.0	0.0	0.0
Power Supply Contract Costs	Expense		(99.0)			
Miscellaneous	Revenue		14.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		(12.0)			
Provision for Electricity Sector (MOF)	Expense		12.0			
Interest on Debt	Expense		(3.0)	0.0	0.0	0.0
Demand Management Support Costs	Expense		1.8	0.0	0.0	0.0
			0.0	0.0	0.0	0.0
Other (Finance)	Expense		(1.0)	0.0	0.0	0.0
	Revenue	-	-	-	-	
Brampton Income	Revenue		3.0	0.0	0.0	0.0
			0.0	0.0	0.0	0.0
OPG Income	Revenue		0.0	85.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue			(6.0)		
Provision for Electricity Sector (OEFC)	Expense			**85.0**		
Provision for Electricity Sector (MOF)	Expense			(85.0)		
OPG Income	Revenue		6.0			
ONFA and other Fair Value Adjustments	Revenue		(6.0)			
HOI Income	Revenue		0.0	141.9	181.8	195.4
Provision for Electricity Sector (OEFC)	Expense			141.9		
Provision for Electricity Sector (MOF)	Expense			(141.9)		
	n/a		0.0	0.0	0.0	0.0
			0.0	0.0	0.0	0.0
Net Reduction of Power Purchase Contracts	Revenue		0.1	(0.1)	(0.1)	(0.1)
	Revenue		0.0	0.0	0.0	0.0
OPG Income	Revenue		0.0	16.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue			(1.0)		
Provision for Electricity Sector (OEFC)	Expense			**16.0**		
Provision for Electricity Sector (MOF)	Expense			(16.0)		

		0.0	0.0	0.0	0.0
	n/a	0.0	0.0	0.0	0.0
HOI Income	Revenue	0.0	5.3	5.3	5.3
Provision for Electricity Sector (OEFC)	Expense		(12.4)		
Provision for Electricity Sector (MOF)	Expense		12.4		
oded formula in the cell	n/a	0.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	(30.4)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		17.8		
Provision for Electricity Sector (MOF)	Expense		(17.8)		
Interest on Debt	Expense	(0.0)	1.0	(0.0)	1.0
Interest on Debt	Expense	0.0	15.0	15.0	5.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	0.0	(7.8)	(8.7)	(10.3)
HOI Income	Revenue	0.0	(47.4)	(54.0)	(54.0)
Provision for Electricity Sector (OEFC)	Expense	0.0	(47.4)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	47.4	0.0	0.0
OPG Income	Revenue	0.0	(61.0)	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	0.0	(21.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	(61.0)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	61.0	0.0	0.0
OPG Income	Revenue	0.0	(21.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	(21.0)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	21.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	0.0	21.0	0.0	0.0
HOI Income	Revenue	0.0	(23.6)	(27.4)	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	(23.6)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	23.6	0.0	0.0
OPG Income	Revenue	0.0	15.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	15.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	(15.0)	0.0	0.0
OPG Income	Revenue	0.0	21.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	0.0	(18.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	21.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	(21.0)	0.0	0.0
HOI Income	Revenue	0.0	(23.8)	(28.9)	(10.1)
Provision for Electricity Sector (OEFC)	Expense	0.0	(23.8)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	23.8	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
HOI Income	Revenue		16.1	26.7	20.6
Provision for Electricity Sector (OEFC)	Expense		16.1		
Provision for Electricity Sector (MOF)	Expense		(16.1)		
n/a	n/a	0.0	0.0	0.0	0.0
OPG Income	Revenue		(4.9)	(11.9)	(17.1)
Provision for Electricity Sector (OEFC)	Expense		(4.9)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		4.9	0.0	0.0
OPG Income	Revenue		283.0		
Provision for Electricity Sector (OEFC)	Expense		283.0		
Provision for Electricity Sector (MOF)	Expense		(283.0)		
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue		95.0		
OPG Income	Revenue		0.0	(475.0)	(500.0)
HOI Income	Revenue		(112.6)	(142.1)	(170.6)
Provision for Electricity Sector (OEFC)	Expense		(112.6)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		112.6	0.0	0.0
HOI Income	Revenue		(3.3)	(3.0)	(0.1)

Provision for Electricity Sector (OEFC)	Expense		(3.3)		
Provision for Electricity Sector (MOF)	Expense		3.3		
HOI Income	Revenue		14.7	14.4	12.9
Provision for Electricity Sector (OEFC)	Expense		14.7	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		(14.7)	0.0	0.0
HOI Income	Revenue		(16.1)	(26.7)	(20.6)
Provision for Electricity Sector (OEFC)	Expense		(16.1)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		16.1	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)		0.0	7.8	8.7	10.3
n/a	n/a	0.0	0.0	0.0	0.0
Other (Finance)			0.0	(1.0)	(1.0)
OPG Income	Revenue		0.0	0.0	0.0
HOI Income	Revenue		0.1	0.5	0.6
Provision for Electricity Sector (OEFC)	Expense		0.1	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		(0.1)	0.0	0.0
OPG Income	Revenue		(477.1)	(145.2)	(153.1)
Provision for Electricity Sector (OEFC)	Expense		(305.7)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		305.7	0.0	0.0
OPG Income	Revenue		39.0	0.0	0.0
OPG - ONFA and other Fair Value Adjustments	Revenue		171.5	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
OPG Income	Revenue		119.3	36.3	38.3
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue		(119.3)	(36.3)	(38.3)
Provision for Electricity Sector (OEFC)	Expense		0.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		0.0	0.0	0.0
OPG Income	Revenue		(283.0)	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue		(95.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		0.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		0.0	0.0	0.0
HOI Income	Revenue		116.8	147.1	176.1
Provision for Electricity Sector (OEFC)	Expense		0.0	0.0	80.3
Provision for Electricity Sector (MOF)	Expense		0.0	0.0	(80.3)
OPG Income	Revenue		37.5	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue		12.5	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		0.0	14.4	23.1
Provision for Electricity Sector (MOF)	Expense		0.0	(14.4)	(23.1)
Power Supply Contract Recoveries	Revenue		(109.9)	(142.1)	(166.7)
Power Supply Contract Costs	Expense		109.9	142.1	166.7
OPG Income	Revenue		283.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue		95.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		141.1	141.9	0.0
Provision for Electricity Sector (MOF)	Expense		(141.1)	(141.9)	0.0
HOI Income	Revenue		(116.8)	(147.1)	(176.1)
Provision for Electricity Sector (OEFC)	Expense		(116.8)	(147.1)	(103.4)
Provision for Electricity Sector (MOF)	Expense		116.8	147.1	103.4
HOI Income	Revenue		(0.0)	(0.2)	(0.2)
Provision for Electricity Sector (OEFC)	Expense		(0.0)	(0.2)	0.0
Provision for Electricity Sector (MOF)	Expense		0.0	0.2	0.0
Interest on Debt	Expense		(2.5)	8.0	(7.0)

OPG - ONFA and other Fair Value Adjustments	Revenue	22.5	0.0	0.0
OPG Income	Revenue	327.0	113.0	325.0
Provision for Electricity Sector (OEFC)	Expense	327.0	113.0	252.0
Provision for Electricity Sector (MOF)	Expense	(327.0)	(113.0)	(252.0)
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	54.0	(77.0)	7.0
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	(8.0)	(15.0)	(10.0)
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	(5.0)	(5.0)	(5.0)
OPG Income	Revenue	(185.0)	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	(65.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	(185.0)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	185.0	0.0	0.0
OPG Income	Revenue	427.1	145.2	153.1
Provision for Electricity Sector (OEFC)	Expense	427.1	145.2	153.1
Provision for Electricity Sector (MOF)	Expense	(427.1)	(145.2)	(153.1)
OPG Income	Revenue	11.0	4.0	2.0
Provision for Electricity Sector (OEFC)	Expense	11.0	4.0	2.0
Provision for Electricity Sector (MOF)	Expense	(11.0)	(4.0)	(2.0)
OPG Income	Revenue	185.0		
Provision for Electricity Sector (OEFC)	Expense	185.0		
Provision for Electricity Sector (MOF)	Expense	(185.0)		
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	65.0		
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	5.0	(4.0)	(2.0)
OPG Income	Revenue	(2.3)	37.5	67.7
Provision for Electricity Sector (OEFC)	Expense	(2.3)	37.5	67.7
Provision for Electricity Sector (MOF)	Expense	2.3	(37.5)	(67.7)
HOI Income	Revenue	17.1	18.6	0.0
Provision for Electricity Sector (OEFC)	Expense	17.1	18.6	0.0
Provision for Electricity Sector (MOF)	Expense	(17.1)	(18.6)	0.0
HOI Income	Revenue	8.4	7.7	24.4
Provision for Electricity Sector (OEFC)	Expense	8.4	7.7	24.4
Provision for Electricity Sector (MOF)	Expense	(8.4)	(7.7)	(24.4)
HOI Income	Revenue	(8.5)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	(8.5)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	8.5	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		50.4	50.4
Provision for Electricity Sector (MOF)	Expense		(50.4)	(50.4)
Interest on Debt	Expense	0.5	(4.0)	(5.0)
Electricity Debt Retirement Charge	Revenue	(19.0)	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	3.5	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	(35.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	100.0	100.0	225.0
Provision for Electricity Sector (MOF)	Expense	(100.0)	(100.0)	(225.0)
OPG Income	Revenue	100.0	100.0	225.0
		(0.0)	(0.0)	(0.0)
		0	***0***	***0***	***0***

2020-21
1,676
865
-811
0

2020-21	Further Explanation of Change and source of data
0.0	Regular quarterly ONFA Update
0.0	Benefit to OEFC under s.50.3: $411M gain, SIFB
0.0	Change to OEFC payment for interest costs of Debt for Equity Swap
38.1	Revised Provincial Debt Interest related to Hydro One Equity
(104.1)	From FTD, revised Debt Interest (net of revisions to Provincial and OPG debt interest)
0.0	Revised numbers from OEP with 2019-20 Risk
0.0	Updated numbers from OPG Q1 2017 FS
0.0	Updating H1 Net Income for actuals. Note does not update Brampton Income at this point. Will
-	No Change to numbers, just re-inputting data and saving sources
-	No Change to numbers, just re-inputting data and saving sources
-	No change to fiscal impact numbers. Deleting Budget 2016 and adding Budget 2017 fiscal imp
-	No Change to numbers, just re-inputting data and saving sources
0.0	Updated with CIT Numbers received from H1 as part of s.91.2 MB20 allocation from MOF
0.0	No Change to numbers, just re-inputting data and saving sources
0.0	Only included H1 Net Income - Common Shareholders before. Added preferred shareholder im
0.0	Updating OPG Income Tax Expense with info from OPG Monthly Presentation to Shareholder
1.8	Updating OPG GRC payable to OEFC and Proxy Property Tax from Answer back from OPG al
(210.6)	Based on H1 final offering and expected First Nations Sale by the end of 2017 (CY), with a wei
0.0	Based on EY analysis, and then applying fiscalization. Confirmation also received from OPCD.
0.0	Based on KPMG analysis, then fiscalization and other adjustments from OPCD.
-	**[NOT APPLIED, CALCULATIONS AND DATA LEFT ON THE FILE]** Used Brampton's Financ
0.0	Don't expect finalized 2016-17 data to become available in time for ESDI allocation. Will shift th
0.0	make decision on shifting when we know 2016-17 status.

-	No change to numbers. Just re-organizing spreadsheet. No backup data.
-	No change to numbers. Just re-organizing spreadsheet. No backup data.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided another scenario backup/source
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just updated the links to refer ot the delta between 2017 and On Deck
0.0	Adjustment to ESDI to include Hydro One Brampton
0.0	Finalizing 2016-17 DRC Based on Draft OEFC AR
0.0	Received actual PILs amounts from FTD with breakdown of source. Updated 2016-17 numbers
0.0	2016-17 - Non-ONFA Fair Value Adjustment
0.0	Round Hydro One ownership assumptions to 70.05% two decimal places to be consistent with
0.0	Revising Hydro One Amount for consistency with OPCD. Equity Adjustments
0.0	Updated Provision tab. Made two separate Provision amounts for ESDI in OEFC AR and Dedic
0.0	Updating Power Supply Recoveries to Public Accounts/OEFC AR actuals
0.0	Updating Miscellaneous to OEFC AR actuals
0.0	Updated 2016-17 Interest on Debt (IESO, OPG, Other (Net))
0.0	
0.0	2017-18 - Demand Management Support Costs (no change) - Linking correctly
0.0	2016-17 - Updating Operating Expense in OEFC and corresponding changes elsewhere and s
-	No change to numbers. Just re-organized spreadsheet
0.0	Revised H1 Brampton Net Income (for GBE Line only)
0.0	Revising for OPG's Q3 Finances
0.0	Revising OPG's Net Income for latest monthly report
211.1	Reverting ownership back to 70.05% from change 20170518-3. Will coordinate with other area
0.0	Updating Risks based on Hydro One Q2 Results Model
0.0	Updated two Risk components for the Avista Acquisition.
(0.0)	No significant changes, but used actual amortization liability schedule. Hence the rounding imp
0.0	Updating Debt Guarantee for actuals based on OEFC AR
0.0	Revising OPG's Net Income for latest monthly report

0.0	Linking interest revenue data for 2017-18 to 2020-21
0.0	OPG Revenue Risks from: OEB Staff Submission and OPG Updated Filings
5.3	Corrected Net income for 100% ownership in preferred shares and 70.05% in Commons Share
0.0	Updated the formula in the cell for 2017-18 Net Income Before Tax so that the numbers are no
0.0	Updated PILs to include OPCD public accounts adjustment
1.3	
5.0	
(12.2)	
(54.0)	
0.0	
0.0	
0.0	increase built into net income was $82m between NI and PILs
0.0	Remove $21m from PILs
0.0	expense impacts
0.0	expense impacts
0.0	need to also remove the $21m PILs built into OPG net incme
0.0	
0.0	
0.0	We removed $21m from PILs above, before having added it in (check is that lines 123 to 130 a
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
(13.0)	variances include: 2017-18 preferred vs common share fix, 2018-19 largely ROE change from
0.0	
0.0	
0.0	
0.0	
0.0	
21.6	
0.0	
(24.1)	
0.0	
0.0	**Distribution (October)**
(750.0)	
(185.3)	
0.0	
0.0	
(2.3)	

15.2	
0.0	
0.0	
(21.6)	
0.0	
0.0	
0.0	Updating OPG Rate application Revenue Risks based on revised calculations
12.2	
0.0	
(1.0)	Received Revised FTD Forecast
0.3	
0.7	
0.0	
0.0	
(180.7)	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	Removed based on Dec 2017 OEB decision
0.0	Removed based on Dec 2017 OEB decision
0.0	Removed based on Dec 2017 OEB decision
0.0	Removed based on Dec 2017 OEB decision
45.2	
(45.2)	
44.2	
(44.2)	
0.0	
0.0	
(44.2)	
44.2	
190.8	
311.7	
(311.7)	
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M
(170.7)	
170.7	
0.0	
0.0	
0.0	
0.0	
(190.8)	
(263.6)	
263.6	
(0.3)	
(0.5)	
0.5	**Distribution (January)**
0.4	

0.0
(39.3)
33.7
(33.7)
(127.3)
(10.0)
(6.0)
0.0
0.0
0.0
0.0
180.7
180.7
(180.7)
3.0
3.0
(3.0)

(2.0)
96.5
96.5
(96.5)
0.0
0.0
0.0
19.2
19.2
(19.2)
0.0
0.0
0.0
50.4
(50.4)
(4.4)
0.0
0.0
0.0
325.0
(325.0)
325.0
(0.0)

0

Data Validation:

Options
Revenue (F
OPG
Hydro One
Provision

ONFA
Other Data

update once revised numbers are received.

acts

ıpact as well.

bout the BP
ghted average ownership for 2017-18. Also adjusted future net income attributed to the province.

ial Statements to produce an estimate. May require additional calculations.
ıis to 2017-18.

(from 2016 and On Deck)

s to reflect this.

OPCD.

:ated Earnings in Public Accounts.

ources.

s to ensure broadening change and reduction in net income happens concurrently in forecasts.

acts/changes.

es

t hardcoded directly

dd up to -$82m gain that we wanted to remove.

9.09% to 8.78% not previously captured.

Risks)

Electricity Sector Outlook

$ Millions

	Actual 2015-16	Interim 2016-17	Plan 2017-18	2018-19	2019-20	2020-21
On Deck Outlook as of March 2017						
Income from Investment in Government Business Enterprises						
OPG Income[1]	291	304	97	732	625	1,066
OPG - ONFA and other Fair Value Adjustments[2]	172	8	-	-	-	-
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	-
HOI Income[3]	236	516	520	562	603	652
Brampton Income	20	15	-	-	-	-
Total OPG and HOI Income	**719**	**842**	**617**	**1,294**	**1,229**	**1,717**
Other Fees and Licences	**127**	**122**	**102**	**91**	**88**	**81**
Electricity Expenses of the Province						
Provision for Electricity Sector[4]	(3)	(342)	(125)		-	-
Public Debt Interest - Electricity Sector	(520)	(492)	(492)	(492)	(492)	(492)
Subtotal	(523)	(834)	(617)	(492)	(492)	(492)
Public Debt Interest - Impact of ONFA						
Amortization of Deferred Revenue re profit on sale of H1 notes						
Total Electricity Expenses of the Province	**(523)**	**(834)**	**(617)**	**(492)**	**(492)**	**(492)**
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	3,228	373	405	476	538	679
Other Revenue						
Electricity Debt Retirement Charge[5]	859	625	623	-	-	-
Power Supply Contract Recoveries	875	739	292	325	301	273
Net Reduction of Power Purchase Contracts	172	129	74	41	30	28
Other Fees and Licences	(127)	(122)	(102)	(91)	(88)	(81)
Miscellaneous	9	-	-	-	-	-
Expenses						
Interest on Debt	(596)	(532)	(422)	(374)	(342)	(250)
Power Supply Contract Costs	(875)	(739)	(292)	(325)	(301)	(273)
Electricity Consumer Price Protection Fund	-	-	-	-	-	-
Demand Management Support Costs[6]	(8)	(10)	(10)	-	-	-
Provision for Electricity Sector	3	342	125	-	-	-
Other (Finance)	(7)	(6)	(6)	(6)	(6)	(6)
Total OEFC Income	**3,533**	**800**	**687**	**46**	**132**	**370**
Impact on Surplus/(Deficit)	**3,856**	**930**	**789**	**939**	**957**	**1,676**

Notes: The Hydro One net income outlook above (2016-17 to 2020-21) reflects the Province's 70% ownership share after the initial IPO in 2015 and the secondary offering in April 2016. At the time of 2017 Budget, net estimated fiscal impacts from future Hydro One offerings are reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

Notes:

1.OPG's 2016-17 outlook reflected its reported earnings. 2017-18 to 2019-20 reflects OPG's preliminary 2017-2019 business plan (as fiscalized by OPG). 2020-21 estimates are based on OPG's calendar year-based business plan projections. OPG net income also reflects IFRS adjustments fiscal impact decisions that were made centrally.

2. Provincial consolidation adjustments for unrealized earnings on the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds, as of the end of December 2016.

3. Hydro One 2016-17 income reflects its reported net income, adjusted for Hydro One IPO impacts. 2017-18 to 2020-21 projections are based on CEFD projections using the latest public information. The Hydro One net income outlook above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering as of 2017 Budget were reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial ONFA consolidation adjustments, less the interest on the Province's OPG/Hydro One debt payable to OEFC. The provision is currently assumed to end once the DRC ends on a legislated fixed end date of April 1, 2018.

5. Reflects April 23, 2014 announcement that DRC will be eliminated for residential users, after December 31, 2015. The end date of DRC for remaining users is legislated to be on April 1, 2018. Estimates are subject to change based on actual consumption.

6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Electricity Sector Outlook

$ Millions

	Actual 2014-15	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
On Deck Outlook as of February 2018							
Income from Investment in Government Business Enterprises							
OPG Income[1]	574	291	299	905	500	728	677
OPG - ONFA and other Fair Value Adjustments[2]	239	172	43	194	-	-	-
Hydro One - Unrealized Gains Adjustment	(8)	-	-	-	-	-	-
HOI Income[3]	741	236	500	346	353	412	438
Brampton Income		20	18	-	-	-	-
Total OPG and HOI Income	**1,546**	**719**	**860**	**1,445**	**853**	**1,140**	**1,115**
Other Fees and Licences (Debt Guarantee fee)	**131**	**127**	**122**	**102**	**99**	**98**	**91**
Electricity Expenses of the Province							
Provision for Electricity Sector[4]	(795)	-	(290)	(797)	(449)	(736)	(711)
Public Debt Interest - Electricity Sector	(520)	(520)	(514)	(454)	(404)	(404)	(404)
Subtotal	(1,315)	(520)	(803)	(1,251)	(853)	(1,140)	(1,115)
Public Debt Interest - Impact of ONFA							
Amortization of Deferred Revenue re profit on sale of H1 notes							
Total Electricity Expenses of the Province	**(1,315)**	**(520)**	**(803)**	**(1,251)**	**(853)**	**(1,140)**	**(1,115)**
OEFC Income							
Taxation Revenue							
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	180	3,247	334	499	387	531	535
Other Revenue							
Electricity Debt Retirement Charge[5]	956	859	621	604	-	-	-
Power Supply Contract Recoveries	950	875	838	182	183	134	103
Net Reduction of Power Purchase Contracts	217	172	129	74	41	30	28
Other Fees and Licences	(131)	(127)	(122)	(102)	(99)	(98)	(91)
Miscellaneous	9	9	14	-	-	-	-
Expenses							
Interest on Debt	(658)	(596)	(513)	(477)	(484)	(473)	(402)
Power Supply Contract Costs	(950)	(875)	(838)	(182)	(183)	(134)	(103)
Electricity Consumer Price Protection Fund	-	-	-	-	-	-	-
Demand Management Support Costs[6]	(9)	(8)	(8)	(10)	-	-	-
Provision for Electricity Sector	795	-	290	797	449	736	711
Other (Finance)	(6)	(7)	(7)	(6)	(7)	(7)	(7)
Total OEFC Income	**1,353**	**3,549**	**737**	**1,379**	**287**	**719**	**774**
Impact on Surplus/(Deficit)	**1,715**	**3,876**	**915**	**1,675**	**386**	**817**	**865**
variance to OEFC check		*(156)*	*(454)*	*(531)*	-	-	-

Notes:

1.OPG's 2017-18 to 2020-21 outlook reflects OPG's 2018-2021 Business Plan and Includes OPG head office properties sale proceeds and Lakeview property sale proceeds. 2021-22 estimates are based on OPG's calendar year-based business plan projections for 2021 and a CEFD projection for 2022. OPG net income also reflect projected IFRS adjustments as provided by OPCD at the time of the 2017 Budget. Note: all Asset Optimization transactions are re-categorised from Sales and Rentals in this Outlook.

2. Provincial consolidation adjustments for unrealized earnings on the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds, as of the end of September 2017.

3. Hydro One 2017-18 is based on actual Hydro One results for 2017 and CEFD projection for 2018. Quarterly earnings are adjusted for the provincial ownership share during the quarter. 2018-19 and onwards are CEFD projections using the latest public information and reflects the Province's ownership share following the May 2017 share disposition and including the First Nations sale in December 2017. Note: all Asset Optimization transactions are re-categorised from Sales and Rentals in this Outlook.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial ONFA consolidation adjustments, minus the interest on debt payable to OEFC. The provision is now assumed to continue after 2017-18 based on TB/MBC approval of the PRRT submission to continue ESDI payments to OEFC beyond 2017-18.

5. Reflects that DRC eliminated for residential users, after December 31, 2015. The end date of DRC for remaining users is legislated to be on April 1, 2018. Estimates are subject to change based on actual consumption.

6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Electricity Sector Change Since Budget	$ Millions					
($million)	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Changes from Budget 2017 as of February 2018						
Income from Investment in Government Business Enterprises						
OPG Income	(5)	808	(232)	103	(389)	2016-17 small decrease due to IFRS adjustment revision and OPG Net Income revision. 2017-18 increase is largely due to the re-categorization from Sales and Rentals to OPG net income proceeds from the sale of OPG head office and Lakeview properties. This accounts for $483M of the increase. Note that whicle the re-categorization itself is fiscally-neutral proceeds from property sales are $206M higher than projected at the time of the 2017 Budget. 2017-18 results are also boosted by lower projected IFRS adjustment for 2017-18 and lower OPG expenses than assumed at the time of Budget 2017. 2018-19 to 2020-21 chnages reflect the negative impact of higher projeceted IFRS adjustment impacts over that period partially offset by higher OPG net income in 2018-19 and 2020-21 and more than offset by higher OPG net income in 2019-20.
ONFA and other Fair Value Adjustments	35	194	-	-	-	Largely revision to ONFA fair value as of December 31, 2017
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	
HOI Income	(16)	(173)	(209)	(191)	(214)	2016-17 slight decrease from Budget 2017 Interim projection. 2017-18 onwards mainly reflects i) re-categorization from Sales and Rentals to Hydro One net income of the impact of a lower Provincial share of Hydro One net income from Hydro One share sales ii) impact of OEB Sep. 2017 decision on Hydro One transmission rates and iii) interest expense on Avitsa debentures (in 2017-18 and 2018-19).
Brampton Income	3.3					
Total OPG and HOI Income	**17**	**828.5**	**(441)**	**(89)**	**(603)**	
Other Fees and Licences	**-**	**-**	**8**	**10**	**10**	
Electricity Expenses of the Province						
Provision for Electricity Sector	53	(672)	(449)	(736)	(711)	**[NOTE: A positive number on this line indicates a decrease in the provision, while a negative number means an increase in provision expense.]** Changes to the Provision (ESDI) expense in 2017-18 mainly reflect higher OPG net income due to recategorisation from Sales and Rentals (see above). Change in out-years reflects TB/MBC approval in 2017-18 PRRT approval to continue Provision for the Electricity Sector (i.e., Electricity Sector Dedicated Income to OEFC) beyond 2017-18. 2017 Budget assumed previous policy whereby ESDI ended after 2017-18.
Public Debt Interest - Electricity Sector	(22)	38	88	88	88	2016-17 PDI at ($514m) was slightly larger than ($492m) projected at Interim. 2017-18 and 2018-19 and onward change reflects revised projections for Provincial debt interest as a result of debt pay downs related to Hydro One's April 2016 and April 2017 offerings, repectively.
Total Electricity Expenses of the Province	**31**	**(635)**	**(361)**	**(648)**	**(623)**	

Electricity Sector Change Since Budget	$ Millions					
($million)	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs)	(40)	93	(89)	(7)	(143)	2016-17 decrease largely due to an OPCD Public Accounts PILs adjustment related to reconciling between OPCD and OEFC net opening assets. OPG PILs also slightly lower than projected. 2017-18 increase is largely due to inclusion of PILs related to disposition of OPG headquarters and Lakeview properties. 2018-19 onward lower mainly due to lower OPG income tax PILs. Property tax componenst are close to Budget 2017.
Other Revenue						
Electricity Debt Retirement Charge	(4)	(19)	-	-	-	
Power Supply Contract Recoveries	99	(110)	(142)	(167)	(170)	Variance in 16-17 is largely due to retroactive payments that the OEFC made to certain non-utility generators (NUGs) with former Ontario Hydro power purchase agreement (PPA) contracts with OEFC. OEFC was required to make these payment following the dismissal by the Supreme Court of Canada of OEFC's application for leave to appeal a judgment of the Court of Appeal of Ontario on a 2015 court decision. Going-forward, variance is largely due to suspension or early termination of some NUG PPAs in response to the IESO's NUG curtailment initiative.
Net Reduction of Power Purchase Contracts	0.1	(0)	(0)	(0)	(0)	
Other Fees and Licences	-	-	(8)	(10)	(10)	
Revenue Pool Residual	-	-	-		-	
Miscellaneous	14	-	-	-	-	
Expenses						
Interest on Debt	19	(55)	(110)	(131)	(152)	2017-18 and onward reflects revised debt interest outlook net of revisions to OEFC interest revenue from OPG, Hyro One IESO and Province.
Power Supply Contract Costs	(99)	110	142	167	170	Same as Power supply contract recoveries above. Power supply contract costs are fully recovered by power supply contract recoveries.
Electricity Consumer Price Protection Fund	-	-	-	-	-	
Demand Management Support Costs	1.8	-	-	-	-	
Provision for Electricity Sector	(53)	672	449	736	711	see explanation above for "Provision for Electriocty Sector" (line 17)
Other (Finance)	(1.0)	-	(1)	(1)	(1)	
Total OEFC Income	**(63)**	**692**	**241**	**587**	**404**	
Impact on Surplus/(Deficit)[1]	**-15**	**886**	**-553**	**-139**	**-811**	Note: A significant component of the changes above affecting this net is from a fiscally-neutral recategorisation of revenue impacts from the Asset Optimisation (AO) initiative previously shown in Sales and Rentals in Budget 2017 for commercial confidentiality. The pure changes to non-AO electricity sector changes is significantly fiscally negative. IN 2018-19 ONWARD. See summary table below for breakdown of total change between these components.
Information: Breakdown of change between revenue and expense						
Total Revenue Impact	87	793	(672)	(262)	(916)	
Total Expenditure impact	101	(93)	(119)	(123)	(105)	

Electricity Sector Outlook (PSAB)

Negative Revenue Risks	$ Millions				
($ millions)	Plan				
	2017-18	2018-19	2019-20	2020-21	2021-22
Generic					
OPG Generation Risk: Nuclear Output (-1.6 TWh)[1]	(120)	(120)	(120)	(120)	
1% decrease in Hydro One actual load[2]	(57)	(59)	(62)	(63)	
Lower OPG's Equity weighting & Return on Equity (ROE)[3]	(12)	(20)	(26)	(45)	
Lower Hydro One Return on Equity (ROE)[4]	(9)	(36)	(38)	(40)	
ONFA adjsutment risk		(400) to 0	(400) to 0	(400) to 0	(400) to 0
Regulatory					
Hydro One Distribution rate application[5]	(50)	(50)	(50)	(50)	
OPG Switch from accrual based to cash based accounting for pension and OPEB[6]	–	(600)			
Regulatory Risk - Timing of OPG Rate Decision[7]	–				
OEB Staff Recommendations wrt OPG rate application(May 2017)[8]	–				
Nuclear Liabilities Cash vs. Accrual[9]	–				
OEB decision on Hydro One tax recapture (if one-time write-down)[10]	(420)				
Accounting					
OPG IFRS Consolidation Risks[11]		—	—	—	
Other Risks					
ONFA adjustment decrease[12]	(100)				
Avista Acquisition - Termination fee		(49)			
PILs risk related to defesement of Stranded debt and potential wind down of OEFC[13]					(20)

Note: These risks do not reflect the impacts on electricity sector revenue and expense of reclassification of the Asset Optimization strate

1. OPG's market and generation risks related to nuclear reliability similar to the scenarios OPG developed for its sales margins to capture major market risk factors (e.g., natural gas prices, coal prices, foreign exchange, nuclear reliability) in its 2012 business plan. Currently, only the nuclear reliability risk is captured at the current regulated rate for OPG's nuclear generation.

2. Estimated revenue impact if Hydro One load for Transmission and Distribution is 1% lower than projected for all years in CEFD Hydro One Forecast. Based on the assumption a 1% increase in load is directly proportional to a 1% change in revenue requirements.

3. Risk range for Hydro One transmission and distribution reflects potential risk of lower ROE by 0.5% vs assumed ROEs in business plan along with reduced deemed debt to equity weighting of 55%/45% from the current 51%/49%.

4. Risk range for Hydro One transmission and distribution reflects potential risk of lower ROE by 0.5% vs assumed ROEs in CEFD Hydro One Forecast based on the most recent rate applications and forecasted ROE rates.

5. OEB is expected to make a decision on Hydro One's Distibution rate application for 2018 during the first half of 2018.

6. Previous risk removed shifted from 2017-18 to 2018-19. OEB's September 2017 Report, established accrual accounting method as default rate setting method to recover Pension and Other Pension Benefits (OPEBs) costs and recommended continuance of variance account tracking the difference between cash vs. accrual basis reporting for Pension and OPEB. This finding mitigates this risk. However, OEB December 28, OPG rate decision instructs OPG to submit request to dispose of Pension and OPEB deferral and variance account balances during 2018 for its 2019 payment application. OEB's final decision will be made at that time. Note, the impact of a decision could fall in 2019-20 depending on timing of the OEB decision.

7. **Previous risk removed with timing impact now reflected in OPG outlook.**. OEB December 28, decision and order provides an effective date for new rates of June 1, 2017. OPG's business plan assumed OEB decision would be effective as of January 1, 2017. OPG estimated an impact of -$60M for each month for which OEB decsion is not retroactive. The resulting $300M estimated impact has been included in the OPG outlook.

8. **Previous risk removed .** Estimated impact of OEB December 28the decision and order with respect to OPG rates is now reflected on the OPG Outlook.

9. **Previous risk removed.** Risk is related to potential switch to cash-basis accounting for regulated recovery of nuclear payment anmounts. OEB December 28, 2017 Decision and Order has deferred this issue to next OPG rate application in 2021 for 2022 to 2027 period.

10. The OEB's Sep. 28, 2017 ruling on Hydro One's Transmission rate application included direction on sharing, with ratepayers, tax savings related to the Hydro One IPO. Hydro One filed a Motion to Review this decision with the OEB and has also filed a court appeal. Hydro One's 2017 Q3 financial report notes that if the Motion to Review and appeal are unsuccesful the company would record a one-time write-down of $885 million (for transmission and distribution net income) reflecting the OEB decision. The risk above reflects this risk at the Province's current 47.4% average share allocation. Hydro One noted that timing for the Motion to Review and appeal is uncertain. It expects the OEB Review to start in Q1 but noted that it could run in to Q2. As a result the impact could occur in 2018-19.

11. **Previous risk figures removed.** OPCD provided IFRS impact estimates (largely related to OPG) at the time of Budget 2017. A portion of these were reflected in in OPG's and Hydro One's net income outlook at the time of the 2017. The current Electricity Outlook now reflects this additional IFRS risk. Table below outlines OPG IFRS Risks versus what is built into the 2017 Budget Fiscal Plan. The new IFRS adjustments figures are pending from OPG via Energy in the next few days.

	2017-18	2018-19	2019-20	2020-21
OPG IFRS Risk	(400)	(475)	(700)	(750)
Risks Built into Fiscal Plan at 2017 Budget	(400)	0	(200)	0
Additional Risks now picked up in this Electricity Outlook	0	(475)	(500)	(750)

Electricity Sector Outlook (PSAB)

Positive Revenue Risks ($ millions)	Plan 2017-18	2018-19	2019-20	2020-21
Generic				
OPG Generation Risk: Nuclear Output (+1.1 TWh)[1]	85	85	85	85
1% increase in Hydro One actual load[2]	57	59	61	63
Higher OPG Return on Equity (ROE)[3]	6	22	19	33
Higher Hydro One Return on Equity (ROE)[4]	19	69	50	50
ONFA adjsutment risk		0 to 400	0 to 400	0 to 400
Regulatory				
Accounting				
Other Risks				
ONFA adjustment increase[5]	100			

gy or updates to AO strategy.

1. OPG's market and generation risks related to nuclear reliability similar to the scenarios OPG developed for its sales margins to capture major market risk factors (e.g., natural gas prices, coal prices, foreign exchange, nuclear reliability) in its 2012 business plan. Currently, only the nuclear reliability risk is captured at the current regulated rate for OPG's nuclear generation.

2. Estimated revenue impact if Hydro One load for Transmission and Distribution is 1% higher than projected for all years in CEFD Hydro One Forecast. Based on the assumption a 1% increase in load is directly proportional to a 1% change in revenue requirements.

3. Risk range for OPG reflects potential risk of higher ROE in 2018-2021 (for nuclear base) vs assumed ROE in OPG's 2016 business plan and corresponding rate application. Assumed ROE is 9.85%, respresenting recent in 2010.

4. Risk range for Hydro One transmission and distribution reflects potential risk of higher ROE vs assumed ROEs in the Hydro One CEFD Forecast for 2018-2021. Assumed ROE is 9.85%, representing recent high in 2010.

5. Reflects risk around the consolidation adjustment to OPG net income, whereby the realized portion of gains or losses of OPG's nuclear funds are added or subtracted from OPG net income. Currently $194M positive adjustment reflecting valuations as of December 31, 2017 is included in the OPG outlook. Given current market volatility the ONFA adjustment could change significantly by the end of the Province's fiscal year, March 31, 2018. The net debt adjustment to be included in the fiscal plan consistent with the December 31, 2017 valuations/reports would also be subject to the same type of volatility.

ONTARIO ELECTRICITY FINANCIAL CORPORATION
On Deck Outlook as of March 2017

$ Millions

	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Revenue						
Revenue Pool Residual						
Debt Retirement Charge	859	625	623	-	-	-
Payments-in-lieu of tax:						
OPG	268	302	315	366	408	537
Legacy Hydro One (Including Brampton)	2,929	7	2	2	2	2
Hydro One CIT dedicated to OEFC	3	20	20	22	23	25
MEUs	27	44	68	86	105	114
Total PILs & CIT dedicated to OEFC[1]	3,228	373	405	476	538	679
Interest :						
OPG	173	179	168	153	135	135
H1						
IESO	2	3	3	3	3	3
Province	520	492	492	492	492	492
Other	28	10	5	5	5	5
Total Interest	723	684	668	653	635	635
Power Supply Contract Recoveries	875	739	292	325	301	273
Amortization of NUG liability	172	129	74	41	30	28
Electricity sector dedicated income	3	342	525	-	-	-
Gain to OEFC under s. 50.3	172	-	-	-	-	-
Miscellaneous	9	-	-	-	-	-
	6,041	2,893	2,587	1,495	1,504	1,615
Expense						
Debt interest	1,319	1,216	1,090	1,027	977	885
Interest on nuclear risk funding						
Demand Management Support Costs	8	10	10	-	-	-
Amortization of deferred debt costs	-	-	-			
Power Supply Contract Costs	875	739	292	325	301	273
Debt Guarantee fee	127	122	102	91	88	81
Operating	7	6	6	6	6	6
	2,336	2,093	1,500	1,449	1,372	1,245
Excess (Deficiency) of Revenue over Expense	**3,705**	**800**	**1,087**	**46**	**132**	**370**
Prior period adjustment	87					
Stranded Debt - Year End	**4,393**	**3,593**	**2,506**	**2,460**	**2,328**	**1,958**

Note: All the Hydro One ownership broadening impacts, other than the ownership change from the initial IPO in 2015 and the secondary offering in April 2016, were reflected in Sales and Rentals as of the 2017 Budget.

ONTARIO ELECTRICITY FINANCIAL CORPORATION
On Deck Outlook as of February 2018 **$ Millions**

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Revenue						
Revenue Pool Residual						
Debt Retirement Charge	859	621	604	0	0	0
Payments-in-lieu of tax:						
OPG	268	224	440	277	401	394
Legacy Hydro One (Including Brampton)	2,929	4	2	2	2	2
Hydro One CIT dedicated to OEFC	3	25	24	22	23	25
MEUs	27	112	33	86	105	114
Total PILs & CIT dedicated to OEFC[1]	3,228	364	499	387	531	535
Interest :						
OPG	173	167	155	166	158	131
H1						
IESO	2	2	3	3	3	3
Province	520	514	454	404	404	404
Other	28	20	20	20	10	10
Total Interest	723	703	632	593	575	548
Power Supply Contract Recoveries	875	838	182	183	134	103
Amortization of NUG liability	172	129	74	41	30	28
Electricity sector dedicated income	3	302	797	449	736	711
Gain to OEFC under s. 50.3[2]	172	411	531	0	0	0
Miscellaneous	9	14	0	0	0	0
	6,041	3,382	3,319	1,652	2,006	1,925
Expense						
Debt interest	1,319	1,216	1,109	1,077	1,048	950
Interest on nuclear risk funding						
Demand Management Support Costs	8	8	10	0	0	0
Amortization of deferred debt costs	0	0	0			
Power Supply Contract Costs	875	838	182	183	134	103
Debt Guarantee fee	127	122	102	99	98	91
Operating	7	7	6	7	7	7
	2,336	2,191	1,409	1,366	1,287	1,151
Excess (Deficiency) of Revenue over Expense	3,705	**1,191**	**1,911**	**287**	**719**	**774**
Prior period adjustment	87					
Stranded Debt - Year End	4,393	**3,202**	**1,292**	**1,005**	**286**	**(488)**

1

Payments-in-lieu of tax:	2015-16 Public Accounts
OPG	290
Legacy Hydro One (Including Brampton)	2,941
Hydro One CIT dedicated to OEFC	0
MEUs	15
	3,247

2 **2017-18 value preliminary estimate, subject to change.**

ONTARIO ELECTRICITY FINANCIAL CORPORATION

Changes from Budget 2017 as of February 2018 **$ Millions**

	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Revenue						
Debt Retirement Charge	(4)	(19)	-	-	-	
Payments-in-lieu of tax:						
OPG	(78)	125	(89)	(7)	(143)	2016-17 decrease largely due to an OPCD Public Accounts PILs adjustment related to reconciling between OPCD and OEFC net opening assets. OPG PILs also slightly lower than projected. 2017-18 increase is largely due to inclusion of PILs related to disposition of OPG headquarters and Lakeview properties. 2018-19 onward lower mainly due to lower OPG income tax PILs. Property tax componenst are close to Budget 2017. .
Legacy Hydro One (Including Brampton)	(3)	-	-	-	-	
Hydro One CIT dedicated to OEFC	5	3	-	-	-	Adjustment based on updated information in Hydro One rate application
MEUs	68	(35)	-	-	-	Large increase in 2016-17 from $80M payment during transfer of H01 Brampton to new consolidated MEU Alectra.
Total PILs	(9)	93	(89)	(7)	(143)	
Interest :						
OPG	(12)	(13)	13	23	(4)	Update to OPG interest outlook (wrt interest on OEFC loan).
H1	-	-	-	-	-	
IESO	(1)	-	-	-	-	
Province	22	(38)	(88)	(88)	(88)	2016-17 PDI at ($514m) was slightly larger than ($492m) projected at Interim. 2017-18 and 2018-19 and onward change reflects revised projections for Provincial debt interest as a result of debt pay downs related to Hydro One's April 2016 and April 2017 offerings, repectively.
Other	10	15	15	5	5	
Total Interest	19	(36)	(60)	(60)	(87)	
Power Supply Contract Recoveries	99	(110)	(142)	(167)	(170)	Variance is largely due to retroactive payments that the OEFC made to certain non-utility-generators (NUGs) with former Ontario Hydro power purchase agreement contracts with OEFC. OEFC was required to make these payment following the dismissal by the Supreme Court of Canada of OEFC's application for leave to appeal a judgment of the Court of Appeal of Ontario on a 2015 court decision.
Amortization of NUG liability	0	(0)	(0)	(0)	(0)	
Electricity sector dedicated income	(41)	272	449	736	711	The decrease in OEFC ESDI in 2017-18 reflects i) the IFRS adjustment of $400 million in 2017-18 that was not reflected in the OEFC ESDI projection at the time of the 2017 Budget (Note the IFRS adjustment was reflected in OPG net income for the 2017 Budget fiscal plan) and ii) the lower OPG and Hydro One net income due to OEB's 2017 rate decisions. Changes to the Provision (ESDI) expense in 2017-18 mainly reflect higher OPG net income due to recategorisation from Sales and Rentals of proceeds from the sale of OPG headquarters properties and Lakeview properties. Th eincrease in 2018-19 onward reflects TB/MBC approval in 2017-18 PRRT approval to continue Provision for the Electricity Sector (i.e., Electricity Sector Dedicated Income to OEFC) beyond 2017-18. 2017 Budget assumed previous policy whereby ESDI ended after 2017-18.
Gain to OEFC under s. 50.3	411	531	-	-	-	
Miscellaneous	14	-	-	-	-	
	489	732	157	502	310	
Expense						
Debt interest	-	19	50	71	65	Revised outlook for OEFC debt interest outlook
Interest on nuclear risk funding	-	-	-	-	-	
Demand Management Support Costs	(2)	-	-	-	-	
Amortization of deferred debt costs	-	-	-	-	-	
Power Supply Contract Costs	99	(110)	(142)	(167)	(170)	Same as Power supply contract recoveries above. Power supply contract costs are fully recovered by power supply contract recoveries.
Debt Guarantee fee	-	-	8	10	10	
Operating	1	-	1	1	1	
	98	(91)	(83)	(85)	(94)	
Excess (Deficiency) of Revenue over Expense	**391**	**823**	**241**			
Stranded Debt - Year End	**3,202**	**1,292**	**1,005**	**286**	**(488)**	

Provision for Electricity Sector (Dedicated Electricity Earnings/Electricity Sector Dedicated Earnings)

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Income from Investment in Government Business Enterprises						
OPG Income	291	299	905	500	728	677
Hydro One Income[1]	232	501	346	353	412	438
Hydro One Brampton (if applied separately)		15				
Total Income	**523**	**815**	**1,251**	**853**	**1,140**	**1,115**
Public Debt Interest - Electricity Sector						
OPG			(300)	(300)	(300)	(300)
Hydro One[1]			(154)	(104)	(104)	(104)
Public Debt Interest - Electricity Sector (OEFC Interest revenue)	**(520)**	**(514)**	**(454)**	**(404)**	**(404)**	**(404)**
MOF Provision Expense (before adjustments)	**3**	**302**	**797**	**449**	**736**	**711**
Other Adjustments						
Prior-year Adjustment[2]		3				
Exclude Brampton[3]		(15)				
MOF Provision Expense (after other adjustments)	**0**	**290**	**797**	**449**	**736**	**711**
Cumulative Shortfall Adjustment						
Opening Balance	0	0	0	0	0	0
Deduction / (Addition)	0	0	0	0	0	0
Ending Balance	0	0	0	0	0	0
Dedicated Electricity Earnings (all adjustments) (Public Accounts)	**0**	**290**	**797**	**449**	**736**	**711**
Electricity Sector Dedicated Income (OEFC Annual Report)	**3**	**302**	**797**	**449**	**736**	**711**

Notes:

1. The Hydro One financials above now reflects the Provincial share allocation as of January 2018.

2. 2016-17 Adjustment was due to the discrepancy between the numbers in MOF expense in PA 2015-16 and OEFC Financials in 2015-16 due to timing issues. $3M adjustment rectifies this discrepancy

3. Brampton was excluded from the Ministry of Finance's ESDI allocation.

Ontario Power Generation

OPG Income - Budget 2017

$ Millions

	Actual	Interim	Plan				
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22
OPG Net Income After Tax (Adjusted)	291	304	97	732	625	1,066	
OPG Net Income After Tax	*291*	*379*	*480*	*678*	*726*	*913*	
Extraordinary Gains	-	-	-	-	-	-	
GA - OPG Trust Interest Revenue			*17*	*54*	*99*	*153*	
OPG IFRS consolidation risk picked up in Fiscal Plan		(75)	(400)		(200)		
ONFA and other Fair Value Adjustments	(75)	8					
ONFA Adjustments	-	8					
Other Fair Value Adjustments	(75)						

OPG PIL - Budget 2017

$ Millions

	Actual	Interim		
	2015-16	2016-17	2017-18	2018-19
Net Income Before Tax	383	396	572	867
Net Income After Tax (Adjusted)	291	304	97	732
Income Taxes	92	92	92	135
GRC: Payable to OEFC	198	196	205	212
Proxy Property Tax	16	14	18	19
Ontario Capital Tax	0	0	0	0
Total	**306**	**302**	**315**	**366**

OPG Income - January 2018

$ Millions

	Actual	Actual	Current Outlook				
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22
OPG Net Income	291	377	1,195	795	1,053	877	1,070
GA Financing - OPG Trust Interest Revenue[2]			10	80	150	225	225
OPG IFRS consolidation risk[3]		(78.00)	(300)	(375)	(475)	(425)	(625)
OPG Net Income (Adjusted before ONFA)	**291**	**299**	**905**	**500**	**728**	**677**	**670**
ONFA Adjustments	247	49	194				
Other Fair Value Adjustments	(75)	(6)					
ONFA and other Fair Value Adjustments	**172**	**43**	**194**				
OPG Net Income	**463**	**342**	**1,099**	**500**	**728**	**677**	**670**

OPG PIL - January 2018

$ Millions

	Actual	Actual		Cu
	2015-16	2016-17	2017-18	2018-19
Income Before Tax	383	308	1,126	554
OPG Net Income (Adjusted before ONFA)	291	299	905	500
OPG Income Tax (PILs)	92	9	221	54
GRC: Payable to OEFC	198	201	206	209
Proxy Property Tax to OEFC	16	14	13	14
Ontario Capital Tax	0	0	0	0
Total OPG PILs	**306**	**224**	**440**	**277**

1. OPG's May 2017 head office facilities sale impacts are re-categorized from Sales and Rentals to OPG net income and PILs in the current Electricity Outlook update. This update now also includes 2017-18 proceeds from the Lakeview properties sale.

2. This reflects interest earnings on GA financing costs which are consolidated back to Province

3. IFRS risk provided by OPCD as of 2017 Budget

Hydro One Ownership Calculation:		SOURCE:
Total number of shares outstanding[1]	595,000,000	1. Hydro One Ltd Annual Report 2015, pg 94 of PDF, pg 92 of the Report.
Additional Common Shares Issued since IPO	386,711	
IPO November 2015		
Initial Public Offering(2015)[2]	81,100,000	2. From news release: http://hydroone.mediaroom.com/2015-11-05-Hydro-One-Limited-Announces-Closing-of-IPO
Over allotment option (2015)[3]	8,150,000	3. From news release: http://hydroone.mediaroom.com/2015-11-12-Hydro-One-Limited-Announces-Closing-of-IPO-Over-Allotment-Option
Sales to PWU/SEP Trusts	5,646,340	
Total	94,896,340	
Province's remaining ownership, Nov 2015 (# Shares)	**500,103,660**	
Province's remaining ownership, Nov 2015 (%)	**84.05%**	
Secondary Offering April 2016		
Secondary Offering (2016)	72,434,800	4. Hydro One Ltd. Q2 Report, pg 1 http://www.hydroone.com/InvestorRelations/FinancialReporting/Documents/Hydro%20One%20Ltd%20Second%20Quarter%20
Over allotment option (2016)	10,865,200	
Total	83,300,000	
Province's remaining ownership, Apr 2016 (# Shares)	**416,803,660**	
Province's remaining ownership, Apr 2016 (%)	**70.05%**	
Final Offering May 2017		
Final Offering (2017)	120,000,000	Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by-the-Provin
Over allotment option (2017)	-	Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by-the-Provin
Total	120,000,000	
Province's remaining ownership, May 8, 2017 (# Shares)	296,803,660	Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by-the-Provin
Province's remaining ownership, May 8, 2017 (%)	**49.88%**	
First Nations Sale, closed on December 29, 2017	14,391,012	Source: http://www.S:\Users\CEF\Hydro 2018\OEFC\RbP\Outlook\01. January\Backup\20180103-0 - H1 First Nations Sales\
	2.4170865%	Source: https://news.ontario.ca/mei/en/2017/05/ontario-raises-28-billion-from-final-hydro-one-share-offering.html
Province's remaining onwership - post First Nations Sale (#Shares)	282,412,648	
Province's remaining onwership - post First Nations Sale (%)	**47.43%**	
Avista Impact (projected closing date 2nd half of 2018)		
Contingent Convertible Debenture	$1,540,000,000	
Conversion Price	$21	
Potential Dilution (# Shares)	71,962,617	
Revised Total number of shares outstanding	**666,962,617**	
Province's remaining onwership - post Avista Acquisition (#Shares)	282,412,648	
Province's remaining onwership - post Avista Aquisition (%)	**42.34%**	

Ownership Percentage in 2017-18 Fiscal Year	Number of Months	Percentage of Year
70.05%	1	8.3%
49.88%	8	66.7%
47.43%	3	25.0%
	12	
Average 2017-18 FY Ownership:	**51.0%**	

Ownership Percentage in 2018-19 Fiscal Year (assume Avista closing end of September 2018)	Number of Months	Percentage of Year
47.43%	6	50.0%
42.34%	6	50.0%
	12	
Average 2018-19 FY Ownership:	**44.9%**	

Ownership Percentage in 2019-20 Fiscal Year Onwards
42.34%

Accretive to earnings per share and cash flow for Hydro One in the first full year post closing
above is from Hydro One transaction overview. Check what this means for timing of additional shares and /or earnings.

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Hydro One Net Income and PILs

Hydro One Income - Budget 2017
($ millions)

	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Hydro One Net Income After Tax	685	737	742	802	862	931
Hydro One - Unrealized Gains Adjustment						

2016-17 to 2020-21 from CEFD Hydro One 2016 model.

Hydro One PIL - Budget 2017
($ millions)

	2015-16	2016-17	2017-18	2018-19
Net Income After Tax	685	737	742	802
Income Taxes PILs	132	160	181	205
Proxy Property Tax	2	2	2	2
Ontario Capital Tax	0	0	0	0
Total	**134**	**162**	**183**	**207**

Hydro One Income - December 2017
($ millions) **$ Millions**

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21	2021-22
Hydro One Net Income After Tax			662	706	831	885	943
Hydro One Net Income After Tax - Including Adjustments	670	680	662	706	831	885	943
Hydro One - Net Income Attributable to Preferred Shareholders	15	18	18	18	18	18	18
Hydro One - Unrealized Gains Adjustment							

Hydro One (100% Ownership)
($ millions) **$ Millions**

	Actual 2015-16	Actual 2016-17	2017-18	Cu 2018-19
Net Income After Tax - Common Shares	670	680	662	706
Net Income After Tax - Preferred Shares	15	18		
Income Taxes PILs	132	160	181	205
Proxy Property Tax	2	2	2	2
Ontario Capital Tax	0	0	0	0

Public Debt Interest and Section 50.3 payments

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Hydro One Public Debt Interest and Section 50.3 payments						
Government Annual Interest Costs - Hydro One	220	220	220	220	220	220
Reduction in Interest Costs due to Broadening[1]		(29)	(66)	(116)	(116)	(116)
Province Annual Interest Costs - Hydro One Debt	**220**	**191**	**154**	**104**	**104**	**104**
Province Annual Interest Cost - OPG Debt	300	300	300	300	300	300
Total Public Debt Interest	**520**	**514**	**454**	**404**	**404**	**404**

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Gain to OEFC under s. 50.3	172	411	531	0	0	0

1. The Hydro One reduction in interest costs above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering are currently reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

2020-21							
220	ID# (Track Cha	Fiscal Year	alue (Hardcode	Value (Linked)	Description	Source Details	Source (Link)
-116	20170501-2	2016-17	411,152,733	411,152,733	s 50.3 Gain for	Calculation provided by SIFB	
104	20170501-3	2016-17	29	29	Reduction in Int	Internal Calculation	
	20170501-3	2017-18	66	-116	Reduction in Int	Internal Calculation	
	20170501-3	n/a	220	220	Annual Interest	Internal Calculation	
300							
404							

2020-21	ID# (Track Cha	Fiscal Year	alue (Hardcode	Value (Linked)	Description	Source Details	Source (Link)
0	n/a	n/a	5126		($M) Provinces	OEFC 1999-2000 FS, pg 24	
	n/a	n/a	5.85%		Annual Interest	OEFC 1999-2000 FS, pg 26	
			299.871				

	OPG's Annual Interest Costs:		300	
20170713-1	2016-17	-513,768,361	Provincial interest cost for equity investment in OPG, H1 in 2016-17 Monthly Balances Sheet (from FTD) S:\Users\CEF\Hydro 2017\OEFC\RbP\Outlook\07. July\Backup\20170713-1\interest fr	
s. 50.3	531	531	S:\Users\CEF\Hydro 2018\OEFC\RbP\Outlook\02. February\Back-up files	

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PROVINCIAL CONSOLIDATION ADJUSTMENTS
Ontario Nuclear Funds Agreement

Adjustment for Change in OPG Reported Net Income

Adjustment for DSF Unrealized Earnings

Unrealized Earnings as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Bruce Variance Account Adjustment
OPG Net Income Adjustment

Adjustment for UFSF Unrealized Earnings

Unrealized Earnings as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Bruce Variance Account Adjustment
OPG Net Income Adjustment

Unrealized Earnings -- Fiscal YTD

Adjustment for Change in Due to Province

Adjustment for DSF Due to Province
Due to Province (cost basis) as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Change in Due to Province -- Fiscal YTD

Adjustment for UFSF Due to Province

Due to Province (cost basis) as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Change in Due to Province -- Fiscal YTD

Provincial Consolidation Adjustment

Other Data

	Actual 2016-17	2017-18
Debt Retirement Charge	621	0

	2016-17	2017-18
Power Supply Contract Recoveries	838	182

	2016-17	2017-18
Interest		
OPG	167	155
IESO	2	3
Other (Net)	20	20
Expense		
Debt interest	1216	1109

	Actual 2016-17	2017-18
MEU - PIL Income Tax	109.8	
MEU - PIL Property Tax	0.6	
MEU - GRC	1.2	
TOTAL MEU PILs	111.6	

	Actual 2016-17	2017-18
Miscellaneous/Other (OEFC FS)	14	
Demand Management Support Costs (IEI)	8	10
Operating [Expense]	7	6
Interest on nuclear risk funding	-	-
Amortization of deferred debt costs	-	-
Amortization of NUG liability	129	74
Debt Guarantee Fee	122	102

Expense (Electrictiy Summary Tab)		
Other (Finance)	-7	-6
Demand Management Support Costs (IEI)	-8	-10
Debt Guarantee Fee	(122)	(102)

Plan 2018-19	2019-20	2020-21	2020-21
0	0	0	0

Plan 2018-19	2019-20	2020-21	2020-21
183	134	103	103

Plan 2018-19	2019-20	2020-21	2020-21	
166	158	131	119	updated Feb 15, FTD
3	3	3	3	updated Feb 15, FTD
20	10	10	10	updated Feb 15, FTD
1077	1048	950	818	updated Feb 15, FTD

Plan 2018-19	2019-20	2020-21	2020-21

Plan 2018-19	2019-20	2020-21	2020-21
7	7	7	7
-	-	-	-
-	-	-	-
41	30	28	28
99	98	91	91
-7	-7	-7	-7
(99)	(98)	(91)	-91

ID# (Track Changes	Fiscal Year	Value (Hardcoded)	Value (Linked)
20170510-2	2016-17	$ 739,216,115	
20170510-2	2017-18	$ 291,629,707	
20170510-2	2018-19	$ 324,906,017	
20170510-2	2019-20	$ 300,648,570	
20170510-2	2020-21	$ 273,240,858	
20170501-4	2016-17	179	179
20170501-4	2017-18	169	169
20170501-4	2018-19	179	179
20170501-4	2019-20	175	175
20170501-4	2020-21	148	148
20170501-5	2016-17	1216	1,216
20170501-5	2017-18	1121	1,121
20170501-5	2018-19	1094	1,094
20170501-5	2019-20	1053	1,053
20170501-5	2020-21	963	963
20170731-3	2016-17	621	
20170811-1	2016-17	109.8	
20170811-1	2016-17	0.6	
20170811-1	2016-17	1.2	
20170815-5	2016-17	$ 838,000,000	
20170815-6	2016-17	$ 14,000,000	
20170815-8	2016-17	8	
20170815-9	2017-18	10	
20170815-10	2016-17	7	
20171211-2	2017-18	6	6
20171211-2	2018-19	7	7
20171211-2	2019-20	7	7
20171211-2	2020-21	7	7
20170815-7	2016-17	167	
20170815-7	2016-17	2	
20170815-7	2016-17	20	
20170815-7			

ID# (Track Changes	Fiscal Year	Value (Hardcoded)	Value (Linked)
20170905-1	2016-17	129	129
20170905-1	2017-18	74	74

20170905-1	2018-19	41	41
20170905-1	2019-20	30	30
20170905-1	2020-21	28	28
20170905-2	2016-17	122	
20170906-1	2017-18	3	3
20170906-1	2018-19	3	3
20170906-1	2019-20	3	3
20170906-1	2020-21	3	3
20170906-1	2017-18	20	5
20170906-1	2018-19	20	5
20170906-1	2019-20	10	5
20170906-1	2020-21	10	5
20171211-0	2017-18	1115	
20171211-0	2018-19	1089	
20171211-0	2019-20	1060	
20171211-0	2020-21	963	
20171211-1	2017-18	102	102
20171211-1	2018-19	99	99
20171211-1	2019-20	98	98
20171211-1	2020-21	91	91
20171211-1			
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20171211-1			
20171211-1			
20171211-1			

ID# (Track Changes	Fiscal Year	Value (Hardcoded)	Value (Linked)
20180104-2	2017-18	$ 181,776,685	
20180104-2	2018-19	$ 182,785,215	
20180104-2	2019-20	$ 133,962,519	
20180104-2	2020-21	$ 102,554,665	

Description	Source Details	Source (Link)
The table below contains an updated preliminary N	SPFB Estimates, Email	
• The tables below provides both last year's submission for NUG costs by CEFD and this year's estimates (both of which exclude HST) based on the most recent NUG model.	SPFB Estimates, BN SPFB Estimates, BN SPFB Estimates, BN SPFB Estimates, BN	
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
Updating DRC from OEFC AR (Drafts)	2017 OEFC DRAFT FS	S:\Users\CEF\Hydro 2017\OEFC'
MEU - PIL Income Tax	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
MEU - PIL Property Tax	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
MEU - GRC	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
Updating to actuals	2017 OEFC AR	2017 OEFC Annual Report - Eng
Updating to actuals	2017 OEFC AR	2017 OEFC Annual Report - Eng
Updating to Actuals	2017 OEFC AR	S:\Users\CEF\Hydro 2017\OEFC'
OEFC 2017-18 IEI/Demand Management Suppor	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Operating Expense - Updating to Actuals	2017 OEFC AR	S:\Users\CEF\Hydro 2017\OEFC'
Revised Operating Expense from FTD Forecast	FTD - October PRRT	
OPG Interest Revenue - Actuals 2016-17	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
IESO Interest Revenue - Actuals 2016-17		
Other (Net) Interest Revenue - Actuals 2016-17		

Description	Source Details	Source (Link)
		S:\Users\CEF\Hydro 2017\OEFC'
	Amortization Schedule.	S:\Users\CEF\Hydro 2017\OEFC'

Sourcing the NUG liability amortization schedule.	Tab: Summary Fiscal Impact	S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Gurantee Fee - Updating to Actuals	2017 OEFC AR (pg 13 (	\\ofina.on.ca\ofadfs\Users\CEF\H
IESO Interest Revenue Plan	OEFC Revenue Forecast for Board - April 2017	\\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H
Other Interest Revenue Plan		\\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H
OEFC Debt Interest Expense (no change, just re-linking)	FTD - January 11	
OEFC Debt Guarantee Fee	FTD - October PRRT	S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC'

Description	Source Details	Source (Link)
Updated FY 2017-18 estimates of NUG costs	SPFB Estimates, BN	Power Purchases and Sales Fore
Updated FY 2017-18 estimates of NUG costs	SPFB Estimates, BN	Power Purchases and Sales Fore
Updated FY 2017-18 estimates of NUG costs	SPFB Estimates, BN	Power Purchases and Sales Fore
Updated FY 2017-18 estimates of NUG costs	SPFB Estimates, BN	Power Purchases and Sales Fore

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\RbP\Outlook\07. July\Backup\20170731-3 - DRC Update\2017 OEFC Annual Report - English - DRAFT.PDF

\RbP\Outlook\08. August\Backup\20170811-1 - Updating PILs for 2016-17\OEFC 2016-17 Pils summary.pdf
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\RbP\Outlook\08. August\Backup\20170815-9 - 2017-18 Demand Management Support Costs (IEI)\OEFC rever
\RbP\Outlook\08. August\Backup\20170815-10 - 2016-17 Operating (Expense)\2017 OEFC Annual Report - Enc

\RbP\Outlook\08. August\Backup\20170815-7 - 2016-17 Updated Interest on Debt Revenue\RE Revised OEFC

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ydro 2017\OEFC\RbP\Outlook\09. September\Backup\20170906-1 - OEFC Revenue Forecast for Board
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\RbP\Outlook\12. December\Backup\20171211-1 - Interest Numbers from FTD\OEFC forecast PRRT planning_
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Colour Codes

Formulas are in black text

Hard coded numbers are in blue text

References elsewhere are in purple

Green bold text with or without highlights mean updates required

Policies to follow when making updates to the Outlook

*** To quickly jump to the source numbers for a link, press "**Ctrl + [**"

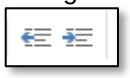
All new numbers must be fully sourced, and follow the colour codes above

Most numbers and text are Arial Size 10, unless it is a title

Add back up materials in a folder with the same numbers as in the 'Track Changes' tab

If there is a reason for italics, or other colours, or formatting make sure it is clear. Othe

Use indents to make things more clear to read



If numbers are taken from another tab they should ONLY be direct links, no calculation

Electricity Summary - (Budget17/On Deck) - Reflects Public Accounts/Financial Statem

OEFC - (Budget17/On Deck) - Reflects OEFC Annual Reports

*Due to slight discrepancies between Public Accounts reporting and OEFC Annual Rep

Outlook Updates Frequency

Frequency	Description	Tab
Monthly	OPG Net Income in-year forecast	OPG
Monthly	OPG PILs in-year forecast	OPG
Quarterly	ONFA Consolidation Adjustment	ONFA
Quarterly	OPG Cash vs Accrual Variance Account	Revenue (Risks)

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ı, adjustment should be done. Even if its just making a negative to a positive. Perform all the calculations on the

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One'!AR29+'Hydro One'!AR31+'Hydro One'!AR32), let's avoid them.

PROGRAM NOTE
MINISTRY OF FINANCE – Electricity Finance Program (Feb 2018)

Government Priority Outcome	**Supportive and Dynamic Business Environment**
Program Type	**Supporting**
Ministry Linkages	**Ministry of Energy**

I. Assessment of Program Base

$M	15-16	16-17	17-18	18-19	19-20	20-21	Growth Rate 15-16 to 17-18	Growth Rate 18-19 to 20-21
Current Allocation								
Operating Expense	892.9	877.8	308.0010	331.0010	307.0010	279.0010		
Capital Expense	0.0	0.0	0.0	0.0	0.0	0.0		
Total Expense	**892.9**	**877.8**	**308.0010**	**331.0010**	**307.0010**	**279.0010**		
% Growth		-2%	-65%	7%	-7.3%	-9.1%	X.X%	X.X%
Operating Assets	109.96	0.0	275.00	0.0				
Capital Assets	0.0	0.0	0.0	0.0	0.0	0.0		

$M	21-22	22-23	23-24	24-25	25-26	26-27	27-28
Capital Expense	X.X	X.X	X.X	X.X	X.X	X.X	X.X
Capital Assets	X.X	X.X	X.X	X.X	X.X	X.X	X.X

Notes:

1. Table should be presented on a fully consolidated basis. Capital assets include acquisitions of consolidated entities. Consolidation information should be consistent with information in ORBIT and information submitted to the Office of the Provincial Controller Division (OPCD).
2. See ORBIT for current allocation.

1) OBJECTIVES

Supports the mandate of the Ontario Electricity Financial Corporation ("OEFC") to e.g., manage its debt, financial risks and other liabilities, arising from the restructuring of Ontario Hydro.

1203-S - Hydro One Inc., provincial corporate tax provision, the Electricity Act, 1998

Under the amendments made to section 91.2 of the *Electricity Act, 1998* in the *Budget Measures Act, 2015*, the Minister of Finance has a statutory requirement to pay OEFC in each fiscal year an amount equal to tax payable under the *Taxation Act, 2007* (i.e., the provincial corporate income tax – CIT) by Hydro One Inc. and its subsidiaries for its taxation year ending in each fiscal year, to continue to help

service and pay down the electricity sector stranded debt. Hydro One Inc. is composed of Hydro One Ltd.'s regulated Ontario distribution, transmission and remotes businesses.

Prior to the IPO of Hydro One Ltd. in November 2015, Hydro One Ltd. and all its subsidiaries, including Hydro One Inc., were subject to electricity payments-in-lieu of taxes (PILs) regime, where PILs were paid to OEFC. Now, Hydro One is required to pay federal and provincial corporate income taxes to the federal and provincial governments respectively.

The Ministry is requesting a placeholder in the amount of $1,000 for 1203-S to avoid disclosing any information which may be used by the market to speculate on the performance of Hydro One. In addition, this is a consistent approach other divisions take when the forecast is not available. The actuals for 2015-16 and 2016-17 were $2.9 million (a partial year only, related to the 2015 calendar year following the November IPO) and $24.8 million, respectively.

1203-12 - OEFC Dedicated Electricity Earnings

The transfer of Dedicated Electricity Earnings to OEFC is in accordance with policy adopted by the government since the restructuring of Ontario Hydro as at April 1, 1999 to dedicate its electricity sector revenues to OEFC to service and pay down the legacy debt and other liabilities of the former Ontario Hydro.

This includes transferring to the OEFC the cumulative combined profits of electricity sector government business enterprises (GBEs) in excess of the interest carrying cost of the government's investment in the GBEs.

OEFC receives the payment as revenue and it appears in OEFC's income statement as "Electricity Sector Dedicated Income" (ESDI).

2) OUTCOMES

Supports the servicing and pay down of OEFC's legacy debt and liabilities related to the former Ontario Hydro, including the reduction of OEFC's unfunded liability ("stranded debt") as reported in OEFC's annual financial statements.

Any payments under these statutory line items would be fiscally neutral as the payment from the Ministry to the OEFC is fully offset against the receipt of revenue of OEFC upon consolidation of OEFC into the Province's finances in the Public Accounts of Ontario (OEFC is an agency of the Ministry of Finance, and its financial results are consolidated into Public Accounts).

3) RESOURCES

OEFC uses its revenues, including transfers under 1203-S and 1203-12, to meet its expenses related to its mandate, under the *Electricity Act, 1998,* to service and pay down its debt and other liabilities.

PROGRAM NOTE
MINISTRY OF FINANCE – Electricity Finance Program (Feb 2018)

4) COST DRIVERS

The costs drivers are not in the control of the Ministry of Finance, as the amounts under 1203-S and 1203-12 arise from the financial performance, tax planning of entities outside its control – Ontario Power Generation and Hydro One, decisions of the Ontario Energy Board, and tax rates.

Under section 91.2 of the *Electricity Act, 1998*, the Minister of Finance has a statutory requirement to pay the OEFC in each fiscal year an amount equal to tax payable under the *Taxation Act, 2007* (i.e., the provincial corporate income tax – CIT) by Hydro One Inc. and its subsidiaries for its taxation year ending in each fiscal year.

Dedicated Electricity Earnings arise from the financial performance of Ontario Power Generation and Hydro One, less the interest carrying cost of the government's investment in the GBEs. Payments under this line item are fiscally neutral as the payment from the Ministry to the OEFC is fully offset against the receipt of revenue of OEFC upon consolidation into the Province's finances in the Public Accounts of Ontario

Cost Drivers	Description
Section 91.2 of the *Electricity Act, 1998*	Under section 91.2 of the *Electricity Act, 1998*, the Minister of Finance has a statutory requirement to pay the OEFC in each fiscal year an amount equal to tax payable under the Taxation Act, 2007 (i.e., the provincial corporate income tax – CIT) by Hydro One Inc. and its subsidiaries for its taxation year ending in each fiscal year. Any payments under this statutory line item would be fiscally neutral as the payment from the Ministry to the OEFC is fully offset against the receipt of revenue of OEFC on the consolidation of the Province's finances in the Public Accounts of Ontario (OEFC is an agency of Ministry of Finance, and its financial results are consolidated into Public Accounts).

5) GROWTH RATES

For the Operating Expense, after consolidations, the decreasing amount / negative growth rate is primarily due to the fact that OEFC's power supply contract mounts, which account for the majority of operating expenses on a net basis, are projected to generally decline over time, primarily due to the termination / expiration of the contracts over time.

6) RISKS

If approval is not provided, the Province and Minister of Finance would be criticized for not supporting and being in compliance with the statutory requirement under s. 91.2 of the *Electricity Act, 1998* and the commitment to help service and pay down the electricity sector stranded debt.

The program amounts are driven by external factors, primarily the financial performance of OPG and Hydro One. However, the transfers to OEFC are fiscally-neutral on consolidation, so there is no fiscal risk from this transfer program.

7) OTHER FACTORS

- The OFA, Corporate and Electricity Finance Division, will request from Hydro One Ltd. ("Hydro One") the provincial tax payable information from Hydro One Inc., upon the availability of the information. Hydro One has no obligations, under US GAAP, to report the provincial CIT publicly, so this information is not available publicly, and there may be concerns on commercial and taxpayer confidentiality. Access to the information on a timely basis may also be challenging in the future. Hydro One does provide other information to the Province to support reporting in Public Accounts of the Province's income from Hydro One.
- The provincial CIT amount provided by Hydro One annually is unaudited and prior to a tax assessment by the Canada revenue Agency.
- Some stakeholders may consider the amount to be very low, and much lower than the annualized amount of corporate income PILs paid by Hydro One to OEFC prior to the IPO.
    - The lower amount is consistent with the communications by the Premier's Advisory Council on Government Assets and in Hydro One's IPO Prospectus, that the newly taxable entity would have a large tax shield ("deferred tax benefit") from a revaluation of assets at fair market value for tax purposes, and as reported in Hydro One's 2015 annual financial statements.
    - The revaluation would also reduce the actual federal CIT paid for a number of years, reducing "leakage" to the federal government.

PROGRAM NOTE
MINISTRY OF FINANCE – Electricity Finance Program (Feb 2018)

II. Requested Program Changes

$M	17-18	18-19	19-20	20-21	Growth Rate 18-19 to 20-21
Proposed Allocation					
MOF Expense	*797.3165*	*449.1131*	*736.2681*	*711.0019*	
OEFC Consolidation Expense	*(599.5398)*	*(259.3269)*	*(595.3046)*	*(601.4462)*	
Operating Expense	197.7767	189.7862	140.9635	109.5557	
Capital Expense	0.0	0.0	0.0	0.0	
Total Expense	0.0	0.0	0.0	0.0	
% Growth		-38.3%	-25.8%	-22.0%	-23.9%
Operating Assets	0.0	0.0			
Capital Assets	0.0	0.0	0.0	0.0	

$M	21-22	22-23	23-24	24-25	25-26	26-27	27-28
Capital Expense	X.X	X.X	X.X	X.X	X.X	X.X	X.X
Capital Assets	X.X	X.X	X.X	X.X	X.X	X.X	X.X

Notes:

1. Table should be presented on a fully consolidated basis. Capital assets include acquisitions of consolidated entities. Consolidation information should be consistent with information in ORBIT and information submitted to the Office of the Provincial Controller Division (OPCD).
2. See ORBIT for current allocation.

* Reflects sum of all financial impacts related to Key Operating, Capital, Climate Change, FTE and Technical Decisions

1) Rationale for Change (including impacts on outcomes)

Under the assumptions in the 2017 Fiscal Plan, the discretionary payment of Dedicated Electricity Earnings from the Minister of Finance to the OEFC was assumed to not continue after March 31, 2018. Since the time of the April 1, 1999, restructuring of Ontario Hydro, it has been assumed that the government policy commitment to dedicate these electricity earnings to OEFC would end once the residual stranded debt was retired. Under the *Budget Measures Act, 2015*, the residual stranded debt concept has been removed from the Act, and the Debt Retirement Charge has a fixed legislatively end date of April 1, 2018, instead of being tied to the retirement of residual stranded debt.

Note that while the Debt Retirement Charge (DRC) paid by non-residential electricity users ends as at April 1, 2018 (and ended for residential users as of January 1, 2016), OEFC is expected to continue to have significant debt and other liabilities to service and pay down. The Ministry of Finance proposes that the government continue to make the fiscally-neutral transfer of Dedicated Electricity Earnings to OEFC after April 1, 2018 to continue to help pay down the OEFC's debt and liabilities.

PROGRAM NOTE
MINISTRY OF FINANCE – Electricity Finance Program (Feb 2018)

The estimated amount of the proposed continued Dedicated Electricity Earnings transfer to OEFC would be $449M for fiscal year 2018-19, $736M for 2019-20, and $711M for 2020-21. However, any payments under this item would be fiscally neutral as the payment from the Ministry to the OEFC is fully offset against the consolidation of revenue of OEFC into the Province's Public Accounts of Ontario. (OEFC is an agency of Ministry of Finance, and its financial results are consolidated into Public Accounts).

The requested Dedicated Electricity Earnings amounts over the 2018-19 to 2020-21 period reflect Hydro One and OPG projected net income performance less the interest carrying cost of the government's investment in the GBEs. The amounts also include projected International Financial Reporting Standard (IFRS) adjustments with respect to OPG net income. These amounts are subject to change.

2) Impacts on Program Resources

No impact

3) Changes in Cost Drivers

No changes in cost drivers.

4) Changes in Growth Rates

N/A

5) Integrated Change Narrative

N/A

There would likely be more of a communications issue to manage if OEFC's financial statements no longer showed Electricity Sector Dedicated Income to OEFC in fiscal 2018-19 and beyond.

6) Program Linkages

N/A

PROGRAM NOTE
MINISTRY OF FINANCE – Electricity Finance Program (Feb 2018)

III. Requested Change Decisions

1) Operating Decisions

Key Decisions

Operating Decisions	$M	18-19	19-20	20-21	Docket #
A. The Ministry is requesting to continue to receive Dedicated Electricity Earnings after April 1, 2018.	*MOF Expense*	*449.1121*	*736.2671*	*711.0009*	
	OEFC Consolidation Expense	*(590.3269)*	*(902.3046)*	*(880.4462)*	X
	Operating Expense	(141.2148	(166.0375)	(169.4453)	
	Operating Asset	0.0			

Non-Financial Decisions

Non-Financial Decisions	Docket #
	X

IV. Risks

Objective(s)	Risk(s)	Risk Category	Risk Level	Rationale for Risk Level & Mitigation Plan Considerations
Under section 91.2 of the Electricity Act, 1998, the Minister of Finance will pay the OEFC an amount equal to tax payable under the Taxation Act, 2007 (i.e., the provincial CIT) by Hydro One Inc. and its subsidiaries for its taxation year ending in each fiscal year.	*If approval is not provided, the Province and Minister of Finance would be criticized for not complying with its statutory requirement under s. 91.2 of the Act / its commitment to help service and pay down the electricity sector stranded debt.*	*Financial and Policy*	*Low*	• **Risk Likelihood:** *Low.* • **Risk Impact:** *Low.* • **Time Scale:** *Ongoing.* **Mitigation/Action Plan Considerations:** • If approval is not provided, the Province and Minister of Finance would potentially be criticized for not complying with its statutory requirement under s. 91.2 of the Electricity Act, 1998, or its commitment to help service and pay down the electricity sector stranded debt. • This request was approved in 2015-16 and 2016-17, and it is unlikely that approvals would not be granted for future years, in compliance with the Act.
The Minister of Finance will continue to pay ESDI to the OEFC to serve and pay down stranded debt after DRC ends on April 1, 2018	*Unfunded liability will be paid down more slowly without projected annual ESDI amount.*	*Financial*	*Low*	• **Risk Likelihood:** Low • **Risk Impact:** Low • **Time Scale:** Ongoing **Mitigation/Action Plan Considerations:** • Unfunded liability will be paid down more slowly without projected annual ESDI. • The loss of ESDI revenue to the OEFC will be in addition to other recent revenue decreases (e.g., from the DRC) as a result of other measures put in place (e.g., for electricity price mitigation). • Overall, impact to the Province is fiscally-neutral on consolidation as the OEFC ESDI revenue offsets the Ministry of Finance ESDI expense.

V. Implementation

Section 91.2 of the *Electricity Act, 1998*

- OPCD, as part of its interactions with Hydro One on Public Accounts, will request the provincial tax payable information from Hydro One. However, Hydro One has no obligations, under US GAAP, to report the provincial CIT publicly, so this information is not otherwise expected to be available in the future.
- The provincial CIT amount provided by Hydro One is unaudited, as Hydro One has no obligations, under US GAAP, to report the provincial CIT publicly.

Vote Item 1203-12: Electricity Sector Dedicated Income (ESDI)

- The Minister of Finance will continue to pay ESDI to the OEFC to help service and pay down debt and liabilities after DRC ends on April 1, 2018.

VI. Communications/Stakeholder Engagement Plans

Section 91.2 of the *Electricity Act, 1998*

- Payment under section 91.2 of the *Electricity Act, 1998* will be included in payments-in-lieu of taxes revenue provided in various public documents, most notably OEFC's annual report and its annual financial statements, with the latter included in Volume 2 of Public Accounts.
- Some stakeholders may consider the amount to be very low, and much lower than the annualized amount of corporate income PILs paid by Hydro One to OEFC prior to the IPO.
    - The lower amount is consistent with the communications by the Premier's Advisory Council on Government Assets and in Hydro One's IPO Prospectus, that the newly taxable entity would have a large tax shield from a "deferred tax benefit", and as reported in Hydro One's 2015 annual financial statements.
    - The deferred tax benefit would also reduce the actual federal CIT paid for a number of years, reducing "leakage" to the federal government.

Vote Item 1203-12: Electricity Sector Dedicated Income (ESDI)

- The Minister of Finance will continue to pay ESDI to the OEFC to help service and pay down OEFC debt and liabilities after DRC ends on April 1, 2018.

PROGRAM NOTE
MINISTRY OF FINANCE – Electricity Finance Program (Feb 2018)

VII. Proposed Minute

There are no changes to the Statutory Operating Expense 1203-S "Hydro One Inc., Provincial Corporate Tax Provision, the Electricity Act, 1998" to facilitate future payments to the OEFC as required under s. 91.2 of the *Electricity Act, 1998*.

The Treasury Board/Management Board of Cabinet receive a request to approve an increase to the Dedicated Electricity Earnings (1203-102) of $449M in 2018-19, $736M in 2019-20 and $711M in 2020-21. No increase is projected for 2019-20.

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These amounts, which are transferred to the OEFC, will be fully offset upon the OEFC's consolidation with the Province. While the Electricity Finance Program allocation will increase, there is no net fiscal impact upon consolidation as this increase is offset by OEFC revenue.

In this regard, the following multi-year resources for the program are as follows:

$M	18-19	19-20	20-21
Operating Expense	189.7862	140.9635	109.5557
Capital Expense	0.0	0.0	0.0
Total Expense	**189.7862**	**140.9635**	**109.5557**
Operating Assets	X.X		
Capital Assets	X.X	X.X	X.X

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Note the following multi-year capital resources:

$M	21-22	22-23	23-24	24-25	25-26	26-27	27-28
Capital Expense	X.X	X.X	X.X	X.X	X.X	X.X	X.X
Capital Assets	X.X	X.X	X.X	X.X	X.X	X.X	X.X

In this regard, the Board approve/note/direct:

i)	An increase of $449,112,100 in 2018-19, $736,267,100 in 2019-20 and $711,000,900 in 2020-21 in Ontario Electricity Financial Corporation Dedicated Electricity Earnings – Electricity Sector Dedicated Income (Vote/item 1203-12) offset by consolidations.	Docket #
ii)	Approve decreases of $590,326,900 in 2018-19, $902,304,600 in 2019-20, and 880,446,200 in 2020-21 in the Ontario Electricity Financial Corporation operating consolidation as a result of updated electricity sector forecasts.	

From:	Ronald Kwan
To:	Bruno Amara
Cc:	Darren Scanlan; Francisco Chinchon; John Kim; Usman Zahid
Subject:	RE: 2018-02-16- OPG 2018-21 Business Plan Review-EFBv5.pptx
Date:	Wednesday, March 21, 2018 3:35:34 PM
Attachments:	2018-02-16- OPG 2018-21 Business Plan Review-CEFDv3.pptx

Hi,

A few comments.

Thanks,
Ron

From: Bruno Amara
Sent: March-21-18 14:13
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Darren Scanlan <Darren.Scanlan@ofina.on.ca>; Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>; Usman Zahid <Usman.Zahid@ofina.on.ca>
Subject: FW: 2018-02-16- OPG 2018-21 Business Plan Review-EFBv5.pptx

Hi Ron

Attached is Energy's slide deck on the OPG 18-21 BP for approval by TB/MBC. EFB and SIFB have reviewed an made a few comments.

Thanks
Bruno

Ontario

MINISTRY OF
ENERGY

Ontario Power Generation 2018-2021 Business Plan

March 2018

Ministry Request

- The Ministry of ENERGY is requesting that Treasury Board/Management Board of Cabinet (TB/MBC):

    1. NOTE the receipt of OPG's 2018-2021 Business Plan.

    2. NOTE that the Minister of Energy will provide concurrence with OPG's Business Plan.

Purpose

- As required by the Memorandum of Agreement (MOA) between Ontario Power Generation and the Minister of Energy, OPG provided its Business Plan for 2018-2021 to the Ministry of Energy on February 12, 2018 for concurrence.
- The Minister's concurrence requires presentation of OPG's business plan before TB/MBC.
- Ministry of Energy staff have reviewed this plan in the context of key government priorities and recommend that TB provide approval.
- The Ministry of Energy review and analysis of OPG's business plan is supported by the Corporate and Electricity Finance Division of the Ontario Financing Authority (OFA).
- The following presentation identifies the key aspects of the business plan and how they interrelate.

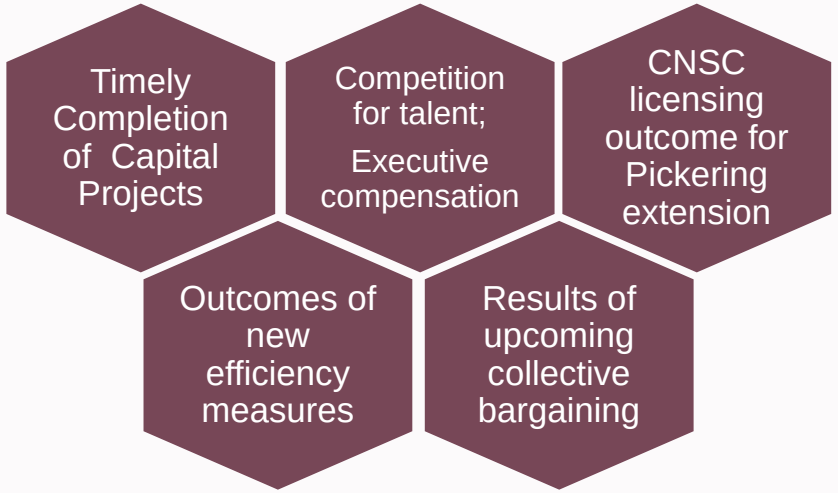
Overview

Business Plan Elements

- The 2018-2021 Business Plan covers an important time for OPG for several reasons:

Business Plan Risks

- Achieving financial performance targets is contingent on positive outcomes in a number of areas:



OPG's ability to manage these elements & risks will determine if it is improves return to the Province and limits ratepayer costs.

Elements of Business Plan

1. **Electricity Production**
   - ❖ Higher than approved production improves financial performance through increased revenue.
   - ❖ Affected by capital projects (e.g., refurb) and Pickering Extension.

2. **Production Costs**
   - ❖ Cost targets fluctuate due to outages, water conditions and efficiency initiatives.
   - ❖ Pickering's cost performance expected to improve relative to previous plan.

3. **Capital Projects**
   - ❖ Timely completion impacts production and project costs
   - ❖ Darlington Refurbishment on track- Unit 2 online in 2020.

4. **Operating Costs & Compensation**
   - ❖ Strategies to increase efficiencies and savings improve financial performance
   - ❖ Subject to collective bargaining that will take place in 2018.

5. **Fair Hydro Plan**
   - Adds ~$6 billion in debt by 2021; Provincial equity doubles by end of plan.
   - Generates net income for OPG ($465 million over 4 years)

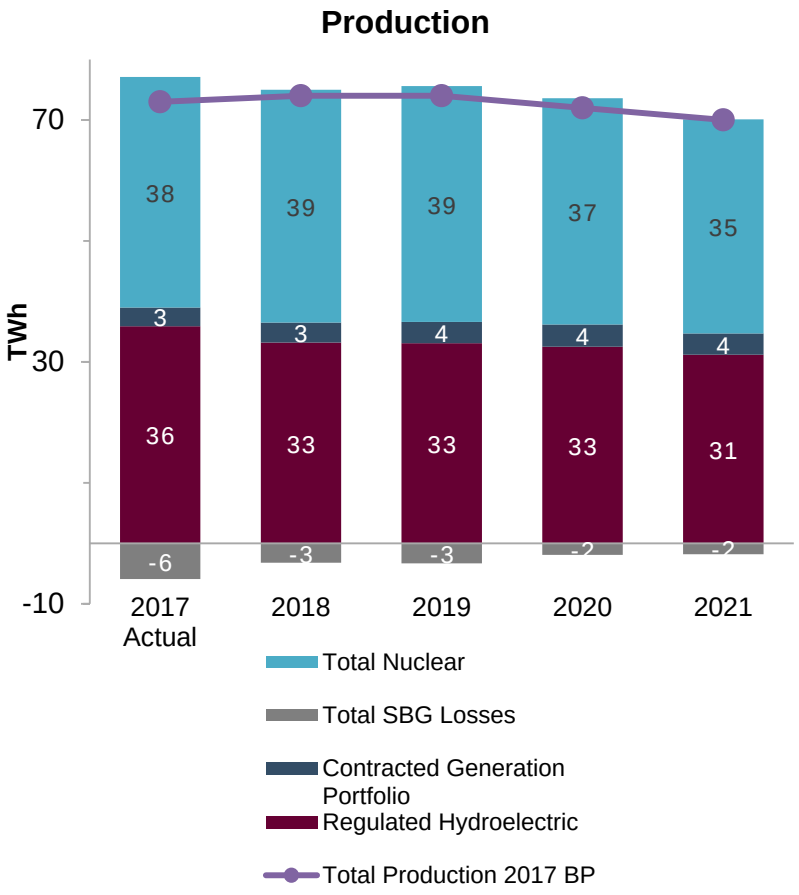
6. **Business Development**
   - Increase revenue through modest hydro expansion, solar, nuclear services & low-carbon technology.
   - Long-term need for new business lines outside of province

7. **Financial Performance**
   - ❖ Performance impacts Province's fiscal position Total Shareholder Return expected to improve over previous plans.

Electricity Production

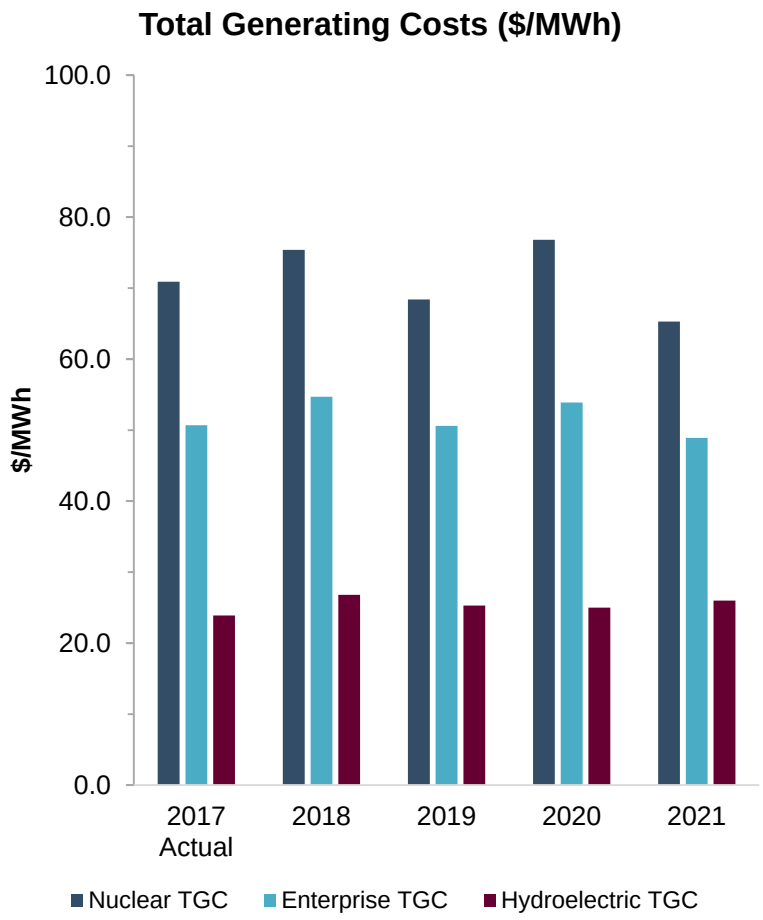
- ❖ Production increases improve financial performance through increased revenue.
- ❖ Forecasts affected by capital projects (e.g., Darlington Refurbishment); Pickering extension and efficiency strategies.

- The plan forecasts a total increase of 5.4 TWh compared to the last business plan.
- Increases are driven by higher production at Pickering Generating Station.
  - OPG will increase time between routine outages, allowing units to run longer.
  - Other reliability improvements reduce Pickering's 'forced loss rate'- (i.e., losses from unplanned shutdowns.)
- The forecasts assume CNSC will grant Pickering licence extension to 2024.
- Production decreases in 2020 when Darlington Unit 2 returns to service and Unit 3 is taken offline. There is also a lengthy planned outage at Pickering.
- The current Thunder Bay biomass energy supply agreement expires in January 2020. The station may participate in a future capacity auction.



Cost of Production

- ❖ Cost targets fluctuate due to outages, water conditions and efficiency initiatives.
- ❖ Pickering's cost performance expected to improve relative to previous plan.



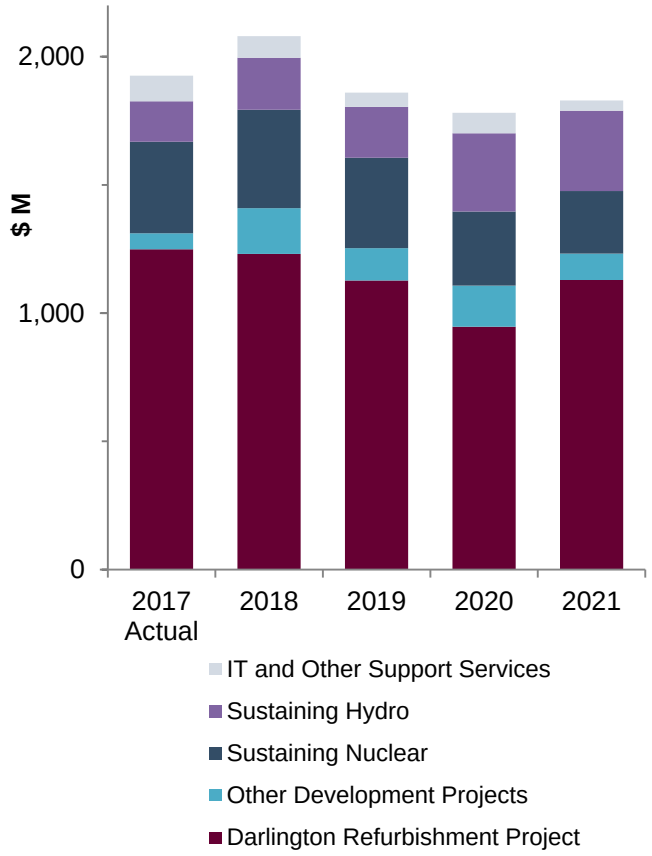
- Total Generating Cost (TGC) per MWh is OPG's measure of operational cost effectiveness.
  - TGC is a performance metric for executive compensation
  - Darlington Generating Station's TGC performance will be how OPG measures the long-term success of its OPG25 restructuring initiative.
- TGC targets fluctuate due to nuclear outages, efficiency initiatives and surplus-baseload generation adjustments due to high water levels.
- The production and cost forecasts are consistent with its OEB rate application. The set rates through 2021 provide planning stability.
  - If OPG exceeds production forecasts, it generates additional revenue. It must absorb costs if production is lower than forecast.

Capital Projects

- ❖ Timely completion impacts production output and costs.
- ❖ Costs deemed imprudent for regulated projects negatively impact financial performance

- The plan includes $4.4 billion in capital expenditures for the Darlington Refurbishment project (DRP). Unit 2 is planned for return to service in early 2020.
- The plan includes $105 million in capital expenditures for the Heavy Water Storage(D2O) project, an enabling sub-project for the DRP that previously experienced delays and cost overruns (note: overall refurbishment has remained within budget and schedule).
- In its rate decision, OEB confirmed it will take a holistic view to assessing DRP costs, evaluating overall project performance against approved budget rather than an individual sub-project basis.
- Other capital expenditures include:
  - Ranney Falls re-development (2019 completion)
  - Nanticoke Solar (2019 completion)
  - Beck generating station upgrades (2022 completion)
  - Other sustaining capital (Hydro unit overhauls; equipment upgrades)
- The plan accelerates capital expenditures for OPG's digital transformation in support of improved efficiency.

Total Capital Expenditures



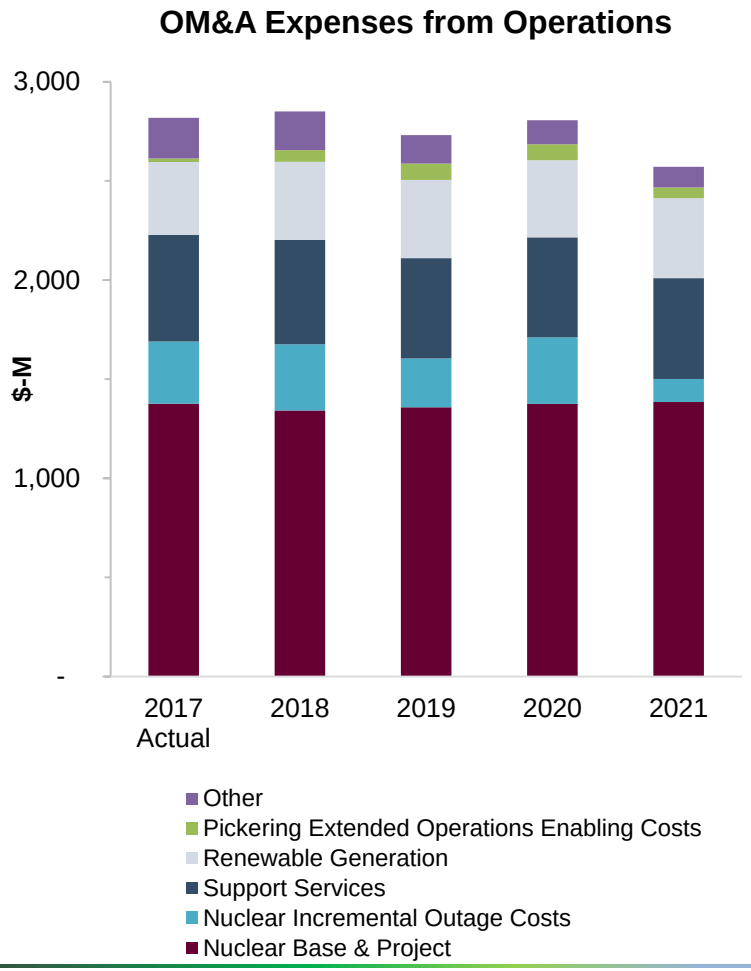
Operating Costs (OM&A)

- ❖ Incremental efficiencies/savings improve financial performance
- ❖ OEB Decision reduces OM&A / compensation

- The plan targets a total decrease in OM&A expenditures of $600 million over four years. Annual spending decreases by $280 million in 2021 compared to 2018.
- The reductions will be achieved through new processes, technology upgrades and reducing nuclear plant outage frequencies.

OPG25 Initiative

- OPG25 is a plan to restructure OPG due to the closure of Pickering in 2024.
- The objective of OPG25 is to ensure operations remain cost-effective and that OPG is positioned for growth.
- The long-term target for the plan is having Darlington operate in the top-quartile for total generating costs.
- The initiative includes a staffing transition work stream, making interaction with unions critical.
- The 2018-21 business plan's cost reductions will help move OPG towards achieving the total target reductions post Pickering operations.

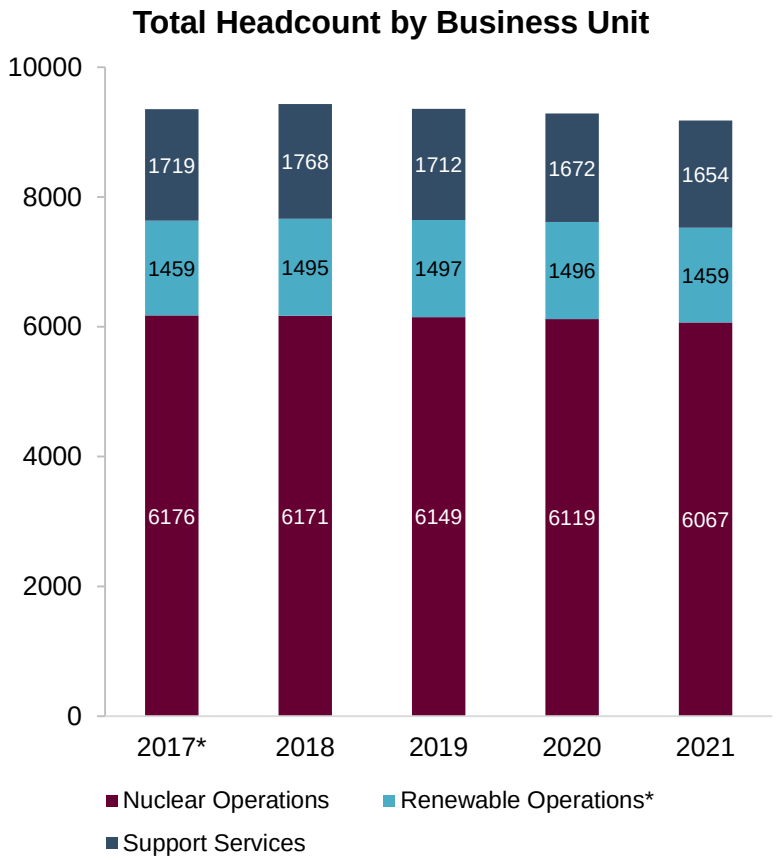


Compensation

Collective Bargaining

- ❖ Collective agreements expire in 2018.
- ❖ Results of collective bargaining will impact efficiency and cost-optimization initiatives.

- Collective bargaining impacts OPG's ability to reduce OM&A. Most employees belong to either the Power Workers Union (PWU) or Society of Energy Professionals (Society).
- Collective agreements with Society & PWU expire in 2018. Negotiated outcomes will impact OPG's ability to meet the plan's savings forecasts. Through collective bargaining, OPG hopes to:
  - Manage wage increases
  - Reduce future workforce costs including pension and benefits
  - Ensure future staff capability
  - Reduce downsizing costs resulting from Pickering closure*
- The plan identifies an accounting risk related to Pickering downsizing costs materializing prior to the next OEB rate application. This would affect net income in the year the costs were recognized.



Compensation

Executive Compensation

- ❖ Executive compensation program implemented in January 2017
- ❖ Compensation program benchmarks against comparator organizations

- OPG implemented an Executive Compensation Program in 2017 compliant with *O.Reg 304/16.*
- The program is designed to provide compensation that is at the 50th percentile of the market and focused on at-risk, performance based pay.
- In 2017, TB/MBC approved exemptions allowing OPG to compare against private sector and international companies.
- Overall compensation for all management group staff increases at 2% based on assumed inflation each year in the plan.
- Short-term incentives are based on individual performance and the corporate scorecard. Strong performance on the scorecard led to increases in executive incentives in 2017.
- Corporate scorecard measures for 2018 include:

2016-2018 executive medium-term incentive performance metrics
(on 3-year cycle ending 2018)

- **Return on Equity**
- **Total Generating Cost**
- **Darlington Refurbishment Major Milestones**

Social Licence: Total Recordable Injury Frequency; no significant events impacting OPG's reputation

Financial Strength: Earnings Before Tax (excluding the Nuclear Waste Management segment), Plan Operating OM&A Expenses.

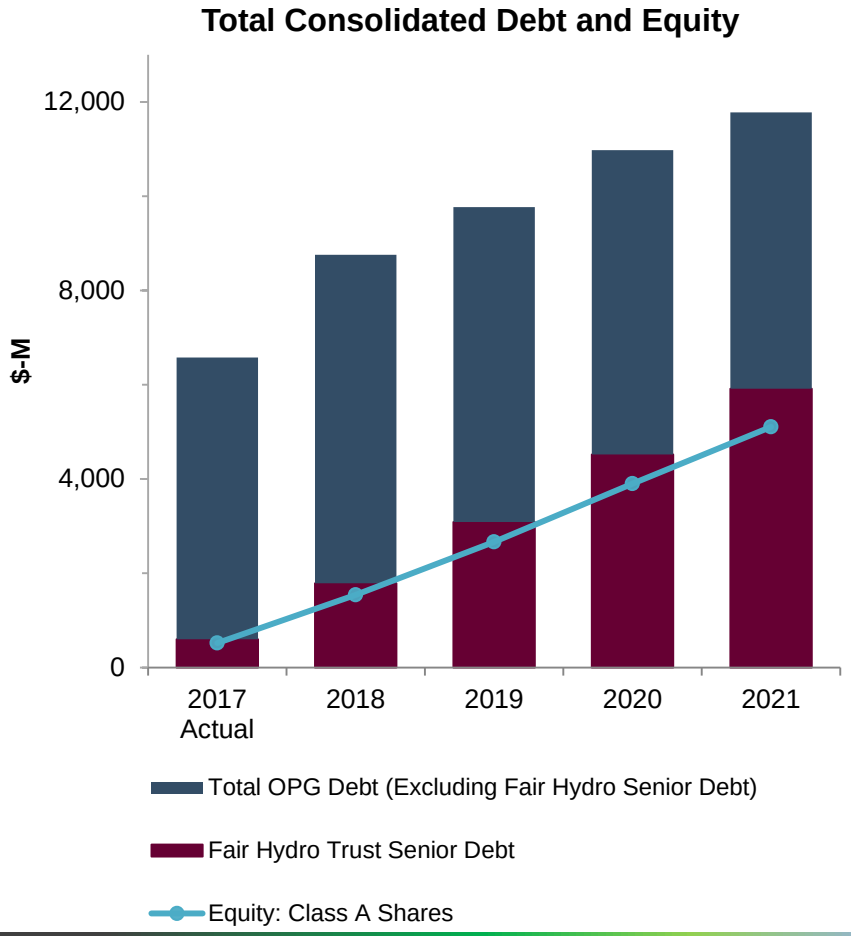
Operational Excellence: Total OPG production adjusted for Surplus Baseload Generation

Project Excellence: DRP costs and schedule; Peter Sutherlands Sr. Generating Station, and total in-service capital

Fair Hydro Plan

- ❖ FHP is managing the deferral of a portion of Global Adjustment (GA) costs.
- ❖ OPG earns revenue and incurs debt; Provincial equity in OPG doubles by 2021.
- ❖ While a new source of revenue for OPG, revenue is paid by Ontario ratepayers.

- In 2017, OPG began its role as OFHP Financial Services Manager (FSM).
- The Fair Hydro Trust contributes to increasing amounts of net income, growing from $10 million in 2018 to $225 million in 2021.
  - This reflects the spread earned on the equity contributions from the Province to fund 44% of OPG's financing of the Trust.
- As the Province provides more funding to facilitate asset purchases in exchange for shares in the company, the government's equity increases, lowering ROE.
- The Fair Hydro Trust external senior debt is projected to increase to $5.9 billion by 2021.



Business Development

- ❖ OPG hopes to grow its business and increase revenue through modest hydro expansion, solar, nuclear services & low-carbon technology.
- ❖ Long-term need for new business lines outside of province.

- OPG hopes to grow its business by investing in commercial innovation, project development and asset acquisition.
- The business plan references organic and non-organic investments:
  - Organic investments are in-house project development of generation and energy products in Ontario. The plan allocates incremental capital funding of ~$200 million for organic investments.
  - Non-organic investments are new opportunities in Ontario. These investments are not included in the plan, however, OPG forecasts up to $3 billion would be available for such investments.

Business Development investment categories:

Innovation & Services
OPG will consider investing in near commercial emerging technologies

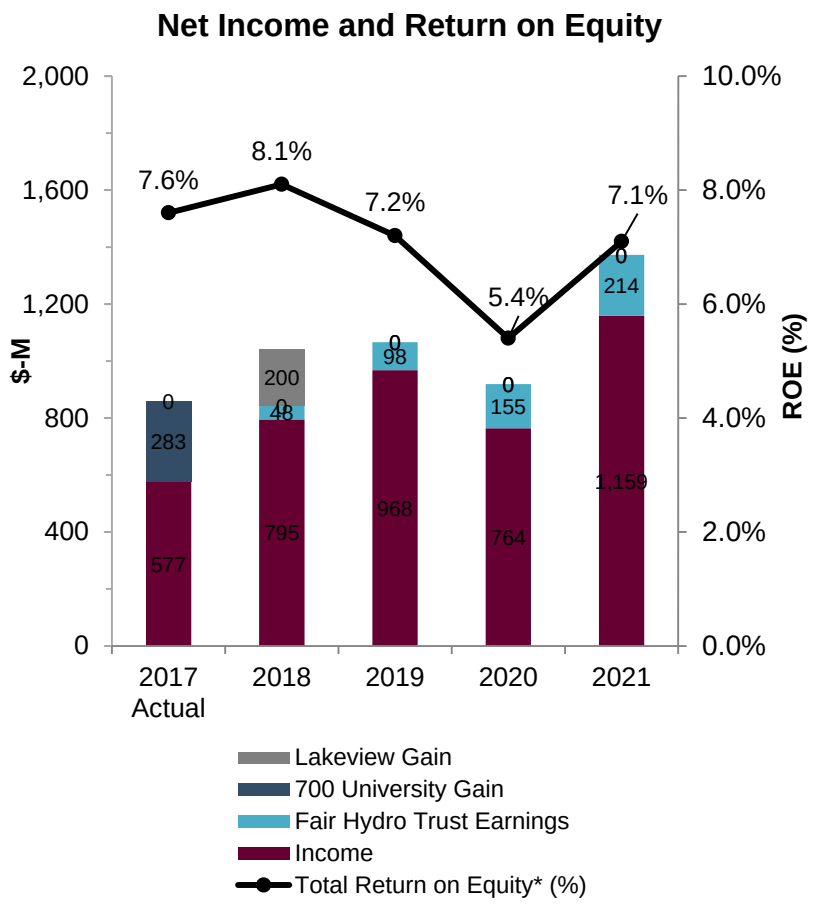
Acquisition and Development
OPG will develop assets and consider acquisitions in Ontario and other North American markets

- As the Shareholder, the Province may need to provide approvals for certain investments (e.g., development and acquisitions).
  - The Ministry of Energy plans to develop a policy framework to guide these approvals.

Financial Performance

Business Plan Results as presented by OPG

- ❖ Plan forecasts total net income to reach $1.37 billion in 2021, from $860 million in 2017
- ❖ OEB Decision provides rate stability over the planning period.



- OPG shareholder return (Net income + PILS) are consolidated to the Province.
- The plan reflects the Ontario Energy Board's (OEB) December 2017 Decision on OPG's regulated rates through 2021, providing stability in the planning period.
- Return on Equity (excluding impact of Fair Hydro Trust) increases from 5.3% in 2017 to 8.1% in 2021. ROE is a performance metric for executive compensation.
- Should OPG fail to meet targets for production, operating cost reductions or capital expenditures, net income improvements may not materialize.
- Net income in 2017/18 is impacted by one-time asset sales (Head Office and Lakeview), ~~which~~ with net proceeds ~~will be~~ credited to the Trillium Trust.

Financial Performance

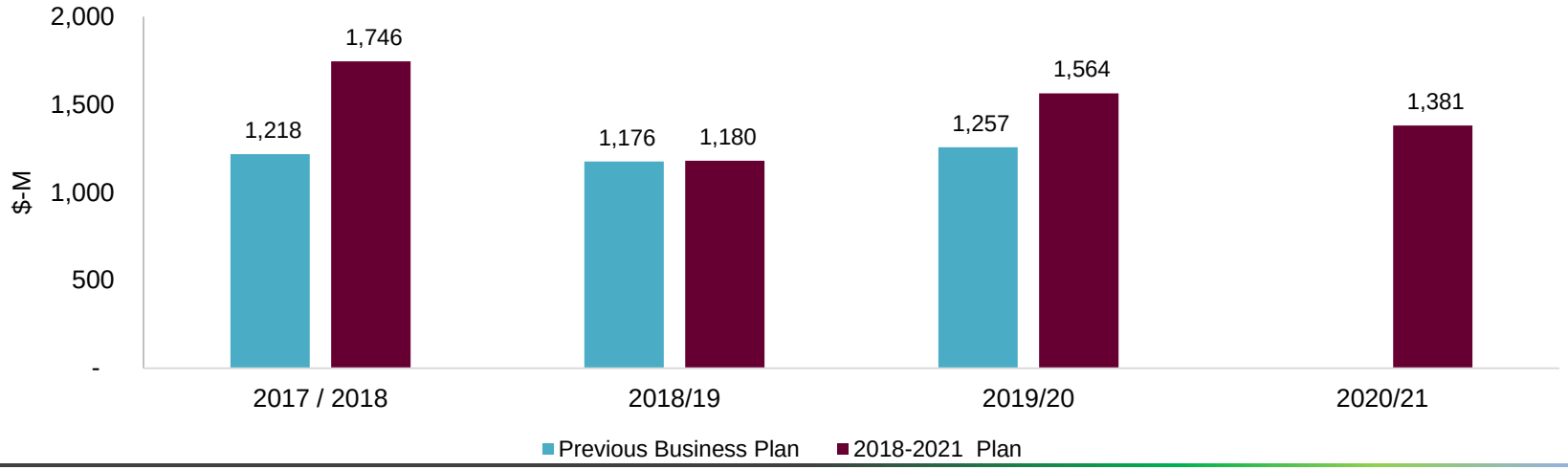
2018-21 Business Plan compared to previous plan

- ❖ Improved net income and shareholder return over previous plans.
- ❖ Projections impacted by efficiency measures and one-time real estate gains.

- The plan's total shareholder return is higher than last year's 2017-19 business plan.
- The financial performance reflects increased efficiency leading to revenue increases from higher production and lower operating costs
- The plan assumes the sale of Lakeview will be complete in 2017/18, resulting in $200M in net income and $70 million in PILS. The sale was not included in last year's plan.
  - OPG closed the sale of the ~~has a purchase agreement for~~ Lakeview site~~, anticipated to close~~ in March, 2018.

Total Shareholder Return

2018-21 BP vs. Previous Business Plan



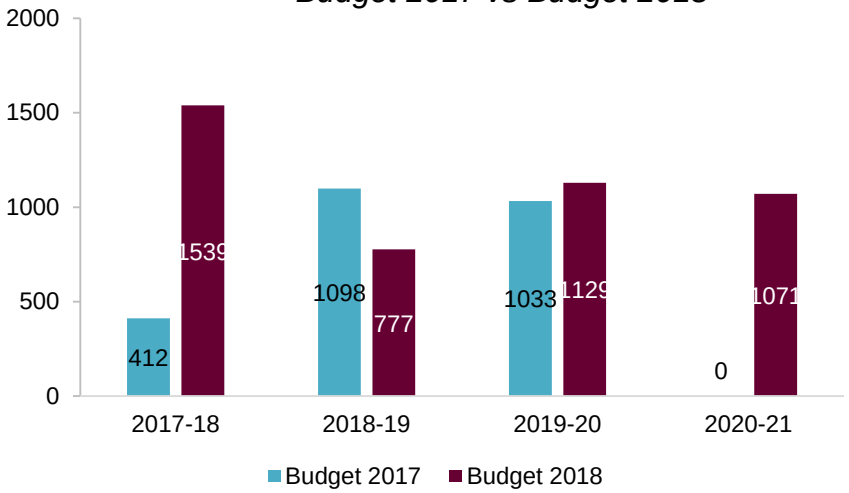
Financial Performance:[OFA to review]

Impacts to Province

- The Ministry of Finance is responsible for incorporating OPG's financial projections into the Province's Fiscal Plan and fiscal plan updates, and Treasury Board Secretariat is responsible for the fiscal consolidation of OPG's financials on the Province's financial statements, which may include accounting adjustments.
- Budget 2018 reflects the impacts of OPG's 2018-2021 Business Plan

- When OPG's planning projections and financial results are consolidated into the Province's Budget and Public Accounts ~~financials~~, some adjustments are required
  - **IFRS:** OPG uses US GAAP accounting standards for financial reporting. The Province consolidates OPG's results adjusted to an International Financial Reporting Standards (IFRS) basis.
  - **Nuclear Funds:** For the operating statement for Public Accounts, an adjustment is made to a realised gains basis, vs a fair value basis on OPG's statements.
  - **Fair Hydro Income:** While OPG separates out this income in its Business Plan, OPG's Financial Services Manger revenue is added to OPG net income when consolidated.

Total OPG Revenues to the Province
Budget 2017 vs Budget 2018



2017/18 positive variance due to:
- $646M for real estate sales included as OPG revenue in Budget 2018,. In Budget 2017, ~~not in Budget 2017 as~~ projected OPG real estate revenues ~~those revenues~~ were included in the Sales and Rentals line.
- Positive ONFA Adjustments included in Budget 2018 not in Budget 2017
- Lower IFRS adjustment in Budget 2018 than Budget 2017

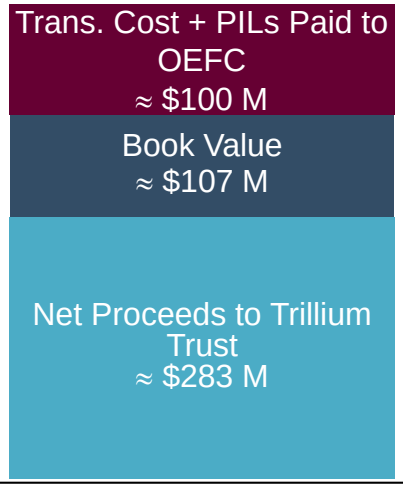
2018/19 negative variance due to:
- Negative IFRS adjustment included in Budget 2018

Financial Performance

Contribution to the Trillium Trust

- Net proceeds from the sale of OPG's ~~its~~ Head Office (700 University) and Lakeview site are paid by OPG to the CRF and credited to the Trillium Trust.
- The Province ~~will~~ has received a dividend payment from OPG for the OPG Head Office Sale. OPG will be required to pay the net proceeds from the Lakeview sale once a Trillium Trust regulation is filed.~~gains on these sales.~~
- The Head Office sale closed in April 2017. Lakeview ~~expected to~~ closed in March, 2018.

Head Office: ~~Designated~~ Net Proceeds to Trillium Trust from OPG



- Shareholder Declaration & Resolution received: December 2015
- Sale closed: April 2017
- Amount credited to Trillium Trust: Mar 2018

Lakeview: Estimated Net Proceeds to Trillium Trust from OPG

- Shareholder Declaration & Resolution received: June 2016
- ~~Expected~~ Sale closed: March 2018
- Regulation required to prescribe amounts to Trillium trust

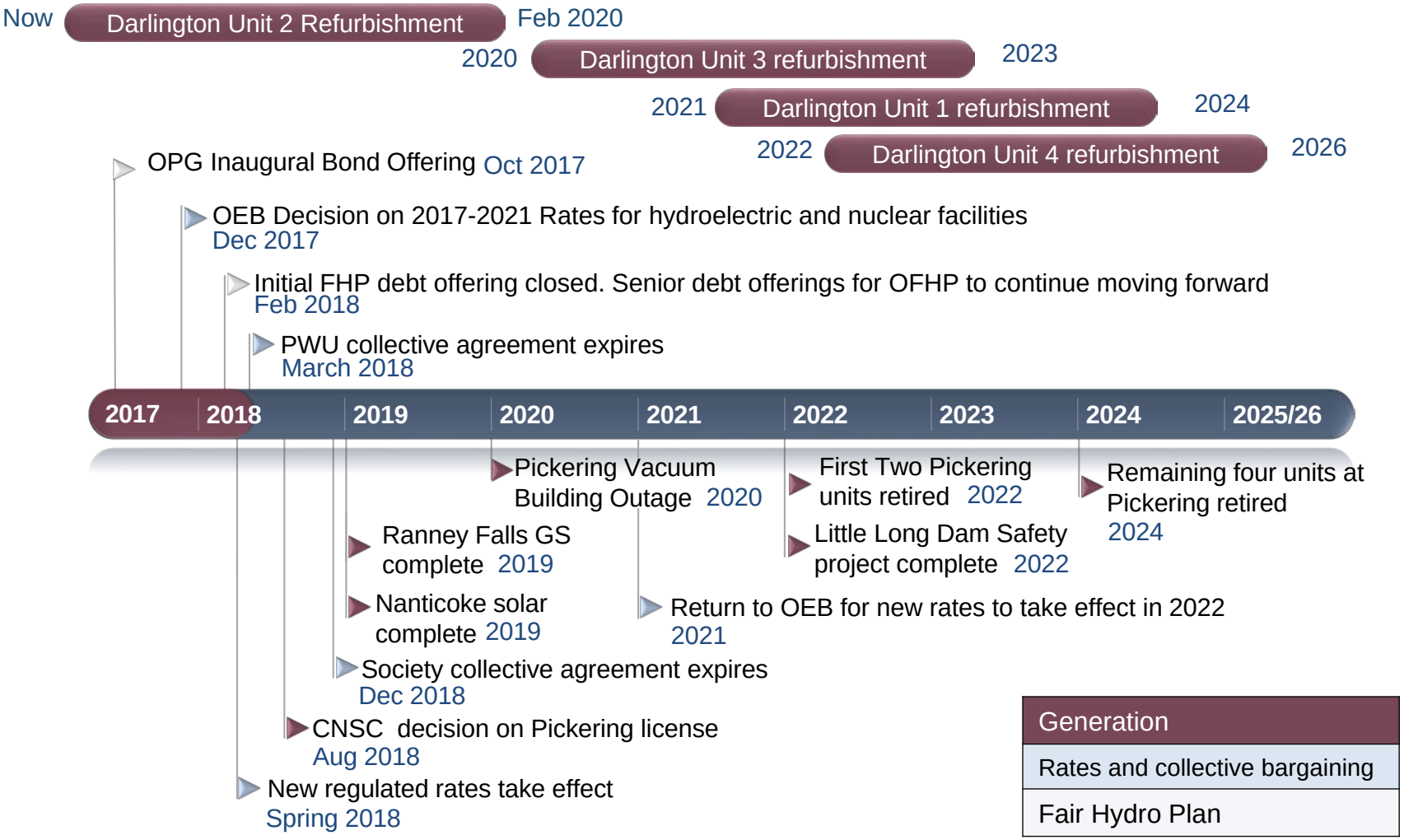
Considerations

- Based on these materials, ENERGY is seeking approval to provide OPG with business plan concurrence.
- At this point OPG has rate stability through the planning period and has demonstrated success in key projects including Darlington refurbishment. The plan is in line with government expectations on reducing costs in order to drive value for Ontario ratepayers and the Province, as Shareholder.
- OPG identified risks that the Ministry will continue to monitor. These include
  - Meeting efficiency targets for cost-savings and production.
  - Successful collective bargaining negotiations with PWU and Society; and
  - Completion of capital projects on budget and schedule
- OPG will continue to seek new business opportunities within Ontario and other jurisdictions. OPG will seek comfort from the Province for any new acquisitions.
- OPG will consider investing in near-commercial emerging technologies, acquisitions and development.

Appendix

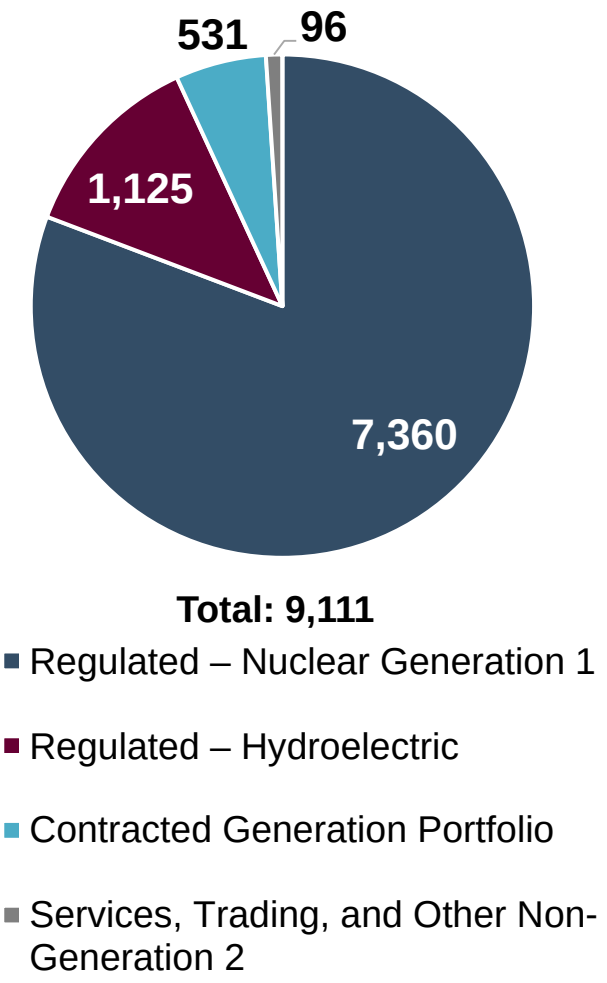
Timeline

- Outcomes from the Business Plan are impacted by the following events:



Company Profile

2017 Average Full-Time Employees

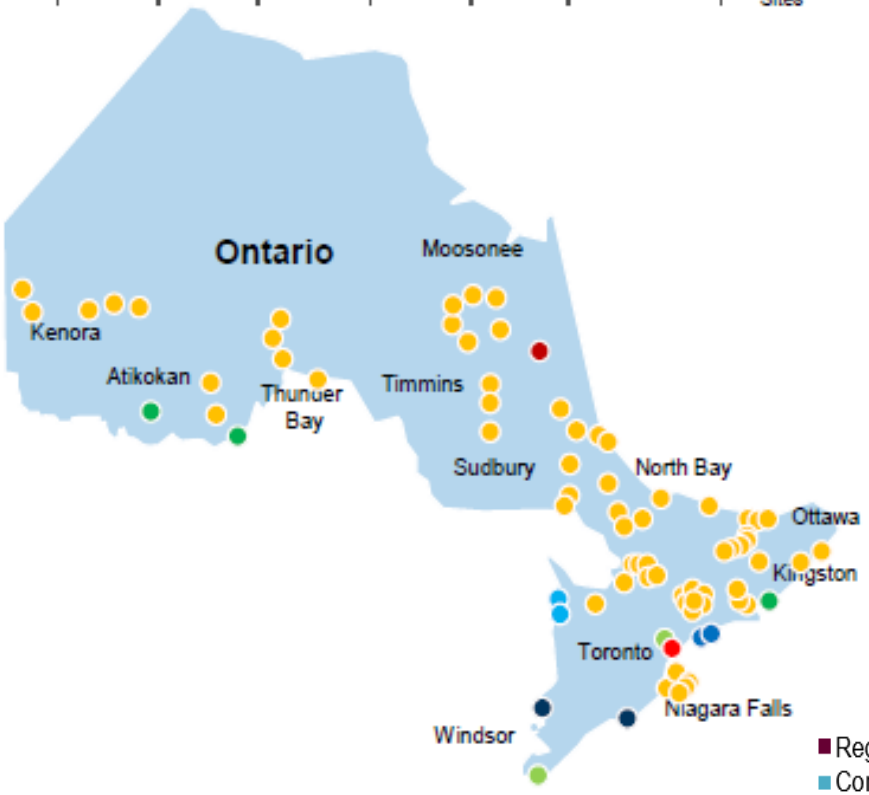


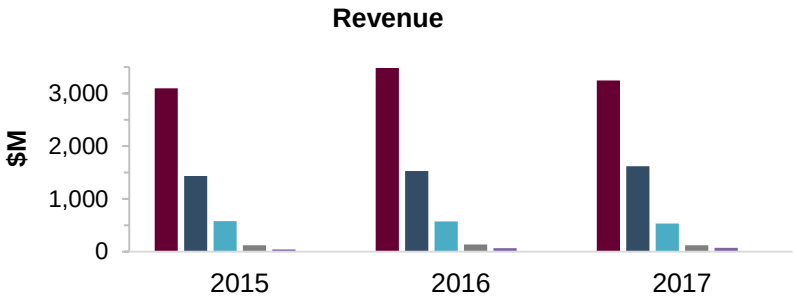
- Majority of OPG's employees are represented by one of two unions:
  1. The Power Workers' Union (PWU); and
  2. The Society.
- The PWU includes most workers below the level of first line manager
- The Society includes supervisors, professional engineers, scientists and other professionals.
- Construction work is performed through 19 craft unions.

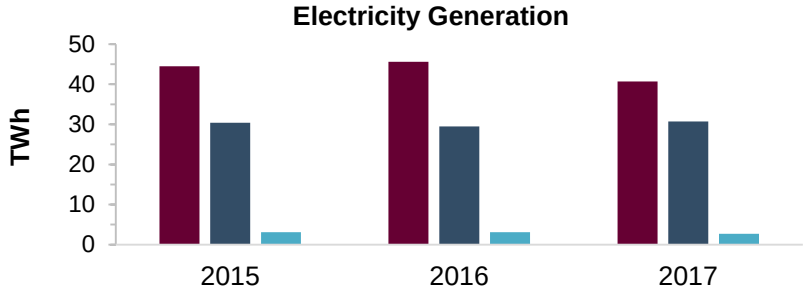
Company Profile

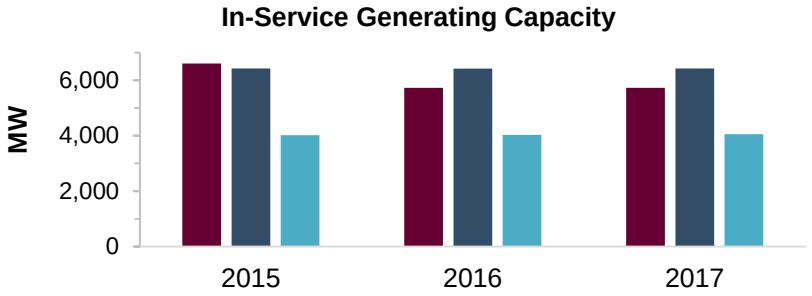
Map of OPG Generating Stations:

2	2	3	2	65	1	1	2
Nuclear Stations	Leased Nuclear Stations	Thermal Stations	Co-Owned Gas-Fired Stations	Hydro-electric Stations	Wind Power Turbine	Hydroelectric Project Under Construction [1]	Brownfield Coal Generation Sites









- Regulated – Nuclear Generation
- Regulated – Hydroelectric
- Contracted Generation Portfolio 1
- Regulated – Nuclear Waste Management
- Services, Trading, and Other Non-Generation

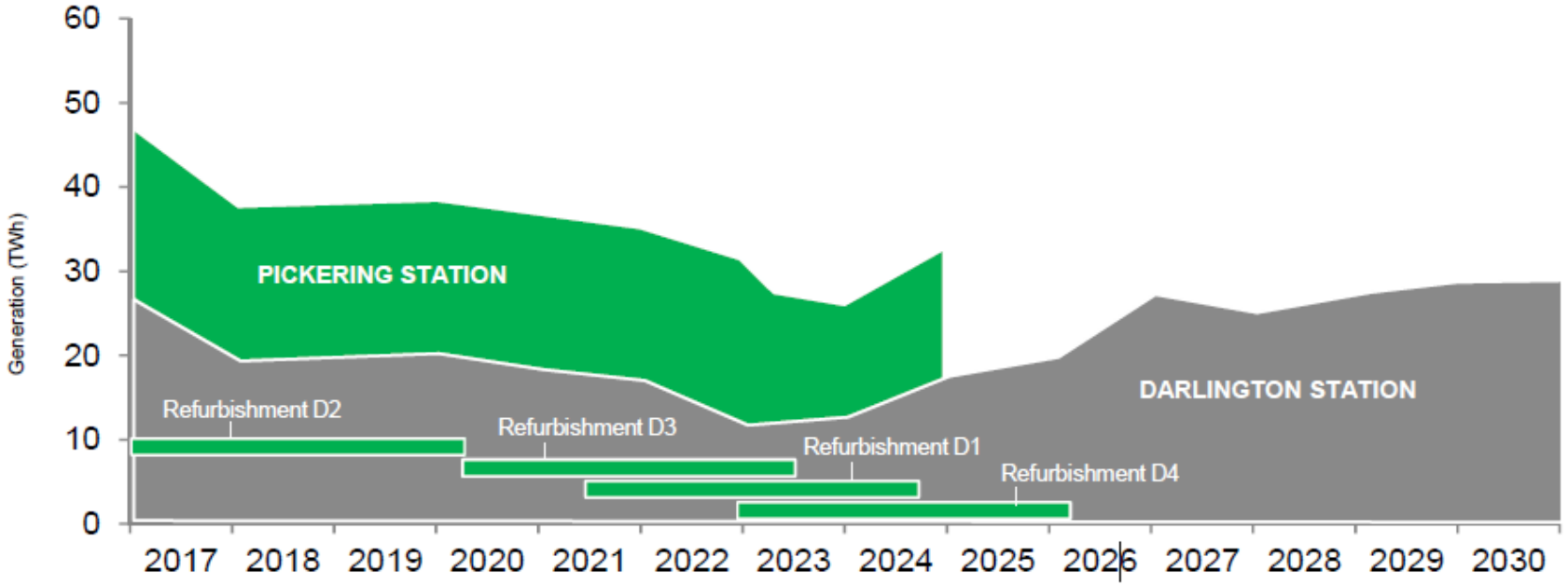
Key Projects: Nuclear

1. Pickering Extension

- OPG is continuing work to extend operations of the Pickering GS to 2024. It is currently licensed to operate to 2020.
- OPG has applied for a license renewal from the CNSC. The ruling is expected in August 2018.

2. Darlington Refurbishment

- OPG is refurbishing the Darlington Nuclear station to extend the operating life of the station by 30 years.
- Status: tracking on schedule and budget.
- Total Budget: $12.8 billion.



Source: OPG Initial Public Debt Program, 2017

Key Projects: Renewables

Biomass

1. Atikokan

Capacity: 205 MW

Converted from coal in 2014

Capex: ~$170M

2. Thunder Bay

Capacity: 153 MW

Converted from coal in 2014

Indigenous Relations

OPG's corporate governance includes an Indigenous Relations policy to help build and develop mutually beneficial working relationships with Indigenous communities proximate to the Company's present and future operations.

Renewables

Hydroelectric

1. Peter Sutherland Sr.

Capacity: 28 MW

Completed: March 2017

Capex: <$300M

2. Lower Mattagami

Capacity: 438 MW

Completed: 2014

Capex: $2.5BN

Solar

1. Nanticoke Solar

Project partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation to build the new facility.

Capacity: 44 MW

Commenced: Q4 2017

Expected completion: 2019

Role of OFHP Financial Services Manager

- In June 2017, the Province enacted the *Ontario Fair Hydro Plan Act, 2017* in order to ensure the costs and benefits associated with the Province's clean energy initiatives are allocated fairly between present and future electricity consumers.
    - The policy goals of the Act are being achieved through the refinancing of a portion of the Global Adjustment (GA).
    - OPG was appointed Financial Services Manager (FSM) under the Act.

- OPG's duties as FSM include:
    - Establishing one or more financing entities to incur funding obligations. OPG established the Fair Hydro Trust in 2017.
    - Preparing a financing plan to evaluate how and when funding obligations should be incurred.
    - Administering investment assets purchased from IESO
    - Determining the monthly clean energy adjustment for each reference period
    - Establishing and charging fees to recover costs, expenditures and earn a return
    - Seeking best available terms for incurrence of a funding obligation
    - Fulfilling various reporting requirements

Board of directors

- OPG's Board of Directors is made up of 14 individuals. Each Director holds office until he or she resigns or a successor is elected or appointed:

Director	Role	Appointed
1. Bernard Lord	Chair	November 2013
2. Jeffrey Lyash	President and CEO of OPG	August 2015
3. William Coley	Director	January 2013
4. Elisabeth DeMarco	Director	April 2014
5. Jean Paul Gladu	Director	November 2015
6. John Herron	Director	November 2013
7. Ani Hotoyan-Joly	Director	March 2017
8. Wendy Kei	Director	March 2017
9. M. George Lewis	Director	February 2005
10. Margaret Mulligan	Director	December 2005
11. Yezdi Pavri	Director	September 2015
12. Gerry Phillips	Director	January 2013
13. Jim Reinsch	Director	August 2015
14. James Sheppard	Director	March 2017

Compensation

2017 Statement of Executive Compensation

- OPG exceeded many of the measures in its Corporate Scorecard, impacting incentive payments.
- Scorecard is based on a predetermined scale of Threshold/Business Plan/Stretch targets (i.e., low/medium/high) and given a weighting. The scorecard is summarized below.

Category	**Performance Measure**	**Threshold Target**	**Business Plan Target**	**Stretch Target**	**2017 Results**	**Score (0 to 1.5)**
Social Licence	All Injury rate (AIR)	0.49	0.37	0.31	0.48	0.54
	Addressing Safety Focus Areas	CEO assessed target			1.5	1.46
	No significant impacts to OPG's reputation					
Financial Strength	Earnings Before Taxes, ($M)	675	875	1075	1296	1.50
	OM&A Expenses ($M)	2675	2550	2425	2474	1.30
Operational Excellence	Production (TWh)	70.3	72.4	74.6	78.1	1.50
Project Excellence	Refurbishment Project Cost – 2017 actual expenditures ($M) as a percentage of approved 2017 budget	100%	97.50%	95%	120%	0.00
	Refurbishment Unit 2 Critical Path Execution – Commencement of Feeder cabinet removal (Milestone	05-Aug-17	26-Jul-17	28-Jun-17	22-Jun-17	1.50
	Refurbishment Unit 2 Critical Path Execution: Progress of Critical path on Dec 31, 2017	All Bellows Severed	50% End Fitting Removed	400 Pressure Tubes Removed	45% of End Fittings Removed	0.95
	Pump Generating Station: In service	06-01-2017	04-01-2017	03-01-2017	02-04-2017	1.50
	Peter Sutherland Generating Station: Both Units in service	10-19-2017	06-30-2017	04-30-2017	03-31-2017	1.50
	Total In-service Capital -	$578 (+/- 10% to +/- to 15%)	$578 (+/- 3% to +/- 10%)	$578 (to +/- 3%)	$625 (+8%)	1.00
	Total Weighted Score[1]					**1.19**

Exceeded Stretch Target
Exceeded BP Target
Below BP Target
Below Threshold

From:	Nelms, Scott (MOF)
To:	Gadi Mayman
Cc:	Steen Hume (CAB); Mike Manning; Ronald Kwan; Ken Kandeepan
Subject:	RE: Draft Fees Regulation
Date:	Tuesday, September 26, 2017 2:23:42 PM

Thanks Gadi

From: Gadi Mayman [mailto:Gadi.Mayman@ofina.on.ca]
Sent: September 26, 2017 2:15 PM
To: Nelms, Scott (MOF) <Scott.Nelms@ontario.ca>
Cc: Hume, Steen (ENERGY) <Steen.Hume@ontario.ca>; Manning, Mike (OFA) <Mike.Manning@ofina.on.ca>; Kwan, Ronald (OFA) <Ronald.Kwan@ofina.on.ca>; Kandeepan, Ken (OFA) <Ken.Kandeepan@ofina.on.ca>
Subject: Re: Draft Fees Regulation

Thanks, Scott. I understand that there are a few items in here that are a little different than what we'd expected, so we'll get back to you with our consolidated OFA response tomorrow.

Regards,
Gadi

On Sep 26, 2017, at 12:18 PM, Nelms, Scott (MOF) <Scott.Nelms@ontario.ca> wrote:

> Hi Gadi,
>
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reviewing / providing oversight in this regard?

- Also, do the costs they've outlined seem reasonable? In particular, LSB is wondering whether this leaves the door open for OPG to pass through any overhead costs (i.e. should we be explicit about excluding them)?

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In terms of next steps, OPG would like to get a draft to their Board in time for the meeting on Friday. ENERGY LSB is hoping for comments by tomorrow. I don't think we need anything too detailed or formal, but a quick sniff test would be useful to ensure we are on the right track.

Thanks for your help,
Scott

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This message, including any attachments, is meant only for the use of the individual(s) to whom it is intended and may contain information that is privileged/confidential. Any unauthorized use, copying or disclosure is strictly prohibited. If you are not the intended recipient or have received this message in error, please notify us immediately by reply e-mail and permanently delete this message, including any attachments, without reading them, and destroy all copies. Thank you.

From:	Ken Kandeepan
To:	Gadi Mayman
Cc:	Anna Strathy; Ronald Kwan; Mike Manning
Subject:	RE: Draft Fees Regulation
Date:	Tuesday, September 26, 2017 2:10:32 PM

Not entirely, Mike is scheduling an internal meeting for most likely tomorrow so that we can provide consolidated comments.

Thanks

Ken K

From: Gadi Mayman
Sent: Tuesday, September 26, 2017 2:09 PM
To: Mike Manning <Mike.Manning@ofina.on.ca>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>; Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
Cc: Anna Strathy <Anna.Strathy@ofina.on.ca>
Subject: Fwd: Draft Fees Regulation

Are all of you OK with this? If you are, I'm fine, too, but I'm having trouble reading it with all of the markups and black lines.

Gadi

Begin forwarded message:

> **From:** "Nelms, Scott (MOF)" <Scott.Nelms@ontario.ca>
> **Date:** September 26, 2017 at 12:18:07 PM EDT
> **To:** "Mayman, Gadi (OFA)" <Gadi.Mayman@ofina.on.ca>
> **Cc:** "Hume, Steen (ENERGY)" <Steen.Hume@ontario.ca>, "Manning, Mike (OFA)" <Mike.Manning@ofina.on.ca>, "Kwan, Ronald (OFA)" <Ronald.Kwan@ofina.on.ca>
> **Subject: Draft Fees Regulation**
>
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Thanks for your help,
Scott

From:	Ken Kandeepan
To:	Scott Nelms (ENERGY)
Cc:	Steen Hume (CAB); Mike Manning; Ronald Kwan; Gadi Mayman; Carlos Yep; James Devine; John Kim; Anna Strathy
Subject:	RE: Draft Fees Regulation
Date:	Wednesday, September 27, 2017 4:48:04 PM

Hi Scott

As per Gadi's email yesterday, pls find below our consolidated comments. Pls feel free to contact Mike or me if you have any questions.
Base Fee:

10bps is high. We recommend a compromise of 5bps to be reviewed in a year. As background, market investment manager fees are 1-2bps for passive fixed income funds.

This is also consistent with the actual fees paid by OPG and Province to co-manage the nuclear fund's index fixed income funds. Note that the index funds require constant rebalancing by the investment manager.

OPG is receiving 44% equity investment from the Province at 0% cost and lending the funds as subordinated debt at a forecasted yield of around 5%, I.e. For each $2.5B of Global Asset X 44% equity injection would contribute, $55 million net revenue to OPG for each of the 10 years and would continue over repayment period albeit as a reduced amount as the Global Asset is paid down.

Variable Fee: We recommend going back to the original proposal of "… not more than plus/minus 1% … on the net annual funding obligation …"
That means deleting column 1 and item 2 of the table.

Pass through costs: Pass through costs as outlined in the draft regulations appear reasonable. As suggested in Scott's email including tighter language that prevents any OPG costs from being passed through makes sense. As further due diligence it may be advisable for the for the Financing Entity as part of its annual audit or as a separate assurance audit to have the external auditors opine whether the actual pass through costs of the Financing Entity in each fiscal year is in accordance with the regulations.

Thanks

Ken k

From: Gadi Mayman
Sent: Tuesday, September 26, 2017 2:15 PM
To: Scott Nelms (ENERGY) <Scott.Nelms@ontario.ca>
Cc: Steen Hume (CAB) <Steen.Hume@ontario.ca>; Mike Manning <Mike.Manning@ofina.on.ca>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>; Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>

Subject: Re: Draft Fees Regulation

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Regards,
Gadi

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Thanks for your help,
Scott

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From: Shajee Kathirgamanathan
To: Ronald Kwan; John Kim
Cc: Bruno Amara; Usman Zahid
Subject: RE: ESDI Quaterly Update v12_Markup_clean.pptx
Date: Monday, December 04, 2017 5:17:48 PM
Attachments: ESDI Quaterly Update v16.pptx
ESDI Quaterly Update v16_clean.pptx

Hi Ron,

Please find attached the revised ESDI deck. Tracked change and clean version attached. Will delete the comments in the 'clean' version before sending out.

Files attached and found here:
S:\Users\CEF\Hydro 2017\OEFC\RbP\Outlook\11. November\ESDI for OEFC

Thanks,
Shajee

From: Ronald Kwan
Sent: Friday, December 01, 2017 11:31 AM
To: Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>
Cc: Bruno Amara <Bruno.Amara@ofina.on.ca>; Usman Zahid <Usman.Zahid@ofina.on.ca>
Subject: RE: ESDI Quaterly Update v12_Markup_clean.pptx

Hi Shajee,

A few more comments and questions.

Ron

From: Shajee Kathirgamanathan
Sent: December-01-17 10:21 AM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>
Cc: Bruno Amara <Bruno.Amara@ofina.on.ca>; Usman Zahid <Usman.Zahid@ofina.on.ca>
Subject: RE: ESDI Quaterly Update v12_Markup_clean.pptx

Hi Ron,

Thanks for your comments. Please see attached our revisions. We accepted your edits and addressed your comments, including adding in an extra slide.

File attached and found here:

S:\Users\CEF\Hydro 2017\OEFC\RbP\Outlook\11. November\ESDI for OEFC

Thanks,
Shajee

Shajee Kathirgamanathan
Office: 416-325-1402 | Mobile: 647-294-3359
shajee.kathirgamanathan@ofina.on.ca

From: Ronald Kwan
Sent: Wednesday, November 29, 2017 6:55 PM
To: John Kim <John.Kim@ofina.on.ca>
Cc: Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Usman Zahid <Usman.Zahid@ofina.on.ca>
Subject: RE: ESDI Quaterly Update v12_Markup_clean.pptx

Hi John,

I may be missing out on the nomenclature nuances. Some comments and suggestions as attached. Let's discuss.

Thanks,
Ron

From: John Kim
Sent: November-29-17 18:07
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Usman Zahid <Usman.Zahid@ofina.on.ca>
Subject: RE: ESDI Quaterly Update v12_Markup_clean.pptx

Resending….

From: John Kim
Sent: Wednesday, November 29, 2017 6:07 PM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>
Subject: RE: ESDI Quaterly Update v12_Markup_clean.pptx

Saved here:
S:\Users\CEF\Hydro 2017\OEFC\RbP\Outlook\11. November\ESDI for OEFC

And forgot to copy Usman so resending.

From: John Kim
Sent: Wednesday, November 29, 2017 6:05 PM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>
Subject: ESDI Quaterly Update v12_Markup_clean.pptx

Hi Ron,

This deck is to update you on where we propose the 2017-18 estimated ESDI value to be versus $525M that was in the Q1 2017 financials and $140M FTD recently is booking in the draft Q2 2017. This is more for internal discussion for now but could be transition to a full deck quickly.

We would propose updating it to $306M for Q2 2017. We label it as “Budget 2018” but is to represent our latest outlook.

We have asked for a draft financials earlier and following up again now.

Thanks,

John

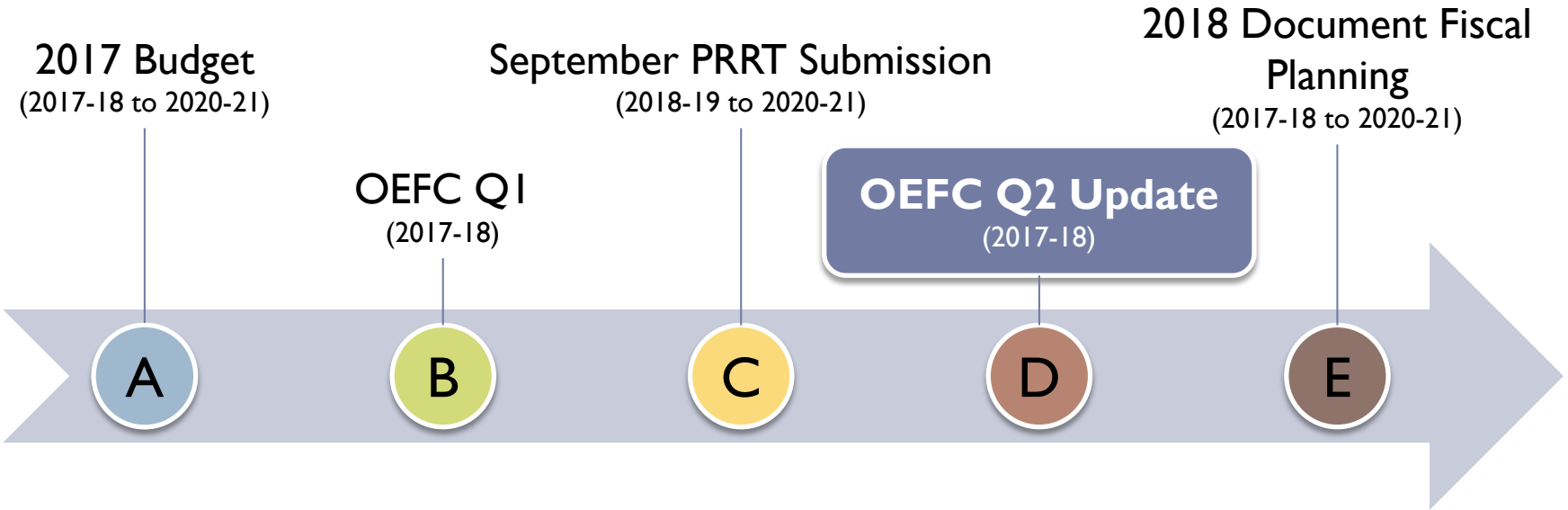
DRAFT

Updating ESDI 2017-18 OEFC Financials

Corporate and Electricity Finance Division
[DATE]

Overview

- This presentation provides a brief overview of anticipated 2017-18 ESDI and an extended outlook to 2020-21 if ESDI is to be approved to continue beyond 2017-18.
- Revised ESDI outlook proposed for OEFC Q2 financial statements reflects:
  - 'unpacking' of asset optimization net impacts previously reported under 'Sales and Rentals
  - full estimated IFRS reporting impacts to OPG
  - revised projections not previously incorporated into the fiscal plan.
- Numbers are subject to further updates as results get finalized.
- The timeline of changes from 2017 Budget is shown below along with relevant years of projected ESDI. Details provided on the following slides.



DRAFT

ESDI Updates - Overview

- The following summary provides an overview of the changes since Budget 2017 and projections for the 2018 Document. Detailed explanation provided on the slides following.
- Note, projections for all years were not provided for every update.

	$ Millions	2017-18	2018-19	2019-20	2020-21
A	**2017 Budget**	**125**	**802**	**737**	**1,225**
	1. OPG - Removed IFRS Risk	*400*	*-*	*200*	*-*
B	**OEFC Q1 Update**	**525**			
	2. OPG - Re-Pack IFRS Risk	*(400)*	*-*	*(200)*	*-*
	3. OPG - August Update	*40*	*-*	*-*	*-*
	4. Hydro One - Preferred Shares	*6*	*6*	*6*	*6*
	5. Public Debt Interest Expense	*38*	*38*	*38*	*38*
C	**September PRRT Submission**		***846***	***780***	***1,269***
	6. OPG - September Update	*15*	*-*	*-*	*-*
	7. OPG - Updated Fair Hydro Trust Interest Revenue	*(5)*	*(12)*	*(17)*	*(24)*
	8. Hydro One - Updated Net Income Forecasts	*(79)*	*(84)*	*(43)*	*(45)*
D	**OEFC Q2 Update**	**140**			
	9. OPG - Updating for IFRS Risks	*0*	*(475)*	*(500)*	*(750)*
	10. 'Unpacking' - OPG Head office sale	*283*	*-*	*-*	*-*
	11. 'Unpacking' - Hydro One net income	*(113)*	*(142)*	*(171)*	*(185)*
	12. Hydro One - Updating Net Income Projections	*(5)*	*(15)*	*(8)*	*(9)*
E	**Document 2018 Fiscal Planning**	**306**	**118**	**41**	**255**

Note: Numbers may not add up due to rounding. Excludes consolidation adjustments for Ontario Nuclear Funds Agreement (ONFA) and other fair value adjustments.

ESDI Updates - Details

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	5. Public Debt Interest Expense	*38*	*38*	*38*	*38*
C	**September PRRT Submission**		***846***	***780***	***1,269***

- The updates from 2017 Budget to OEFC Q1 Update are as follows:
  1. The original ESDI estimate of $525M shown in Q1 2017-18 financial statements did not include the IFRS adjustment of $400M that was incorporated in 2017 Budget separately from OPG outlook provided by Corporate and Electricity Finance Division (CEFD).

- The updates from OEFC Q1 Update to the September PRRT Submission includes the following:
  2. Incorporating OPG's IFRS consolidation adjustment as per Budget 2017
  3. OPG's August 2017 shareholder update with increased projected net income (803M vs 702M at Budget 2017), partially as a result of increased returns from OPG headquarter sales (283M vs 222M at Budget 2017) that are removed and attributed to Sales and Rental rather than OPG/ESDI line at this point.
  4. Adjusting Hydro One net income to incorporate Preferred Shares 100% attributable to the Province.
  5. Changes in interest expense (i.e., government's annual interest cost in investments of OPG and Hydro One) due to reduced provincial Hydro One share ownership.

Note: Numbers may not add up due to rounding. Net income for ESDI exclude consolidation adjustments for Ontario Nuclear Funds Agreement (ONFA) and other fair value adjustments.

DRAFT

ESDI Updates - Details

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Hydro One – OEB Decision on tax recapture (if one-time write down)[3]	*(440)*	*6*	*7*	*10*
~~*Hydro One – Motion to Review OEB Transmission Ruling[4]*~~	~~*40*~~	~~*54*~~	~~*41*~~	~~*43*~~
Hydro One – Avista Acquisition Termination Fee (EBT Impact)[5]	-	*(51)*	-	-

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PRRT Submission Update

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% Growth		0.0%	0.0%	0.0%	X.X%
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Capital Assets	0.0	0.0	0.0	0.0	

$M	21-22	22-23	23-24	24-25	25-26	26-27	27-28
Capital Expense	X.X	X.X	X.X	X.X	X.X	X.X	X.X
Capital Assets	X.X	X.X	X.X	X.X	X.X	X.X	X.X

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Updating ESDI 2017-18 OEFC Financials

Corporate and Electricity Finance Division
[DATE]

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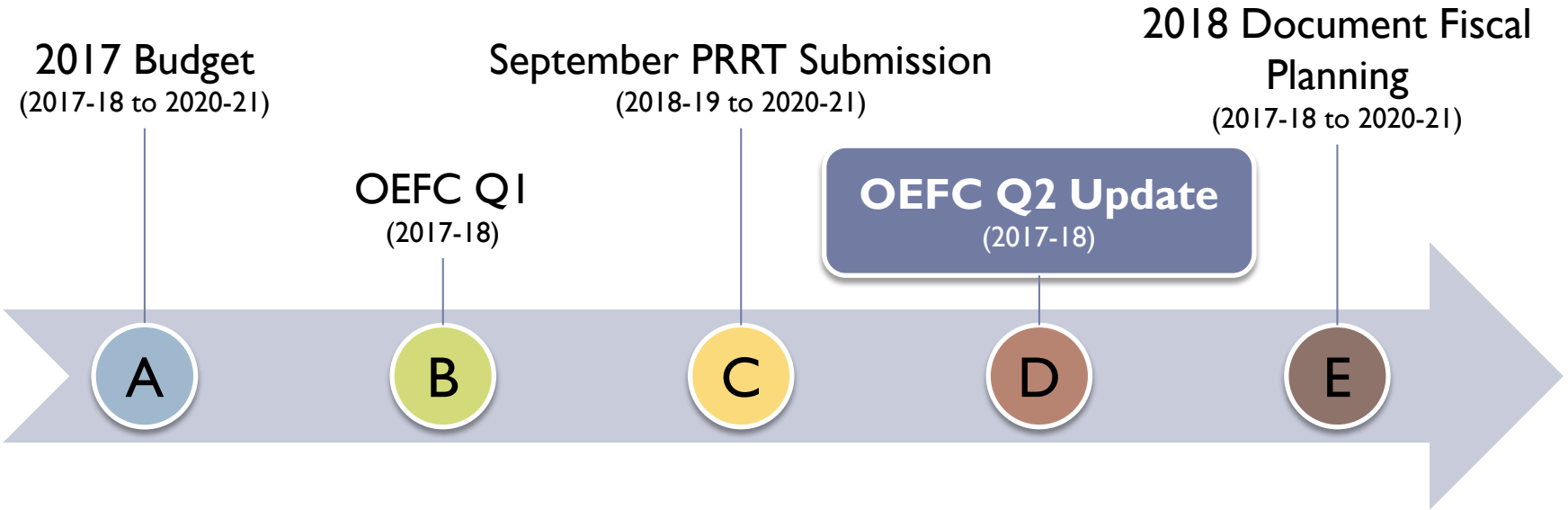

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From:	Ronald Kwan
To:	Shajee Kathirgamanathan; John Kim
Cc:	Bruno Amara; Usman Zahid
Subject:	RE: ESDI Quaterly Update v12_Markup_clean.pptx
Date:	Friday, December 01, 2017 11:31:10 AM
Attachments:	ESDI Quaterly Update v14_Markup.pptx

Hi Shajee,

A few more comments and questions.

Ron

From: Shajee Kathirgamanathan
Sent: December-01-17 10:21 AM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>
Cc: Bruno Amara <Bruno.Amara@ofina.on.ca>; Usman Zahid <Usman.Zahid@ofina.on.ca>
Subject: RE: ESDI Quaterly Update v12_Markup_clean.pptx

Hi Ron,

Thanks for your comments. Please see attached our revisions. We accepted your edits and addressed your comments, including adding in an extra slide.

File attached and found here:
S:\Users\CEF\Hydro 2017\OEFC\RbP\Outlook\11. November\ESDI for OEFC

Thanks,
Shajee

Shajee Kathirgamanathan
Office: 416-325-1402 | Mobile: 647-294-3359
shajee.kathirgamanathan@ofina.on.ca

From: Ronald Kwan
Sent: Wednesday, November 29, 2017 6:55 PM
To: John Kim <John.Kim@ofina.on.ca>
Cc: Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Usman Zahid <Usman.Zahid@ofina.on.ca>
Subject: RE: ESDI Quaterly Update v12_Markup_clean.pptx

Hi John,

I may be missing out on the nomenclature nuances. Some comments and suggestions as attached.

Let's discuss.

Thanks,
Ron

From: John Kim
Sent: November-29-17 18:07
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Usman Zahid <Usman.Zahid@ofina.on.ca>
Subject: RE: ESDI Quaterly Update v12_Markup_clean.pptx

Resending….

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Cc: Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>
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Saved here:
S:\Users\CEF\Hydro 2017\OEFC\RbP\Outlook\11. November\ESDI for OEFC

And forgot to copy Usman so resending.

From: John Kim
Sent: Wednesday, November 29, 2017 6:05 PM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>
Subject: ESDI Quaterly Update v12_Markup_clean.pptx

Hi Ron,

This deck is to update you on where we propose the 2017-18 estimated ESDI value to be versus $525M that was in the Q1 2017 financials and $140M FTD recently is booking in the draft Q2 2017. This is more for internal discussion for now but could be transition to a full deck quickly.

We would propose updating it to $306M for Q2 2017. We label it as "Budget 2018" but is to represent our latest outlook.

We have asked for a draft financials earlier and following up again now.

Thanks,

John

DRAFT

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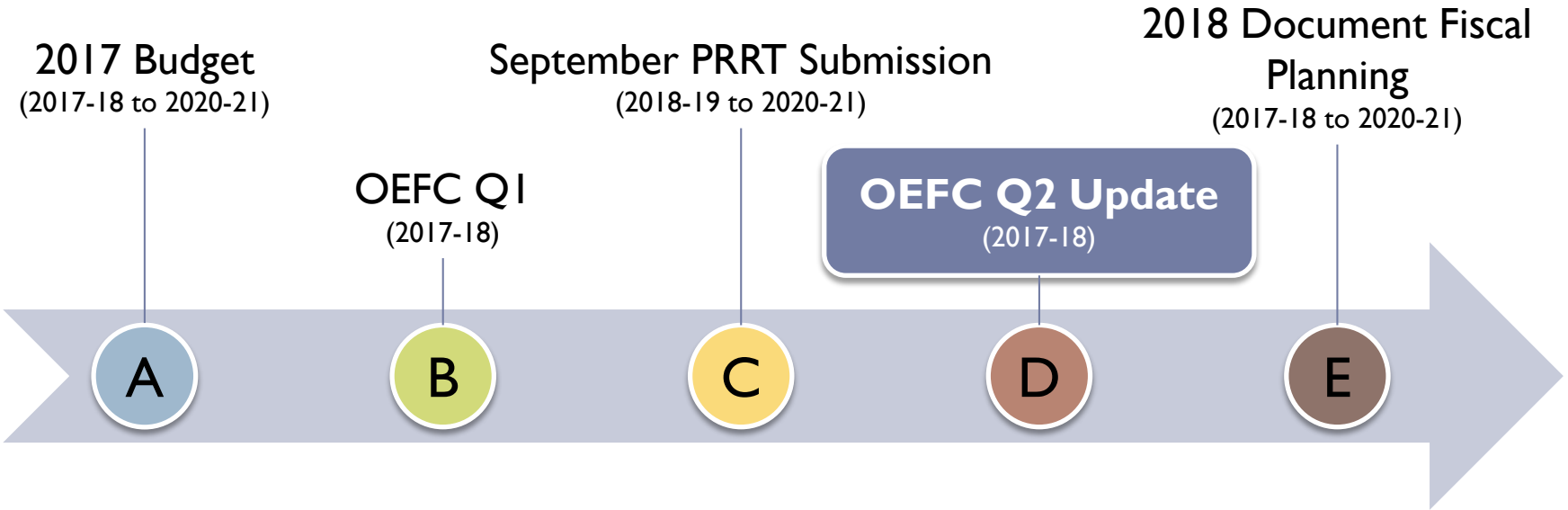

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PRRT Submission Update

DRAFT

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$M	21-22	22-23	23-24	24-25	25-26	26-27	27-28
Capital Expense	X.X	X.X	X.X	X.X	X.X	X.X	X.X
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From: Shajee Kathirgamanathan
To: Ronald Kwan; John Kim
Cc: Bruno Amara; Usman Zahid
Subject: RE: ESDI Quaterly Update v12_Markup_clean.pptx
Date: Friday, December 01, 2017 10:21:26 AM
Attachments: ESDI Quaterly Update v14.pptx
ESDI Quaterly Update v14.pptx

Hi Ron,

Thanks for your comments. Please see attached our revisions. We accepted your edits and addressed your comments, including adding in an extra slide.

File attached and found here:
S:\Users\CEF\Hydro 2017\OEFC\RbP\Outlook\11. November\ESDI for OEFC

Thanks,
Shajee

Shajee Kathirgamanathan
Office: 416-325-1402 | Mobile: 647-294-3359
shajee.kathirgamanathan@ofina.on.ca

From: Ronald Kwan
Sent: Wednesday, November 29, 2017 6:55 PM
To: John Kim <John.Kim@ofina.on.ca>
Cc: Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Usman Zahid <Usman.Zahid@ofina.on.ca>
Subject: RE: ESDI Quaterly Update v12_Markup_clean.pptx

Hi John,

I may be missing out on the nomenclature nuances. Some comments and suggestions as attached. Let's discuss.

Thanks,
Ron

From: John Kim
Sent: November-29-17 18:07
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Usman Zahid <Usman.Zahid@ofina.on.ca>
Subject: RE: ESDI Quaterly Update v12_Markup_clean.pptx

Resending….

From: John Kim
Sent: Wednesday, November 29, 2017 6:07 PM
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Cc: Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>
Subject: RE: ESDI Quaterly Update v12_Markup_clean.pptx

Saved here:
S:\Users\CEF\Hydro 2017\OEFC\RbP\Outlook\11. November\ESDI for OEFC

And forgot to copy Usman so resending.

From: John Kim
Sent: Wednesday, November 29, 2017 6:05 PM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>
Subject: ESDI Quaterly Update v12_Markup_clean.pptx

Hi Ron,

This deck is to update you on where we propose the 2017-18 estimated ESDI value to be versus $525M that was in the Q1 2017 financials and $140M FTD recently is booking in the draft Q2 2017. This is more for internal discussion for now but could be transition to a full deck quickly.

We would propose updating it to $306M for Q2 2017. We label it as “Budget 2018” but is to represent our latest outlook.

We have asked for a draft financials earlier and following up again now.

Thanks,

John

DRAFT

Updating ESDI 2017-18 OEFC Financials

Corporate and Electricity Finance Division
[DATE]

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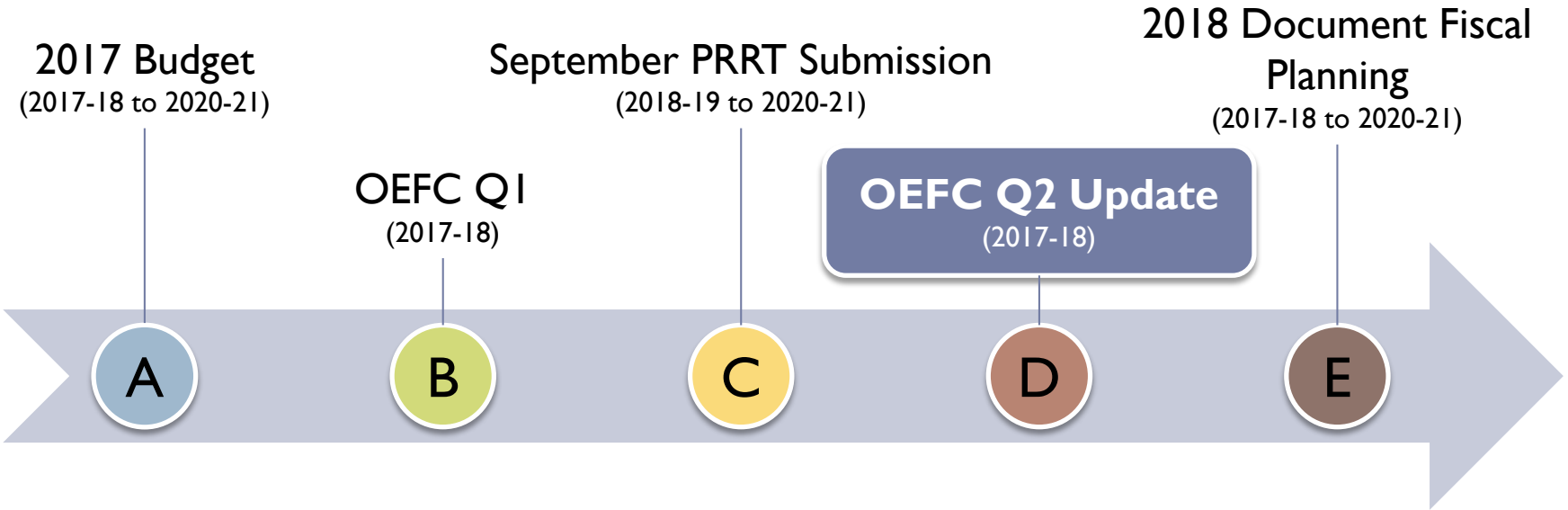

DRAFT

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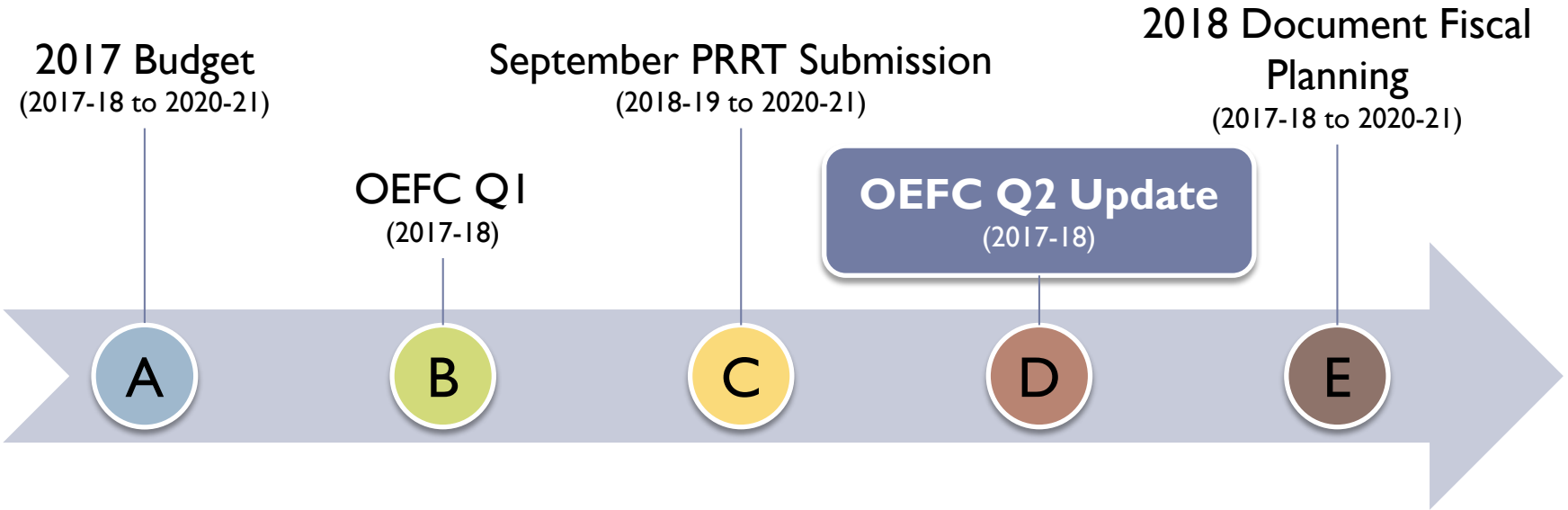

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To: John Kim
Cc: Shajee Kathirgamanathan; Bruno Amara; Usman Zahid
Subject: RE: ESDI Quaterly Update v12_Markup_clean.pptx
Date: Wednesday, November 29, 2017 6:55:00 PM
Attachments: ESDI Quaterly Update v12_Markup2.pptx

Hi John,

I may be missing out on the nomenclature nuances. Some comments and suggestions as attached. Let's discuss.

Thanks,
Ron

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Sent: November-29-17 18:07
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Usman Zahid <Usman.Zahid@ofina.on.ca>
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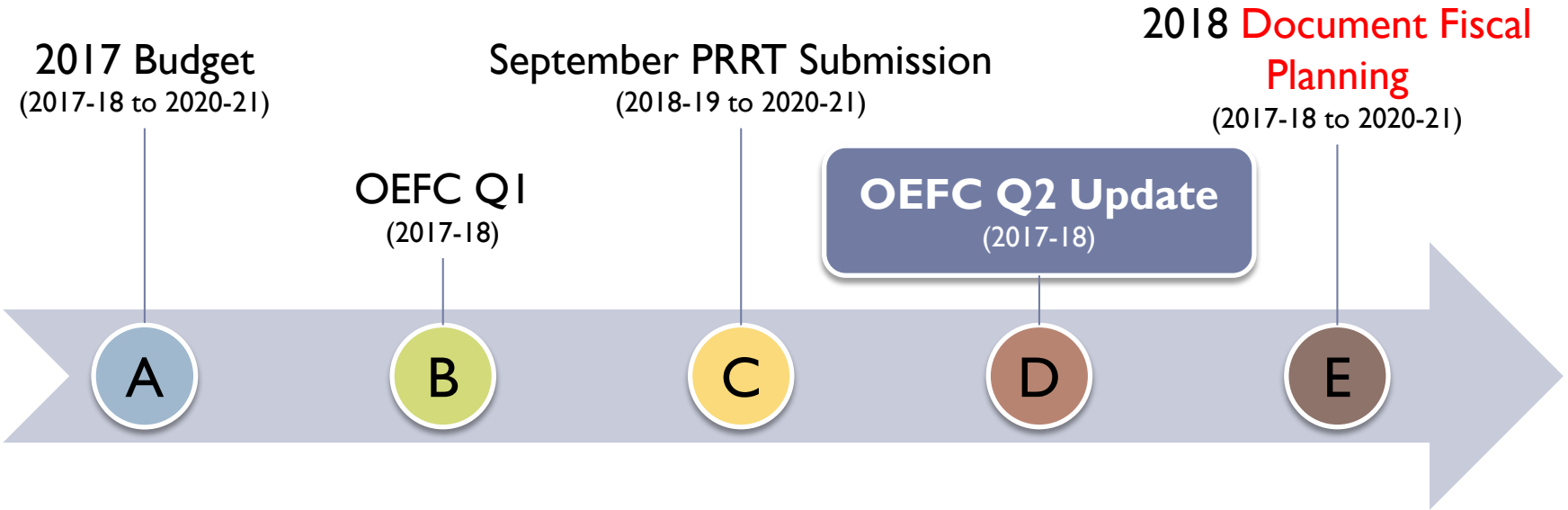

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Capital Assets	0.0	0.0	0.0	0.0	

$M	21-22	22-23	23-24	24-25	25-26	26-27	27-28
Capital Expense	X.X	X.X	X.X	X.X	X.X	X.X	X.X
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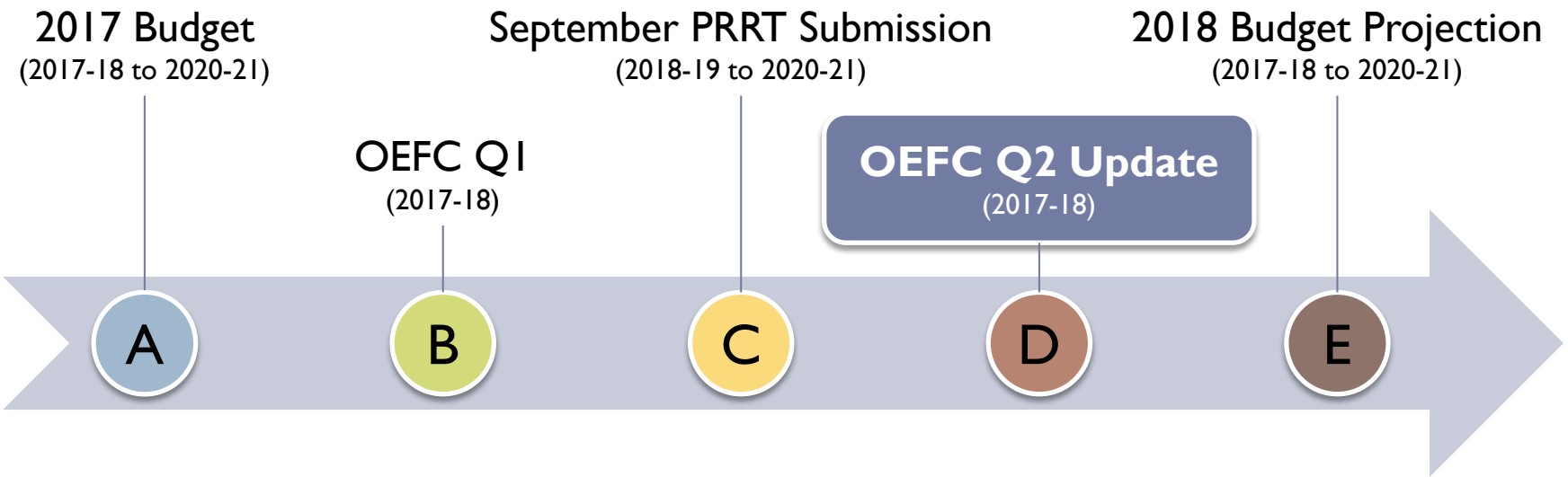

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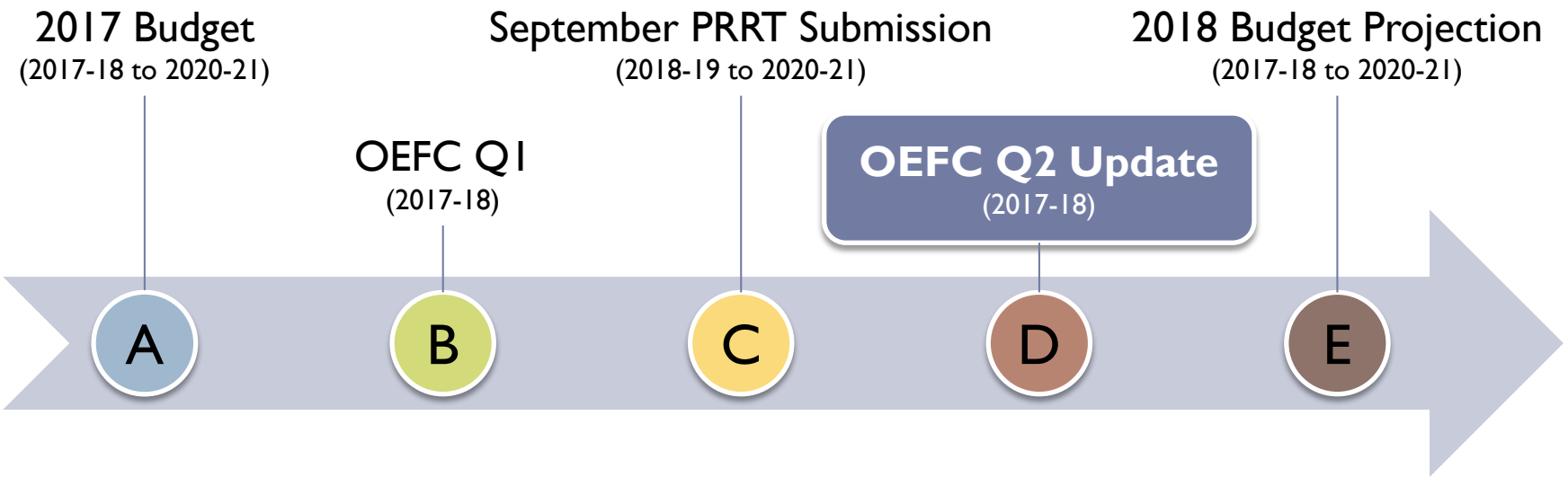

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E	**Budget 2018**	**306**	**118**	**41**	**255**

- The updates from the September PRRT Submission to the current OEFC Q2 Update are as follows:
  6. Increased OPG projected net income attributable to ESDI from the September OPG Shareholder Update.
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Note: Numbers may not add up due to rounding.

PRRT Submission Update

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PRRT Submission Update

- As part of the PRRT process, the Ministry of Finance submitted the below ESDI provision:

II. Requested Program Changes

$M	17-18	18-19	19-20	20-21	Growth Rate 18-19 to 20-21
Proposed Allocation					
MOF Expense		*(846)*	*(780)*	*(1,269)*	
OEFC Consolidation Expense		*846*	*780*	*1,269*	
Operating Expense	0.0	0.0	0.0	0.0	
Capital Expense	0.0	0.0	0.0	0.0	
Total Expense	0.0	0.0	0.0	0.0	
% Growth		0.0%	0.0%	0.0%	X.X%
Operating Assets	0.0	0.0			
Capital Assets	0.0	0.0	0.0	0.0	

$M	21-22	22-23	23-24	24-25	25-26	26-27	27-28
Capital Expense	X.X	X.X	X.X	X.X	X.X	X.X	X.X
Capital Assets	X.X	X.X	X.X	X.X	X.X	X.X	X.X

Notes:

1. Table should be presented on a fully consolidated basis. Capital assets include acquisitions of consolidated entities. Consolidation information should be consistent with information in ORBIT and information submitted to the Office of the Provincial Controller Division (OPCD).
2. See ORBIT for current allocation.

* Reflects sum of all financial impacts related to Key Operating, Capital, Climate Change, FTE and Technical Decisions

PRRT Submission Update

- The continuation of ESDI beyond April 1, 2018 was proposed in this PRRT submission as OEFC is expected to continue to have significant debt and other liabilities to service and pay down.
- However, any payments under this statutory line item would be fiscally neutral as the payment from the Ministry to the OEFC is fully offset against the consolidation of revenue of OEFC into the Province's Public Accounts.
- Corporate Quality Service Division (CQSD) has confirmed that there will be opportunity to revise ESDI amounts submitted in the PRRT note.
- The timing of these revisions is to be confirmed with TBS.

From:	Shajee Kathirgamanathan
To:	Ronald Kwan; John Kim
Cc:	Bruno Amara; Usman Zahid
Subject:	RE: ESDI Quaterly Update v12_Markup_clean.pptx
Date:	Monday, December 04, 2017 6:22:26 PM
Attachments:	ESDI Quaterly Update v16.pptx ESDI Quaterly Update v16_clean.pptx

---

Hi Ron,

One additional edit on the ESDI deck; corrected an issue with the footnote on the risks slide.

Clean and Tracked changes files attached in v16 and found here:
S:\Users\CEF\Hydro 2017\OEFC\RbP\Outlook\11. November\ESDI for OEFC

Thanks,
Shajee

From: Shajee Kathirgamanathan
Sent: Monday, December 04, 2017 5:18 PM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>
Cc: Bruno Amara <Bruno.Amara@ofina.on.ca>; Usman Zahid <Usman.Zahid@ofina.on.ca>
Subject: RE: ESDI Quaterly Update v12_Markup_clean.pptx

Hi Ron,

Please find attached the revised ESDI deck. Tracked change and clean version attached. Will delete the comments in the 'clean' version before sending out.

Files attached and found here:
S:\Users\CEF\Hydro 2017\OEFC\RbP\Outlook\11. November\ESDI for OEFC

Thanks,
Shajee

From: Ronald Kwan
Sent: Friday, December 01, 2017 11:31 AM
To: Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>
Cc: Bruno Amara <Bruno.Amara@ofina.on.ca>; Usman Zahid <Usman.Zahid@ofina.on.ca>
Subject: RE: ESDI Quaterly Update v12_Markup_clean.pptx

Hi Shajee,

A few more comments and questions.

Ron

From: Shajee Kathirgamanathan
Sent: December-01-17 10:21 AM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>
Cc: Bruno Amara <Bruno.Amara@ofina.on.ca>; Usman Zahid <Usman.Zahid@ofina.on.ca>
Subject: RE: ESDI Quaterly Update v12_Markup_clean.pptx

Hi Ron,

Thanks for your comments. Please see attached our revisions. We accepted your edits and addressed your comments, including adding in an extra slide.

File attached and found here:
S:\Users\CEF\Hydro 2017\OEFC\RbP\Outlook\11. November\ESDI for OEFC

Thanks,
Shajee

Shajee Kathirgamanathan
Office: 416-325-1402 | Mobile: 647-294-3359
shajee.kathirgamanathan@ofina.on.ca

From: Ronald Kwan
Sent: Wednesday, November 29, 2017 6:55 PM
To: John Kim <John.Kim@ofina.on.ca>
Cc: Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Usman Zahid <Usman.Zahid@ofina.on.ca>
Subject: RE: ESDI Quaterly Update v12_Markup_clean.pptx

Hi John,

I may be missing out on the nomenclature nuances. Some comments and suggestions as attached. Let's discuss.

Thanks,
Ron

From: John Kim
Sent: November-29-17 18:07
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>

Cc: Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Usman Zahid <Usman.Zahid@ofina.on.ca>
Subject: RE: ESDI Quaterly Update v12_Markup_clean.pptx

Resending….

From: John Kim
Sent: Wednesday, November 29, 2017 6:07 PM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>
Subject: RE: ESDI Quaterly Update v12_Markup_clean.pptx

Saved here:
S:\Users\CEF\Hydro 2017\OEFC\RbP\Outlook\11. November\ESDI for OEFC

And forgot to copy Usman so resending.

From: John Kim
Sent: Wednesday, November 29, 2017 6:05 PM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>
Subject: ESDI Quaterly Update v12_Markup_clean.pptx

Hi Ron,

This deck is to update you on where we propose the 2017-18 estimated ESDI value to be versus $525M that was in the Q1 2017 financials and $140M FTD recently is booking in the draft Q2 2017. This is more for internal discussion for now but could be transition to a full deck quickly.

We would propose updating it to $306M for Q2 2017. We label it as “Budget 2018” but is to represent our latest outlook.

We have asked for a draft financials earlier and following up again now.

Thanks,

John

DRAFT

Updating ESDI 2017-18 OEFC Financials

Corporate and Electricity Finance Division
[DATE]

Overview

- This presentation provides a brief overview of anticipated 2017-18 ESDI and an extended outlook to 2020-21 if ESDI is to be approved to continue beyond 2017-18.
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  - 'unpacking' of asset optimization net impacts previously reported under 'Sales and Rentals
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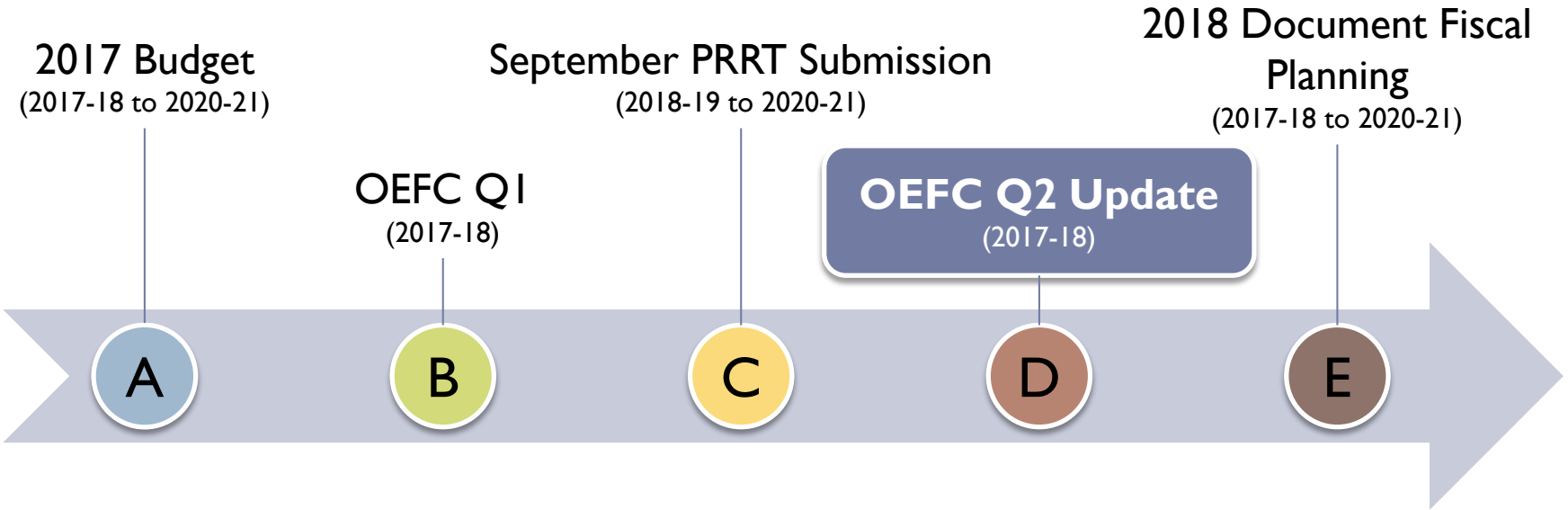

DRAFT

ESDI Updates - Overview

- The following summary provides an overview of the changes since Budget 2017 and projections for the 2018 Document. Detailed explanation provided on the slides following.
- Note, projections for all years were not provided for every update.

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	2. OPG - Re-Pack IFRS Risk	*(400)*	*-*	*(200)*	*-*
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	5. Public Debt Interest Expense	*38*	*38*	*38*	*38*
C	**September PRRT Submission**		***846***	***780***	***1,269***
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ESDI Updates - Details

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Additional Risks

- Major additional risks that may affect the contribution of OPG and Hydro One to ESDI are outlined in the table below.
- These amounts are subject to change based on final results and outcomes of Ontario Energy Board rate decision for OPG, the OEB's review of the Hydro One decision on the deferred tax benefit, and Hydro One's court appeal on that decision, and acquisition activities. Numbers may also change due to impacts of tax planning activities of OPG and Hydro One.

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Hydro One – OEB Decision on tax recapture (if one-time write down)[3]	*(440)*	*6*	*7*	*10*
~~*Hydro One – Motion to Review OEB Transmission Ruling[4]*~~	~~*40*~~	~~*54*~~	~~*41*~~	~~*43*~~
Hydro One – Avista Acquisition Termination Fee (EBT Impact)[~~5~~4]	-	*(51)*	-	-

1. Reflects OEB staff report (May 2017) recommendations with respect to OPG's rate application. (Includes OPG rate application updates). Represents earnings before tax impact; actual net income/ESDI impact may vary due to tax planning activities by OPG.
2. Reflects ~~other~~ risks from ~~an~~ OEB decisions on the switch from accrual to cash accounting from Pension and Other Post Employment Benefits (OPEB) tracked in a variance account ($600M in 2017-18) and switch to cash accounting for regulated recovery of nuclear payment amounts ($450M annually)~~., pensions/OPEB, nuclear liabilities treatment).~~ Represents earnings before tax impact; actual net income/ESDI impact may vary due to tax planning activities by OPG.
3. The OEB's Sep. 28, 2017 ruling on Hydro One's Transmission rate application included direction on sharing, with ratepayers, tax savings related to the Hydro One IPO. The estimated annual ongoing impact of this is factored into the current outlook. This risk reflects the net income impact if a decision is made by Hydro One that the impact of the ruling has to be accounted for as an immediate one-time write-down. The risk reflects the roughly 50% provincial ownership pending re-categorization from the AO Sales and Rentals outlook.
4. ~~On October 18, 2017, Hydro One filed a Notice of Motion to Review and vary the Decision and Order dated September 28, 2017. Upside risks based on Hydro One's motions to vary the OEB decision.~~
5. Represents Provincial share (49.9%) of earnings before tax impact should acquisition be terminated and Hydro One pay Avista $103M termination fee. Actual net income and ESDI impact may vary due to tax planning activities.

PRRT Submission Update

DRAFT

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DRAFT

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Corporate and Electricity Finance Division
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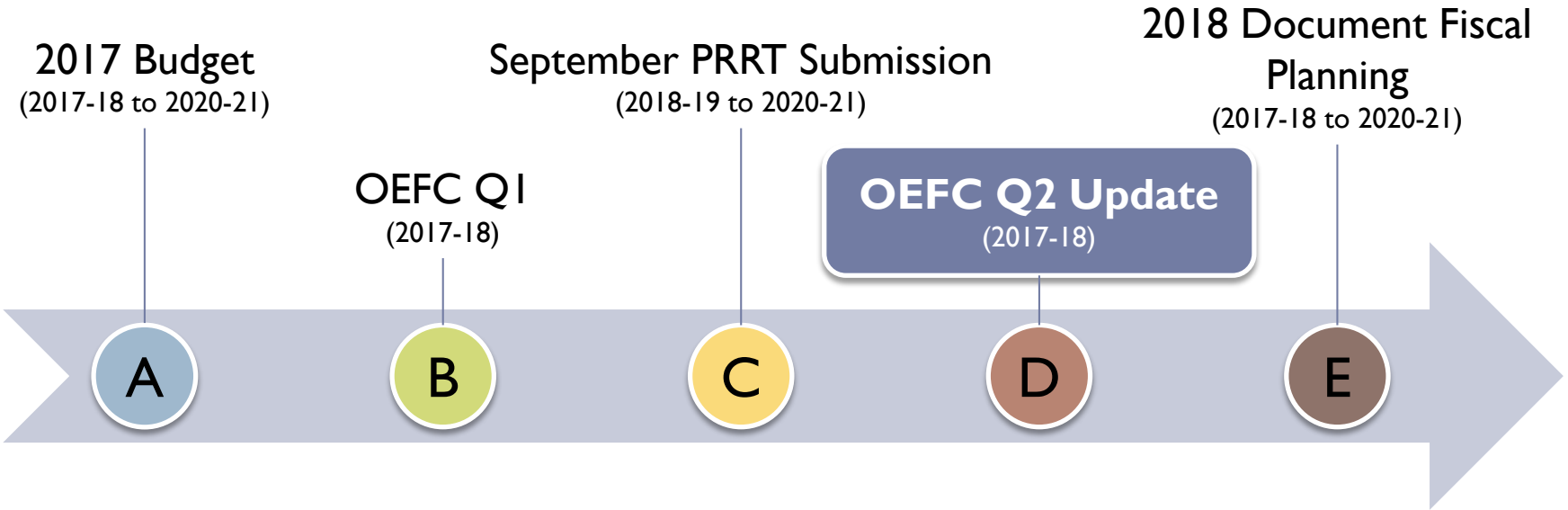

DRAFT

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1. Reflects OEB staff report (May 2017) recommendations with respect to OPG's rate application. (Includes OPG rate application updates). Represents earnings before tax impact; actual net income/ESDI impact may vary due to tax planning activities by OPG.
2. Reflects risks from OEB decisions on the switch from accrual to cash accounting from Pension and Other Post Employment Benefits (OPEB) tracked in a variance account ($600M in 2017-18) and switch to cash accounting for regulated recovery of nuclear payment amounts ($450M annually). Represents earnings before tax impact; actual net income/ESDI impact may vary due to tax planning activities by OPG.
3. The OEB's Sep. 28, 2017 ruling on Hydro One's Transmission rate application included direction on sharing, with ratepayers, tax savings related to the Hydro One IPO. The estimated annual ongoing impact of this is factored into the current outlook. This risk reflects the net income impact if a decision is made by Hydro One that the impact of the ruling has to be accounted for as an immediate one-time write-down. The risk reflects the roughly 50% provincial ownership pending re-categorization from the AO Sales and Rentals outlook.
4. Represents Provincial share (49.9%) of earnings before tax impact should acquisition be terminated and Hydro One pay Avista $103M termination fee. Actual net income and ESDI impact may vary due to tax planning activities.

PRRT Submission Update

DRAFT

PRRT Submission Update

- As part of the PRRT process, the Ministry of Finance submitted the below ESDI provision:

II. Requested Program Changes

$M	17-18	18-19	19-20	20-21	Growth Rate 18-19 to 20-21
Proposed Allocation					
MOF Expense		*(846)*	*(780)*	*(1,269)*	
OEFC Consolidation Expense		*846*	*780*	*1,269*	
Operating Expense	0.0	0.0	0.0	0.0	
Capital Expense	0.0	0.0	0.0	0.0	
Total Expense	0.0	0.0	0.0	0.0	
% Growth		0.0%	0.0%	0.0%	X.X%
Operating Assets	0.0	0.0			
Capital Assets	0.0	0.0	0.0	0.0	

$M	21-22	22-23	23-24	24-25	25-26	26-27	27-28
Capital Expense	X.X	X.X	X.X	X.X	X.X	X.X	X.X
Capital Assets	X.X	X.X	X.X	X.X	X.X	X.X	X.X

Notes:

1. Table should be presented on a fully consolidated basis. Capital assets include acquisitions of consolidated entities. Consolidation information should be consistent with information in ORBIT and information submitted to the Office of the Provincial Controller Division (OPCD).
2. See ORBIT for current allocation.

* Reflects sum of all financial impacts related to Key Operating, Capital, Climate Change, FTE and Technical Decisions

PRRT Submission Update

- The continuation of ESDI beyond April 1, 2018 was proposed in this PRRT submission as OEFC is expected to continue to have significant debt and other liabilities to service and pay down.
- However, any payments under this statutory line item would be fiscally neutral as the payment from the Ministry to the OEFC is fully offset against the consolidation of revenue of OEFC into the Province's Public Accounts.
- Corporate Quality Service Division (CQSD) has confirmed that there will be opportunity to revise ESDI amounts submitted in the PRRT note.
- The timing of these revisions is to be confirmed with TBS.

From: Nelms, Scott (MOF)
To: Ronald Kwan
Subject: RE: ESDI
Date: Monday, March 27, 2017 12:52:27 PM

Great. That's what I was hoping. I am not as familiar with it so wanted to double check we aren't missing anything.

Sent with BlackBerry Work (www.blackberry.com)

From: Ronald Kwan <Ronald.Kwan@ofina.on.ca<mailto:Ronald.Kwan@ofina.on.ca>>
Date: Monday, Mar 27, 2017, 12:18 PM
To: Nelms, Scott (MOF) <Scott.Nelms@ontario.ca<mailto:Scott.Nelms@ontario.ca>>
Subject: Re: ESDI

Hi Scott,

On a prospective basis, the Province's cost of financing the equity injection is supposed to be offset by the increase in OPG net income, so, the net impact on ESDI should be, on a planning basis at least, nil.

However, I understand that OPG is supposed to be subject to some risk, so in actual results, ESDI theoretically could be affected in a given year.

Why do you ask? OPG shouldn't care, as ESDI is just an internal reallocation within the Province, and nets to zero on consolidation of OEFC -- so the AFG and OPCD shouldn't care either.

Ron

_____

From: Nelms, Scott (MOF) <Scott.Nelms@ontario.ca>
Sent: March 27, 2017 10:58:00 AM
To: Ronald Kwan
Subject: ESDI

Hi Ron,

Would OPG's involvement in GA financing have any implications for ESDI? I assume no, but wanted to double check.

Thanks,
Scott

Scott Nelms
Electricity Investment and Governance Secretariat | Ministry of Finance
7th Floor | 375 University ave. | Toronto, ON
w: (416) 212-6469 | c: (647) 330-2681
scott.nelms@ontario.ca<mailto:scott.nelms@ontario.ca>

_____

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From: Gadi Mayman
To: Ken Kandeepan
Cc: Lynsey Wynberg; Ronald Kwan; Mike Manning
Subject: RE: EXTERNAL - RE: OEFC Funding of the Global Adjustment Deferral
Date: Thursday, February 16, 2017 9:08:31 AM

Yes, that makes sense.

-----Original Message-----
From: Ken Kandeepan
Sent: Thursday, February 16, 2017 9:04 AM
To: Gadi Mayman <Gadi.Mayman@ofina.on.ca>
Cc: Lynsey Wynberg <Lynsey.Wynberg@ofina.on.ca>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>; Mike Manning <Mike.Manning@ofina.on.ca>
Subject: FW: EXTERNAL - RE: OEFC Funding of the Global Adjustment Deferral

Hi Gadi

I suggest that we respond as follows: pls let me know if you have any changes

Hi John

Gadi and others spent considerable time last night discussing the equity injection option and we are unclear as to how the Province will be made whole from a fiscal perspective. I suggest that you proceed with fleshing out this option and once we have all the details a decision can be made as to its viability.

Thanks

Ken k

-----Original Message-----
From: LEE John -TREASURY [mailto:john.s.lee@opg.com]
Sent: Thursday, February 16, 2017 8:28 AM
To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
Cc: Veinot, Cindy (TBS) <Cindy.Veinot@ontario.ca>; Nadine Petsche (MOF) <Nadine.Petsche@ontario.ca>; RYFA Ken -TREASURY <ken.ryfa@opg.com>; CHENG Alec -FIN & C CTRL <alec.cheng@opg.com>
Subject: RE: EXTERNAL - RE: OEFC Funding of the Global Adjustment Deferral

Ken:

Have you had any confirmation from Gadi on the approach. As you know time is of the essence, as a result we are proceeding with discussions with the external auditors this morning to brief them on the approach and get their thoughts on the accounting implications and what needs to be done from a structuring perspective to ensure that the varying objectives can be met. Please advise ASAP.

John

-----Original Message-----
From: Ken Kandeepan [mailto:Ken.Kandeepan@ofina.on.ca]
Sent: Wednesday, February 15, 2017 6:37 PM
To: LEE John -TREASURY
Cc: Veinot, Cindy (TBS); Nadine Petsche (MOF); RYFA Ken -TREASURY; CHENG Alec -FIN & C CTRL
Subject: Re: EXTERNAL - RE: OEFC Funding of the Global Adjustment Deferral

Thanks John, it seems that what you are saying is OPG's net income will increase, all else being equal, by the

amount of the interest relating to the equity injection.

In which case upon consolidation there will be no fiscal impact to the Province.

As you work through the options this needs to be fleshed out since the Trust will be consolidated with OPG we need to understand how OPG will show a net interest income.

Thanks

Ken k

> On Feb 15, 2017, at 6:28 PM, LEE John -TREASURY <john.s.lee@opg.com> wrote:
>
> Ken:
> To clarify the expectation is that equity injected into OPG which is on-lend to the Trust would result in net interest income that would roll up to the Province and this would cover the interest expense for the associated debt at the Province. The dividend comment was meant to describe mechanism on how to get cash to the province.
>
> John
>
> -----Original Message-----
> From: Ken Kandeepan [mailto:Ken.Kandeepan@ofina.on.ca]
> Sent: Wednesday, February 15, 2017 5:51 PM
> To: LEE John -TREASURY; 'Veinot, Cindy (TBS)'
> Cc: Nadine Petsche (MOF)
> Subject: RE: EXTERNAL - RE: OEFC Funding of the Global Adjustment Deferral
>
> Hi John and Cindy
>
> I just realized that in the event of an equity injection by the Province to OPG for a maximum of 49%, will as we discussed, have no impact on the Province's net debt.
>
> Unfortunately there will be an IOD impact. John, I remember you mentioning that OPG will increase the dividends it pays to the Province by an amount equivalent to the interest on the equity injection to date, however, that will only provide a cash and not a fiscal offset.
>
> The only way a fiscal offset can be provided is if OPG's net income increases by an amount equal to the increase in the Province's IOD (all else being equal). In which case the Province will be fiscally whole upon consolidation.
>
> But I am not sure that going to happen since the Trust will not contribute to OPG's bottom line, or at least that's my understanding.
>
> As such the potential fiscal impact from the increased IOD may be an issue for the Province re this option. In any event I will check with Gadi and circle back.
>
> Thanks
>
> Ken k
>
> -----Original Message-----
> From: HAHN PARKER Janet -TREASURY [mailto:j.hahnparker@opg.com]
> Sent: Wednesday, February 15, 2017 4:50 PM
> To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
> Cc: LEE John -TREASURY <john.s.lee@opg.com>; 'Veinot, Cindy (TBS)' <Cindy.Veinot@ontario.ca>
> Subject: RE: EXTERNAL - RE: OEFC Funding of the Global Adjustment Deferral
>
> Thank you. Will do.

>
> -----Original Message-----
> From: Ken Kandeepan [mailto:Ken.Kandeepan@ofina.on.ca]
> Sent: Wednesday, February 15, 2017 4:49 PM
> To: HAHN PARKER Janet -TREASURY
> Cc: LEE John -TREASURY; 'Veinot, Cindy (TBS)'
> Subject: RE: EXTERNAL - RE: OEFC Funding of the Global Adjustment Deferral
>
> Cindy is free now if you can set up the call.
>
> Thanks
>
> Ken k
>
> -----Original Message-----
> From: HAHN PARKER Janet -TREASURY [mailto:j.hahnparker@opg.com]
> Sent: Wednesday, February 15, 2017 3:43 PM
> To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
> Cc: LEE John -TREASURY <john.s.lee@opg.com>
> Subject: RE: EXTERNAL - RE: OEFC Funding of the Global Adjustment Deferral
>
> Thank you.
> This is of utmost importance. Please advise soonest.
> Janet
>
> -----Original Message-----
> From: Ken Kandeepan [mailto:Ken.Kandeepan@ofina.on.ca]
> Sent: Wednesday, February 15, 2017 3:37 PM
> To: HAHN PARKER Janet -TREASURY
> Cc: LEE John -TREASURY
> Subject: RE: EXTERNAL - RE: OEFC Funding of the Global Adjustment Deferral
>
> My apologies for the delay, unfortunately I am yet to hear back from Cindy, will let you know as soon as I do.
>
> Thanks
>
> Ken K
>
> -----Original Message-----
> From: HAHN PARKER Janet -TREASURY [mailto:j.hahnparker@opg.com]
> Sent: Wednesday, February 15, 2017 1:57 PM
> To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
> Cc: LEE John -TREASURY <john.s.lee@opg.com>
> Subject: RE: EXTERNAL - RE: OEFC Funding of the Global Adjustment Deferral
>
> Ken,
>
> Please advise on this call. Timing is important.
> A prompt response would be most appreciated,
>
> Thank you,
> Janet Hahn Parker
>
> 416 592-6749
> j.hahnparker@opg.com
>
> -----Original Message-----

> From: Ken Kandeepan [mailto:Ken.Kandeepan@ofina.on.ca]
> Sent: Wednesday, February 15, 2017 9:30 AM
> To: LEE John -TREASURY
> Cc: CHENG Alec -FIN & C CTRL; RYFA Ken -TREASURY; LIU Sheen -TREASURY; HAHN PARKER Janet -TREASURY
> Subject: EXTERNAL - RE: OEFC Funding of the Global Adjustment Deferral
>
> *** Exercise caution. This is an EXTERNAL email. DO NOT open attachments or click links from unknown senders or unexpected email. ***
>
> Thanks John for the quick response, I have forwarded your email to Cindy, since her presence and/or Nadine's is essential if we are having a conference call, will get back to you as soon as I hear from her.
>
>
> Ken K
>
> -----Original Message-----
> From: LEE John -TREASURY [mailto:john.s.lee@opg.com]
> Sent: Wednesday, February 15, 2017 9:09 AM
> To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
> Cc: CHENG Alec -FIN & C CTRL <alec.cheng@opg.com>; RYFA Ken -TREASURY <ken.ryfa@opg.com>; LIU Sheen -TREASURY <sheen.liu@opg.com>; HAHN PARKER Janet -TREASURY <j.hahnparker@opg.com>
> Subject: RE: OEFC Funding of the Global Adjustment Deferral
>
> Ken:
>
> Got your voice message with respect to your proposal to have OEFC fund the Global Adjustment deferral indirectly by lending to OPG and having OPG subsequently lend to a Financing Trust. I agree that this would be the simplest funding mechanism. However since the key objective for the Province to avoid having to recognize the debt and writeoff the Global Adjustment deferral OPG must maintain Government Business Entity (GBE) status. In order to remain a GBE, we must be able to "in the normal course of its operations, maintain its operations and meet its liabilities from revenue received from sources outside of the government reporting entity." I understanding from Alec Cheng (OPG accounting) who was on yesterday accounting call with Nadine (Controllers Office) that OPG GBE status would be put at high risk under the proposed scheme due to the proposed quantum of lending from the OEFC. Our accounting group along with Treasury will be performing some further assessment on this but it may be worth arranging another call with you and your accounting group to layout the issues since the Province seems to be driven by very tight and uncertain timelines and I want everyone to be up to speed.
>
> We can make ourselves available for a call this morning. Please advise.
>
>
> John
>
>
>
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From:	Ronald Kwan
To:	John Kim
Subject:	RE: EXTERNAL - Urgent -- Electricity Rate Mitigation (feedback requested today)
Date:	Friday, February 24, 2017 4:39:55 PM

Hi John,

Would you ask Nadine to cc you as well when these kinds of communications are made with OPG.

Thanks,
Ron

From: Ken Kandeepan
Sent: February-24-17 16:22
To: Gadi Mayman <Gadi.Mayman@ofina.on.ca>
Cc: Christina Zhang <Christina.Zhang@ofina.on.ca>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>
Subject: FW: EXTERNAL - Urgent -- Electricity Rate Mitigation (feedback requested today)

From: Ken Kandeepan
Sent: Friday, February 24, 2017 4:19 PM
To: Nadine Petsche (MOF) <Nadine.Petsche@ontario.ca>; Veinot, Cindy (TBS) <Cindy.Veinot@ontario.ca>
Cc: John Psinas <John.Psinas@ofina.on.ca>; George Sakura <George.Sakura@ofina.on.ca>
Subject: FW: EXTERNAL - Urgent -- Electricity Rate Mitigation (feedback requested today)

I am very confused as to how the GA deferral in the table includes an interest component, perhaps Nadine you could ask them to provide us with their entries for the OPG and the Trust using Cindy's model. That should hopefully shed much needed clarity.

Thanks

Ken k

From: CHENG Alec -FIN & C CTRL [mailto:alec.cheng@opg.com]
Sent: Friday, February 24, 2017 4:06 PM
To: CHENG Alec -FIN & C CTRL <alec.cheng@opg.com>; Nadine Petsche (MOF) <Nadine.Petsche@ontario.ca>; MAUTI John -FIN & C CTRL <john.mauti@opg.com>
Cc: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>; 'Veinot, Cindy (TBS)' <Cindy.Veinot@ontario.ca>; LEE John -TREASURY <john.s.lee@opg.com>
Subject: RE: EXTERNAL - Urgent -- Electricity Rate Mitigation (feedback requested today)

Sorry, sent this before I attached the table.

Customer Bill				
	Current Yr	New Yr		
	0	1	2	3
Other (Non-GA components)	60	60	60	60
GA	100	100	100	100
GA Deferral		-30	-31.5	-33.1
Interest			1.5	3.1
Total Bill	160	130	130	130

From: CHENG Alec -FIN & C CTRL
Sent: Friday, February 24, 2017 4:04 PM
To: 'Petsche, Nadine (TBS)'; MAUTI John -FIN & C CTRL
Cc: Kandeepan, Ken (OFA); Veinot, Cindy (TBS); LEE John -TREASURY
Subject: RE: EXTERNAL – Urgent -- Electricity Rate Mitigation (feedback requested today)

Our comments:

- We cannot verify the IESO entries, but assuming that KPMG is looking at that.
- The current proposal is to have the Trust collect revenue from customers, so the Trust should recognize revenue (which comprise of interest and other recovery amounts) before we start collecting the principal amount from the customers (i.e. before year 5) (see the table below as an illustration)
- I understand that this is a simplified model, but some additional features should be added at a later date when we have more certainty:
    - the financing model would include debt at different rates based on the tranche and the rate implicitly charged to customers would be determined based on the ultimate model and the legislation (may not be the same as the debt financing rate)
    - the Trust will have embedded features which will introduce other variability into the Trust

---

From: Petsche, Nadine (TBS) [mailto:Nadine.Petsche@ontario.ca]
Sent: Friday, February 24, 2017 12:28 PM
To: MAUTI John -FIN & C CTRL; CHENG Alec -FIN & C CTRL
Cc: Kandeepan, Ken (OFA); Veinot, Cindy (TBS); LEE John -TREASURY
Subject: EXTERNAL – Urgent -- Electricity Rate Mitigation (feedback requested today)
Importance: High

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John/Alec,

In advance of next Monday's FPC meeting, we would like to confirm our understanding of the net fiscal impact under the Electricity Rate Mitigation model as currently envisioned. Attached for your review is a model outlining the transactions and impacts as we understand them. The net impact on interest expense to OFA and the Trust appears on lines AS 40 – AS 42.

We would appreciate your comments on the attached as well as any suggestions on how to address the net fiscal impact over the term of the proposal, today if possible.

Regards,
Nadine

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From: Ken Kandeepan
To: Carlos Yep
Cc: Mike Manning; James Devine; John Psinas; John Kim; Ronald Kwan
Subject: RE: EXTERNAL – FHP Questions - Funding Profile
Date: Thursday, February 15, 2018 12:58:56 PM

Thanks Carlos, this is useful.

Ken k

From: Carlos Yep
Sent: Thursday, February 15, 2018 12:52 PM
To: Mike Manning <Mike.Manning@ofina.on.ca>; James Devine <James.Devine@ofina.on.ca>; Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>; John Psinas <John.Psinas@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Subject: FW: EXTERNAL – FHP Questions - Funding Profile

FYI

From: RYFA Ken -TREASURY [mailto:ken.ryfa@opg.com]
Sent: Wednesday, February 07, 2018 12:19 PM
To: Talwar, Shruti (ENERGY) <Shruti.Talwar@ontario.ca>; Carlos Yep <Carlos.Yep@ofina.on.ca>
Cc: Graham Young (MOI) <Graham.Young@ontario.ca>; LADAK Lubna -TREASURY <lubna.ladak@opg.com>; LIU Sheen -TREASURY <sheen.liu@opg.com>; GO Matthew -TREASURY <matthew.go@opg.com>
Subject: RE: EXTERNAL – FHP Questions

Shruti,
Now that the FHT has issued term debt the funding composition is starting to get more complicated. To help understand this below is a summary of the overall funding in the FHT which is now split between warehouse funding and term funding:

			Term debt takeout		
Warehouse Funding		Initial Balance	(980,392,156.86)	Ending Balance	
Senior debt	B=51% x A	601,290,000.00	(500,000,000.00)	101,290,000.00	51%
Subordinated	39/51 X B	459,810,000.00	(382,353,000.00)	77,457,000.00	39%
Junior subordinated	10/51 X B	117,900,000.00	(98,040,000.00)	19,860,000.00	10%
		1,179,000,000.00	(980,393,000.00)	198,607,000.00	
Term Debt Funding					
Senior debt	51.00%		500,000,000.00	500,000,000.00	51%
Subordinated	39.00%		382,353,000.00	382,353,000.00	39%
Junior subordinated	10.00%		98,040,000.00	98,040,000.00	10%
		-	980,393,000.00	980,393,000.00	
Total Funding					
Senior debt	51.00%	601,290,000.00	-	601,290,000.00	51%
Subordinated	39.00%	459,810,000.00	-	459,810,000.00	39%
Junior subordinated	10.00%	117,900,000.00	-	117,900,000.00	10%
		1,179,000,000.00	-	1,179,000,000.00	

1) The equity injection in December was used to fund the subordinated warehouse notes not the term notes. The warehouse notes have a base rate representing all-in funding costs of the senior warehouse notes per s 2.03(b). This funding cost is variable so any rate provided will only apply to a particular period. The December rate was approximately 2.5%. Per s 2.04(b)(i) & (c)(i) the applicable spread for sub and jr sub of this issuance was set at 0.10%.

   The sub and jr sub term notes that correspond to the senior term notes priced yesterday are different. The actual rates are still under review for the sub and jr sub which should be finalized soon.

2) Yes, next equity injection is likely March but could be February as well. For March transaction we would clear out as much of the IESO variance account as possible most of which is reflected in the February month end balance.

Hope this helps.
Thanks,
Ken

From: Talwar, Shruti (ENERGY) [mailto:Shruti.Talwar@ontario.ca]
Sent: Wednesday, February 07, 2018 11:25 AM
To: RYFA Ken -TREASURY <ken.ryfa@opg.com>; Yep, Carlos (OFA) <Carlos.Yep@ofina.on.ca>
Cc: Young, Graham (ENERGY) <Graham.Young@ontario.ca>
Subject: EXTERNAL – FHP Questions

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Hi Ken, Carlos,

Hope you are both well.

I have a couple of questions re: equity injection. They may be both for Ken, but Carlos may be useful to loop you in as well.

1) Can you please provide the interest rate for suboardinate and jr. suboardinate term notes for the transaction that closed on Dec 20, 2017. Per the interest protocol agreement, the interest rate is the 'applicable base rate' (defined in S 2.03) and 'applicable spread' (defined in S 2.04). Section 2.06 of the protocol notes the sharing of this information with ENERGY and OFA. We need this information as soon as possible.

2) What is the timing for the next equity injection? Are you thinking it will be as of the regulatory asset balance as at Feb 28, 2018? In which case, could we expect a request in early March? As you know, the transaction needs to close before March 31 to align with our approved allocations from Treasury Board.

Thank you. Feel free to give me a call with any questions.
Shruti

Shruti Talwar
Director, Strategic Policy and Analytics Branch
Strategic, Network and Agency Policy Division
Ontario Ministry of Energy
416.325-8698

shruti.talwar@ontario.ca

From: Ken Kandeepan
To: Gadi Mayman
Cc: Ronald Kwan; Lynsey Wynberg; Mike Manning; Gavin He
Subject: RE: EXTERNAL – RE: OEFC Funding of the Global Adjustment Deferral
Date: Thursday, February 16, 2017 8:59:48 AM

Hi Gadi

My understanding is that when the asset is sold to OPG Trust by the IESO it converts into an intangible asset as opposed to a regulatory asset. This is because there is no OEB requirement in the future in order to write down the asset. The write down can commence theoretically from the point in time the GA recoveries exceed the payment to generators.

With regard to your second question the OPG uses the Province's equity injection (assuming that the approach that's agreed upon) to lend to the Trust. If so yes the OPG makes money on that segment. Having said that the Trust will capitalize the interest expense on their books and actual payment of the interest to OPG commences only when the GA recoveries exceed the payment to generators.

There may be issues from the OPG's auditors on how OPG can recognize the interest income given that actual settlement is many years into the future. This is probably why we require further details from OPG on this option.

Thanks

Ken k

From: Gadi Mayman
Sent: Wednesday, February 15, 2017 11:54 PM
To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
Cc: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; Lynsey Wynberg <Lynsey.Wynberg@ofina.on.ca>; Mike Manning <Mike.Manning@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>
Subject: Re: EXTERNAL – RE: OEFC Funding of the Global Adjustment Deferral

Hmmm. If I understand this chain correctly, and I'm likely missing something important, would we have a non-regulated entity making hundreds of millions of dollars a year that the ratepayers ultimately have to cover in the future? Or would it be OPG, not the trust, making that profit from the interest on their loan to the trust, and if it's OPG making the profit, can't the OEB weigh in? If either's the case, it would be kind of contrary to the very robust language the government has been using about the OEB providing ratepayer protection with privatized electrical utilities.

On Feb 15, 2017, at 10:36 PM, Ken Kandeepan <Ken.Kandeepan@ofina.on.ca> wrote:

> That's my understanding as well.
>
> Thanks

Ken k

On Feb 15, 2017, at 10:34 PM, Ronald Kwan <Ronald.Kwan@ofina.on.ca> wrote:

> Hi. Ken, emails crossed. I agree, but it would mean OPG is not being regulated by the OEB on this.
>
> Ron
>
> On Feb 15, 2017, at 10:32 PM, Ken Kandeepan <Ken.Kandeepan@ofina.on.ca> wrote:
>
> > No, I was informed by OPCD that IESO will set up the reg asset as you point out but will promptly sell same to the Trust. So the expectation is that at the end of each fiscal year the reg asset set up in that year would be sold to the OPG Trust.
> >
> > Thanks
> >
> > Ken k
> >
> > On Feb 15, 2017, at 10:27 PM, Ronald Kwan <Ronald.Kwan@ofina.on.ca> wrote:
> >
> > > Hi,
> > >
> > > I may be wrong on this, so correct me if so, as I have not been at the accounting meetings on this structure.
> > >
> > > But, based on the Energy submission, I took it as IESO would have the regulatory asset. As such, I took it that the Trust would be outside of OPG's OEB regulated entity.
> > >
> > > Ron
> > >
> > > On Feb 15, 2017, at 10:21 PM, Gadi Mayman <Gadi.Mayman@ofina.on.ca> wrote:
> > >
> > > > First getting it past their auditors will be a challenge, as you've said, and secondly getting the OEB to accept that OPG should be earning the extra $750 million per year that we'd need at the peak of the debt accumulation will be even

more challenging. It would have to be a hit to ratepayers. That would be even harder to explain than a hit to them from an ROE to the Province, which, as you've seen, I've had trouble wrapping my mind around in earlier emails.

On Feb 15, 2017, at 10:11 PM, Ken Kandeepan <Ken.Kandeepan@ofina.on.ca> wrote:

> Not entirely, though the underlying concept is similar. This is just logical speculation on my part but what John is probably driving at is the Trust pays OPG the interest but instead of expensing same it's capitalized.
>
> As such when the Trust is consolidated with OPG the interest income remains in OPG's books since there is no expense to offset it in the books of the Trust.
>
> Ergo, OPG has a net interest income which all else being equal increases its net income, which in turn when consolidated with Province, provides the required fiscal offset to the increase in the Province's IOD.

The problem here would be how willing OPG's auditors will be in recognizing an interest income on OPG books that will be paid in about 15 years time and that too on a piecemeal basis.

Having said all of this let me repeat I may be quite mistaken and John may have a more feasible solution in mind.

Thanks

Ken k

On Feb 15, 2017, at 9:36 PM, Gadi Mayman <Gadi.Mayman@ofina.on.ca> wrote:

> Sounds to me that they're going where Scott Nelms alluded to in his email with an ROE

for the
Province
that
would
offset
our
borrowing
cost?

Adding
Ron
and
Mike
so that
all of
us at
the
OFA
are
aware
of the
same
facts,
as this
is
moving
quickly,
and
any of
us may
be
asked
at any
time
about
it,
including
on
Friday
when
you

and I are away, Ken.

Gadi

From: Ken Kandeepan
Sent: Wednesday, February 15, 2017 9:19 PM
To: Gadi Mayman
Cc: Lynsey Wynberg
Subject: Fwd: EXTERNAL – RE: OEFC Funding of the Global Adjustment Deferral

Hi Gadi

My exchange with John, as you can see little short on the details.

Thanks

Ken k

Begin forwarded message:

From: Ken

Kandeepan
<Ken.Kandeepan@ofina.on.ca>

Date:
February
15,
2017
at
6:36:48
PM
EST

To:
LEE
John
-
TREASURY
<john.s.lee@opg.com>

Cc:
"Veinot,
Cindy
(TBS)"
<Cindy.Veinot@ontario.ca>,
"Nadine
Petsche
(MOF)"
<Nadine.Petsche@ontario.ca>,
RYFA
Ken
-
TREASURY
<ken.ryfa@opg.com>,
CHENG
Alec
-
FIN
&
C
CTRL
<alec.cheng@opg.com>

Subject:
Re:
EXTERNAL
â
€“
RE:
OEFC
Funding

of
the
Global
Adjustment
Deferral

Thanks
John,
it
seems
that
what
you
are
saying
is
OPG's
net
income
will
increase,
all
else
being
equal,
by
the
amount
of
the
interest
relating
to
the
equity
injection.

In
which
case
upon
consolidation
there
will
be
no
fiscal
impact
to

the
Province.

As
you
work
through
the
options
this
needs
to
be
fleshed
out
since
the
Trust
will
be
consolidated
with
OPG
we
need
to
understand
how
OPG
will
show
a
net
interest
income.

Thanks

Ken
k

On
Feb
15,

2017, at 6:28 PM, LEE John - TREASURY <john.s.lee@opg.com> wrote:

Ken:

To clarify the expectation is that equity injected into OPG which is on-lend to the Trust would result in net interest income that would roll up to the Province and this would cover the interest expense

for the associated debt at the Province. The dividend comment was meant to describe mechanism on how to get cash to the province.

John

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-
-
-
-
Original Message-
-
-
-
-
From: Ken Kandeepan [mailto:Ken.Kandeepan@ofina.on.ca]
Sent: Wednesday, February 15, 2017 5:51 PM

To:
LEE
John
-
TREASURY;
'Veinot,
Cindy
(TBS)'

Cc:
Nadine
Petsche
(MOF)

Subject:
RE:
EXTERNAL
–
RE:
OEFC
Funding
of
the
Global
Adjustment
Deferral

Hi
John
and
Cindy

I
just
realized
that
in
the
event
of
an
equity
injection
by
the
Province
to
OPG
for
a

maximum of 49%, will as we discussed, have no impact on the Province's net debt.

Unfortunately there will be an IOD impact. John, I remember you mentioning that OPG will increase the dividends it pays to the Province by an amount equivalent to the interest on the equity

injection to date, however, that will only provide a cash and not a fiscal offset.

The only way a fiscal offset can be provided is if OPG's net income increases by an amount equal to the increase in the Province's IOD (all else being equal). In which case

the
Province
will
be
fiscally
whole
upon
consolidation.

But
I
am
not
sure
that
going
to
happen
since
the
Trust
will
not
contribute
to
OPG's
bottom
line,
or
at
least
that's
my
understanding.

As
such
the
potential
fiscal
impact
from
the
increased
IOD
may
be
an
issue

for
the
Province
re
this
option.
In
any
event
I
will
check
with
Gadi
and
circle
back.

Thanks

Ken
k

-
-
-
-
-
Original
Message-
-
-
-
-
From:
HAHN
PARKER
Janet
-
TREASURY
[mailto:j.hahnparker@opg.com]
Sent:
Wednesday,
February
15,
2017
4:50
PM

To:
Ken
Kandeepan
<Ken.Kandeepan@ofina.on.ca>

Cc:
LEE
John
-
TREASURY
<john.s.lee@opg.com>;
'Veinot,
Cindy
(TBS)'
<Cindy.Veinot@ontario.ca>

Subject:
RE:
EXTERNAL
–
RE:
OEFC
Funding
of
the
Global
Adjustment
Deferral

Thank
you.
Will
do.

-
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-
-
-
Original
Message-
-
-
-
-

From:
Ken
Kandeepan
[mailto:Ken.Kandeepan@ofina.on.ca]

Sent:
Wednesday,
February
15,
2017
4:49
PM

To:
HAHN
PARKER
Janet
-
TREASURY

Cc:
LEE
John
-
TREASURY;
'Veinot,
Cindy
(TBS)'

Subject:
RE:
EXTERNAL
–
RE:
OEFC
Funding
of
the
Global
Adjustment
Deferral

Cindy
is
free
now
if
you
can
set
up
the
call.

Thanks

Ken
k

-
-
-
-
-
Original
Message-
-
-
-
-

From:
HAHN
PARKER
Janet
-
TREASURY
[mailto:j.hahnparker@opg.com]

Sent:
Wednesday,
February
15,
2017
3:43
PM

To:
Ken
Kandeepan
<Ken.Kandeepan@ofina.on.ca>

Cc:
LEE
John
-
TREASURY
<john.s.lee@opg.com>

Subject:
RE:
EXTERNAL
–
RE:
OEFC
Funding
of
the
Global

Adjustment
Deferral

Thank
you.

This
is
of
utmost
importance.
Please
advise
soonest.

Janet

-
-
-
-
-
Original
Message-
-
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-
-

From:
Ken
Kandeepan
[mailto:Ken.Kandeepan@ofina.on.ca]

Sent:
Wednesday,
February
15,
2017
3:37
PM

To:
HAHN
PARKER
Janet
-
TREASURY

Cc:
LEE
John
-

TREASURY

Subject:
RE:
EXTERNAL
–
RE:
OEFC
Funding
of
the
Global
Adjustment
Deferral

My
apologies
for
the
delay,
unfortunately
I
am
yet
to
hear
back
from
Cindy,
will
let
you
know
as
soon
as
I
do.

Thanks

Ken
K

-
-
-
-

-
Original
Message-
-
-
-
-

From:
HAHN
PARKER
Janet
-
TREASURY
[mailto:j.hahnparker@opg.com]

Sent:
Wednesday,
February
15,
2017
1:57
PM

To:
Ken
Kandeepan
<Ken.Kandeepan@ofina.on.ca>

Cc:
LEE
John
-
TREASURY
<john.s.lee@opg.com>

Subject:
RE:
EXTERNAL
–
RE:
OEFC
Funding
of
the
Global
Adjustment
Deferral

Ken,

Please

advise on this call. Timing is important.

A prompt response would be most appreciated,

Thank you,

Janet Hahn Parker

416 592-6749

j.hahnparker@opg.com

Original Message-----

From: Ken Kandeepan [mailto:Ken.Kandeepan@ofina.on.ca]

Sent: Wednesday, February 15, 2017 9:30

AM

To:
LEE
John
-
TREASURY

Cc:
CHENG
Alec
-
FIN
&
C
CTRL;
RYFA
Ken
-
TREASURY;
LIU
Sheen
-
TREASURY;
HAHN
PARKER
Janet
-
TREASURY

Subject:
EXTERNAL
–
RE:
OEFC
Funding
of
the
Global
Adjustment
Deferral

***
Exercise
caution.
This
is
an
EXTERNAL
email.
DO
NOT

open
attachments
or
click
links
from
unknown
senders
or
unexpected
email.
***

Thanks
John
for
the
quick
response,
I
have
forwarded
your
email
to
Cindy,
since
her
presence
and/or
Nadine's
is
essential
if
we
are
having
a
conference
call,
will
get
back
to
you
as
soon
as
I
hear

from
her.

Ken
K

-
-
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Original
Message-
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-
-

From:
LEE
John
-
TREASURY
[mailto:john.s.lee@opg.com]

Sent:
Wednesday,
February
15,
2017
9:09
AM

To:
Ken
Kandeepan
<Ken.Kandeepan@ofina.on.ca>

Cc:
CHENG
Alec
-
FIN
&
C
CTRL
<alec.cheng@opg.com>;
RYFA
Ken
-

TREASURY
<ken.ryfa@opg.com>;
LIU
Sheen
-
TREASURY
<sheen.liu@opg.com>;
HAHN
PARKER
Janet
-
TREASURY
<j.hahnparker@opg.com>

Subject:
RE:
OEFC
Funding
of
the
Global
Adjustment
Deferral

Ken:

Got
your
voice
message
with
respect
to
your
proposal
to
have
OEFC
fund
the
Global
Adjustment
deferral
indirectly
by
lending
to
OPG
and
having

OPG subsequently lend to a Financing Trust. I agree that this would be the simplest funding mechanism. However since the key objective for the Province to avoid having to recognize the debt and writeoff the Global Adjustment deferral OPG must maintain Government Business Entity (GBE) status. In order to remain

a GBE, we must be able to "in the normal course of its operations, maintain its operations and meet its liabilities from revenue received from sources outside of the government reporting entity." I understanding from Alec Cheng (OPG accounting) who was on yesterday accounting call with Nadine (Controllers Office) that

OPG GBE status would be put at high risk under the proposed scheme due to the proposed quantum of lending from the OEFC.

Our accounting group along with Treasury will be performing some further assessment on this but it may be worth arranging another call with you and your accounting

group to layout the issues since the Province seems to be driven by very tight and uncertain timelines and I want everyone to be up to speed.

We can make ourselves available for a call this morning. Please advise.

John

-

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-

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AND/OR
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recipient,
you
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hereby
notified
that
any
review,
retransmission,
dissemination,
distribution,
copying,
conversion
to
hard
copy
or
other
use
of
this
communication
is
strictly
prohibited.
If
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are
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and
have
received
this
message
in
error,
please
notify
me
by
return
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delete
this
message
from
your
system.
Ontario
Power
Generation
Inc.

This
message,
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individual(s)
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Any
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without
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them,
and
destroy
all

copies.
Thank
you.

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Ontario
Power
Generation
Inc.

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Ontario
Power
Generation
Inc.

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MESSAGE
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other use of this communication is strictly prohibited. If you are not the intended recipient and have received this message in error, please notify me by return e-mail and delete this message from your system. Ontario Power Generation Inc.

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CONFIDENTIAL.
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mail
and
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this
message
from
your
system.
Ontario
Power
Generation
Inc.

From: HO Philip -FIN & C CTRL
To: John Kim
Cc: MAK Ricky -FIN & C CTRL; Ronald Kwan; DYKXHOORN Sandra -CORPRELCOMM
Subject: RE: EXTERNAL – RE: OPG Q1 2017 Submission to Province
Date: Thursday, May 11, 2017 1:46:37 PM
Attachments: Q1 2017 MDA - DRAFT - PROVINCE MAILING_CEFD edit v4_OPG responses.docx

---

Hi John,

Please find attached our responses to the Ministry of Finance comments. Thank you.

Regards,

Philip Ho

From: John Kim [mailto:John.Kim@ofina.on.ca]
Sent: Tuesday, May 02, 2017 6:38 PM
To: HO Philip -FIN & C CTRL
Cc: MAK Ricky -FIN & C CTRL; Ronald Kwan
Subject: EXTERNAL – RE: OPG Q1 2017 Submission to Province

*** Exercise caution. This is an EXTERNAL email. DO NOT open attachments or click links from unknown senders or unexpected email. ***

Hi Philip,

See attached.

John

From: HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
Sent: April-28-17 5:04 PM
To: 'Shruti.Talwar@ontario.ca' <Shruti.Talwar@ontario.ca>; Sunita Chander (ENERGY) <Sunita.Chander@ontario.ca>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>
Subject: OPG Q1 2017 Submission to Province

Hi All,

Please find attached OPG's draft Q1 2017 Management's Discussion and Analysis (MD&A) and Financial Statements for the Province's review.

We would greatly appreciate comments on the above **no later than Tuesday, May 2nd**.

These documents will be filed with the Ontario Securities Commission on **Friday, May 12th** following OPG's Board of Directors meeting.

Kindly forward all comments directly to Philip Ho – philip.ho@opg.com.

To assist the review process, the following are the key items in the Q1 2017 MD&A:

Highlights	
Recent Developments	MD&A p.9-11
Darlington Refurbishment	MD&A p.9; 13-14
Ontario's Fair Hydro Plan	MD&A p.10
Peter Sutherland Sr. GS project	MD&A p.9, 13

Philip Ho, CPA, CA | Senior Manager, External Reporting & Accounting Policy | Ontario Power Generation
700 University Avenue, Toronto ON M5G 1X6 | Phone: (416) 592-3320| E-mail: philip.ho@opg.com

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ONTARIO POWER GENERATION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

2017 FIRST QUARTER REPORT

[DRAFT]

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ONTARIO POWER GENERATION

ONTARIO POWER GENERATION INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) should be read in conjunction with the unaudited interim consolidated financial statements and accompanying notes of Ontario Power Generation Inc. (OPG or Company) as at and for the three months ended March 31, 2017. OPG's unaudited interim consolidated financial statements are prepared in accordance with United States generally accepted accounting principles (US GAAP) and are presented in Canadian dollars.

For a complete description of OPG's corporate strategies, risk management, corporate governance, and the effect of critical accounting policies and estimates on OPG's results of operations and financial condition, this MD&A should also be read in conjunction with OPG's audited consolidated financial statements, accompanying notes, the Annual Information Form, and the MD&A as at and for the year ended December 31, 2016.

As required by *Ontario Regulation 395/11*, as amended, a regulation under the *Financial Administration Act* (Ontario), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. In 2014, the Ontario Securities Commission approved an exemption which allows OPG to apply US GAAP up to January 1, 2019. The term of the exemption is subject to certain conditions, which may result in the expiry of the exemption prior to January 1, 2019. For details, refer to the section, *Critical Accounting Policies and Estimates* under the heading, *Exemptive Relief for Reporting under US GAAP,* in OPG's 2016 annual MD&A. This MD&A is dated May 12, 2017.

FORWARD-LOOKING STATEMENTS

The MD&A contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could", and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

All forward-looking statements involve inherent assumptions, risks, and uncertainties, including those set out under the section, *Risk Management,* and forecasts discussed under the section, *Core Business, Strategy, and Outlook.* All forward-looking statements could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's generating station performance and availability, fuel costs, surplus baseload generation (SBG), cost of fixed asset removal and nuclear waste management, performance and earnings of investment funds, refurbishment of existing facilities, development and construction of new facilities, pension and other post-employment benefit (OPEB) obligations and funds, income taxes, proposed new legislation, the ongoing evolution of Ontario's electricity industry, environmental and other regulatory requirements, health, safety and environmental developments, business continuity events, the weather, financing and liquidity, applications to the Ontario Energy Board (OEB) for regulatory prices, the impact of regulatory decisions by the OEB, and forecasts of earnings, cash flows, Funds from Operations (FFO) Adjusted Interest Coverage, Return on Common Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI), Total Generating Cost (TGC) and capital expenditures. Accordingly, undue reliance should not be placed on any forward-looking statement. The forward-looking statements included in this MD&A are made only as of the date of this MD&A. Except as required by applicable securities laws, OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events, or otherwise.

THE COMPANY

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG was established under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (Province or Shareholder).

As at March 31, 2017, OPG's electricity generation portfolio had an in-service capacity of 16,205 megawatts (MW). OPG operates two nuclear generating stations, 66 hydroelectric generating stations, three thermal generating stations, and one wind power turbine. In addition, OPG and TransCanada Energy Ltd. co-own the 550 MW Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS). OPG and ATCO Power Canada Ltd. co-own the 560 MW Brighton Beach gas-fired combined cycle GS (Brighton Beach). OPG's 50 percent share of the in-service capacity and generation volume of these co-owned facilities is included in the generation portfolio statistics set out in this report. The income from the co-owned facilities is accounted for using the equity method of accounting, and OPG's share of income is presented as income from investments subject to significant influence in the Contracted Generation Portfolio segment.

OPG also owns two other nuclear generating stations, the Bruce A GS and the Bruce B GS, which are leased on a long-term basis to Bruce Power LP (Bruce Power). Income from these leased stations is included in revenue under the Regulated – Nuclear Generation segment. The leased stations are not included in the generation portfolio statistics set out in this report. A description of OPG's segments is provided in OPG's 2016 annual MD&A in the section, *Business Segments*.

All of OPG's owned and co-owned generating facilities are located in Ontario. OPG does not operate PEC, Brighton Beach, the Bruce A GS and the Bruce B GS.

In-Service Generating Capacity

OPG's in-service generating capacity by business segment as of March 31, 2017 and December 31, 2016 was as follows:

	As at	
(MW)	**March 31 2017**	**December 31 2016**
Regulated – Nuclear Generation [1]	**5,728**	5,728
Regulated – Hydroelectric	**6,421**	6,421
Contracted Generation Portfolio [2]	**4,056**	4,028
Total	**16,205**	16,177

[1] The in-service generating capacity as of March 31, 2017 and December 31, 2016 excludes Unit 2 of the Darlington GS. The unit, which has a generating capacity of 878 MW, was taken offline in mid-October 2016 and is currently undergoing refurbishment.
[2] Includes OPG's share of in-service generating capacity of 275 MW for PEC and 280 MW for Brighton Beach.

During the three months ended March 31, 2017, the total in-service capacity increased by 28 MW. The increase was due to the completion of Peter Sutherland Sr. hydroelectric GS, which was placed in-service on March 31, 2017. The Peter Sutherland Sr. GS is discussed in the section, *Highlights* under the heading, *Recent Developments*.

HIGHLIGHTS

Overview of Results

This section provides an overview of OPG's unaudited interim consolidated operating results. Significant factors which contributed to OPG's results during the three months ended March 31, 2017, compared to the same period in 2016, are discussed below.

(millions of dollars – except where noted) (unaudited)	Three Months Ended March 31 2017	2016
Revenue	**1,176**	1,478
Fuel expense	**155**	172
Gross margin	**1,021**	1,306
Operations, maintenance and administration	**708**	686
Depreciation and amortization	**167**	312
Accretion on fixed asset removal and nuclear waste management liabilities	**238**	232
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(189)**	(147)
Income from investments subject to significant influence	**(10)**	(8)
Property taxes	**11**	12
	925	1,087
Income before other gains, interest, and income taxes	**96**	219
Other gains	**(3)**	(23)
Income before interest and income taxes	**99**	242
Net interest expense	**19**	33
Income before income taxes	**80**	209
Income tax expense	**12**	81
Net income	**68**	128
Net income attributable to the Shareholder	**64**	123
Net income attributable to non-controlling interest [1]	**4**	5
Electricity production (TWh) [2]	**18.6**	21.0
Cash flow		
Cash flow provided by operating activities	**118**	366

[1] Relates to the 25 percent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in the Lower Mattagami Limited Partnership.

[2] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

Net income attributable to the Shareholder was $64 million for the first quarter of 2017, a decrease of $59 million compared to 2016. Income before interest and income taxes was $99 million for 2017, a decrease of $143 million compared to 2016. The following summarizes the significant factors which contributed to the variance:

Significant factors that reduced income before interest and income taxes:

- As expected, lower revenue from the nuclear base regulated price of approximately $134 million, partially offset by the largely associated decrease in fuel expense of $13 million, reflecting lower electricity generation of 2.3 terawatt hours (TWh) from the Regulated – Nuclear Generation segment and the continuation of existing base regulated prices set by the OEB in 2014. Existing base regulated prices continue to be in effect pending the OEB's decision on OPG's current application for new regulated prices, expected in the second half of 2017. The lower nuclear generation was primarily due to the ongoing

refurbishment of Unit 2 at the Darlington GS since October 2016. The existing base regulated prices were set to allow the Company to recover its approved nuclear costs over a higher nuclear production volume, based on the 2014 and 2015 outage profile that did not include a refurbishment outage. OPG has requested January 1, 2017 as the effective date of the new regulated prices. Further details on OPG's current application for new regulated prices can be found under the heading, *Recent Developments – OPG's Application for New Regulated Prices.*

- Higher operations, maintenance and administration (OM&A) expenses of $22 million, mainly in the Regulated – Nuclear Generation segment, reflecting use of temporary staff and planned hiring to fill vacant positions due to attrition, and higher material costs related to maintenance work at the nuclear stations.
- A gain of $22 million recorded in the first quarter of 2016 to reflect the OEB's decision on OPG's motion asking the OEB to review and vary parts of its November 2014 decision on OPG's regulated prices.

Significant factors that increased income before interest and income taxes:

- Higher earnings on the nuclear fixed asset removal and nuclear waste management funds (Nuclear Segregated Funds) of $42 million, primarily due to higher earnings on the Used Fuel Segregated Fund
- Higher hydroelectric incentive mechanism revenue of $7 million from the Regulated – Hydroelectric segment.

The expiry of rate riders for the recovery of approved balances in OEB-authorized regulatory variance and deferral accounts (regulatory accounts) on December 31, 2016 contributed to the decrease in revenue in the first quarter of 2017, compared to the same period in 2016, but was primarily offset by a decrease in the amortization expense related to regulatory account balances. New rate riders have been requested in OPG's application for new regulated prices with the OEB, effective January 1, 2017.

Net interest expense decreased by $14 million in the first quarter of 2017, compared to the same quarter in 2016, primarily due to a higher amount of interest costs capitalized for the Darlington Refurbishment project.

Income tax expense decreased by $69 million in the first quarter of 2017, compared to the same quarter in 2016, primarily due to lower income before income taxes in the first quarter of 2017 and a higher income tax expense in the first quarter of 2016 due to a reduction in regulatory assets related to income taxes.

Segment Results

The following table summarizes OPG's income before interest and income taxes by business segment. A detailed discussion of OPG's performance by reportable segment is included in the section, *Discussion of Operating Results by Business Segment*.

	Three Months Ended March 31	
(millions of dollars)	**2017**	**2016**
Income (loss) before interest and income taxes		
Regulated – Nuclear Generation	**(118)**	46
Regulated – Hydroelectric	**180**	196
Contracted Generation Portfolio	**77**	78
Total electricity generation business segments	**139**	320
Regulated – Nuclear Waste Management	**(47)**	(83)
Services, Trading, and Other Non-Generation	**7**	5
	99	242

Electricity Generation

Electricity generation was as follows:

(TWh)	Three Months Ended March 31 2017	2016
Regulated – Nuclear Generation	**10.0**	12.3
Regulated – Hydroelectric	**8.0**	7.9
Contracted Generation Portfolio [1]	**0.6**	0.8
Total OPG electricity generation	**18.6**	21.0
Total electricity generation by other generators in Ontario [2]	**18.6**	18.9

[1] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

[2] Non-OPG generation is calculated as the Ontario electricity demand plus net exports, as published by the Independent Electricity System Operator (IESO), minus OPG electricity generation.

The lower electricity generation from the Regulated – Nuclear Generation segment in the first quarter of 2017 compared to the same quarter in 2016 was primarily a result of the removal from service of Unit 2 at the Darlington GS for the duration of the unit's refurbishment that began in October 2016. This decrease in electricity generation was partially offset by an increase in generation from the Pickering GS, primarily due to a decrease in the number of planned outage days.

The higher electricity generation from the Regulated – Hydroelectric generating segment in the first quarter of 2017 was primarily due to a lower volume of water spilled as a result of less prevalent SBG conditions, largely offset by the impact of lower water flows on the eastern and northeastern Ontario river systems, compared to the first quarter in 2016.

The lower electricity generation from the Contracted Generation Portfolio segment was primarily the result of lower water flows on the northeastern Ontario river systems.

OPG's operating results are affected by changes in grid-supplied electricity demand resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. For the first quarter of 2017, Ontario's electricity demand as reported by the IESO was 34.3 TWh compared to 35.2 TWh for the same quarter in 2016, which excludes electricity exports out of the province.

Power that is surplus to the Ontario market is managed by the IESO, mainly through generation reductions at hydroelectric, other grid-connected renewable resources and nuclear stations. Reducing hydroelectric production, which often results in spilling of water, is the first measure used by the IESO to manage SBG conditions. While baseload generation supply surplus in Ontario was less prevalent in the first quarter of 2017 compared to the same period in 2016, OPG lost 0.8 TWh of hydroelectric generation due to SBG conditions in the first quarter of 2017. OPG lost 1.7 TWh of hydroelectric generation due to SBG conditions during the first quarter of 2016. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions during these periods was offset by the impact of a regulatory variance account authorized by the OEB. OPG did not forgo any electricity production at its nuclear stations due to SBG conditions.

Average Sales Prices

The majority of OPG's generation is from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments. The same base regulated prices for electricity generated by these segments, authorized by the OEB effective November 1, 2014, were in effect during the first quarter of 2017 as in 2016. These prices will remain in effect until such time as the OEB approves new regulated prices based on OPG's current application, discussed under the heading, *Recent Developments – OPG's Application for New Regulated Prices.* The base regulated prices established in 2014 are discussed in OPG's 2016 annual MD&A in the section, *Revenue Mechanisms for Regulated and Non-Regulated Generation*.

The average sales price for the Regulated – Nuclear Generation segment was 5.8 cents per kilowatt hour (¢/kWh) during the first quarter of 2017, compared to 7.0 ¢/kWh during the same quarter in 2016. The decrease in the average sales price was primarily due to the expiry, on December 31, 2016, of the OEB-authorized nuclear rate rider of $10.84 per megawatt hour (MWh) for the recovery of variance and deferral account balances. The average sales price for the Regulated – Hydroelectric segment was 4.2 ¢/kWh during the first quarter of 2017, compared to 4.4 ¢/kWh during the same quarter in 2016. The decrease in average sales price was primarily due to the expiry, on December 31, 2016, of a regulated hydroelectric rate rider of $3.19/MWh for the recovery of variance and deferral account balances. These rate riders were established to recover approved balances recorded in OEB-authorized regulatory variance and deferral accounts in prior years. As such, the year-over-year changes in revenue from the rate riders were largely offset by changes in amortization expense related to regulatory account balances. There were no rate riders in effect during the first quarter of 2017 for either nuclear or regulated hydroelectric generation, pending the outcome of OPG's current application with the OEB for new regulated prices, including rate riders.

Cash Flow from Operations

Cash flow provided by operating activities for the three months ended March 31, 2017 was $118 million, compared to $366 million for the same period in 2016. As expected, the decrease in cash flow provided by operating activities in the first quarter of 2017, compared to the same quarter in 2016, was primarily due to lower generation revenue receipts reflecting lower generation from the Regulated – Nuclear Generation segment as a result of the ongoing refurbishment of Unit 2 at the Darlington GS and the expiry, on December 31, 2016, of the OEB-authorized rate riders for nuclear and regulated hydroelectric generation. The decrease in cash flow in the first quarter of 2017 was also due to higher income tax installments and higher OM&A expenditures, compared to the same quarter in 2016. The decrease in cash flow provided by operating activities was partially offset by lower pension plan contributions reflecting an updated actuarial valuation of the OPG registered pension plan filed with the Financial Services Commission of Ontario in September 2016, and lower contributions to the Used Fuel Segregated Fund and the Decommissioning Segregated Fund. Both the Used Fuel Segregated Fund and the Decommissioning Segregated Fund were determined to be fully funded based on an updated estimate of OPG's nuclear waste management and nuclear facilities decommissioning obligations pursuant to a reference plan approved by the Province, for years 2017 to 2021, under the Ontario Nuclear Funds Agreement (ONFA), effective January 1, 2017. Pursuant to the ONFA, the reference plan is required to be updated at least once every five years. Contributions to either or both of the Nuclear Segregated Funds may be required in the future should the funds be in an underfunded position at the time of the next ONFA reference plan update. The year-over-year decrease in cash flow also was partially offset by the payment of a supplemental rent rebate to Bruce Power in the first quarter of 2016 in relation to a period in 2015. The lease agreement for the Bruce nuclear generating stations giving rise to this rebate was amended in late 2015 to eliminate this provision going forward.

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Funds from Operations Adjusted Interest Coverage

FFO Adjusted Interest Coverage is an indicator of OPG's ability to meet interest obligations from operating cash flow. The indicator is measured over a 12-month period. FFO Adjusted Interest Coverage was 5.1 times for the 12 month-periods ended March 31, 2017 and December 31, 2016. FFO Adjusted Interest Coverage in 2017 reflected a year-over-year decrease in FFO before interest due to lower cash flow provided by operating activities, offset by the

impact of a lower adjusted interest expense due to a decrease in the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets.

The decrease in the excess of interest on pension and OPEB benefit obligations over expected return on pension plan assets in 2017 was primarily due to the change in the method used to estimate the interest cost and current service cost component of pension and OPEB costs. Effective January 1, 2017, OPG adopted a full yield curve approach to the estimation of these cost components, by applying the specific spot rates along the yield curve used in the determination of the projected benefit obligations to the relevant projected cash flows. Under the previous method, these components of pension and OPEB costs were calculated using the same single weighted-average discount rates as reflected in the calculation of the benefit obligations. This change in the method was accounted for prospectively, as a change in estimate. The resulting reduction in pension and OPEB costs in the first quarter of 2017 was largely offset by the impact of OEB-authorized variance and deferral accounts. Further details on the full yield curve approach can be found in the 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Pension and Other Post-Employment Benefits*. **[UPDATE]**

Return on Common Equity Excluding Accumulated Other Comprehensive Income

ROE Excluding AOCI is an indicator of OPG's performance consistent with its strategy to provide value to the Shareholder. ROE Excluding AOCI is measured over a 12-month period. ROE Excluding AOCI for the 12 months ended March 31, 2017 was 3.5 percent, compared to 4.2 percent for the 12 months ended December 31, 2016. The decrease was primarily due to lower net income attributable to the Shareholder. As expected, reduced revenue due to the continuation of existing base regulated prices that do not reflect the lower nuclear generation as a result of the Unit 2 refurbishment outage at the Darlington GS negatively impacted net income and ROE Excluding AOCI for the 12-month period ended March 31, 2017. The continuation of existing base regulated prices until such time as new regulated prices are approved by the OEB later in 2017 will negatively affect OPG's ROE Excluding AOCI.

Enterprise Total Generating Cost per MWh

The Enterprise TGC per MWh was $47.86 for the three months ended March 31, 2017, compared to $41.82 for the same period in 2016. The increase in Enterprise TGC per MWh for the three months ended March 31, 2017, compared to the same period in 2016, was expected and primarily due to the decrease in electricity generation reflecting the Unit 2 refurbishment outage at the Darlington GS.

Nuclear Total Generating Cost per MWh

The Nuclear TGC per MWh was $69.87 for the three months ended March 31, 2017, compared to $56.37 for the same period in 2016. The increase in Nuclear TGC per MWh for the three months ended March 31, 2017, compared to the same period in 2016, was expected and primarily due to the decrease in nuclear electricity generation reflecting the Unit 2 refurbishment outage at the Darlington GS.

Hydroelectric Total Generating Cost per MWh

The Hydroelectric TGC per MWh was $19.79 for the three months ended March 31, 2017, which was comparable to $19.94 for the same period in 2016.

ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are not measurements in accordance with US GAAP and should not be considered alternative measures to net income, cash flow provided by operating activities, or any other performance measure under US GAAP. OPG believes that these non-GAAP financial measures are effective indicators of its performance and are consistent with the Company's strategic imperatives and related objectives. The definition and calculation of ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are found in the section, *Supplementary Non-GAAP Financial Measures*.

Recent Developments

Darlington Refurbishment

In October 2016, OPG commenced the refurbishment of the first Darlington GS unit, Unit 2, as planned, as part of the Darlington Refurbishment project. The unit was taken offline safely on October 15, 2016 and de-fuelling of the reactor, the first critical refurbishment activity undertaken once the unit is removed from service, was safely completed in January 2017. Islanding of Unit 2, the physical separation of the unit under refurbishment from the three operating units, was completed in April 2017, signifying the completion of the first major segment of the project. The second segment commenced immediately following the islanding of Unit 2. The second segment continues preparatory work to support the removal of feeder tubes and fuel channel assemblies, including opening the reactor air lock doors, installation of shielding, setting up specialized tooling and equipment, and commencing the disassembly and removal of reactor components. Once refurbished, Unit 2 is scheduled to be returned to service in the first quarter of 2020, at which time capital expenditures of approximately $4.8 billion are planned to be placed in service. The project is tracking on schedule and budget.

The Darlington Refurbishment project is discussed further in the section, *Core Business, Strategy, and Outlook* under the heading, *Project Excellence.*

Peter Sutherland Sr. Hydroelectric GS

In March 2017, the project to construct the 28 MW two-unit Peter Sutherland Sr. hydroelectric GS successfully completed final testing and commissioning of the turbine and generator units and both units were declared substantially complete. On March 31, 2017, the project received a permit from the Ministry of Environment and Climate Change (MOECC) to take water for operations to allow the station to operate commercially. This in-service date is well ahead of the originally planned schedule of the first half of 2018. The project's schedule was accelerated to take advantage of favourable weather conditions. The project is expected to close below the approved budget of $300 million, following the completion of site remediation, camp dismantling, demobilization and other project close-out activities.

The project was constructed in partnership with the Coral Rapids Power Corporation (CRP), a corporation wholly owned by the Taykwa Tagamou Nation, through the PSS Generating Station Limited Partnership (PSS). Under the partnership agreement, as the unit is placed in-service, the CRP may acquire up to a 33 percent partnership interest through its investment in PSS. In April 2017, the CRP acquired a 33 percent interest in PSS.

OPG's Application for New Regulated Prices

In May 2016, OPG filed a 5-year application with the OEB for new base regulated prices for production from its regulated hydroelectric and nuclear facilities, with a proposed effective date of January 1, 2017, on the basis of an incentive regulation ratemaking methodology for the hydroelectric operations and a custom incentive regulation framework for the nuclear operations. For the hydroelectric facilities, the application proposes to escalate the existing base regulated prices, with some adjustments, for each of the years 2017 to 2021, based on a formula that considers an industry specific inflation factor less a productivity improvement factor and less a stretch factor intended to incent additional innovation and efficiency. For the nuclear operations, the application proposes revenue requirements for each of the years 2017 to 2021 based on OPG's forecast of operating costs, reduced by a stretch factor amount, as well as a return on rate base and an annual forecast of production. The application also requests new rate riders, effective January 1, 2017, to recover or repay the December 31, 2015 balances in all of the Company's OEB-authorized variance and deferral accounts, with the exception of the Pension & OPEB Cash Versus Accrual Differential Deferral Account, less amounts previously approved for recovery or repayment through rate riders that were in effect to December 31, 2016. The Pension & OPEB Cash Versus Accrual Differential Deferral Account is discussed further in the section, *Balance Sheet Highlights* under the heading, *Pension & OPEB Cash Versus Accrual Differential Deferral Account*.

Consistent with the requirements of *Ontario Regulation 53/05*, OPG's application submission in May 2016 incorporated a nuclear rate smoothing proposal. This proposal would result in OPG deferring a portion of the approved annual nuclear revenue requirements during the period from January 1, 2017 to the end of the Darlington Refurbishment project in a deferral account for future collection.

In March 2017, the Province amended *Ontario Regulation 53/05* to require that the portion of the approved annual nuclear revenue requirements deferred for future collection under rate smoothing be determined with a view of making more stable year-over-year changes in OPG's weighted-average nuclear and hydroelectric regulated prices, including rate riders. Previously, the regulation required that the deferred amounts be determined with a view of making more stable year-over-year changes in OPG's nuclear regulated prices only, excluding rate riders. The amendment is intended to make more predictable the impact on customer bills resulting from changes in OPG's overall regulated prices, reducing the average year-over-year change in customer bills over the term of OPG's current application. Following the amendment, in March 2017, OPG submitted a modified rate smoothing proposal to the OEB to reflect the new requirements of the regulation, as part of the application for new regulated prices. OPG expects to recognize amounts deferred under rate smoothing as income in the period to which the underlying approved revenue requirements relate.

In March 2017, the OEB approved a settlement agreement reached by OPG and intervenors on a limited set of issues in OPG's application (Settlement Agreement). Among the settled issues, the agreement provided for the continuation of all applicable existing variance and deferral accounts and accepted a number of variance and deferral account balances for recovery, as requested in OPG's application. In addition, the Settlement Agreement accepted OPG's proposed adjustments to the existing regulated hydroelectric base regulated prices for the purposes of determining the starting point for an incentive regulation formula for the 2017 to 2021 period. The Settlement Agreement did not impact OPG's financial results for the three months ended March 31, 2017.

The OEB conducted 23 public oral hearing days on the unsettled issues in OPG's application between February 27, 2017 and April 13, 2017, as part of an overall public proceeding on the application. Final arguments in the proceeding are scheduled to be completed by June 19, 2017. The OEB's decision on the application, including the effective date of approved new regulated prices, is expected in the second half of 2017.

Ontario's Fair Hydro Plan

On March 2, 2017, the Province announced Ontario's Fair Hydro Plan (the Plan) aimed at reducing electricity bills for all residential consumers in the province by 25 percent on average ~~for all residential consumers in the province~~. Approximately 500,000 small businesses and farms would also benefit. As part of the Plan, the Province has proposed refinancing a portion of the Global Adjustment costs over a longer time period for Regulated Price Plan eligible customers (e.g., residential, farm, small businesses). On May [11], 2017, the Province introduced legislation that, if passed, will enable the IESO and OPG to work together to implement this financing as requested by the Province. Any final agreement to implement OPG's involvement with the Plan ~~is~~ would be subject to approval by OPG's Board of Directors, which has established a Special Committee to provide oversight on behalf of the Board of Directors. **[MONITOR]**

Shareholder Declaration and Shareholder Resolution to Sell Certain Real Estate Properties

In December 2015, OPG received a Shareholder Declaration and a Shareholder Resolution requiring the Company to sell its head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street in Toronto, Ontario. A purchase and sale agreement was executed in December 2016, and the sale was completed in April 2017. An after-tax gain on sale of approximately $280 million **[MONITOR]** was recognized upon completion of the transaction in the second quarter of 2017. Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act (2014)*, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the act, into the Province's Consolidated Revenue Fund. OPG is working with the

Commented [RM2]: OPG – We have updated the placement of the wording as suggested.

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Ministry of Finance to finalize the prescribed costs incurred in connection with the disposition of the sale and the designated proceeds that will be transferred ~~in~~to the Trillium Trust ~~Fund~~.

In June 2016, OPG received a Shareholder Declaration and a Shareholder Resolution that requires the Company to sell its former Lakeview GS site located in Mississauga, Ontario. OPG is in the process of preparing the site for sale. Pursuant to the June 2016 Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act (2014)*, OPG is required to transfer the proceeds, net of prescribed deductions under the act, from this disposition into the Province's Consolidated Revenue Fund. **[MONITOR]**

Neither the former Lakeview GS site nor the Company's head office premises and associated parking facility are considered core assets to OPG's business, and are reported under the Services, Trading, and Other Non-Generation segment.

Commented [RM5]: OPG – The wording has been updated to as follows:

"OPG is working with the Ontario Ministry of Finance to finalize the prescribed costs incurred in connection with the disposition of the sale and the designated proceeds that will be transferred into the Consolidated Revenue Fund, in accordance with the *Trillium Trust Act, 2014*."

CORE BUSINESS, STRATEGY, AND OUTLOOK

The discussion in this section is qualified in its entirety by the cautionary statements included in the section, *Forward-Looking Statements,* at the beginning of the MD&A.

OPG's mission is to provide low cost power in a safe, clean, reliable and sustainable manner for the benefit of its customers and its Shareholder. OPG also seeks to pursue, on a commercial basis, generation development projects and other business growth opportunities to the benefit of the Shareholder.

The following sections provide an update to OPG's disclosures in the 2016 annual MD&A related to its four key strategic imperatives – operational excellence, project excellence, financial strength, and social licence. A detailed discussion of these strategic imperatives is included in the 2016 annual MD&A in the section, *Core Business, Strategy, and Outlook*.

Operational Excellence

Operational excellence at OPG is accomplished by the safe and environmentally responsible generation of reliable and cost-effective electricity from the Company's generating assets through a highly trained and engaged workforce.

Public Safety

To ensure continued public safety, radiation exposure to members of the public resulting from the operation of OPG's nuclear generating stations is estimated on an annual basis for individuals living or working near the stations. The annual dose to the public resulting from operations of each nuclear facility is expressed in microsieverts (µSv), which is an international unit of radiation dose measurement. For 2016, the annual public doses resulting from the Darlington GS operations and the Pickering GS operations were 0.6 µSv and 1.5 µSv, respectively, which is approximately 0.1 percent and 0.2 percent of the annual legal limit of 1,000 µSv, respectively.

Electricity Generation Production and Reliability

- As part of the plan to extend Pickering operations, OPG is continuing to undertake further technical work to confirm that the station's pressure tubes, a key life-limiting component of the station, will remain fit for service for operation to 2024. OPG is also nearing completion of component condition assessments to identify the work required to support the continued operation of the station. The accounting end of life assumptions for the Pickering GS, currently set at the end of 2020, are expected to be reassessed, after the required fuel channel maintenance strategies in support of extended operations have been implemented on the initial units, taking into account the requirement for the Canadian Nuclear Safety Commission's (CNSC) approval, discussed below.
- OPG's current five-year operating licence for the Pickering GS was approved by the CNSC in 2013 and expires on August 31, 2018. This licence was issued assuming that the station would shut down in 2020. By June 30,

2017, OPG is required to confirm to the CNSC the end date of commercial operations of all operating Pickering units. Work on the Pickering licence renewal application is proceeding and is expected to be filed August 31, 2017 for the CNSC's approval in 2018. The requested licence renewal will span the planned extended operations period, through to the end of the planned period to de-fuel, de-water, and place the station in a safe state condition after shutdown. OPG will submit a Periodic Safety Review, Global Assessment Report, and Integrated Implementation Plan (IIP) for the station to the CNSC as part of the licence renewal.

- In 2016, OPG submitted applications with the CNSC seeking a ten-year licence renewal for the Western Waste Management Facility (WWMF), located at the Bruce generating stations' site, to May 31, 2027, and a ten-year licence renewal for the Pickering Waste Management Facility (PWMF) to August 31, 2028. The licence renewal applications were presented to the CNSC at public hearings in April 2017. The current licence for the WWMF expires on May 31, 2017 and for the PWMF on March 31, 2018. Renewal decisions on the WWMF and PWMF licences are expected to be issued prior to expiry of the respective current licences. **[MONITOR]**
- During the first quarter of 2017, OPG completed the reservoir refurbishment at Sir Adam Beck Pump GS and the replacement of the Shebandowan Lake Control Dam at the Kakabeka Falls GS.
- Work continues on the rehabilitation of Unit 10 of the Sir Adam Beck 1 GS, Unit 1 of the Sir Adam Beck Pump GS, and the overhaul and upgrade of Unit 1 of the Harmon GS.
- Work continues work on the replacement of the Station Service System at R.H. Saunders GS and Synchronizing Breakers at Lennox GS.
- OPG plans to commence several major sustaining hydroelectric projects during 2017, including the overhaul and upgrade of Unit 2 of the DeCew Falls 2 GS, the upgrade of Unit 2 of the Lower Notch GS, and the upgrade of Unit 2 of the Little Long GS.
- Later in 2017, OPG will be starting definition phase activities, including engineering studies, condition assessments, and stakeholder engagement, as part of a Water Conveyance System project to restore structural integrity, flow capacity and ensure safe and reliable operations, of the Sir Adam Beck 1 GS canal and associated structures, for approximately the next 50 years.

As part of streamlining OPG's hydroelectric operations, OPG will be reducing from five regional hydroelectric offices to four by integrating the Central Operations group into its existing operations. This will result in operational efficiency improvements. Currently, work is in progress to plan and implement this change.

OPG continues to progress on its plan to remove site structures from Nanticoke GS. Project milestones in 2017 include the elimination of coal yard equipment and structures and removal of ash silos, and the selection of a contractor to remove the stacks, the powerhouse, interior equipment and supporting site structures.

Environmental Performance

In 2016, the Government of Ontario passed the *Climate Change Mitigation and Low-Carbon Economy Act, 2016* and the associated *Cap and Trade Program Regulation*. The legislation provides the foundation for regulating greenhouse gas (GHG) emissions in Ontario and establishes a cap and trade program, with the first compliance period being from January 1, 2017 to December 31, 2020.

The cap and trade program is a market mechanism intended to give Ontarians an incentive to reduce GHG emissions by putting a price on carbon. OPG has an internal program to meet its GHG emissions compliance obligations. With OPG's low GHG emitting fleet, these obligations do not have a material financial impact on the Company. The Ontario MOECC held the first quarterly auction of GHG allowances on March 22, 2017.

Disclosures related to the Company's environmental policy and environmental risks can be found in OPG's 2016 annual MD&A.

Project Excellence

OPG is pursuing a number of generation development and other major projects in support of Ontario's electricity planning initiatives. The status updates for OPG's major projects as of March 31, 2017 are outlined in the following table with further details below.

Project	Capital expenditures		Approved budget	Expected in-service date	Current status
(millions of dollars)	Year-to-date	Life-to-date			
Darlington Refurbishment	306	3,491	12,800 [1]	First unit - 2020 Last unit - 2026	Islanding of Unit 2 was completed in April 2017. Preparatory work in the reactor vault to support the removal of feeder tubes and fuel channel assemblies is in progress. The project is tracking on schedule and on budget.
Peter Sutherland Sr. Hydroelectric GS	22	258	300	2017	The station was placed in-service on March 31, 2017, ahead of the originally planned schedule, and is expected to close below the approved budget. Refer to the section, *Core Business, Strategy, and Outlook* under the heading, *Recent Developments* for further details.
Sir Adam Beck Pump GS Reservoir Refurbishment	2	48	58	2017	The refurbishment was completed and the reservoir was returned to service in February 2017, ahead of the originally planned in-service date and below the approved budget.
Ranney Falls Hydroelectric GS	2	5	77	2019	Project definition work has been completed and site clearing and mobilization work has commenced.
Nanticoke Solar Facility	1	2		2019	Project definition work is in progress and construction is planned to commence as early as in the fourth quarter of 2017.
Deep Geologic Repository for low and intermediate level radioactive waste (L&ILW)	2 [2]	197 [2]			Additional information requested by the Canadian Environmental Assessment Agency (CEAA) based on their review of the material submitted by OPG in December 2016 is being prepared and will be submitted by May 26, 2017.

[1] The total project budget of $12.8 billion is for the refurbishment of all four units at the Darlington GS.
[2] Expenditures are charged against the Nuclear Liabilities.

Darlington Refurbishment

The Darlington generating units are forecast to be approaching their originally designed end-of-life. Refurbishment of the four generating units is expected to extend the operating life of the station by approximately 30 years.

In 2016, the Darlington Refurbishment project transitioned from the planning phase to the execution phase, as OPG commenced the refurbishment of the first unit, Unit 2, in October 2016, as planned. The unit was taken offline on October 15, 2016. De-fuelling of the reactor, the first critical refurbishment activity undertaken once the unit is removed from service, was safely completed in January 2017, ahead of schedule, with a total of 480 fuel channels de-fuelled. Islanding of Unit 2, the physical separation of the refurbishment unit from the three operating units, was completed in April 2017, signifying the completion of the first major segment of the project. The second segment commenced immediately following the islanding of the unit. The second segment continues the preparatory work to support the removal of feeder tubes and fuel channel assemblies, including opening the reactor air lock doors, installation of shielding, setting up specialized tooling and equipment, and commencing the disassembly and removal of reactor components. Once refurbished, Unit 2 is scheduled to be returned to service in the first quarter of 2020, at which time capital expenditures of approximately $4.8 billion are planned to be placed in service. The project is tracking on schedule and budget.

A number of pre-requisite projects in support of the execution phase of the project, including construction of facilities, infrastructure upgrades and installation of safety enhancements, have been completed. This includes the Containment Filtered Venting System and the Third Emergency Power Generator safety enhancement projects that were placed in-service in April 2017 **[MONITOR]**. Completion of the Heavy Water Storage and Drum Handling Facility has been delayed due to challenges with construction. Remediation measures are in progress **[UPDATE]**. This delay will not impact the overall Darlington Refurbishment project schedule, as the Heavy Water Storage and Drum Handling Facility is not on the critical path. The remaining projects are tracking for completion within the overall refurbishment execution schedule. **[UPDATE]**

In addition to the de-fuelling and islanding of Unit 2 completed, the following other key project activities are continuing in 2017:

- Completion of preparation activities to support Retube and Feeder Replacement work.
- Continued refurbishment task rehearsals for the specialized tooling to be used for removal and replacement of feeder tubes and fuel channel assemblies at OPG's reactor training and mock-up facility.
- Removal of Unit 2 feeder tubes and commencement of the fuel channel removal series.
- Completion of the Re-tube Waste Processing Building Facility.
- Continued construction of the Heavy Water Storage and Drum Handling.
- Commencement of the major turbine generator overhaul and fuel handling power track replacement.
- Continued execution of work to support the requirements set out in the CNSC-approved IIP for the Darlington GS.

In addition to the execution of refurbishment activities for Unit 2, OPG has commenced planning for the refurbishment of Unit 3, and is entering into associated commitments to procure major components that require long-lead times. As of March 31, 2017, $43 million has been invested in planning activities related to the refurbishment of the second unit. These planning activities are being undertaken in accordance with the refurbishment project schedule.

Sir Adam Beck Pump GS Reservoir Refurbishment

The Sir Adam Beck Pump GS refurbishment construction began in April 2016 and the 300-hectare reservoir was returned to service in February 2017 upon completion of the reservoir commissioning program. The Sir Adam Beck Pump GS facility allows OPG to pump and store water diverted from the Sir Adam Beck generating complex during periods of low electricity demand to be used to generate up to 600 MW of electricity during subsequent periods of high electricity demand. The work on the project included installation of a new partial liner and construction of a grout

curtain in the bedrock foundation of the reservoir dyke. The refurbishment is expected to add approximately 50 more years to the reservoir's life. The project was completed ahead of the originally planned in-service date of April 2017 and below the approved budget of $58 million.

Ranney Falls Hydroelectric GS

In the first quarter of 2017, OPG completed the contractor selection process and awarded contracts for the construction of a 10 MW single-unit powerhouse on the existing Ranney Falls GS site, as part of the Regulated – Hydroelectric segment. The new unit will replace an existing unit that reached its end of life in 2014. The civil contractor has begun site clearing and mobilization. The expected in-service date is in the fourth quarter of 2019 with a budget of $77 million.

Nanticoke Solar Facility

The project to construct a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands under a Large Renewable Procurement contract with the IESO, through Nanticoke Solar LP, is planned to commence as early as in the fourth quarter of 2017. In the first quarter of 2017, OPG purchased SunEdison Canadian Construction LP's (SECCLP) interests in Nanticoke Solar LP, originally a partnership between OPG, SECCLP and a subsidiary of the Six Nations of the Grand River Development Corporation, and is working to obtain approvals and permits required to enable the commencement of construction. The facility is expected to be completed in the first quarter of 2019.

Deep Geologic Repository for Low and Intermediate Level Waste

OPG has proposed a deep geologic repository as the preferred solution for the safe long-term management of the L&ILW produced from the continued operation of OPG-owned nuclear generating stations. Agreement has been reached with local municipalities for OPG to develop the L&ILW Deep Geologic Repository (DGR) on lands adjacent to the WWMF in Kincardine, Ontario.

In 2012, the CNSC and the CEAA appointed a three-member Joint Review Panel (JRP) for OPG's proposed L&ILW DGR. The JRP examined the environmental effects of the proposed L&ILW DGR to meet the requirements of the *Canadian Environmental Assessment Act*. In May 2015, the JRP submitted its report and recommendations on the Environmental Assessment (EA) to the federal Minister of Environment. The report concluded that, given mitigation, there is unlikely to be significant environmental impact from the project and recommended that the Minister approve the EA. The report suggested that the project should be implemented expeditiously.

In February 2016, the federal Minister of Environment and Climate Change requested additional information on certain aspects of the EA, including information related to alternate locations for the project and potential for cumulative environmental effects if Canada's planned used fuel deep geologic repository being developed by the Nuclear Waste Management Organization were to be located in close proximity to OPG's proposed L&ILW DGR. OPG has completed the requested studies and submitted the requested information in December 2016, as planned. Following CEAA's review of OPG's submission and a period of public comment, the CEAA has requested additional information from OPG. OPG has reviewed the information request and will respond to the CEAA by May 26, 2017. An EA Decision Statement by the Minister is expected by the fourth quarter of 2017. Based on the information submitted to the Minister in December 2016, the L&ILW DGR Project at the WWMF site remains OPG's preferred solution for the safe long-term management of the L&ILW, based on a relative consideration of environmental effects, transportation risks, transportation and other project-related costs and uncertainties, and the absence of certainty of improved safety or environmental quality at an alternate location.

OPG anticipates a site preparation and construction licence may be issued in the first half of 2018, if the EA Decision Statement supports licensing. OPG has initiated work to ensure all licensing-related submissions will be completed and ready to be submitted to the CNSC for an expeditious license review. In addition, work has been initiated to seek OPG's Board of Directors' approval to proceed to the definition phase work in 2018. This includes completion of engineering design activities. OPG also continues its engagement with the Saugeen Ojibway Nations toward

securing community support for the L&ILW DGR. The in-service date of the L&ILW DGR is expected to be approximately six to seven years from the start of construction. **[CONFIRM]**

Financial Strength

As a commercial enterprise, OPG's financial priority is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future growth.

Increase Revenue, Reduce Costs and Achieve Appropriate Return

In the second quarter of 2016, OPG filed a 5-year application with the OEB for new base regulated prices for production from its regulated hydroelectric and nuclear facilities, with a proposed effective date of January 1, 2017. Consistent with the requirements of *Ontario Regulation 53/05*, OPG's application incorporates a rate smoothing proposal, as amended in March 2017. The application seeks to ensure that nuclear regulated prices under the rate smoothing approach allow for sufficient cash flow to meet the Company's liquidity needs, support cost effective funding for the Darlington Refurbishment project and other expenditures, and maintain the Company's investment grade credit rating, while taking into account both near-term and future impacts on customers. In addition, the application will further challenge and incentivize OPG to find additional cost reductions and efficiencies within its operations, as a result of greater de-coupling of regulated prices from costs and a longer rate-setting period under the OEB's incentive ratemaking framework. The application also seeks an increase in the nuclear rate base, effective in early 2020, to reflect the planned placement in service of approximately $4.8 billion of capital expenditures upon the scheduled return to service of Unit 2 at the Darlington GS as part of the Darlington Refurbishment project and, effective in 2017, an increase in the deemed capital structure applied to the total regulated rate base to 49 percent equity and 51 percent debt from 45 percent equity and 55 percent debt reflected in the existing regulated prices. If approved, this would improve OPG's return on Shareholder's investment.

A public oral hearing on OPG's application commenced in late February 2017 and was completed in April 2017, with final arguments scheduled to be completed by June 19, 2017. The OEB's decision on the application, including the effective date of approved new regulated prices, is expected in the second half of 2017. Further details on OPG's rate application can be found in the section, *Highlights* under the heading, *Recent Developments*.

For generation assets that do not form part of the assets regulated by the OEB, OPG's strategy has been to secure appropriate long-term revenue arrangements. In line with this strategy, virtually all of OPG's non-regulated operating facilities and assets under construction are subject to long-term Energy Supply Agreements (ESAs) or other long-term contracts with the IESO. This includes the Peter Sutherland Sr. GS, which will begin earning contracted revenue under its hydroelectric ESA once the IESO confirms commercial operation, but effective on March 31, 2017. The ESA expires in 2067. **[CONFIRM]**

Ensure Availability of Cost Effective Funding

In April 2017, DBRS Limited (DBRS) re-affirmed the long-term credit rating on OPG's debt at 'A (low)' and OPG's commercial paper rating at 'R-1 (low)'. All ratings from DBRS have a stable outlook.

Social Licence

As the largest electricity generator in Ontario with diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust. OPG is committed to maintaining high standards of public safety and corporate citizenship, including environmental stewardship, transparency, community engagement, and Indigenous relations.

OPG is focused on building long-term, mutually beneficial working relationships with Indigenous communities, businesses and organizations across Ontario, and continues to support procurement, employment and educational opportunities with its Indigenous community partners. The Company seeks to establish these relationships based on

a foundation of respect for the languages, customs, and political, social and cultural organizations of the Indigenous communities. OPG's commitment in this area includes pursuing generation-related development partnerships on the basis of long-term commercial arrangements, such as the construction of the Peter Sutherland Sr. GS in partnership with Taykwa Tagamou Nation and the development of the Nanticoke solar facility in partnership with the Six Nations of the Grand River. In March 2017, the Peter Sutherland Sr. GS was placed in-service and, in April 2017, the Taykwa Tagamou Nation acquired a 33 percent interest in PSS under the partnership agreement. OPG also continues to engage with Indigenous communities regarding the Company's regulated nuclear waste operations, through regularly scheduled meetings and ongoing dialogue in connection with OPG's proposed L&ILW DGR, and the re-licensing of the PWMF and the WWMF.

Outlook

The financial performance of OPG's regulated operations is driven, in large part, by the outcome of applications for regulated prices to the OEB. The existing base regulated prices were established by the OEB effective November 1, 2014 based on a forecast of costs and production for the regulated facilities for the 2014 to 2015 period. The future outcome of OPG's current application for new regulated prices is expected to provide substantial price certainty for the regulated business for the 2017 to 2021 period.

In its application, OPG has requested January 1, 2017 as the effective date for the new regulated prices. In December 2016, the OEB issued an order declaring the existing base regulated prices interim, which preserves the OEB's ability to make the new regulated prices effective as early as January 1, 2017. The OEB's decision on the application, including the effective date of the new regulated prices, is expected in the second half of 2017. Considering the timing of OPG's application and OPG's procedural adherence to date, the Company believes that the OEB could make the new regulated prices effective January 1, 2017 in its decision on the application. This would allow OPG to recover the difference between the approved new regulated prices and the existing regulated prices for the period between January 1, 2017 and the implementation date of the new prices based on the OEB's order.

The continuation of existing regulated prices until the OEB's decision on OPG's application is issued is expected to continue to contribute to lower income, particularly from the Regulated – Nuclear Generation segment, and lower ROE Excluding AOCI during 2017, compared to 2016. In large part, this is due to the year-over-year reduction in nuclear electricity generation resulting from the Unit 2 refurbishment outage at the Darlington GS, given that the existing nuclear regulated prices were determined in 2014 based on a higher production forecast that reflected the operation of all four units at the station. As such, the OEB's decision on the effective date of the new regulated prices, as well as the timing of the decision issuance, could have a significant impact on OPG's financial results during 2017. OPG's application for new regulated prices is further discussed in the section, *Highlights* under the heading, *Recent Developments*.

Nuclear base regulated prices resulting from OPG's current application will be subject to a rate smoothing mechanism that defers collection of a portion of OEB-approved revenues. As expected, combined with the expiry of rate riders in effect to the end of 2016 and a year-over-year reduction in nuclear generation due to the Darlington Unit 2 refurbishment outage, this will result in lower cash flow from operations and a lower FFO Adjusted Interest Coverage ratio in 2017, compared to 2016. The continuation of existing base regulated prices until such time as new prices are determined and implemented by the OEB also is expected to contribute to lower cash flow from operations in 2017. OPG expects to continue to have the necessary financial capacity and sufficient access to cost effective financing sources to continue to fund its capital requirements and other disbursements.

Lower nuclear generation due to the Darlington refurbishment outages will continue to negatively impact the Enterprise TGC metric for the duration of the refurbishment project. Variability in sustaining capital investment expenditures, including major sustaining projects for the hydroelectric operations, also will impact the Enterprise TGC in future periods.

Several OEB-authorized regulatory variance and deferral accounts currently in place contribute to reducing the relative variability of the Company's income and ROE Excluding AOCI. Among others, these variance accounts include those related to the revenue impact of variability in water flows and forgone production due to SBG conditions at the regulated hydroelectric stations. There is no variance or deferral account in place related to the impact of generation performance of the nuclear stations on revenue from base regulated prices. Considering the impact of the variance and deferral accounts, the Regulated – Hydroelectric segment generally is expected to produce overall more predictable earnings compared to the Regulated – Nuclear Generation segment. OPG continues to operate and maintain its nuclear facilities with a view to optimize their performance and availability, while focusing on improving the overall reliability and predictability of the fleet.

Electricity generated from most of OPG's non-regulated assets is subject to Energy Supply Agreements with the IESO. Based on these agreements, OPG expects the Contracted Generation Portfolio segment to continue to contribute a generally stable level of earnings and cash flow from operations going forward.

OPG's forecast capital expenditures for 2017 are approximately $1.8 billion. This includes amounts for the Darlington Refurbishment project, hydroelectric and other development projects including the completion of the Peter Sutherland Sr. GS and the expansion of the Ranney Falls GS, and sustaining capital investments across the generating fleet. OPG's major projects are discussed in the *Project Excellence* section.

In addition to the operating and financial performance of the electricity generation business, OPG's results are affected by the earnings on the Nuclear Segregated Funds, which are reported in the Regulated – Nuclear Waste Management segment. While the Nuclear Segregated Funds are managed to achieve, in the long term, the target rate of return based on the discount rate specified in the ONFA, the rates of return earned in a given period can be subject to various external factors including financial market conditions and changes in the Ontario CPI. In the short term, these factors can be volatile and cause fluctuations in the Company's income. This volatility is partially mitigated by the impact of the Bruce Lease Net Revenues Variance Account and, as discussed below, the funded status of the two segregated funds.

As OPG does not have the right to withdraw surplus amounts from the Nuclear Segregated Funds when the segregated funds are overfunded relative to the life cycle funding liability pursuant an approved ONFA Reference Plan, OPG limits the amount of Nuclear Segregated Funds assets reported on the balance sheet to the present value life cycle funding liability per the most recently approved ONFA reference plan. Additionally, OPG recognizes the portion of the surplus in the Decommissioning Segregated Fund that it may direct to the Used Fuel Fund in accordance with the ONFA, up to the amount, if any, by which the Used Fuel Fund is underfunded. This reduces the volatility of earnings on the Nuclear Segregated Funds reflected in net income when the Nuclear Segregated Funds are in a fully funded or overfunded position. As at March 31, 2017, the Decommissioning Segregated Fund was overfunded by approximately 24 percent, and the Used Fuel Segregated Fund was marginally overfunded, by less than one percent, based on the 2017 ONFA Reference Plan. Variability in asset performance due to volatility inherent in financial markets and changes in Ontario CPI may result in either or both funds becoming underfunded in the future.

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DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

Regulated – Nuclear Generation Segment

(millions of dollars) (unaudited)	Three Months Ended March 31 2017	2016
Revenue	**652**	926
Fuel expense	**68**	81
Gross margin	**584**	845
Operations, maintenance and administration	**589**	563
Depreciation and amortization	**107**	230
Property taxes	**6**	7
(Loss) income before other losses, interest, and income taxes	**(118)**	45
Other gains	**-**	(1)
(Loss) income before interest and income taxes	**(118)**	46

Segment earnings decreased by $164 million during the first quarter of 2017, compared to the same quarter in 2016. The decrease in earnings was expected and primarily due to reduced revenue from the nuclear base regulated price of approximately $134 million, partly offset by the largely associated decrease in fuel expense of $13 million, reflecting lower electricity generation of 2.3 TWh and the continuation of the existing nuclear base regulated price set by the OEB in 2014. The existing regulated price continues to be in effect pending the OEB's decision on OPG's application for new regulated prices, proposed to be effective on January 1, 2017. The lower nuclear generation was primarily due to the ongoing Unit 2 refurbishment outage at the Darlington GS that began October 2016. The existing regulated price does not reflect the lower generation as a result of the refurbishment outage, as that price were set to allow the Company to recover its approved nuclear costs over a higher nuclear production volume based on the 2014 and 2015 outage profile that did not include a refurbishment outage. The year-over-year reduction in nuclear electricity generation was partially offset by the impact of the decreased number of planned outage days at the Pickering GS in the first quarter of 2017, compared to the same quarter in 2016.

The increase in OM&A expenses of $26 million in the first quarter of 2017, compared to the same quarter in 2016, also contributed to lower segment earnings. The increase in OM&A expenses reflected use of temporary staff and planned hiring to fill vacant positions due to attrition, and higher material costs related to maintenance work at the nuclear stations.

The expiry of an OEB-authorized nuclear rate rider on December 31, 2016 contributed to the decrease in segment revenue in the first quarter of 2017, compared to the same quarter in 2016. As rate riders allow for recovery of approved balances in OEB-authorized regulatory variance and deferral accounts, this decrease in revenue was largely offset by a decrease in amortization expense related to regulatory account balances. A new rate rider has been requested in OPG's application with the OEB for new regulated prices effective January 1, 2017.

The Unit Capability Factors for the Darlington GS and Pickering GS for 2017 and 2016 were as follows:

	Three Months Ended March 31 2017	2016
Unit Capability Factor *(%)* [1]		
Darlington GS	**85.3**	97.2
Pickering GS	**78.5**	72.8

[1] The nuclear Unit Capability Factor excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS was excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

The Unit Capability Factor at the Darlington GS decreased in the first quarter of 2017, compared to the same quarter in 2016, primarily due to a higher number of unplanned outage days at the station in the first quarter of 2017.

The increase in the Unit Capability Factor at the Pickering GS in the first quarter of 2017, compared to the same quarter in 2016, was primarily due to a lower number of planned outage days at the station in the first quarter of 2017.

Regulated – Nuclear Waste Management Segment

(millions of dollars) (unaudited)	Three Months Ended March 31 **2017**	**2016**
Revenue	**27**	34
Operations, maintenance and administration	**29**	36
Accretion on nuclear fixed asset removal and nuclear waste management liabilities	**234**	228
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(189)**	(147)
Loss before interest and income taxes	**(47)**	(83)

Earnings from the segment improved by $36 million in the first quarter of 2017 compared to the same quarter in 2016. The year-over-year improvement in earnings was primarily due to higher earnings from the Nuclear Segregated Funds.

Higher earnings on the Used Fuel Segregated Fund, net of the impact of the Bruce Lease Net Revenue Variance Account, were the primary reasons for the higher Nuclear Segregated Fund earnings during the first quarter of 2017, compared to the same period in 2016. As the Used Fuel Segregated Fund was overfunded as at December 31, 2016 and March 31, 2017, the earnings on the fund recorded in income during the first quarter of 2017 were based at the growth rate of the present-value used fuel life cycle funding liability per the 2017 ONFA Reference Plan. During the first quarter of 2016, the Used Fuel Segregated Fund was underfunded based on the ONFA reference plan then in effect and therefore earnings on the fund reflected the CPI-adjusted rate of return guaranteed by the Province under the ONFA for funding related to the initial 2.23 million used fuel bundles and market returns on the portion of the fund not guaranteed by the Province.

As of December 31, 2016, OPG recorded a decrease of approximately $1,570 million to the nuclear fixed asset removal and nuclear waste management liabilities (Nuclear Liabilities) and associated asset retirement costs capitalized as part of the carrying value of the nuclear generating stations to reflect the comprehensive update of the underlying assumptions and baseline cost estimates for these liabilities carried out as part of the 2017 ONFA Reference Plan update process. The resulting year-over-year decreases in accretion on fixed asset removal and nuclear waste management liabilities recorded in the Regulated – Nuclear Waste Management segment and depreciation and fuel expenses recorded in the Regulated – Nuclear Generation segment during the first quarter of 2017, compared to the same quarter in 2016, were largely offset by the impact of the Bruce Lease Net Revenues Variance Account and the Nuclear Liability Deferral Account authorized by the OEB. Further details on the change in the estimate of the Nuclear Liabilities as of December 31, 2016 are described in OPG's 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Asset Retirement Obligation*.

Under the current OEB-approved cost recovery methodology, the changes in expenses associated with the year-end 2016 adjustment to the Nuclear Liabilities are not expected to materially affect OPG's income during 2017, as the associated impact on expenses is expected to continue to be largely offset by the impact of the Bruce Lease Net Revenues Variance Account and the Nuclear Liability Deferral Account until such time as the OEB implements corresponding changes to OPG's nuclear regulated prices, and subsequently to be offset by the impact of the new regulated prices.

Regulated – Hydroelectric Segment

(millions of dollars) (unaudited)	Three Months Ended March 31 2017	2016
Revenue [1]	**363**	385
Fuel expense	**73**	79
Gross margin	**290**	306
Operations, maintenance and administration	**76**	76
Depreciation and amortization	**34**	56
Income before other gains, interest and income taxes	**180**	174
Other gains	**-**	(22)
Income before interest and income taxes	**180**	196

[1] During the three months ended March 31, the Regulated – Hydroelectric segment revenue included incentive payments of $8 million in 2017 and $1 million in 2016 related to the OEB-approved hydroelectric incentive mechanism. The mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers.

The decrease in income before interest and income taxes of $16 million during the first quarter of 2017, compared to the same period in 2016, was primarily due to a gain of $22 million recognized during the first quarter of 2016 to reflect the OEB's January 2016 decision to reverse a portion of an earlier capital cost disallowance related to the Niagara Tunnel project expenditures, in response to a motion by OPG. The decrease in income was partially offset by higher hydroelectric incentive mechanism payments in the first quarter of 2017.

The decrease in revenue was largely due to the expiry of an OEB-authorized rate rider on December 31, 2016. As the rider allowed for the recovery of approved balances in OEB-authorized regulatory variance and deferral accounts, the resulting reduction in revenue was largely offset by lower amortization expense related to the regulatory account balances.

The Hydroelectric Availability for the stations included in the Regulated – Hydroelectric segment was as follows:

	Three Months Ended March 31 2017	2016
Hydroelectric Availability *(%)*	**89.5**	94.8

The Hydroelectric Availability decreased in the first quarter of 2017, compared to the same period in 2016, primarily due to the reservoir refurbishment project at the Sir Adam Beck Pump GS and a higher number of unplanned outage days for the regulated hydroelectric stations.

Contracted Generation Portfolio Segment

(millions of dollars) (unaudited)	Three Months Ended March 31 2017	2016
Revenue	**143**	145
Fuel expense	**14**	12
Gross margin	**129**	133
Operations, maintenance and administration	**39**	40
Depreciation and amortization	**19**	19
Accretion on fixed asset removal liabilities	**2**	2
Property taxes	**2**	2
Income from investments subject to significant influence	**(10)**	(8)
Income before interest and income taxes	**77**	78

Income before interest and income taxes decreased by $1 million during the first quarter of 2017, compared to the same period in 2016. The decrease primarily resulted from lower revenues from the Lower Mattagami River generating stations. The decrease was partially offset by higher gross margin from the Lennox GS, which was primarily due to increased market demand.

The Hydroelectric Availability and the Thermal Equivalent Forced Outage Rate (EFOR) for the Contracted Generation Portfolio segment were as follows:

	Three Months Ended March 31 2017	2016
Hydroelectric Availability *(%)*	**83.6**	83.9
Thermal EFOR *(%)*	**12.6**	0.9

The Hydroelectric Availability in the first quarter of 2017, was comparable to the same period in 2016. The higher thermal EFOR in the first quarter of 2017, compared to the same period in 2016, was primarily due to a higher number of unplanned outage days at a Lennox GS unit as a result of a transmission outage.

Services, Trading, and Other Non-Generation Segment

(millions of dollars) (unaudited)	Three Months Ended March 31 2017	2016
Revenue	**17**	21
Gross margin	**17**	21
Operations, maintenance and administration	**1**	4
Depreciation and amortization	**7**	7
Accretion on fixed asset removal liabilities	**2**	2
Property taxes	**3**	3
Loss before other losses, interest, and income taxes	**4**	5
Other gains	**(3)**	-
Income before interest and income taxes	**7**	5

Segment earnings increased by $2 million during the first quarter of 2017, compared to the same quarter in 2016, due to lower OM&A expenses reflecting the decision, in the fourth quarter of 2016, to proceed with the decommissioning of the Lambton GS, and dividend income from OPG's investment in Hydro One Limited (Hydro One) shares acquired in April 2016. OPG acquired the shares for investment purposes to mitigate the risk of future price volatility related to OPG's future share delivery obligations under the collective agreements with the Power Workers' Union and The

Society of Energy Professionals. The increase in segment earnings was partially offset by lower revenues from the Company's electricity trading activities in the first quarter of 2017.

LIQUIDITY AND CAPITAL RESOURCES

OPG's primary sources of liquidity and capital are funds generated from operations, bank financing, credit facilities provided by the Ontario Electricity Financial Corporation (OEFC), long-term corporate debt, and capital market financing. These sources are used for multiple purposes including: to invest in plants and technologies, to undertake major projects, to fund long-term obligations such as contributions to the pension fund and the Nuclear Segregated Funds, to make payments under the OPEB plans, to fund expenditures on Nuclear Liabilities not eligible for reimbursement from the Nuclear Segregated Funds, and to service and repay long-term debt.

Changes in cash and cash equivalents for the three months ended March 31, 2017 and 2016 were as follows:

	Three Months Ended March 31	
(millions of dollars) (unaudited)	**2017**	**2016**
Cash and cash equivalents, beginning of period	**186**	464
Cash flow provided by operating activities	**118**	366
Cash flow used in investing activities	**(363)**	(310)
Cash flow used in financing activities	**279**	20
Net increase	**34**	76
Cash and cash equivalents, end of period	**220**	540

For a discussion regarding cash flow provided by operating activities and the FFO Adjusted Interest Coverage ratio, refer to the details in the section, *Highlights* under the heading, *Overview of Results*.

Investing Activities

Electricity generation is a capital-intensive business. It requires continued investment in plants and technologies to maintain and improve operating performance including asset reliability, safety and environmental performance, to increase generating capacity of existing stations, and to invest in the development of new generating stations, emerging technologies and other business growth opportunities.

Cash flow used in investing activities during the first quarter of 2017 increased by $53 million compared to the same quarter in 2016. The increase was primarily due to higher expenditures on the Darlington Refurbishment project, offset by the staggered maturity of a structured deposit note entered in 2015 in support of the Peter Sutherland Sr. GS project. The principal amount of the deposit note that matured in the first quarter of 2017 was higher than in the same quarter in 2016. The final maturity date of the deposit note was in April 2017.

Financing Activities

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. In the second quarter of 2017, OPG expects to renew and extend the expiry date of both tranches from May 2021 to May 2022. There were no amounts outstanding under the bank credit facility as at March 31, 2017.

There was $133 million of commercial paper outstanding under OPG's commercial paper program as at March 31, 2017.

As at March 31, 2017, OPG also maintained $25 million of short-term, uncommitted overdraft facilities, and a further $460 million of short-term, uncommitted credit facilities, which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other general corporate purposes. As at March 31, 2017, a total of $386 million of Letters of Credit had been issued under these facilities. This included $349 million for the supplementary pension plans, $36 million for general corporate purposes, and $1 million related to the operation of the PEC.

The Company has an agreement to sell an undivided co-ownership interest in its current and future accounts receivable to an independent trust, expiring on November 30, 2018. The maximum amount of co-ownership interest that can be sold under this agreement is $150 million. As at March 31, 2017, no borrowings were issued under this agreement and there were Letters of Credit outstanding under this agreement of $150 million, which were issued in support of OPG's supplementary pension plans.

As at March 31, 2017, the Lower Mattagami Energy Limited Partnership (LME) maintained a $500 million bank credit facility to support the funding requirements for the Lower Mattagami River project including support for LME's commercial paper program. The facility consists of a $300 million tranche maturing in August 2021 and a $200 million tranche maturing in August 2017. As at March 31, 2017, there was no external commercial paper outstanding under LME's commercial paper program. There were also no amounts outstanding under LME's bank credit facility as at March 31, 2017. In October 2016, LME issued senior notes totalling $220 million maturing in October 2026. The effective interest rate and coupon interest rate of these notes were 2.40 percent and 2.31 percent, respectively.

In June 2016, OPG entered into a $700 million general corporate credit facility agreement with the OEFC, which expires on December 31, 2017. As at March 31, 2017, there were outstanding long-term borrowings of $200 million under this credit facility.

As at March 31, 2017, OPG's long-term debt outstanding was $5,684 million, including $1,328 million due within one year.

In February 2017, OPG issued senior notes payable to the OEFC totalling $200 million and maturing in February 2047. The effective interest rate and coupon interest rate of these notes was 4.12 percent.

OPG continues to evaluate arrangements that would appropriately support the Company's financing needs and capital expenditure programs.

BALANCE SHEET HIGHLIGHTS

The following section provides highlights of OPG's unaudited interim consolidated financial position using selected balance sheet data:

(millions of dollars) (unaudited)	As At March 31 2017	As At December 31 2016
Property, plant and equipment – net	**20,248**	19,998
The increase was primarily due to capital expenditures on the Darlington Refurbishment project, partially offset by depreciation expense.		
Nuclear fixed asset removal and nuclear waste management funds *(current and non-current portions)*	**16,157**	15,984
The increase was primarily due to earnings on the Nuclear Segregated Funds, partially offset by reimbursements of eligible expenditures on nuclear fixed asset removal and nuclear waste management activities.		
Short-term debt	**135**	2
The increase was due to commercial paper issued under OPG's commercial paper program.		
Long-term debt *(current and non-current portions)*	**5,670**	5,520
The increase was primarily due to the issuance of senior notes payable to the OEFC totalling $200 million in February 2017.		
Fixed asset removal and nuclear waste management liabilities	**19,683**	19,484
The increase was primarily as a result of accretion expense representing the increase in the present value liabilities due to the passage of time, partially offset by expenditures on nuclear fixed asset removal and waste management activities.		

Pension & OPEB Cash Versus Accrual Differential Deferral Account

In setting OPG's regulated prices effective November 1, 2014, the OEB limited the recovery of the regulated portion of OPG's pension and OPEB costs to the Company's cash expenditures for its pension and OPEB plans. Effective November 1, 2014, the OEB authorized the Pension & OPEB Cash Versus Accrual Differential Deferral Account, which records the difference between OPG's actual pension and OPEB costs for the regulated business determined on an accrual basis in accordance with US GAAP and OPG's corresponding actual cash expenditures for these plans. The OEB's November 2014 decision indicated that the future recovery, if any, of amounts recorded in the deferral account would be subject to the outcome of an OEB generic proceeding on the regulatory treatment and recovery of pension and OPEB costs. The Company has recognized the amount set aside in the Pension & OPEB Cash Versus Accrual Differential Deferral account as a regulatory asset. As at March 31, 2017, the regulatory asset balance was $517 million, which represents the excess of pension and OPEB costs calculated using the accrual basis in accordance with US GAAP over the corresponding cash expenditures for the period from November 1, 2014 to March 31, 2017.

In May 2015, the OEB began a consultation process to develop standard principles to guide its future review of pension and OPEB costs of rate regulated utilities in the electricity and natural gas sectors, including establishing appropriate regulatory mechanisms for cost recovery. OPG is participating in the consultation, which is continuing. In its May 2016 application for new regulated prices, OPG has proposed to continue recording the difference between actual pension and OPEB costs for the regulated business determined on an accrual basis in accordance with US GAAP and OPG's corresponding cash expenditures for these plans in the Pension & OPEB Cash Versus Accrual Differential Deferral Account, pending the outcome of the OEB's consultation process. If, as part of the above consultation process or another proceeding, the OEB decides that the recovery basis for OPG's pension and OPEB amounts should be changed from the accrual basis, OPG may be required to adjust the regulatory asset for the Pension & OPEB Cash Versus Accrual Differential Deferral Account.

Off-Balance Sheet Arrangements

In the normal course of operations, OPG engages in a variety of transactions that, under US GAAP, are either not recorded in the Company's interim consolidated financial statements or are recorded in the Company's interim consolidated financial statements using amounts that differ from the full contract amounts. Principal off-balance sheet activities for OPG include guarantees and long-term contracts.

CHANGES IN ACCOUNTING POLICIES AND ESTIMATES

OPG's significant accounting policies are outlined in Note 3 to the audited consolidated financial statements as at and for the year ended December 31, 2016. A discussion of recent accounting pronouncements is included in Note 2 to OPG's unaudited interim consolidated financial statements as at and for the three months ended March 31, 2017 under the heading, *Significant Accounting Policies and Estimates*. Disclosure regarding OPG's critical accounting policies is included in OPG's 2016 annual MD&A.

RISK MANAGEMENT

The following provides an update to the discussion of the Company's risks and risk management activities included in OPG's 2016 annual MD&A. As such, the disclosure in this section should be read in conjunction with the *Risk Management* section included in the annual MD&A.

Financial Risks

Commodity Markets

Changes in the market price of fuels used to produce electricity can adversely impact OPG's earnings and cash flow from operations.

To manage the risk of unpredictable increases in the price of fuels, the Company has fuel hedging programs, which include using fixed price and indexed contracts.

The percentages hedged of OPG's fuel requirements are shown in the following table. These amounts are based on yearly forecasts of generation and supply mix and, as such, are subject to change as these forecasts are updated.

	2017 [1]	2018	2019
Estimated fuel requirements hedged [2]	75%	74%	63%

[1] Based on actual fuel requirements hedged for the three months ended March 31, 2017 and forecast for the remainder of the year.

[2] Represents the approximate portion of megawatt-hours of expected generation production (and year-end inventory targets) from each type of OPG-operated facility (nuclear, hydroelectric and thermal) for which the Company has entered into contractual arrangements or obligations in order to secure the price of fuel, or which is subject to regulation. In the case of hydroelectric generation, this represents the gross revenue charge and water rental charges. Excess fuel inventories (nuclear and thermal) in a given year are attributed to the next year for the purpose of measuring hedge ratios.

Foreign Exchange

OPG's earnings and cash flow can be affected by movements in the United States dollar relative to the Canadian dollar.

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are primarily denominated in, or tied to, US dollars. To manage this risk, OPG employs various financial instruments such as forwards and other derivative contracts, in accordance with approved risk management policies. As at March 31, 2017, OPG had no foreign exchange contracts outstanding.

Trading

OPG's financial performance can be affected by its trading activities.

OPG's electricity trading operations are closely monitored, with total exposures measured and reported to senior management on a daily basis. The main metric used to measure the financial risk of trading activity is Value at Risk (VaR). VaR is defined as a probabilistic maximum potential future loss expressed in monetary terms for a portfolio based on normal market conditions over a set period of time. For the first quarter of 2017, the VaR utilization ranged between $0.1 million and $0.3 million.

Credit

Deterioration in energy markets counterparty credit and non-performance by suppliers and contractors can adversely impact OPG's earnings and cash flow from operations.

OPG manages its exposure to suppliers or counterparties by evaluating their financial condition and negotiating appropriate collateral or other forms of security. OPG's credit exposure relating to energy markets transactions as at March 31, 2017 was $361 million, including $348 million to the IESO. Management considers the Company's risk exposure relating to electricity sales through the IESO-administered spot market to be low as the IESO oversees the credit worthiness of all market participants. In accordance with the IESO's prudential support requirements, market participants are required to provide collateral to cover funds that they might owe to the market. Of the $13 million remaining exposure as at March 31, 2017, over 95 percent was related to investment grade counterparties.

RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One, the IESO and the OEFC. The

transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly-owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions are summarized below:

	Three Months Ended March 31			
	2017		2016	
(millions of dollars) (unaudited)	**Revenue**	**Expense**	**Revenue**	**Expense**
Hydro One				
Electricity sales	**4**	**-**	2	-
Services	**1**	**5**	1	5
Dividends	**2**			
Province of Ontario				
Change in Decommissioning Segregated Fund amount due to Province [1]	**-**	**163**	-	(177)
Change in Used Fuel Segregated Fund amount due to Province [1]	**-**	**217**	-	(159)
Hydroelectric gross revenue charge	**-**	**28**	-	31
ONFA guarantee fee	**-**	**2**	-	2
OEFC				
Gross revenue charge	**-**	**38**	-	37
Interest expense on long-term notes	**-**	**41**	-	42
Income taxes, net of investment tax credits	**-**	**12**	-	32
IESO				
Electricity related revenue	**1,073**	**6**	1,364	10
	1,080	**512**	1,367	(177)

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at March 31, 2017 and December 31, 2016, the Nuclear Segregated Funds were reported net of amounts due to the Province of $3,795 million and $3,415 million, respectively. The details of accounting for the Nuclear Funds are described in OPG's 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

The receivable, available-for-sale securities, payable and long-term debt balances between OPG and its related parties are summarized below:

(millions of dollars) (unaudited)	**March 31 2017**	**December 31 2016**
Receivables from related parties		
Hydro One	**1**	1
IESO	**348**	421
OEFC	**5**	1
PEC	**4**	4
Province of Ontario	**4**	2
Available-for-sale securities		
Hydro One shares	**218**	212
Accounts payable and accrued charges		
Hydro One	**-**	-
OEFC	**45**	61
Province of Ontario	**7**	2
IESO	**2**	2
Long-term debt (including current portion)		
Notes payable to OEFC	**3,445**	3,295

OPG holds interest-bearing Province of Ontario bonds in the Nuclear Segregated Funds and the OPG registered pension fund. As at March 31, 2017, the Nuclear Segregated Funds and the registered pension fund held $1,650 million and $237 million of interest-bearing Province of Ontario bonds, respectively. As at December 31, 2016, the Nuclear Segregated Funds and the registered pension fund held $1,652 million and $284 million of interest-bearing Province of Ontario bonds, respectively. These bonds are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

INTERNAL CONTROLS OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

The Company maintains a comprehensive system of policies, procedures, and processes that represents its framework for internal controls over financial reporting and for its disclosure controls and procedures (together, ICOFR). There were no changes in the Company's internal control system during the current interim period that has or is reasonably likely to have a material impact to the ICOFR.

QUARTERLY FINANCIAL HIGHLIGHTS

The following tables set out selected financial information from OPG's unaudited interim consolidated financial statements for each of the eight most recently completed quarters.

Quarterly Financial Information

(millions of dollars – except where noted) *(unaudited)*	**March 31 2017**	**December 31 2016**	**September 30 2016**	**June 30 2016**
Revenue	**1,176**	**1,388**	**1,400**	**1,387**
Net income (loss)	**68**	**(8)**	**198**	**135**
Less: Net income attributable to non-controlling interest	**4**	**5**	**4**	**3**
Net income (loss) attributable to the Shareholder	**64**	**(13)**	**194**	**132**
Per common share, attributable to the Shareholder *(dollars)*	**$0.25**	**($0.05)**	**$0.76**	**$0.51**

(millions of dollars – except where noted) *(unaudited)*	**March 31 2016**	**December 31 2015**	**September 30 2015**	**June 30 2015**
Revenue	1,478	1,312	1,426	1,383
Net income (loss)	128	(100)	85	193
Less: Net income attributable to non-controlling interest	5	1	5	4
Net income (loss) attributable to the Shareholder	123	(101)	80	189
Per common share, attributable to the Shareholder *(dollars)*	$0.48	($0.39)	$0.31	$0.74

Trends

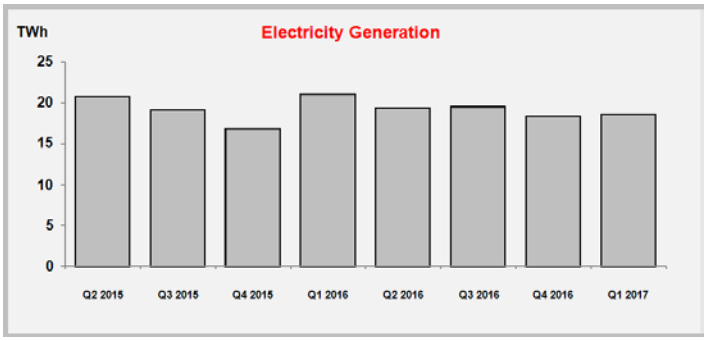
OPG's quarterly results are affected by changes in grid-supplied electricity demand, primarily resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. Weather conditions affect water flows, electricity demand, and prevalence of SBG conditions. Historically, OPG's revenues have been higher in the first quarter of a fiscal year as a result of winter heating demands and in the third quarter due to air conditioning and cooling demands. The financial impact of forgone production due to SBG conditions at the regulated hydroelectric stations and the financial impact of differences between forecast water flows reflected in OEB-approved regulated prices and the actual water flows are offset by regulatory variance accounts authorized by the OEB.

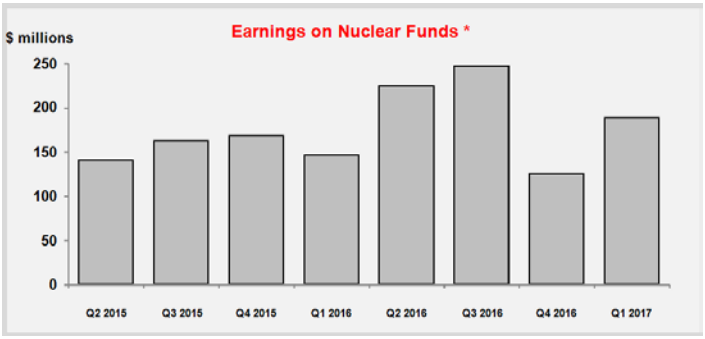
The timing of planned outages at a nuclear generating station during the year can cause variability in year-over-year operating results for partial periods of a fiscal year, including the impact on revenue and OM&A expenses, but is not a significant driver of variability for full fiscal year results.

During the third and fourth quarters of 2015, OPG's electricity generation was reduced by the four-unit Darlington Vacuum Building Outage (VBO), which lasted 47 days from September 14, 2015 to October 30, 2015. A VBO is currently required every 12 years at the Darlington GS.

During the fourth quarter of 2016 and the first quarter of 2017, OPG's electricity generation was reduced as a result of the Unit 2 refurbishment outage at the Darlington GS, which began in October 2016 and is expected to continue until early 2020.

OPG's financial results are also affected by the earnings on the Nuclear Segregated Funds, net of the impact of the Bruce Lease Net Revenues Variance Account.





*net of regulatory variance account

Additional items that affected net income in certain quarters above are described in OPG's 2016 annual MD&A in the section, *Quarterly Financial Highlights*.

SUPPLEMENTARY NON-GAAP FINANCIAL MEASURES

In addition to providing net income and other financial information in accordance with US GAAP, certain non-GAAP financial measures are also presented in OPG's MD&A. These non-GAAP measures do not have any standardized meaning prescribed by US GAAP and, therefore, may not be comparable to similar measures presented by other issuers. OPG utilizes these measures to make operating decisions and assess performance. Readers of the MD&A would utilize these measures in assessing the Company's financial performance from ongoing operations. The Company believes that these indicators are important since they provide additional information about OPG's performance, facilitate comparison of results over different periods, and present measures consistent with the Company's strategies to provide value to the Shareholder, improve cost performance, and to ensure availability of cost effective funding. These non-GAAP financial measures have not been presented as an alternative to net income, cash flow provided by operating activities, or any other measure in accordance with US GAAP, but as indicators of operating performance.

The definitions of the non-GAAP financial measures are as follows:

(1) ROE Excluding AOCI is defined as net income attributable to the Shareholder divided by average equity attributable to the Shareholder excluding AOCI, for the period. ROE Excluding AOCI is measured over a 12-month period and is calculated as follows:

(millions of dollars – except where noted) (unaudited)	Twelve Months Ended March 31 2017	December 31 2016
ROE Excluding AOCI		
Net income attributable to the Shareholder	**377**	436
Divided by: Average equity attributable to the Shareholder, excluding AOCI	**10,834**	10,442
ROE Excluding AOCI *(percent)*	**3.5**	4.2

(2) **FFO Adjusted Interest Coverage** is defined as FFO before interest divided by adjusted interest expense. FFO before interest is defined as cash flow provided by operating activities adjusted for interest paid, interest capitalized to fixed and intangible assets, and changes to non-cash working capital balances for the period. Adjusted interest expense is calculated as net interest expense plus interest income, interest capitalized to fixed and intangible assets, interest related to regulatory assets and liabilities, and the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets, for the period.

FFO Adjusted Interest Coverage is measured over a 12-month period and is calculated as follows:

(millions of dollars – except where noted) (unaudited)	Twelve Months Ended March 31 2017	December 31 2016
FFO before interest		
Cash flow provided by operating activities	**1,457**	1,705
Add: Interest paid	**268**	269
Less: Interest capitalized to fixed and intangible assets	**(152)**	(141)
Add: Changes to non-cash working capital balances	**(22)**	(68)
FFO before interest	**1,551**	1,765
Adjusted interest expense		
Net interest expense	**106**	120
Add: Interest income	**5**	7
Add: Interest capitalized to fixed and intangible assets	**152**	141
Add: Interest related to regulatory assets and liabilities	**32**	30
Add: Excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets	**10**	45
Adjusted interest expense	**305**	343
FFO Adjusted Interest Coverage *(times)*	**5.1**	5.1

(3) **Enterprise Total Generating Cost per MWh** is used to measure OPG's overall organizational cost performance. Enterprise TGC per MWh is defined as OM&A expenses (excluding the Darlington Refurbishment project and other generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to OPG's electricity generation business), fuel expense for OPG-operated stations including hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures (excluding the Darlington Refurbishment project and other generation development projects) incurred during the period, divided by total electricity generation from OPG-operated generating stations plus electricity generation forgone due to SBG conditions during the period.

	Three Months Ended March 31	
(millions of dollars – except where noted) (unaudited)	**2017**	**2016**
Enterprise TGC		
Total OM&A expenses	**708**	686
Total fuel expense	**155**	172
Total capital expenditures	**408**	320
Less: Darlington Refurbishment capital and OM&A costs	**(309)**	(205)
Less: Other generation development project capital and OM&A costs	**(17)**	(38)
Add: OM&A and fuel expenses deferred in regulatory variance and deferral accounts	**(11)**	18
Less: Nuclear fuel expense for non OPG-operated stations	**(13)**	(17)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**11**	18
Less: OM&A expenses ancillary to electricity generation business	**(5)**	(5)
Other adjustments	**(2)**	(5)
	925	944
Adjusted electricity generation *(TWh)*		
Total OPG electricity generation	**18.6**	21.0
Adjust for electricity generation forgone due to SBG conditions and OPG's share of electricity generation from co-owned facilities	**0.7**	1.6
	19.3	22.6
Enterprise TGC per MWh *($/MWh)* [1]	**47.86**	**41.82**

[1] Amounts may not calculate due to rounding.

(4) **Nuclear Total Generating Cost per MWh** is used to measure the cost performance of OPG's nuclear generating assets. Nuclear TGC per MWh is defined as OM&A expenses of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the nuclear electricity generation business), nuclear fuel expense for OPG-operated stations (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs) incurred during the period, divided by nuclear electricity generation for the period.

(millions of dollars – except where noted) (unaudited)	Three Months Ended March 31 **2017**	**2016**
Nuclear TGC		
Regulated – Nuclear Generation OM&A expenses	**589**	563
Regulated – Nuclear Generation fuel expense	**68**	81
Regulated – Nuclear Generation capital expenditures	**366**	249
Less: Darlington Refurbishment capital and OM&A costs	**(309)**	(205)
Add: Regulated – Nuclear Generation OM&A and fuel expenses deferred in regulatory variance and deferral accounts	**(2)**	24
Less: Nuclear fuel expense for non OPG-operated stations	**(13)**	(17)
Less: Regulated – Nuclear Generation OM&A expenses ancillary to nuclear electricity generation business	**(1)**	(1)
Other adjustments	**-**	(1)
	698	693
Nuclear electricity generation *(TWh)*	**10.0**	12.3
Nuclear TGC per MWh *($/MWh)* [1]	**69.87**	56.37

[1] Amounts may not calculate due to rounding.

(5) **Hydroelectric Total Generating Cost per MWh** is used to measure the cost performance of OPG's hydroelectric generating assets. Hydroelectric TGC per MWh is defined as OM&A expenses of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the hydroelectric electricity generation business), hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding expenditures related to the Peter Sutherland Sr. GS and other hydroelectric generation development projects) incurred during the period, divided by total hydroelectric electricity generation plus hydroelectric electricity generation forgone due to SBG conditions during the period. OPG reports hydroelectric gross revenue charge and water rental payments as fuel expense.

	Three Months Ended March 31	
(millions of dollars – except where noted) (unaudited)	**2017**	**2016**
Hydroelectric TGC		
Regulated – Hydroelectric Generation OM&A expenses	**76**	76
Regulated – Hydroelectric Generation fuel expense	**73**	79
Contracted Generation Portfolio OM&A expenses	**39**	40
Contracted Generation Portfolio fuel expense	**14**	12
Regulated – Hydroelectric Generation and Contracted Generation Portfolio capital expenditures	**37**	59
Less: Regulated – Hydroelectric Generation and Contracted Generation Portfolio generation development project capital and OM&A costs	**(16)**	(37)
Less: Thermal OM&A, fuel expenses, and capital expenditures in the Contracted Generation Portfolio	**(39)**	(37)
Less: Regulated – Hydroelectric Generation OM&A and fuel expenses deferred in regulatory variance and deferral accounts	**(9)**	(7)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**11**	18
Other adjustments	**(1)**	2
	185	205
Adjusted hydroelectric electricity generation *(TWh)*		
Regulated – Hydroelectric Generation electricity generation	**8.0**	7.9
Contracted Generation Portfolio electricity generation	**0.6**	0.8
Adjust for hydroelectric electricity generation forgone due to SBG conditions and non-hydroelectric electricity generation of the Contracted Generation Portfolio	**0.7**	1.6
	9.3	10.3
Hydroelectric TGC per MWh *($/MWh)*[1]	**19.79**	19.94

[1] Amounts may not calculate due to rounding.

(6) **Gross margin** is defined as revenue less fuel expense**.**

For further information, please contact: Investor Relations 416-592-6700

1-866-592-6700

investor.relations@opg.com

Media Relations 416-592-4008

1-877-592-4008

www.opg.com

www.sedar.com

From: Ronald Kwan
To: John Kim
Subject: RE: EXTERNAL – RE: OPG Q3 2017 Submission to Province
Date: Wednesday, November 08, 2017 5:30:21 PM

Hi John,

Any need for conforming edits to the financial statement notes?

Ron

From: Ronald Kwan
Sent: November-08-17 17:29
To: 'HO Philip -FIN & C CTRL' <philip.ho@opg.com>; John Kim <John.Kim@ofina.on.ca>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>
Subject: RE: EXTERNAL – RE: OPG Q3 2017 Submission to Province

Thanks Philip, John.

Ron

From: HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
Sent: November-08-17 17:27
To: John Kim <John.Kim@ofina.on.ca>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Subject: RE: EXTERNAL – RE: OPG Q3 2017 Submission to Province

Hi John,

Regarding comment on pg 8, we have removed 'for years 2017 to 2021' as suggested.
Regarding comment on pg 10, we have edited the wording to read 'In order for the Trust to finance the deferred Global Adjustment costs …' as suggested.

Thank you.

Philip

From: John Kim [mailto:John.Kim@ofina.on.ca]
Sent: Wednesday, November 08, 2017 2:04 PM
To: HO Philip -FIN & C CTRL <philip.ho@opg.com>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Subject: RE: EXTERNAL – RE: OPG Q3 2017 Submission to Province

Hi Philip,

On a couple of items, we have follow up. Pls. refer to p. 8 and p. 10.

Thanks,

John

From: HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
Sent: Wednesday, November 08, 2017 1:30 PM
To: John Kim <John.Kim@ofina.on.ca>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Subject: RE: EXTERNAL – RE: OPG Q3 2017 Submission to Province

Hi John,

Please see our responses to your three additional comments. Thank you.

Philip

From: John Kim [mailto:John.Kim@ofina.on.ca]
Sent: Monday, November 06, 2017 7:35 PM
To: HO Philip -FIN & C CTRL <philip.ho@opg.com>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Subject: RE: EXTERNAL – RE: OPG Q3 2017 Submission to Province

Hi Philip,

We have gone through again and some additional comment boxes and edits.

Thanks,

John

From: HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
Sent: Monday, November 06, 2017 6:19 PM
To: John Kim <John.Kim@ofina.on.ca>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Subject: RE: EXTERNAL – RE: OPG Q3 2017 Submission to Province

Hi John,

Please see our responses to your comments. Let us know if you have any others. Thank you.

Regards,

Philip

Philip Ho, CPA, CA | Senior Manager, External Reporting & Accounting Policy | Ontario Power Generation
700 University Avenue, Toronto ON M5G 1X6 | Phone: (416) 592-3320| E-mail: philip.ho@opg.com

---

From: John Kim [mailto:John.Kim@ofina.on.ca]
Sent: Monday, October 30, 2017 6:16 PM
To: HO Philip -FIN & C CTRL <philip.ho@opg.com>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
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Hi Philip,

See attached with our comments on the MD&A.

These are staff level comments as Ron has not had a chance to review.

Thanks,

John

From: HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
Sent: Wednesday, October 25, 2017 12:22 PM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>; 'Montgomery, Kaitlin (MOF)' <Kaitlin.Montgomery@ontario.ca>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>
Subject: OPG Q3 2017 Submission to Province

Hi All,

Please find attached OPG's draft Q3 2017 Financial Results Press Release, Management's Discussion and Analysis (MD&A), and Financial Statements for the Province's review.

We would greatly appreciate comments on the above **no later than Monday, Oct 30th**.

These documents will be filed with the Ontario Securities Commission on **Thursday, November 9th** following OPG's Board of Directors meeting.

Kindly forward all comments directly to Philip Ho – philip.ho@opg.com.

To assist the review process, the following are the key items in the Q3 2017 MD&A:

Highlights	
Recent Developments	MD&A p.10-11
Darlington Refurbishment	MD&A p.13-15
Ontario's Fair Hydro Plan	MD&A p.10-11

Philip Ho, CPA, CA | Senior Manager, External Reporting & Accounting Policy | Ontario Power Generation
700 University Avenue, Toronto ON M5G 1X6 | Phone: (416) 592-3320| E-mail: philip.ho@opg.com

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From: HO Philip -FIN & C CTRL
To: John Kim
Cc: MAK Ricky -FIN & C CTRL; DYKXHOORN Sandra -STAKEREL; GORE Michael -FIN & C CTRL; Ronald Kwan
Subject: RE: EXTERNAL – RE: OPG Q3 2017 Submission to Province
Date: Monday, November 06, 2017 6:19:37 PM
Attachments: Q3 2017 OPG MDA - DRAFT - PROVINCE MAILING_EFB_CommentsV4_addressed by OPG.docx

---

Hi John,

Please see our responses to your comments. Let us know if you have any others. Thank you.

Regards,

Philip

Philip Ho, CPA, CA | Senior Manager, External Reporting & Accounting Policy | Ontario Power Generation
700 University Avenue, Toronto ON M5G 1X6 | Phone: (416) 592-3320| E-mail: philip.ho@opg.com

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Sent: Monday, October 30, 2017 6:16 PM
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Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
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Sent: Wednesday, October 25, 2017 12:22 PM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>; 'Montgomery, Kaitlin (MOF)' <Kaitlin.Montgomery@ontario.ca>

Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>
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Ontario's Fair Hydro Plan	MD&A p.10-11

Philip Ho, CPA, CA | Senior Manager, External Reporting & Accounting Policy | Ontario Power Generation
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ONTARIO POWER GENERATION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

2017 THIRD QUARTER REPORT

[DRAFT]

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ONTARIO POWER GENERATION

ONTARIO POWER GENERATION INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) should be read in conjunction with the unaudited interim consolidated financial statements and accompanying notes of Ontario Power Generation Inc. (OPG or Company) as at and for the three and nine months ended September 30, 2017. OPG's unaudited interim consolidated financial statements are prepared in accordance with United States generally accepted accounting principles (US GAAP) and are presented in Canadian dollars.

For a complete description of OPG's corporate strategies, risk management, corporate governance, and the effect of critical accounting policies and estimates on OPG's results of operations and financial condition, this MD&A should also be read in conjunction with OPG's audited consolidated financial statements, accompanying notes, the Annual Information Form, and the MD&A as at and for the year ended December 31, 2016.

As required by *Ontario Regulation 395/11*, as amended, a regulation under the *Financial Administration Act* (Ontario), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. In 2014, the Ontario Securities Commission approved an exemption which allows OPG to apply US GAAP up to January 1, 2019. The term of the exemption is subject to certain conditions, which may result in the expiry of the exemption prior to January 1, 2019. For details, refer to the section, *Critical Accounting Policies and Estimates* under the heading, *Exemptive Relief for Reporting under US GAAP,* in OPG's 2016 annual MD&A. This MD&A is dated November 9, 2017.

FORWARD-LOOKING STATEMENTS

The MD&A contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could", and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

All forward-looking statements involve inherent assumptions, risks, and uncertainties, including those set out in the section, *Risk Management,* and forecasts discussed in the section, *Core Business, Strategy, and Outlook.* All forward-looking statements could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's generating station performance and availability, fuel costs, surplus baseload generation (SBG), cost of fixed asset removal and nuclear waste management, performance and earnings of investment funds, refurbishment of existing facilities, development and construction of new facilities, pension and other post-employment benefit (OPEB) obligations and funds, income taxes, proposed new legislation, the ongoing evolution of Ontario's electricity industry, environmental and other regulatory requirements, health, safety and environmental developments, business continuity events, the weather, financing and liquidity, applications to the Ontario Energy Board (OEB) for regulatory prices, the impact of regulatory decisions by the OEB, and forecasts of earnings, cash flows, Funds from Operations (FFO) Adjusted Interest Coverage, Return on Common Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI), Total Generating Cost (TGC) and capital expenditures. Accordingly, undue reliance should not be placed on any forward-looking statement. The forward-looking statements included in this MD&A are made only as of the date of this MD&A. Except as required by applicable securities laws, OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events, or otherwise.

THE COMPANY

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG was established under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (Province or Shareholder).

As at September 30, 2017, OPG's electricity generation portfolio had an in-service capacity of 16,210 megawatts (MW). OPG operates two nuclear generating stations, 66 hydroelectric generating stations, three thermal generating stations, and one wind power turbine. In addition, OPG and TransCanada Energy Ltd. co-own the 550 MW Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS). OPG and ATCO Power Canada Ltd. co-own the 560 MW Brighton Beach gas-fired combined cycle GS (Brighton Beach). OPG's 50 percent share of the in-service capacity and generation volume of these co-owned facilities is included in the generation portfolio statistics set out in this report. The income from the co-owned facilities is accounted for using the equity method of accounting, and OPG's share of income is presented as income from investments subject to significant influence in the Contracted Generation Portfolio segment.

OPG also owns two other nuclear generating stations, the Bruce A GS and the Bruce B GS, which are leased on a long-term basis to Bruce Power LP (Bruce Power). Income from these leased stations is included in revenue under the Regulated – Nuclear Generation segment. The leased stations are not included in the generation portfolio statistics set out in this report.

All of OPG's owned and co-owned generating facilities are located in Ontario. OPG does not operate PEC, Brighton Beach, the Bruce A GS and the Bruce B GS.

A description of OPG's segments is provided in OPG's 2016 annual MD&A in the section, *Business Segments*.

In-Service Generating Capacity

OPG's in-service generating capacity by business segment as at September 30, 2017 and December 31, 2016 was as follows:

	As at	
(MW)	**September 30 2017**	**December 31 2016**
Regulated – Nuclear Generation [1]	**5,728**	5,728
Regulated – Hydroelectric	**6,426**	6,421
Contracted Generation Portfolio [2]	**4,056**	4,028
Total	**16,210**	16,177

[1] The in-service generating capacity as of September 30, 2017 and December 31, 2016 excludes Unit 2 of the Darlington GS. The unit, which has a generating capacity of 878 MW, was taken offline in mid-October 2016 and is currently undergoing refurbishment.

[2] Includes OPG's share of in-service generating capacity of 275 MW for PEC and 280 MW for Brighton Beach.

During the nine months ended September 30, 2017, the total in-service capacity increased by 33 MW. The increase was primarily due to the completion of the Peter Sutherland Sr. hydroelectric GS, which was placed in-service at the end of the first quarter of 2017, and the upgrade of Unit 10 of the Sir Adam Beck 1 hydroelectric GS, which was completed in June 2017.

HIGHLIGHTS

Overview of Results

This section provides an overview of OPG's unaudited interim consolidated operating results. Significant factors which contributed to OPG's results during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, are discussed below.

(millions of dollars – except where noted) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Revenue	**1,217**	1,400	**3,539**	4,265
Fuel expense	**185**	187	**518**	541
Gross margin	**1,032**	1,213	**3,021**	3,724
Operations, maintenance and administration	**635**	666	**2,054**	2,061
Depreciation and amortization	**178**	313	**517**	941
Accretion on fixed asset removal and nuclear waste management liabilities	**235**	232	**709**	696
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(196)**	(248)	**(579)**	(620)
Income from investments subject to significant influence	**(11)**	(11)	**(29)**	(28)
Property taxes	**8**	12	**30**	35
	849	964	**2,702**	3,085
Income before other losses (gains), interest and income taxes	**183**	249	**319**	639
Other losses (gains)	**3**	1	**(380)**	(23)
Income before interest and income taxes	**180**	248	**699**	662
Net interest expense	**21**	28	**56**	92
Income before income taxes	**159**	220	**643**	570
Income tax expense	**19**	22	**128**	109
Net income	**140**	198	**515**	461
Net income attributable to the Shareholder	**131**	194	**498**	449
Net income attributable to non-controlling interest [1]	**9**	4	**17**	12
Electricity production (TWh) [2]	**19.4**	19.5	**56.0**	59.9
Cash flow provided by operating activities	**485**	530	**698**	1,211

[1] Relates to the 25 percent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in the Lower Mattagami Limited Partnership, the 33 percent interest of Coral Rapids Power Corporation, a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership, and the 10 percent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP.

[2] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

Third Quarter

Net income attributable to the Shareholder was $131 million for the third quarter of 2017, a decrease of $63 million compared to the same quarter in 2016. Income before interest and income taxes for the third quarter of 2017 was $180 million, a decrease of $68 million compared to the same quarter in 2016.

Commented [A1]:
Wondering if this should be 437?
Since:
Q3 9-mos ended – Q2 6-mos ended = 698-261 = 437

Was Q2 "6-month ended June 30" number for Cash flow provided by operating activities revised?

OPG: In Q3 2017, adjustments for non-cash balances related to Darlington Refurbishment capital expenditures have been reclassified from the "Net changes in non-cash working capital balances" line to the "Investment in property, plant and equipment and intangible assets" line. Comparative amounts have been reclassified accordingly.

Significant factors that reduced income before interest and income taxes:

- Lower earnings from the nuclear base regulated price of approximately $24 million reflecting lower electricity generation of 0.4 terawatt hours (TWh) from the Regulated – Nuclear Generation segment and the continuation of existing base regulated prices set by the OEB in 2014. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS since October 2016, largely offset by an increase in generation from Pickering GS. The increase in generation from the Pickering GS was primarily due to outage optimization, favourable unit conditions and execution of planned outage work. The base regulated prices set in 2014 continue to be in effect pending the OEB's decision on OPG's current application for new regulated prices, expected later in 2017. **[MONITOR]** The existing nuclear base regulated price was set to allow the Company to recover its approved nuclear costs over a higher nuclear production volume, based on the 2014 and 2015 outage profile that did not include a refurbishment outage. OPG has requested January 1, 2017 as the effective date of the new regulated prices.
- Lower earnings on the nuclear fixed asset removal and nuclear waste management funds (Nuclear Segregated Funds) of $52 million.
- Higher depreciation and amortization expense of $16 million in the Regulated – Nuclear Generation segment, excluding amortization expense related to balances in OEB-authorized regulatory variance and deferral accounts (regulatory accounts), primarily due to new assets in service.

The expiry of rate riders for the recovery of approved balances in OEB-authorized regulatory accounts on December 31, 2016 contributed to the decrease in revenue for the three months ended September 30, 2017, compared to the same period in 2016, but was largely offset by a decrease in the amortization expense related to these balances. OPG has requested new rate riders in its current application to the OEB for new regulated prices, with a proposed effective date of January 1, 2017.

Significant factor that increased income before interest and income taxes:

- Lower operations, maintenance and administration (OM&A) expenses of $31 million, mainly in the Regulated – Nuclear Generation segment, as a result of a higher materials and supplies obsolescence charge recognized in the third quarter of 2016, Services, Trading and Other Non-Generation segment due to project expenditures incurred in the third quarter of 2016, and Regulated – Hydroelectric segment due to the timing of repairs and maintenance work in 2017 and a deferral of outages during the high water period.

Net interest expense decreased by $7 million during the third quarter of 2017, compared to the same quarter in 2016, primarily due to a higher amount of interest costs capitalized for the Darlington Refurbishment project expenditures and a higher amount of interest costs deferred in OEB-authorized regulatory accounts.

Income tax expense for the three months ended September 30, 2017 was $19 million, compared to $22 million for the same period in 2016. The decrease in income tax expense was primarily due to lower income before taxes and a higher change in reserves from the resolution of uncertainties, partially offset by a lower amount of tax expense deferred in regulatory assets.

Year-To-Date

Net income attributable to the Shareholder was $498 million for the first nine months of 2017, an increase of $49 million compared to the same period in 2016. Income before interest and income taxes for the first nine months of 2017 was $699 million, an increase of $37 million compared to the same period in 2016.

Significant factor that increased income before interest and income taxes:

- Higher earnings of $390 million from the Services, Trading, and Other Non-Generation segment, primarily reflecting the gain on sale of OPG's head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street that was recognized in the second quarter of 2017. The sale of the

Commented [A2]: If approved by OEB (during Q4), would this result in a higher regulated price and a revenue/net income pick up for 2017 reported in OPG's Q4?

OPG – It depends on the effective date of the decision on the base regulated prices. If the OEB decision on the new base regulated prices are retrospectively effective as of Jan 1, 2017 for example, then it should result in a higher revenue/net income pick up for 2017 assuming the new regulated prices are higher.

assets was required by a Shareholder Declaration and a Shareholder Resolution. The gain on sale was $283 million, which is net of tax effects of $95 million.

Significant factors that reduced income before interest and income taxes:

- Lower earnings from the nuclear base regulated price of approximately $230 million, partially offset by a decrease in nuclear fuel expense of $22 million, reflecting lower electricity generation of 4.0 TWh from the Regulated – Nuclear Generation segment and the continuation of existing base regulated prices set by the OEB in 2014. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS, partially offset by an increase in generation from Pickering GS.
- Lower earnings on the Nuclear Segregated Funds of $41 million.
- Higher depreciation and amortization expense of $30 million in the Regulated – Nuclear Generation segment, excluding amortization expense related to regulatory account balances, primarily due to new assets in service.
- A gain of $22 million recorded in the first quarter of 2016 to reflect the OEB's decision on OPG's motion asking the OEB to review and vary parts of its November 2014 decision on OPG's regulated prices.

The expiry of rate riders for the recovery of approved balances in OEB-authorized regulatory accounts on December 31, 2016 contributed to the decrease in revenue for the nine months ended September 30, 2017, compared to the same period in 2016, but was primarily offset by a decrease in the amortization expense related to these balances.

Net interest expense decreased by $36 million for the nine months ended September 30, 2017, compared to the same period in 2016, primarily due to a higher amount of interest costs capitalized for the Darlington Refurbishment project expenditures and a higher amount of interest costs deferred in OEB-authorized regulatory accounts.

Commented [A3]: Does this imply there were interest costs related to Darlington Refurb previously (same quarter previous year), that were not capitalized, but were able to be capitalized this year?

OPG – There were higher Darlington Refurb project expenditures in 2017, compared to 2016.

Income tax expense for the nine months ended September 30, 2017 was $128 million, compared to $109 million for the same period in 2016. The increase in income tax expense was primarily due to higher income before income taxes.

Segment Results

The following table summarizes OPG's income before interest and income taxes by business segment. A detailed discussion of OPG's performance by reportable segment is included in the section, *Discussion of Operating Results by Business Segment*.

(millions of dollars)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Income (loss) before interest and income taxes				
Regulated – Nuclear Generation	**20**	47	**(267)**	17
Regulated – Hydroelectric	**122**	117	**474**	500
Contracted Generation Portfolio	**75**	74	**229**	219
Total electricity generation business segments	**217**	238	**436**	736
Regulated – Nuclear Waste Management	**(36)**	18	**(123)**	(70)
Services, Trading, and Other Non-Generation	**(1)**	(8)	**386**	(4)
	180	248	**699**	662

Electricity Generation

Electricity generation for the three and nine month periods ended September 30, 2017 and 2016 was as follows:

(TWh)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Regulated – Nuclear Generation	**11.3**	11.7	**30.6**	34.6
Regulated – Hydroelectric	**7.3**	6.9	**23.5**	22.8
Contracted Generation Portfolio [1]	**0.8**	0.9	**1.9**	2.5
Total OPG electricity generation	**19.4**	19.5	**56.0**	59.9
Total electricity generation by all other generators in Ontario [2]	**16.6**	19.5	**51.7**	53.8

[1] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.
[2] Non-OPG generation is calculated as the Ontario electricity demand plus net exports, as published by the Independent Electricity System Operator (IESO), minus OPG electricity generation.

Total OPG electricity generation decreased by 0.1 TWh during the third quarter of 2017, compared to the same quarter in 2016, and by 3.9 TWh during the nine months ended September 30, 2017, compared to the same period in 2016. As expected, the lower electricity generation from the Regulated – Nuclear Generation segment was primarily the result of the removal from service of Unit 2 at the Darlington GS for the duration of the unit's refurbishment, which began in October 2016. This decrease in electricity generation was largely offset by an increase in generation from the Pickering GS, primarily due to outage optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station, and higher hydroelectric generation from the Regulated – Hydroelectric segment.

The higher electricity generation of 0.4 TWh and 0.7 TWh from the Regulated – Hydroelectric segment for the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016, was due to higher water flows primarily on the eastern Ontario river systems, net of water spilled as a result of SBG conditions, discussed below.

The lower electricity generation of 0.6 TWh from the Contracted Generation Portfolio segment for the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to higher SBG conditions. The electricity generation from the Contracted Generation Portfolio segment for the three months ended September 30, 2017 was comparable to the same period in 2016.

OPG's operating results are impacted by changes in grid-supplied electricity demand resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. For the three and nine month periods ended September 30, 2017, Ontario's electricity demand as reported by the IESO was 33.6 TWh and 98.5 TWh, respectively, compared to 36.7 TWh and 103.8 TWh for the same periods in 2016, respectively, excluding electricity exports out of the province.

Power that is surplus to the Ontario market is managed by the IESO, mainly through generation reductions at hydroelectric, other grid-connected renewable resources and nuclear stations. Reducing hydroelectric production is the first measure used by the IESO to manage SBG conditions. Low demand conditions in Ontario continued to be prevalent in 2017, resulting in forgone hydroelectric generation for OPG of 1.1 TWh and 4.5 TWh due to SBG conditions in the three and nine month periods ended September 30, 2017, respectively, compared to 0.5 TWh and 3.9 TWh during the same periods in 2016, respectively. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions during these periods was offset by the impact of a regulatory variance account authorized by the OEB. OPG did not forgo any electricity production at its nuclear stations due to SBG conditions.

Average Sales Prices

The majority of OPG's generation is from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments. The same base regulated prices for electricity generated by these segments, authorized by the OEB effective November 1, 2014, were in effect during the first nine months of 2017 as in 2016. These prices will remain in effect until such time as the OEB approves new regulated prices based on OPG's current application. **[MONITOR]** The base regulated prices established in 2014 are discussed in OPG's 2016 annual MD&A in the section, *Revenue Mechanisms for Regulated and Non-Regulated Generation*.

The average sales price for the Regulated – Nuclear Generation segment was 5.8 cents per kilowatt hour (¢/kWh) during the three and nine month periods ended September 30, 2017, respectively, compared to 6.9 ¢/kWh during the same periods in 2016. The decrease in the average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized nuclear rate rider of $10.84 per megawatt hour (MWh) for the recovery of variance and deferral account balances. The average sales price for the Regulated – Hydroelectric segment was 4.1 ¢/kWh during the three and nine month periods ended September 30, 2017, respectively, compared to 4.4 ¢/kWh during the same periods in 2016. The decrease in the average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized regulated hydroelectric rate rider of $3.19/MWh for the recovery of variance and deferral account balances. The rate riders were established to recover approved balances recorded in the variance and deferral accounts in prior years. As such, the year-over-year changes in revenue from the rate riders were largely offset by changes in amortization expense related to these balances. There were no rate riders in effect during the nine months ended September 30, 2017 for either nuclear or regulated hydroelectric generation, pending the outcome of OPG's current application with the OEB for new regulated prices.

Cash Flow from Operations

Cash flow provided by operating activities was $485 million for the three months ended September 30, 2017 and $698 million for the nine months ended September 30, 2017, compared to $530 million and $1,211 million for the same periods in 2016, respectively. The decrease in cash flow provided by operating activities was expected and primarily due to lower generation revenue receipts reflecting lower generation from the Regulated – Nuclear Generation segment as a result of the ongoing refurbishment of Unit 2 at the Darlington GS and the expiry, on December 31, 2016, of the OEB-authorized rate riders for nuclear and regulated hydroelectric generation. The decrease in cash flow during the nine months ended September 30, 2017 was also due to higher income tax instalments.

The decrease in cash flow provided by operating activities for the three and nine month periods ended September 30, 2017 was partly offset by lower OM&A expenditures and lower contributions to the Used Fuel Segregated Fund in 2017. Both the Used Fuel Segregated Fund and the Decommissioning Segregated Fund were determined to be fully funded based on an updated estimate of OPG's nuclear waste management and nuclear facilities decommissioning obligations pursuant to a reference plan approved by the Province, for years 2017 to 2021, under the Ontario Nuclear Funds Agreement (ONFA), effective January 1, 2017. Pursuant to the ONFA, the reference plan is required to be updated at least once every five years. Contributions to either or both of the Nuclear Segregated Funds may be required in the future should the funds be in an underfunded position at the time of the next ONFA reference plan update. The year-over-year decrease in cash flow also was partially offset by the payment of a supplemental rent rebate to Bruce Power in the first quarter of 2016 in relation to a period in 2015. The lease agreement for the Bruce nuclear generating stations was amended in late 2015 to eliminate this rebate provision going forward.

Return on Common Equity Excluding Accumulated Other Comprehensive Income

ROE Excluding AOCI is an indicator of OPG's performance consistent with the Company's strategy to provide value to the Shareholder. ROE Excluding AOCI is measured over a 12-month period.

ROE Excluding AOCI was 4.4 percent for the 12 months ended September 30, 2017, compared to 4.2 percent for the 12 months ended December 31, 2016. The increase was primarily due to higher net income attributable to the Shareholder for the 12 months ended September 30, 2017, which reflected the gain on sale of OPG's head office premises and associated parking facility recorded in the second quarter of 2017, partially offset by the lower earnings from the decrease in nuclear electricity generation reflecting the Unit 2 refurbishment outage at the Darlington GS without a corresponding increase in the nuclear base regulated price, as expected. The lower nuclear generation as a result of the refurbishment outage will continue to negatively affect OPG's ROE Excluding AOCI until such time as new regulated prices are approved by the OEB, anticipated in the fourth quarter of 2017. **[MONITOR]**

Funds from Operations Adjusted Interest Coverage

FFO Adjusted Interest Coverage is an indicator of OPG's ability to meet interest obligations from operating cash flows. The indicator is measured over a 12-month period. FFO Adjusted Interest Coverage for the 12 months ended September 30, 2017 was 4.2 times, compared to 5.1 times for the 12 months ended December 31, 2016. FFO Adjusted Interest Coverage in 2017 reflected a year-over-year decrease in FFO before interest due to lower cash flow provided by operating activities, partially offset by the impact of a lower adjusted interest expense due to a decrease in the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets.

The decrease in the excess of interest on pension and OPEB benefit obligations over expected return on pension plan assets in the nine months of 2017 was primarily due to the change in the method used to estimate the interest cost and service cost components of pension and OPEB costs. Effective January 1, 2017, OPG adopted a full yield curve approach to the estimation of these cost components, by applying the specific spot rates along the yield curve used in the determination of the projected benefit obligations to the relevant projected cash flows. Under the previous method, these components of pension and OPEB costs were calculated using the same single weighted-average discount rates as reflected in the calculation of the benefit obligations. This change in the method was accounted for prospectively, as a change in estimate. The resulting reduction in pension and OPEB costs for the three and nine month periods ended September 30, 2017 did not have a material impact on net income as it was largely offset by the impact of OEB-authorized variance and deferral accounts in the regulated business segments. Further details on the full yield curve approach can be found in the 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Pension and Other Post-Employment Benefits*.

Enterprise Total Generating Cost per MWh

The Enterprise TGC per MWh decreased to $46.65 for the three months ended September 30, 2017, compared to $50.72 for the same quarter in 2016. The decrease was mainly due to lower OM&A expenses before the impact of regulatory accounts and higher SBG-adjusted hydroelectric generation reflecting higher water flows.

The Enterprise TGC per MWh was $47.77 for the nine months ended September 30, 2017, an increase compared to $46.74 for the same period in 2016. The increase was expected and mainly a result of lower electricity generation due to the Unit 2 refurbishment outage at the Darlington GS, largely offset by lower OM&A expenses before the impact of regulatory accounts and higher SBG-adjusted hydroelectric generation reflecting higher water flows.

If Unit 2 at the Darlington GS was not currently undergoing refurbishment and had continued to operate in a manner consistent with the performance of the remaining units at the Darlington GS, adjusting for generation constraints on these units related to the transition of the station toward refurbishment, the Enterprise TGC would have been approximately $4 per MWh lower for both the three and nine month periods ended September 30, 2017. This sensitivity was calculated using the estimated incremental electricity and associated fuel cost that are expected to have resulted in the absence of the refurbishment.

Nuclear Total Generating Cost per MWh

The Nuclear TGC per MWh was $58.75 for the three months ended September 30, 2017, which was comparable to $58.55 for the same quarter in 2016. For the three months ended September 30, 2017, the higher generation at the Pickering GS and the impact of lower OM&A expenses before the impact of regulatory accounts was mostly offset by the expected decrease in nuclear electricity generation reflecting the Unit 2 refurbishment outage at the Darlington GS and higher sustaining capital expenditures. The Nuclear TGC per MWh was $67.87 for the nine months ended September 30, 2017, compared to $61.07 for the same period in 2016. The increase in the Nuclear TGC per MWh for the nine months ended September 30, 2017 was expected and primarily due to the decrease in nuclear electricity generation, partially offset by lower OM&A expenses before the impact of regulatory accounts.

Hydroelectric Total Generating Cost per MWh

The Hydroelectric TGC per MWh was $26.20 for the three months ended September 30, 2017, compared to $31.01 for the same quarter in 2016. The decrease was primarily due to higher SBG-adjusted hydroelectric electricity generation reflecting higher water flows. The Hydroelectric TGC per MWh was $21.74 for the nine months ended September 30, 2017, compared to $23.99 for the same period in 2016. The decrease was primarily due to lower OM&A expenses before the impact of regulatory accounts and lower sustaining capital expenditures.

ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are not measurements in accordance with US GAAP and should not be considered alternative measures to net income, cash flow provided by operating activities, or any other performance measure under US GAAP. OPG believes that these non-GAAP financial measures are effective indicators of its performance and are consistent with the Company's strategic imperatives and related objectives. The definition and calculation of ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are found in the section, *Supplementary Non-GAAP Financial Measures*.

Recent Developments

Ontario's 2017 Long Term Energy Plan

On October 26, 2017, Ontario's Ministry of Energy issued the 2017 Long Term Energy Plan. The Plan is currently being analyzed by OPG but is not expected to significantly impact OPG's business. There are no fundamental changes from the principles in the 2013 Long Term Energy Plan, which include cost effectiveness, reliability, clean energy and community engagement. The 2017 Long Term Energy Plan fully supports nuclear refurbishment projects in Ontario and the extension of commercial operation of all Pickering units to 2024. **[MONITOR & UPDATE DETAILS FOLLOWING RELEASE]**

OEB's Decision on New Regulated Prices **[MONITOR]**

Ontario's Fair Hydro Plan

OPG continues to prepare for its involvement as the Financial Services Manager for Ontario's Fair Hydro Plan (the Fair Hydro Plan) on a commercial basis. Accordingly, the financing entity was established in XX 2017 as the Fair Hydro Trust (the Trust), following the execution of its constating documents. The majority unitholder and beneficiary of the Trust is a wholly-owned subsidiary of OPG. Through this ownership and OPG's control over the key activities of the Trust, the Company will consolidate the Trust for accounting purposes commencing in the fourth quarter of 2017. **[MONITOR]**

In order for the Trust to provide financing for the deferred Global Adjustment costs, the Trust will incur senior debt from capital markets and subordinated debt from OPG. The Trust is structured to be bankruptcy remote and ring fenced from OPG to protect the Company's assets and operations. In support of the Fair Hydro Plan, the following developments have transpired:

- In October 2017, *Ontario Regulation 206/17 General* was amended to establish details of the recovery mechanism for the monthly carrying costs incurred by the Trust from June 1, 2017 to July 31, 2021 payable by the IESO to the Trust. Originally established in June 2017, this regulation provides more details on the funding obligations incurred by the Trust and the fair allocation amount, the determination and collection of clean energy adjustments, the determination of the finance amount, the true up amount, and the regulatory asset, as well as principles and assumptions relating to the financing plan.
- A plan to amend the Company's Articles of Amalgamation to allow for the creation and issuance of Class A shares to be issued to the Province for its equity investment through OPG in the Fair Hydro Plan is in progress. The Province is expected to provide 44 percent of the total funding requirement related to the deferred Global Adjustment costs, which OPG will invest as subordinated debt into the Trust. OPG's Board approval and a Shareholder Resolution are expected later in the year to authorize the amendment.
- OPG is expected to provide five percent of the total funding requirement of the Trust related to the deferred Global Adjustment costs of the Fair Hydro Plan. OPG issued senior notes payable in October 2017 under a short form base shelf prospectus for general corporate purposes and to fund OPG's subordinated debt investment in the Trust. Further details of the debt offering can be found in the section, *Liquidity and Capital Resources* under the heading, *Financing Activities*.

Commented [A4]: Are any other details available to be released at this time?

OPG – Not for Q3 2017 reporting.

The first set of transactions of the Trust are expected to take place in the fourth quarter of 2017.

Canadian Nuclear Safety Commission Safety Rating for the Darlington GS and the Pickering GS

The Canadian Nuclear Safety Commission (CNSC) publishes an annual report on the safety performance of Canada's nuclear power plants. The report assesses how well plant operators are meeting regulatory requirements and program expectations in the areas of operational performance, safety analysis, radiation protection, waste management and conventional health and safety. On September 8, 2017, the CNSC issued an executive summary of its 2016 annual report. The CNSC gave both the Darlington GS and the Pickering GS the highest possible safety rating of "Fully Satisfactory". The Darlington GS achieved this rating for the eighth consecutive year, while the Pickering GS achieved this rating for the second consecutive year.

CORE BUSINESS, STRATEGY, AND OUTLOOK

The discussion in this section is qualified in its entirety by the cautionary statements included in the section, *Forward-Looking Statements,* at the beginning of the MD&A.

OPG's mission is to provide low cost power in a safe, clean, reliable and sustainable manner for the benefit of customers and its Shareholder. OPG also seeks to pursue, on a commercial basis, generation development projects and other business growth opportunities.

The following sections provide an update to OPG's disclosures in the 2016 annual MD&A related to its four key strategic imperatives – operational excellence, project excellence, financial strength, and social licence. A detailed discussion of these strategic imperatives is included in the 2016 annual MD&A in the section, *Core Business, Strategy, and Outlook*.

Operational Excellence

Operational excellence at OPG is accomplished by the safe and environmentally responsible generation of reliable and cost-effective electricity from the Company's generating assets through a highly trained and engaged workforce.

Electricity Generation Production and Reliability

- As part of the plan to extend Pickering operations, OPG is continuing to undertake the required technical work to confirm that the station's pressure tubes, a key life-limiting component of the station, will remain fit for service for operation to 2024. OPG is also nearing completion of component condition assessments to identify the work required to support the continued operation of the station. The accounting end of life assumptions for the Pickering GS, currently set at the end of 2020, will be reassessed based on the fuel channel analysis and safety case consistent with submissions for the CNSC approval, discussed below. The activities completed to date have had positive results, which will go towards re-confirming Pickering operations past 2020 are technically feasible. The Periodic Safety Review (PSR) is in progress and will confirm that extending operations of the Pickering units will be safe to the public, workers and the environment. The PSR consists of Safety Factor Reports (SFRs), a Global Assessment Report (GAR), and the Integration Improvement Plan (IIP). SFRs have been submitted to the CNSC and the GAR and IIP are on track for CNSC submission in October and November 2017, respectively. Other technical feasibility activities continue to progress as planned. Completion of various technical feasibility assessments are required to reach a high confidence conclusion to allow the station end of life to change for depreciation purposes. OPG's current application with the OEB for new base regulated prices, currently pending the OEB's decision, reflects OPG's plans to extend Pickering operations to 2024 and requests inclusion of the corresponding cost and generation impacts in the determination of the nuclear regulated price.
- OPG's current five-year operating licence for the Pickering GS was approved by the CNSC in 2013 and expires on August 31, 2018. This licence was issued assuming that the station would shut down in 2020. On June 28, 2017, OPG confirmed to the CNSC that it intends to cease commercial operation of all Pickering units on December 31, 2024. On August 28, 2017, OPG submitted a ten-year licence renewal application to the CNSC. The licence term spans the planned extended operations period, through to the end of commercial operation, defueling, dewatering and the start of placing the station in a safe storage state.
- Work continues on the rehabilitation of Unit 2 of the DeCew Falls hydroelectric GS and the rehabilitation and overhaul of Unit 2 of the Lower Notch hydroelectric GS.
- During the third quarter, a new control centre was opened at Saunders GS to merge its operations with Chenaux GS. The new control centre will overlook power production at ten hydroelectric stations along the Madawaska, Ottawa and St. Lawrence rivers.
- As part of the process to decommission the Nanticoke and Lambton generating stations, OPG has begun executing demolition plans that will ensure that the stations are closed safely, securely and in an environmentally responsible manner. The demolition of the Nanticoke coal yard equipment and structures is in progress, with a contract issued in July 2017 for the demolition of the Nanticoke powerhouse and associated structures. Project milestones for the Nanticoke site during the remainder of 2017 include completing the removal of coal yard equipment and structures, demolition of the ash silos, and mobilization of the contractor to prepare for removal of the stacks, powerhouse and associated structures. A competitive bidding process for the demolition of the Lambton GS has been completed, with a contract for the removal of the powerhouse and associated buildings expected to be awarded in 2018. An update of the associated asset retirement obligations related to the Nanticoke and Lambton sites is expected to be finalized in the fourth quarter of 2017.

Environmental Performance

There were no significant changes to environmental legislation affecting the Company during the third quarter of 2017. Disclosures related to the Company's environmental policy and environmental risks can be found in OPG's 2016 annual MD&A.

OPG communicates its environmental performance internally to employees and to external stakeholders, including the Ontario Ministry of the Environment and Climate Change, Environment and Climate Change Canada, the CNSC, and local communities. Details of OPG's environmental performance and initiatives to fulfill the Company's Environmental Policy can be found in OPG's 2016 Sustainability Report, available on the Company's website at www.opg.com. **[MONITOR]**

Project Excellence

OPG is pursuing a number of generation development and other major projects in support of Ontario's electricity planning initiatives. OPG remains focused on delivering projects safely, on time, on budget and with high quality. The status updates for OPG's major projects as at September 30, 2017 are outlined in the following table, with further details below.

Project	Capital expenditures		Approved budget	Expected in-service date	Current status
(millions of dollars)	**Year-to-date**	**Life-to-date**			
Darlington Refurbishment	924	4,109	12,800 [1]	First unit - 2020 Last unit - 2026	The setup of specialized tooling and equipment needed for the removal of reactor components was completed in the third quarter of 2017. All feeder tubes have been removed safely, and the pressure tubes have been severed in preparation for their removal. The Re-tube Waste Processing Building will be available for use in the fourth quarter of 2017. The project is tracking on schedule and on budget.
Peter Sutherland Sr. Hydroelectric GS	38	274	300	2017	The station was placed in-service on March 31, 2017, ahead of the originally planned schedule, and is expected to close below the approved budget. Project close-out activities are in progress.
Ranney Falls Hydroelectric GS	17	20	77	2019	Work is progressing on the expanded forebay, forebay wall concrete replacement, powerhouse and spillway areas. The project is tracking on schedule and on budget.
Nanticoke Solar Facility	1	2	107 **[MONITOR]**	2019	Project definition work is continuing, with construction planned to commence in the first quarter of 2018.
Deep Geologic Repository for low and intermediate level radioactive waste (L&ILW)	7 [2]	202 [2]			On August 21, 2017, the federal Minister of Environment and Climate Change requested further information on the project's environmental assessment (EA). OPG is reviewing the new request and will notify the Canadian Environmental Assessment Agency (CEAA) when it has a timeline for submission of that information.

[1] The total project budget of $12.8 billion is for the refurbishment of all four units at the Darlington GS.
[2] Expenditures are charged against the nuclear fixed asset removal and nuclear waste management liabilities (Nuclear Liabilities).

Commented [A5]: Does this imply that only 700M further is anticipated to be spent by the time Unit 2 gets completed? (Eg. 4.8B in Capital Expenditure)

Eg. from above:
"Once refurbished, Unit 2 is scheduled to be returned to service in the first quarter of 2020, at which time capital expenditures of approximately $4.8 billion are planned to be placed in service."

OPG – No, the LTD in the table includes prerequisite projects already declared in-service. The $4.8B was the OEB submitted estimate of a future in-service amount for Unit 2 refurbishment.

Please see updated wording below:

OPG's current application with the OEB for new regulated prices seeks an increase in the nuclear rate base, effective in the first quarter of 2020, to reflect the planned placement in service of the $4.8 billion in capital expenditures upon return to service of Unit 2, which includes expenditures incurred during the definition and planning phase of the project. Based on OPG's proposal in the application, the revenue requirement impact of the differences between the Unit 2 in-service amount included in the regulated prices and the actual amounts placed in service would be subject to true up via the Capacity Refurbishment Variance Account established by the OEB pursuant to *Ontario Regulation 53/05*. OPG's application proposes that the recovery of the HWSF's costs through regulated prices be subject to a separate prudence review by the OEB, to be conducted as part of a future OEB application.

Darlington Refurbishment

The Darlington generating units are approaching their originally designed end-of-life. Refurbishment of the four generating units is expected to extend the operating life of the station by approximately 30 years. OPG commenced the planning of the refurbishment in 2010.

In 2016, the Darlington Refurbishment project transitioned from the planning phase to the execution phase, as OPG commenced the refurbishment of the first unit, Unit 2, in October 2016, as planned. The unit was taken offline on October 15, 2016. De-fuelling of the reactor, the first critical refurbishment activity undertaken once the unit is removed from service, was completed safely in January 2017, with a total of 480 fuel channels de-fuelled. Islanding of Unit 2, the physical separation of the unit under refurbishment from the three operating units, was completed in April 2017, signifying the completion of the first major segment of the project.

The second major segment includes preparatory work to support the removal of feeder tubes and fuel channel assemblies and the removal of reactor components. The preparatory work was completed in the second quarter of 2017. The Re-tube Tooling Platform for hosting the tooling for the removal, inspection, and installation activities and the setup of specialized tooling and equipment needed for the removal and replacement of the reactor components were completed in the third quarter of 2017. The disassembly of reactor components commenced in August 2017, with the removal of all 960 feeder tubes completed safely in September 2017. This was followed by the severing of pressure tubes, with the severing of bellows and the removal of end fittings expected to commence thereafter and through the end of 2017. Other key project activities executed during the second segment include the completion of the primary side steam generator layup, installation of steam generator access ports to support future inspections, continuation of the major turbine generator overhaul and continued execution of the major electrical scope. OPG is also continuing to execute work to support the requirements set out in the CNSC approved IIP for the station.

Once refurbished, Unit 2 is scheduled to be returned to service in the first quarter of 2020, at which time capital expenditures of approximately $4.8 billion are planned to be placed in service. This includes expenditures incurred during the definition and planning phase of the overall project. The project is tracking on schedule and on budget.

With the substantial completion of the Re-tube Waste Processing Building in November 2017, 17 out of 18 pre-requisite projects in support of the execution phase of the project, including construction of facilities, infrastructure upgrades and installation of safety enhancements, have been completed and placed in service. Completion of the Heavy Water Storage and Drum Handling Facility (HWSF) has been delayed due to challenges with construction. OPG suspended the project in the second quarter of 2017 to evaluate the best approach to optimize cost and schedule and complete the project. Construction activities for the HWSF recommenced in the fourth quarter of 2017 following substantial completion of the Re-tube Waste Processing Building. This plan ensures that the necessary resources are available for both projects and, through resource levelling, improves their execution and cost efficiency. The delay in the completion of the HWSF will not impact the overall Darlington Refurbishment project schedule, as the HWSF is not on the project's critical path. This also will not impact the overall project budget of $12.8 billion, as the costs of the HWSF are included in this total figure. The recovery of HWSF costs through regulated prices will be subject to a prudence review by the OEB, which OPG has proposed be conducted as part of a future OEB application.

In addition to the execution of refurbishment activities on Unit 2, OPG is continuing planning activities for the refurbishment of the second unit, Unit 3, and is entering into associated commitments to procure major components that require long lead times. As of September 30, 2017, $70 million has been invested in planning activities related to the refurbishment of the second unit, Unit 3. These planning activities are being undertaken in accordance with the refurbishment project schedule.

The Financial Accountability Office of Ontario has issued a report titled "*An Assessment of the Financial Risks of the Nuclear Refurbishment Plan*". The report assesses both OPG and Bruce Power's refurbishment activities and the method in which those refurbishments and subsequent nuclear generation is provided to the marketplace. The report

concludes that the base case of refurbishing the six units at the Bruce nuclear GS and the four units at the Darlington nuclear GS provide the most cost effective, low emission generation source available to meet Ontario's baseload electricity requirements. This report re-affirms the positive economic and societal benefits associated with a strong nuclear program in the Province. **[MONITOR]**

Commented [A6]: Not yet released.

OPG – We put MONITOR to ensure status next Thursday before we release.

Ranney Falls Hydroelectric GS

During the third quarter of 2017, OPG continued construction work for a 10 MW single-unit powerhouse on the existing Ranney Falls GS site, as part of the Regulated – Hydroelectric segment. The new unit will replace an existing unit that reached its end of life in 2014. The existing forebay structure demolition has been completed and the upstream cofferdam has been constructed ahead of schedule. Construction continues on the expanded forebay, powerhouse and spillway. Excavation work is substantially complete and forebay wall concrete replacement is in progress. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget.

Nanticoke Solar Facility

The construction of a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands under a Large Renewable Procurement contract with the IESO, through Nanticoke Solar LP, a partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation, is planned to commence in the first quarter of 2018. During the third quarter of 2017, the partnership continued work to obtain approvals and permits required to enable the commencement of construction, and progressed procurement activities for equipment and for engineering and construction services. The facility is expected to be completed in the first quarter of 2019.

Deep Geologic Repository for Low and Intermediate Level Waste

OPG has proposed a deep geologic repository as the preferred solution for the safe long-term management of the L&ILW produced from the continued operation of OPG-owned nuclear generating stations. Agreement has been reached with local municipalities for OPG to develop the L&ILW Deep Geologic Repository (DGR) on lands adjacent to the Western Waste Management Facility (WWMF) in Kincardine, Ontario. The environmental effects of the proposed L&ILW DGR were examined by the CNSC and CEAA-appointed Joint Review Panel (JRP) to meet the requirements of the Canadian Environmental Assessment Act. The JRP submitted its report on the EA to the federal Minister of Environment in May 2015, concluding that, given mitigation, there is unlikely to be significant environmental impact from the project and recommending that the Minister approve the EA. In December 2016, at the request of the federal Minister of Environment and Climate Change, OPG submitted additional information on certain aspects of the EA, including information related to alternate locations for the project. Following its review of OPG's submission and a period of public comment, the CEAA requested further information that OPG subsequently provided in May 2017. In June 2017, the CEAA notified OPG that it had sufficient and adequate information to proceed with the next step of the environmental assessment process and advised that a draft report and updated terms and conditions will be prepared for public review.

On August 21, 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of potential cumulative effects of the project on the Saugeen Ojibway Nations' (SON) physical and cultural heritage, including a description of the potential effects of the project on the Nation's spiritual and cultural connection to the land. OPG is assessing the request and will notify the CEAA when it has determined the timeline for developing a response. The CEAA's draft report for public review will not be issued until this update is provided. The L&ILW DGR at the WWMF site remains OPG's preferred solution for the safe long-term management of the L&ILW.

OPG continues its engagement with the SON toward securing community support for the L&ILW DGR. The in-service date of the L&ILW DGR is expected to be approximately six to seven years from the start of construction.

Financial Strength

As a commercial enterprise, OPG's financial priority is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future growth.

Increase Revenue, Reduce Costs and Achieve Appropriate Return

In May 2016, OPG filed a 5-year application with the OEB for new regulated prices for production from its regulated hydroelectric and nuclear facilities, with a proposed effective date of January 1, 2017. Consistent with the requirements of *Ontario Regulation 53/05*, the application incorporates a rate smoothing proposal that would defer, for future collection, a portion of the approved annual nuclear revenue requirement for the period from January 1, 2017 to the end of the Darlington Refurbishment project, with a view to making changes in OPG's regulated prices more stable year-over-year. The application seeks to ensure that nuclear regulated prices under the rate smoothing approach allow for sufficient cash flow to meet the Company's liquidity needs, support cost effective funding for the Darlington Refurbishment project and other expenditures, and maintain the Company's investment grade credit rating, while taking into account both near-term and future impacts on customers. OPG expects to recognize amounts deferred under rate smoothing as income in the periods to which the underlying approved revenue requirements relate.

The application will further challenge and incentivize OPG to find additional cost reductions and efficiencies within its operations, as a result of greater de-coupling of nuclear and hydroelectric regulated prices from costs and a longer rate-setting period under the OEB's incentive ratemaking framework, which forms the basis for the ratemaking methodologies reflected in the application.

The application seeks an increase in the nuclear rate base, effective in early 2020, to reflect the planned placement in service of approximately $4.8 billion of capital expenditures upon the scheduled return to service of Unit 2 at the Darlington GS as part of the Darlington Refurbishment project and, effective in 2017, an increase in the deemed capital structure applied to the total regulated rate base to 49 percent equity and 51 percent debt, from 45 percent equity and 55 percent debt reflected in the existing regulated prices. The application also requests new rate riders, effective January 1, 2017, to recover or repay the December 31, 2015 balances in all of the Company's OEB-authorized variance and deferral accounts, with the exception of the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the portion of these balances previously approved for recovery or repayment through rate riders that were in effect during 2016.

The OEB's decision on the application, including the effective date of approved new regulated prices, is expected later in 2017. **[MONITOR]**

For generation assets that do not form part of the assets regulated by the OEB, OPG's strategy has been to secure appropriate long-term revenue arrangements. In line with this strategy, virtually all of OPG's non-regulated operating facilities and assets under construction are subject to long-term Energy Supply Agreements (ESAs) or other long-term contracts with the IESO.

Ensure Availability of Cost Effective Funding

In April 2017, DBRS Limited (DBRS) re-affirmed the long-term credit rating on OPG's debt at 'A (low)' and OPG's commercial paper rating at 'R-1 (low)'. All ratings from DBRS have a stable outlook. In July 2017, S&P Global Ratings (S&P) re-affirmed OPG's long-term credit rating at 'BBB+' with a stable outlook. S&P's commercial paper rating for OPG is 'A-1 (low)'.

Social Licence

As the largest electricity generator in Ontario with diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust. OPG is committed to maintaining high standards of public safety and corporate citizenship, including environmental stewardship, transparency, community engagement, and Indigenous relations.

OPG is focused on building long-term, mutually beneficial working relationships with Indigenous communities, businesses and organizations across Ontario, and continues to support procurement, employment and educational opportunities with its Indigenous community partners. The Company seeks to establish these relationships based on a foundation of respect for the languages, customs, and political, social and cultural organizations of the Indigenous communities.

In June 2017, OPG launched an Indigenous Business Engagement (IBE) Initiative. The purpose of this initiative is to increase access to procurement opportunities for Indigenous businesses interested in supplying materials and services to OPG. The IBE Initiative is based on a strategy that will identify opportunities in contracts, scopes of work and business plans for potential Indigenous business engagement; include criteria related to suppliers' ability to engage or partner with Indigenous people or businesses in assessing procurement proposals; and invest in relationships with Indigenous communities by increasing outreach efforts to enhance understanding of how to do business with OPG. OPG has continued to engage with various Indigenous business and communities as well as its suppliers to promote the IBE Initiative. In September 2017, OPG presented the IBE to the Mohawk Council of Akwesanse (Akwesanse). As a result, Akwesanse plans to create a database of businesses in the community that will participate in contracting and supply opportunities with OPG. In September 2017, OPG also hosted a similar presentation to the Williams Treaties First Nations, located proximate to the Pickering and Darlington Nuclear Generating Stations, at the quarterly meeting for these communities.

OPG is developing recruitment plans targeting Indigenous people. In October 2017, OPG participated in five Indigenous-specific career fairs to attract such talent. **[MONITOR]**

OPG has a transportation electrification strategy that will help position OPG as a leader in transportation electrification in Ontario. This strategy is intended to leverage OPG's clean electricity to support action on climate change, create growth opportunities for OPG, and enhance OPG's brand and social licence.

Commented [A7]: Sp. "Akwesasne" ?

OPG – fixed spelling to as follows:

In September 2017, OPG presented the IBE to the Mohawk Council of Akwesasne (Akwesasne). As a result, the Akwesasne plan to create a database of businesses in the community that will participate in contracting and supply opportunities with OPG.

Commented [A8]: Does this deal with OPG owned fleet and other vehicles, or in line with the infrastructure for EV vehicles.

Can further details be provided in particular on the point of 'creating growth opportunities for OPG'.

OPG – revised wording for this paragraph as follows:

OPG has a strategy to help position the Company as a leader in transportation electrification in the province. The strategy aims to leverage the Company's clean, reliable and cost-effective electricity to power transportation, capitalize on future commercial growth opportunities, and enhance the Company's social licence. OPG is pursuing initiatives to increase the use of electric vehicles within its operations, and is assessing vehicle grid integration and hydrogen applications for the transportation sector.

Outlook

The financial performance of OPG's regulated operations is driven, in large part, by the outcome of applications for regulated prices to the OEB. The existing base regulated prices were established by the OEB effective November 1, 2014 based on a forecast of costs and production for the regulated facilities for the 2014 to 2015 period. The future outcome of OPG's current application for new regulated prices, currently pending the OEB's decision, is expected to provide substantial price certainty for the regulated business for the 2017 to 2021 period.

In its application, OPG has requested January 1, 2017 as the effective date for the new regulated prices. In December 2016, the OEB issued an order declaring the existing base regulated prices interim, which preserves the OEB's ability to make the new regulated prices effective as early as January 1, 2017. Considering the timing of OPG's application and OPG's procedural adherence throughout the proceeding, the Company believes that the OEB could make the new regulated prices effective January 1, 2017. This would allow OPG to recover the difference between the approved new regulated prices and the existing regulated prices for the period between January 1, 2017 and the implementation date of the new prices based on the OEB's order. The OEB's decision on the application, including the effective date of the new regulated prices, is expected in the fourth quarter of 2017. **[MONITOR]** The continuation of existing regulated prices until the issuance of the OEB's decision is expected to continue to contribute to lower income, particularly from the Regulated – Nuclear Generation segment, and, excluding the gain on sale of the Company's head office premises and associated parking facility recorded in the second quarter of 2017, lower

ROE Excluding AOCI during 2017, compared to 2016. In large part, this is due to the year-over-year reduction in nuclear electricity generation resulting from the Unit 2 refurbishment outage at the Darlington GS, given that the existing nuclear regulated prices were determined in 2014 based on a higher production forecast that reflected the operation of all four units at the station. As such, the OEB's decision on the effective date of the new regulated prices, as well as the timing of the decision issuance, could have a significant impact on OPG's financial results during 2017.

Nuclear base regulated prices resulting from OPG's current application will be subject to a rate smoothing mechanism that defers collection of a portion of OEB-approved revenues to future periods. As expected, combined with the expiry of rate riders in effect to the end of 2016, a year-over-year reduction in nuclear generation due to the Unit 2 refurbishment outage at the Darlington GS and the continuation of existing regulated prices until such time as new prices are implemented by the OEB, this will result in lower cash flow from operating activities in 2017, compared to 2016. OPG expects to continue to have the necessary financial capacity and sufficient access to cost effective financing sources to continue to fund its capital requirements and other disbursements.

Lower nuclear generation due to the Darlington Refurbishment outages will continue, as planned, to negatively impact the Enterprise TGC metric for the duration of the refurbishment project. Variability in sustaining capital investment expenditures, including major sustaining projects for the hydroelectric operations, also will impact the Enterprise TGC in future periods.

Several OEB-authorized regulatory variance and deferral accounts currently in place contribute to reducing the relative variability of the Company's income and ROE Excluding AOCI. Among others, the regulatory accounts include those related to the revenue impact of variability in water flows and forgone production due to SBG conditions at the regulated hydroelectric stations. As there are no variance or deferral accounts in place related to the impact of generation performance of the nuclear stations on revenue from base regulated prices, the Regulated – Hydroelectric segment generally is expected to produce overall more predictable earnings. OPG continues to operate and maintain its nuclear facilities with a view to optimize their performance and availability, while focusing on improving the overall reliability and predictability of the fleet.

Electricity generated from most of OPG's non-regulated assets is subject to ESAs with the IESO. Based on these agreements, OPG expects the Contracted Generation Portfolio segment to continue to contribute a generally stable level of earnings and cash flow from operations going forward.

OPG's total forecast capital expenditures for the 2017 year are approximately $2.0 billion. This includes amounts for the Darlington Refurbishment project, hydroelectric and other development projects including the completion of the Peter Sutherland Sr. GS and the expansion of the Ranney Falls GS, and sustaining capital investments across the generating fleet. OPG's major projects are discussed in the section, *Project Excellence*.

In addition to the operating and financial performance of the electricity generation business, OPG's results are affected by the earnings on the Nuclear Segregated Funds, which are reported in the Regulated – Nuclear Waste Management segment. While the Nuclear Segregated Funds are managed to achieve, in the long term, the target rate of return based on the discount rate specified in the ONFA, the rates of return earned in a given period can be subject to various external factors including financial market conditions and, for the portion of the Used Fuel Segregated Fund guaranteed by the Province under the ONFA, changes in the Ontario consumer price index (CPI). In the near term, these factors can be volatile and cause fluctuations in the Company's income. This volatility is partially mitigated by the impact of the OEB-authorized Bruce Lease Net Revenues Variance Account and, as discussed below, the funded status of the two segregated funds.

As OPG does not have the right to withdraw surplus amounts from the Nuclear Segregated Funds, OPG limits the amount of Nuclear Segregated Funds assets reported on the balance sheet to the present value of such life cycle funding liability. This reduces the volatility of earnings on the Nuclear Segregated Funds reflected in net income when the funds are in a fully funded or overfunded position. As at September 30, 2017, the Decommissioning

Segregated Fund was overfunded by approximately 23 percent, and the Used Fuel Segregated Fund was marginally overfunded, by less than one percent, based on the 2017 ONFA Reference Plan. Variability in asset performance due to volatility inherent in financial markets and changes in Ontario CPI, or changes in funding liability estimates, may result in either or both funds becoming underfunded in the future.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

Regulated – Nuclear Generation Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue	**739**	885	**2,000**	2,631
Fuel expense	**81**	79	**217**	239
Gross margin	**658**	806	**1,783**	2,392
Operations, maintenance and administration	**511**	521	**1,693**	1,665
Depreciation and amortization	**116**	230	**333**	691
Property taxes	**7**	6	**20**	19
Income (loss) before other losses, interest, and income taxes	**24**	49	**(263)**	17
Other losses	**4**	2	**4**	-
Income (loss) before interest and income taxes	**20**	47	**(267)**	17

For the three and nine month periods ended September 30, 2017, the segment earnings decreased by $27 million and $284 million, respectively, compared to the same periods in 2016. The decrease in earnings was expected and primarily due to reduced revenue from the nuclear base regulated price of approximately $24 million and $230 million, respectively. The decrease was partially offset by an associated year-over-year decrease in fuel expense. The decrease in revenue during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, reflected lower electricity generation of 0.4 TWh and 4.0 TWh, respectively, primarily due to the ongoing Unit 2 refurbishment outage at the Darlington GS that began in October 2016, without a corresponding increase in the base regulated price. The existing nuclear base regulated price set by the OEB in 2014 continues to be in effect pending the OEB's decision on OPG's application for new regulated prices, proposed to be effective on January 1, 2017. The existing price does not reflect the lower generation as a result of the Darlington Refurbishment project, as it was set to allow the Company to recover its approved nuclear costs over a higher nuclear production volume, based on the 2014 and 2015 outage profile that did not include a refurbishment outage. The reduction in nuclear electricity generation for the three months ended September 30, 2017 was largely offset by the higher electricity generation from the Pickering GS.

OM&A expenses decreased by $10 million during the third quarter of 2017, compared to the same period in 2016, as a result of a higher materials and supplies obsolescence charge recognized in 2016. OM&A expenses increased by $28 million during the nine months ended September 30, 2017, compared to the same period in 2016, due to planned maintenance activities in 2017.

Depreciation and amortization expense, excluding amortization expense related to regulatory account balances, increased by $16 million and $30 million during the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016, primarily due to new assets in service.

The expiry of an OEB-authorized nuclear rate rider on December 31, 2016 contributed to the decrease in segment revenue for the three and nine month periods ended September 30, 2017, compared to the same periods in 2016. As rate riders allow for recovery of approved balances in OEB-authorized regulatory accounts, this decrease in revenue was largely offset by a decrease in amortization expense related to these balances. There was no rate rider

in effect during the nine months ended September 30, 2017, pending the outcome of OPG's current application to the OEB for new regulated prices.

The Unit Capability Factors for the Darlington and Pickering generating stations were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Unit Capability Factor *(%)* [1]				
Darlington GS	**96.2**	89.6	**82.1**	87.6
Pickering GS	**88.7**	77.3	**83.8**	73.8

[1] The nuclear Unit Capability Factor excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS was excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

The Unit Capability Factor at the Darlington GS increased in the third quarter of 2017, compared to the same quarter in 2016, primarily due to the lower number of planned outage days during the third quarter of 2017. The lower Unit Capability Factor at the Darlington GS for the nine months ended September 30, 2017, compared to the same period in 2016, reflected the higher number of planned outage days, largely driven by constraints related to the transition of the station toward refurbishment.

The increase in Unit Capability Factor at the Pickering GS for the three and nine month periods ended September 30, 2017 was primarily due to outage optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station compared to 2016.

Regulated – Nuclear Waste Management Segment

(millions of dollars) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Revenue	**33**	36	**90**	102
Operations, maintenance and administration	**35**	38	**96**	108
Accretion on nuclear fixed asset removal and nuclear waste management liabilities	**230**	228	**696**	684
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(196)**	(248)	**(579)**	(620)
(Loss) Income before interest and income taxes	**(36)**	18	**(123)**	(70)

The segment loss before interest and income taxes was $36 million and $123 million during the three and nine months ended September 30, 2017, respectively, a decrease in earnings of $54 million and $53 million compared to the same periods in 2016. The decline in earnings was primarily due to lower earnings from the Nuclear Segregated Funds, net of the impact of the impact of the Bruce Lease Net Revenues Variance Account, reflecting higher earnings from market returns on fund assets and the CPI-adjusted rate of return guaranteed by the Province for the portion of the Used Fuel Segregated Fund related to the initial 2.23 million used fuel bundles (committed return) in the third quarter of 2016.

As both the Decommissioning Segregated Fund and the Used Fuel Fund were in an overfunded position during the three and nine months period ended September 30, 2017, compared to the underlying funding liabilities per the approved ONFA Reference Plan, the earnings on the funds during these periods reflected the growth rate in the present value of the funding liabilities and were not impacted by market returns and committed return. The higher earnings on both funds during the three and nine months periods ended September 30, 2016 reflected market returns and committed return, as the Decommissioning Segregated Fund became over 120 percent funded during the third quarter of 2016 while the Used Fuel Fund was underfunded, compared to the corresponding funding liabilities.

Higher market returns and committed return in the third quarter of 2016 in relation to the funding liabilities' growth rate reflected in fund earnings during 2017 resulted in a year-over-year decrease in the amount of earnings on the Nuclear Segregated Funds.

As of December 31, 2016, OPG recorded a decrease of approximately $1,570 million to the Nuclear Liabilities and associated asset retirement costs capitalized as part of the carrying value of the nuclear generating stations. The resulting year-over-year decreases in accretion on fixed asset removal and nuclear waste management liabilities recorded in the Regulated – Nuclear Waste Management segment and depreciation and fuel expenses recorded in the Regulated – Nuclear Generation segment during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, were offset by the impact of the Bruce Lease Net Revenues Variance Account and the Nuclear Liability Deferral Account authorized by the OEB.

Under the current OEB-approved cost recovery methodology, these changes in expenses also are not expected to materially affect OPG's income during the rest of 2017, as they are expected to continue to be largely offset by the impact of the regulatory accounts until such time as the OEB implements corresponding changes to OPG's nuclear regulated prices, and subsequently by the impact of such new regulated prices. Further details on the change in the estimate of the Nuclear Liabilities as of December 31, 2016 are described in OPG's 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Asset Retirement Obligation*. **[MONITOR]**

Regulated – Hydroelectric Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue [1]	**327**	350	**1,069**	1,148
Fuel expense	**88**	88	**258**	259
Gross margin	**239**	262	**811**	889
Operations, maintenance and administration	**81**	87	**232**	238
Depreciation and amortization	**34**	56	**103**	169
Property tax	**1**	1	**1**	1
Income before other losses (gains), interest and income taxes	**123**	118	**475**	481
Other losses (gains)	**1**	1	**1**	(19)
Income before interest and income taxes	**122**	117	**474**	500

[1] During the three and nine month periods ended September 30, 2017, the Regulated – Hydroelectric segment revenue included incentive payments of $4 million and $9 million, respectively, related to the OEB-approved hydroelectric incentive mechanism (three and nine month periods ended September 30, 2016 – incentive payments of $6 million and $8 million, respectively). The mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers. The incentive payments are reduced to remove incentive revenues arising in connection with SBG conditions.

The increase in segment income before interest and income taxes of $5 million during the third quarter of 2017, compared to the same quarter in 2016, was primarily the result of a decrease in OM&A expenses, mainly due to the timing of repairs and maintenance work in 2017 and a deferral of outages during the high water period.

The decrease in segment income before interest and income taxes of $26 million during the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to a gain of $22 million recognized during the first quarter of 2016 to reflect the OEB's January 2016 decision to reverse a portion of an earlier capital cost disallowance related to the Niagara Tunnel project expenditures, in response to a motion by OPG. The income impact of OEB-approved variance accounts also contributed to the year-over-year decrease in income for the period. These factors were partially offset by the decrease in OM&A expenses related to the timing of repairs and maintenance work in 2017 and a deferral of outages during the high water period.

The decrease in revenue from the segment for the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was largely due to the expiry of an OEB-authorized rate rider on

December 31, 2016. As the rider allowed for the recovery of approved balances in OEB-authorized regulatory accounts, the resulting reduction in revenue was largely offset by lower amortization expense related to these balances. There was no rate rider in effect during the first nine months of 2017 pending the outcome of OPG's current application to the OEB for new regulated prices.

The Hydroelectric Availability for the stations included in the Regulated – Hydroelectric segment was as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Hydroelectric Availability *(%)*	**87.6**	84.1	**89.0**	89.8

The Hydroelectric Availability in the third quarter of 2017 was higher compared to the same period in 2016, primarily due to a higher number of planned outages in 2016 as a result of the refurbishment of the Sir Adam Beck Pump GS reservoir between April 2016 and February 2017. The marginal decrease in Hydroelectric Availability during the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to a higher number of unplanned outage days at the Northwestern Ontario and Niagara region hydroelectric stations, partially offset by higher availability from the Sir Adam Beck Pump GS.

Contracted Generation Portfolio Segment

(millions of dollars) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Revenue	**141**	149	**431**	431
Fuel expense	**15**	19	**42**	42
Gross margin	**126**	130	**389**	389
Operations, maintenance and administration	**39**	44	**118**	129
Depreciation and amortization	**20**	19	**59**	56
Accretion on fixed asset removal liabilities	**3**	2	**7**	6
Property taxes	**-**	1	**5**	6
Income from investments subject to significant influence	**(11)**	(11)	**(29)**	(28)
Income before other loss, interest and income taxes	**75**	75	**229**	220
Other loss	**-**	1	**-**	1
Income before interest and income taxes	**75**	74	**229**	219

Income before interest and income taxes from the segment increased by $1 million and $10 million during the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016. The increase in earnings for the three months ended September 30, 2017 mainly resulted from revenues from the Peter Sutherland Sr. GS that was placed in-service at the end of the first quarter of 2017 and lower OM&A expenses, partially offset by lower revenue from the Atikokan GS. The decrease in revenue from the Atikokan GS was primarily due to higher revenues in 2016, when the station was called upon to provide the needed support to the electricity system in Northwestern Ontario as a result of an outage at a local transformer station. For the nine months ended September 30, 2017, the increase in earnings was primarily due to lower OM&A expenses. The lower OM&A expenses for the three and nine month periods ended September 30, 2017 were mainly due to the prospective adoption of the full yield curve approach to the estimation of the service and interest cost components of pension and OPEB costs starting in 2017.

The Hydroelectric Availability and the Thermal Equivalent Forced Outage Rate (EFOR) for the Contracted Generation Portfolio segment were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Hydroelectric Availability *(%)*	**66.1**	68.2	**76.9**	79.6
Thermal EFOR *(%)*	**2.6**	2.1	**6.0**	1.3

Lower Hydroelectric Availability during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was primarily due to an increase in the number of planned outage days at the Lower Mattagami River hydroelectric generating stations.

The higher Thermal EFOR during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was primarily due to a higher number of unplanned outage days at a Lennox GS unit as a result of a transmission outage and a generator cooling water system outage in 2017.

Services, Trading, and Other Non-Generation Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue	**9**	15	**36**	52
Fuel expense	**1**	1	**1**	1
Gross margin	**8**	14	**35**	51
Operations, maintenance and administration	**1**	11	**2**	20
Depreciation and amortization	**8**	8	**22**	25
Accretion on fixed asset removal liabilities	**2**	2	**6**	6
Property taxes	**-**	4	**4**	9
(Loss) income before other gains, interest, and income taxes	**(3)**	(11)	**1**	(9)
Other gains	**(2)**	(3)	**(385)**	(5)
Income (loss) before interest and income taxes	**(1)**	(8)	**386**	(4)

Segment earnings improved by $7 million during the third quarter of 2017, compared to the same quarter in 2016. The improvement in earnings was primarily due to lower OM&A expenses reflecting project expenditures incurred in the third quarter of 2016, and OPG's decision, in the fourth quarter of 2016, to proceed with the decommissioning of Lambton GS.

Segment income before interest and income taxes increased by $390 million for the nine months ended September 30, 2017, compared to the same period in 2016. The increase in earnings mainly reflected the gain on the sale of OPG's head office premises and associated parking facility recorded during the second quarter of 2017.

LIQUIDITY AND CAPITAL RESOURCES

OPG's primary sources of liquidity and capital are funds generated from operations, bank financing, credit facilities provided by the Ontario Electricity Financial Corporation (OEFC), long-term corporate debt, and capital market financing. These sources are used for multiple purposes including: to invest in plants and technologies, to undertake major projects, to fund long-term obligations such as contributions to the pension fund and the Nuclear Segregated Funds, to make payments under the OPEB plans, to fund expenditures on Nuclear Liabilities not reimbursable from the Nuclear Segregated Funds, to service and repay long-term debt, to provide general working capital, and to fund OPG's investment in the Fair Hydro Plan.

Changes in cash and cash equivalents for the three and nine month periods ended September 30 are as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Cash and cash equivalents, beginning of period	**242**	295	**186**	464
Cash flow provided by operating activities	**485**	530	**698**	1,211
Cash flow used in investing activities	**(463)**	(390)	**(720)**	(1,253)
Cash flow provided by (used in) financing activities	**16**	(9)	**116**	4
Net increase (decrease)	**38**	131	**94**	(38)
Cash and cash equivalents, end of period	**280**	426	**280**	426

For a discussion of cash flow provided by operating activities and the FFO Adjusted Interest Coverage ratio, refer to the details in the section, *Highlights* under the heading, *Overview of Results*.

Investing Activities

Electricity generation is a capital-intensive business. It requires continued investment in plants and technologies to maintain and improve operating performance including asset reliability, safety and environmental performance, to increase the generating capacity of existing stations, and to invest in the development of new generating stations, emerging technologies and other business growth opportunities.

Cash flow used in investing activities during the third quarter of 2017 was $463 million, compared to $390 million for the same period in 2016. The increase in cash flow used for investing activities mainly resulted from higher expenditures on the Darlington Refurbishment project in the third quarter of 2017.

Cash flow used in investing activities decreased by $533 million for the nine months ended September 30, 2017, compared to the same period in 2016. The decrease in net cash flow used in investing activities was primarily due to the receipt of proceeds from the sale of OPG's head office premises and associated parking facility in the second quarter of 2017 pursuant to a Shareholder Declaration and Shareholder Resolution, and the acquisition of nine million common shares of Hydro One Limited (Hydro One) in the second quarter of 2016, partially offset by higher expenditures on the Darlington Refurbishment project in 2017. OPG acquired the Hydro One shares for investment purposes, to mitigate the risk of future price volatility related to the Company's future share delivery obligations under the collective agreements with the Power Workers' Union and The Society of Energy Professionals.

Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from the sale of head office premises and associated parking facility, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. OPG expects that the amount of designated proceeds to be transferred into the Consolidated Revenue Fund will be largely consistent with the after-tax gain on sale. The transfer is expected to take place later in 2017.

Financing Activities

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. In the second quarter of 2017, OPG renewed and extended the expiry date of both tranches from May 2021 to May 2022. There were no amounts outstanding under the bank credit facility as at September 30, 2017.

There was $160 million of commercial paper outstanding under OPG's commercial paper program as at September 30, 2017.

As at September 30, 2017, OPG also maintained $25 million of short-term, uncommitted overdraft facilities, and a further $463 million of short-term, uncommitted credit facilities, which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other general corporate purposes. As at September 30, 2017, a total of $388 million of Letters of Credit had been issued under these facilities. This included $349 million for the supplementary pension plans, $38 million for general corporate purposes, and $1 million related to the operation of the PEC.

The Company has an agreement to sell an undivided co-ownership interest in its current and future accounts receivable to an independent trust, expiring on November 30, 2018. The maximum amount of co-ownership interest that can be sold under this agreement is $150 million. As at September 30, 2017, no borrowings were issued under this agreement and there were Letters of Credit outstanding under this agreement of $150 million, which were issued in support of OPG's supplementary pension plans.

As at September 30, 2017, Lower Mattagami Energy Limited Partnership (LME) maintained a $400 million bank credit facility to support the funding requirements for the Lower Mattagami River project including support for LME's commercial paper program and the issuance of the Letters of Credit. The facility consists of a $300 million tranche which, in the third quarter of 2017, was extended to mature in August 2022 and a $100 million tranche which, in the third quarter of 2017, was reduced from $200 million and extended to mature in August 2018. As at September 30, 2017, there was no external commercial paper outstanding under LME's commercial paper program. A letter of credit of $55 million was issued in July 2017 and remains outstanding as at September 30, 2017 under the $300 million tranche of the credit facility.

In June 2016, OPG entered into a $700 million general corporate credit facility agreement with the OEFC, which expires on December 31, 2017. In the third quarter of 2017, the agreement was amended to increase the credit facility to $2,350 million and to extend its expiry date to December 31, 2018.

In February 2017, OPG issued senior notes payable to the OEFC totalling $200 million and maturing in February 2047. The effective interest rate and coupon interest rate of these notes was 4.12 percent. In June 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in June 2047. The effective interest rate and coupon interest rate of these notes was 3.65 percent. In August 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in August 2047. The effective interest rate and coupon interest rate of these notes was 3.86 percent. In September 2017, OPG issued senior notes payable to the OEFC totalling $400 million and maturing in September 2047. The effective interest rate and coupon interest rate of these notes was 4.07 percent. As at September 30, 2017, there were outstanding long-term borrowings of $800 million under this credit facility.

In October 2017, OPG issued $500 million of senior notes payable under a Medium Term Note Program. The notes bear a coupon interest rate of 3.32 percent and an effective rate of 3.43 percent, payable semi-annually until maturity on October 4, 2027. The offering was made under OPG's $2 billion short form base shelf prospectus dated September 12, 2017. The net proceeds will be used for general corporate purposes, including the financing of OPG's subordinated debt investment in the Fair Hydro Plan.

As at September 30, 2017, OPG's long-term debt outstanding was $5,482 million, including $628 million due within one year.

OPG continues to evaluate arrangements that would appropriately support the Company's financing needs and capital expenditure programs.

Contractual and Commercial Commitments

Pension Plan Actuarial Valuation

A new actuarial valuation of the OPG registered pension plan was filed with the Financial Services Commission of Ontario in September 2017 with an effective date of January 1, 2017. The annual funding requirements in accordance with the new actuarial valuation are $212 million for 2017, $215 million for 2018, and $219 million for 2019. The next actuarial valuation must have an effective date no later than January 1, 2020.

BALANCE SHEET HIGHLIGHTS

The following section provides highlights of OPG's unaudited interim consolidated financial position using selected balance sheet data:

(millions of dollars) (unaudited)	As At September 30 2017	As At December 31 2016
Property, plant and equipment - net	**20,801**	19,998
The increase was primarily due to capital expenditures on the Darlington Refurbishment project, partially offset by depreciation expense.		
Nuclear fixed asset removal and nuclear waste management funds *(current and non-current portions)*	**16,534**	15,984
The increase was primarily due to earnings on the Nuclear Segregated Funds, partially offset by reimbursements of eligible expenditures on nuclear fixed asset removal and nuclear waste management activities.		
Short-term debt	**160**	2
The increase was due to commercial paper issued under OPG's commercial paper program during the third quarter of 2017.		
Fixed asset removal and nuclear waste management liabilities	**20,075**	19,484
The increase was primarily a result of accretion expense representing the increase in the liabilities due to the passage of time, partially offset by expenditures on nuclear fixed asset removal and waste management activities.		

Off-Balance Sheet Arrangements

In the normal course of operations, OPG engages in a variety of transactions that, under US GAAP, are either not recorded in the Company's interim consolidated financial statements or are recorded in the Company's interim consolidated financial statements using amounts that differ from the full contract amounts. Principal off-balance sheet activities for OPG include guarantees and long-term contracts.

CHANGES IN ACCOUNTING POLICIES AND ESTIMATES

OPG's significant accounting policies are outlined in Note 3 to the audited consolidated financial statements as at and for the year ended December 31, 2016. A discussion of recent accounting pronouncements and change in accounting estimate are included in Note 2 to OPG's unaudited interim consolidated financial statements as at and for the three and nine month periods ended September 30, 2017 under the heading, *Significant Accounting Policies and Estimates*. Disclosure regarding OPG's critical accounting policies is included in OPG's 2016 annual MD&A.

RISK MANAGEMENT

The following provides an update to the discussion of the Company's risks and risk management activities included in OPG's 2016 annual MD&A. As such, the disclosure in this section should be read in conjunction with the *Risk Management* section included in the annual MD&A.

Risks to Achieving Project Excellence

Deep Geologic Repository for Low and Intermediate Level Waste

In August 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of the potential cumulative effects of the DGR project on the physical and cultural heritage of the SON, taking into account the results of the SON Community Process. OPG continues to work with the SON, however the timing and outcome of the SON Community Process and the EA decision by the Minister are uncertain.

Risks to Maintaining Financial Strength

Commodity Markets

Changes in the market price of fuels used to produce electricity can adversely impact OPG's earnings and cash flow from operations.

To manage the risk of unpredictable increases in the price of fuels, the Company has fuel hedging programs, which include fixed price and indexed contracts.

The percentages hedged of OPG's fuel requirements are shown in the following table. These amounts are based on yearly forecasts of generation and supply mix, and as such, are subject to change as these forecasts are updated.

	2017 [1]	2018	2019
Estimated fuel requirements hedged [2]	73%	73%	69%

[1] Based on actual fuel requirements hedged for the nine months ended September 30, 2017 and forecast for the remainder of the year.

[2] Represents the approximate portion of megawatt-hours of expected generation production (and year-end inventory targets) from each type of OPG-operated facility (nuclear, hydroelectric and thermal) for which the Company has entered into contractual arrangements or obligations in order to secure the price of fuel, or which is subject to regulation. In the case of hydroelectric generation, this represents the gross revenue charge and water rental charges. Excess fuel inventories (nuclear and thermal) in a given year are attributed to the next year for the purpose of measuring hedge ratios.

Foreign Exchange

OPG's earnings and cash flow can be affected by movements in the United States dollar (USD) relative to the Canadian dollar.

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are denominated in, or tied to, USD. To manage this risk, OPG periodically employs various financial instruments such as forwards and other

derivative contracts, in accordance with approved risk management policies. As at September 30, 2017, OPG had no foreign exchange contracts outstanding.

Trading

OPG's financial performance can be affected by its trading activities.

OPG's electricity trading operations are closely monitored, with total exposures measured and reported to senior management on a daily basis. The main metric used to measure the financial risk of trading activity is Value at Risk (VaR). VaR is defined as a probabilistic maximum potential future loss expressed in monetary terms for a portfolio based on normal market conditions over a set period of time. For the third quarter of 2017, the VaR utilization ranged between $0.2 million and $0.3 million.

Credit

Deterioration in energy markets counterparty credit and non-performance by suppliers and contractors can adversely impact OPG's earnings and cash flow from operations.

OPG manages its exposure to suppliers or counterparties by evaluating their financial condition and negotiating appropriate collateral or other forms of security. OPG's credit exposure relating to energy markets transactions as at September 30, 2017 was $356 million, including $346 million with the IESO. Management considers the Company's risk exposure relating to electricity sales through the IESO-administered spot market to be low as the IESO oversees the credit worthiness of all market participants. In accordance with the IESO's prudential support requirements, market participants are required to provide collateral to cover funds that they might owe to the market. Of the $10 million remaining exposure as at September 30, 2017, over 95 percent was related to investment grade counterparties.

Fair Hydro Plan

OPG's role in connection with the Fair Hydro Plan could have reputational impacts on the Company.

The *Ontario Fair Hydro Plan Act, 2017* received Royal Assent on June 1, 2017 and its attendant regulations came into force in June, July, and October 2017. **[UPDATE]** The regulations clarify aspects of the structure and program logistics required for OPG, as the Financial Services Manager of the Fair Hydro Plan, to refinance a portion of the Global Adjustment through the Trust. OPG's reputation could potentially be adversely impacted through its involvement with the Fair Hydro Plan and through stakeholder opinions related to this involvement.

Recovery of Pension and OPEB Costs

On September 14, 2017, the OEB issued its final report on the guiding principles and the policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the electricity and natural gas sectors. The report reaffirmed the conclusions of the initial report issued in May 2017, including the establishment of the accrual basis of accounting as the default rate-setting method and the establishment of a variance account to record asymmetric carrying charges in favour of ratepayers on the differences between the accrual costs recovered and cash payments made by a utility for pension and OPEB plans. The report requires OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the Pension & OPEB Cash Versus Accrual Differential Deferral Account that has been in effect since November 1, 2014, until such time as the OEB approves the resumption of the accrual basis of recovery. The future recovery of amounts recorded in the account will be subject to this approval. The report confirmed that OPG would become subject to the carrying charges on the differences between accrual costs and cash payments going back to November 1, 2014, with the charges calculated on the portion of such differences that have been recovered through regulated prices. The carrying charges will be determined at prescribed interest rate set quarterly by the OEB based on the quarterly return of a mid-term corporate bond index yield. This outcome has reduced OPG's risk related to the recovery of actual pension and OPEB accrual costs and the recovery of the balance in the Pension & OPEB Cash Versus Accrual Differential Deferral Account.

The account had a balance of $552 million as at September 30, 2017 and is recognized on the Company's consolidated balance sheet as a regulatory asset. OPG's financial results for the three and nine month periods ended September 30, 2017 were not impacted by the issuance of the OEB's report.

RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One, the IESO and the OEFC. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions are summarized below:

	Three Months Ended September 30			
	2017		2016	
(millions of dollars) (unaudited)	**Revenue**	**Expense**	**Revenue**	**Expense**
Hydro One				
Electricity sales	**2**	**-**	1	-
Services	**-**	**3**	-	3
Dividends	**2**	**-**	-	2
Province of Ontario				
Decommissioning Fund excess funding [1]	**-**	**(44)**	-	201
Used Fuel Fund rate of return guarantee and excess funding [1]	**-**	**(39)**	-	295
Gross revenue charges	**-**	**27**	-	28
ONFA guarantee fee	**-**	**2**	-	2
Other	**-**	**2**	-	-
OEFC				
Gross revenue charges	**-**	**62**	-	57
Interest expense on long-term notes	**-**	**40**	-	42
Income taxes, net of investment tax credits	**-**	**23**	-	28
IESO				
Electricity related revenue	**1,126**	**4**	1,293	7
	1,130	**80**	1,294	665

(millions of dollars) (unaudited)	Nine Months Ended September 30 2017 Revenue	2017 Expense	2016 Revenue	2016 Expense
Hydro One				
Electricity sales	**7**	**-**	4	-
Services	**1**	**8**	1	12
Dividends	**6**	**-**	-	4
Province of Ontario				
Decommissioning Fund excess funding [1]	**-**	**164**	-	137
Used Fuel Fund rate of return guarantee and excess funding [1]	**-**	**217**	-	190
Gross revenue charges	**-**	**84**	-	91
ONFA guarantee fee	**-**	**6**	-	6
Other	**-**	**3**	-	-
OEFC				
Gross revenue charges	**-**	**156**	-	147
Interest expense on long-term notes	**-**	**122**	-	127
Income taxes, net of investment tax credits	**-**	**132**	-	112
IESO				
Electricity related revenue	**3,228**	**11**	3,894	22
	3,242	**903**	3,899	848

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at September 30, 2017 and December 31, 2016, the Nuclear Segregated Funds were reported net of amounts due to the Province of $3,796 million and $3,415 million, respectively. The details of accounting for the Nuclear Segregated Funds are described in OPG's 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

The receivable, available-for-sale securities, payable and long-term debt balances between OPG and its related parties are summarized below:

(millions of dollars) (unaudited)	September 30 2017	December 31 2016
Receivables from related parties		
Hydro One	**1**	1
IESO	**346**	421
OEFC	**3**	1
PEC	**2**	4
Province of Ontario	**5**	2
Available-for-sale securities		
Hydro One shares	**190**	212
Accounts payable and accrued charges		
OEFC	**37**	61
Province of Ontario	**6**	2
IESO	**2**	2
Long-term debt (including current portion)		
Notes payable to OEFC	**3,245**	3,295

OPG holds interest-bearing Province of Ontario bonds in the Nuclear Segregated Funds and the OPG registered pension fund. As at September 30, 2017, the Nuclear Segregated Funds held $1,498 million of interest-bearing Province of Ontario bonds, while the registered pension fund had no such holdings. As at December 31, 2016, the Nuclear Segregated Funds and the registered pension fund held $1,652 million and $284 million of interest-bearing Province of Ontario bonds, respectively. These bonds are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

There have been no related party transactions related to the Fair Hydro Plan and associated financing activities. The first transaction between the Trust and the IESO is expected later in 2017.

INTERNAL CONTROLS OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

The Company maintains a comprehensive system of policies, procedures, and processes that represents its framework for internal controls over financial reporting and for its disclosure controls and procedures (together, ICOFR). There were no changes in the Company's internal control system during the current interim period that has or is reasonably likely to have a material impact to the ICOFR.

QUARTERLY FINANCIAL HIGHLIGHTS

The following tables set out selected financial information from OPG's unaudited interim consolidated financial statements for each of the eight most recently completed quarters.

(millions of dollars - except where noted) (unaudited)	**September 30 2017**	**June 30 2017**	**March 31 2017**	**December 31 2016**
Revenue	**1,217**	1,146	1,176	1,388
Net income (loss)	**140**	307	68	(8)
Less: Net income attributable to non-controlling interest	**9**	4	4	5
Net income (loss) attributable to the Shareholder	**131**	303	64	(13)
Per common share, attributable to the Shareholder *(dollars)*	**$0.51**	$1.18	$0.25	($0.05)

(millions of dollars - except where noted) (unaudited)	**September 30 2016**	**June 30 2016**	**March 31 2016**	**December 31 2015**
Revenue	1,400	1,387	1,478	1,312
Net income (loss)	198	135	128	(100)
Less: Net income attribute to the non-controlling interest	4	3	5	1
Net income (loss) attributable to the Shareholder	194	132	123	(101)
Per common share, attributable to the Shareholder *(dollars)*	$0.76	$0.51	$0.48	($0.39)

Trends

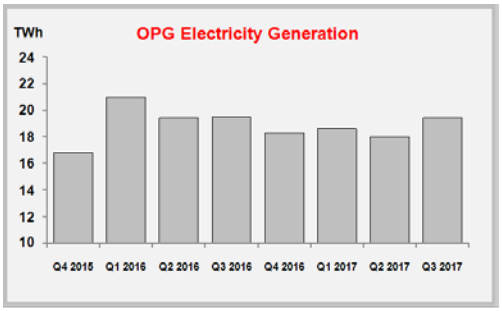
OPG's quarterly results are affected by changes in grid-supplied electricity demand, primarily resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. Weather conditions affect water flows, electricity demand, and prevalence of SBG conditions. Historically, OPG's revenues have been higher in the first

quarter of a fiscal year as a result of winter heating demands and in the third quarter due to air conditioning and cooling demands. The financial impact of forgone production due to SBG conditions at the regulated hydroelectric stations and the financial impact of differences between forecast water flows reflected in OEB-approved regulated prices and the actual water flows are mitigated by regulatory variance accounts authorized by the OEB.

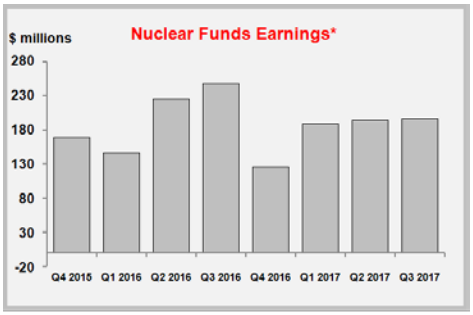
The timing of planned outages at a nuclear generating station during the year can cause variability in year-over-year operating results for partial periods of a fiscal year, including the impact on revenue and OM&A expenses, but is not a significant driver of variability for full fiscal year results.

OPG's electricity generation was reduced as a result of the Unit 2 refurbishment outage at the Darlington GS, which began in October 2016 and is expected to continue until early 2020.

OPG's financial results are also affected by the earnings on the Nuclear Segregated Funds, net of the impact of the Bruce Lease Net Revenues Variance Account.



Additional items that affected net income in certain quarters above are described in OPG's 2016 annual MD&A under



*net of regulatory variance account

the section, *Quarterly Financial Highlights*.

SUPPLEMENTARY NON-GAAP FINANCIAL MEASURES

In addition to providing net income and other financial information in accordance with US GAAP, certain non-GAAP financial measures are also presented in OPG's MD&A. These non-GAAP measures do not have any standardized meaning prescribed by US GAAP and, therefore, may not be comparable to similar measures presented by other issuers. OPG utilizes these measures to make operating decisions and assess performance. Readers of the MD&A would utilize these measures in assessing the Company's financial performance from ongoing operations. The Company believes that these indicators are important since they provide additional information about OPG's performance, facilitate comparison of results over different periods, and present measures consistent with the Company's strategies to provide value to the Shareholder, improve cost performance, and ensure availability of cost effective funding. These non-GAAP financial measures have not been presented as an alternative to net income, cash flow provided by operating activities, or any other measure in accordance with US GAAP, but as indicators of operating performance.

The definitions of the non-GAAP financial measures are as follows:

(1) **ROE Excluding AOCI** is defined as net income attributable to the Shareholder divided by average equity attributable to the Shareholder excluding AOCI, for the period. ROE Excluding AOCI is measured over a 12-month period and is calculated as follows:

	Twelve Months Ended	
(millions of dollars – except where noted) (unaudited)	**September 30 2017**	**December 31 2016**
ROE Excluding AOCI		
Net income attributable to the Shareholder	**485**	436
Divided by: Average equity attributable to the Shareholder, excluding AOCI	**11,055**	10,442
ROE Excluding AOCI *(percent)*	**4.4**	4.2

(2) **FFO Adjusted Interest Coverage** is defined as FFO before interest divided by adjusted interest expense. FFO before interest is defined as cash flow provided by operating activities adjusted for interest paid, interest capitalized to fixed and intangible assets, and changes to non-cash working capital balances for the period. Adjusted interest expense is calculated as net interest expense plus interest income, interest capitalized to fixed and intangible assets, interest related to regulatory assets and liabilities, and the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets, for the period.

FFO Adjusted Interest Coverage is measured over a 12-month period and is calculated as follows:

	Twelve Months Ended	
(millions of dollars – except where noted) (unaudited)	**September 30 2017**	**December 31 2016**
FFO before interest		
Cash flow provided by operating activities	**1,082**	1,595
Add: Interest paid	**270**	269
Less: Interest capitalized to fixed and intangible assets	**(161)**	(141)
Less: Changes to non-cash working capital balances	**38**	42
FFO before interest	**1,229**	1,765
Adjusted interest expense		
Net interest expense	**84**	120
Add: Interest income	**8**	7
Add: Interest capitalized to fixed and intangible assets	**161**	141
Add: Interest related to regulatory assets and liabilities	**43**	30
Add: Excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets [1]	**-**	45
Adjusted interest expense	**296**	343
FFO Adjusted Interest Coverage *(times)*	**4.2**	5.1

[1] A value of nil is used in the calculation when interest on pension and OPEB projected benefit obligations is equal to, or lower than, expected return on pension plan assets.

(3) **Enterprise Total Generating Cost per MWh** is used to measure OPG's overall organizational cost performance. Enterprise TGC per MWh is defined as OM&A expenses (excluding the Darlington Refurbishment project and other generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to OPG's electricity generation business), fuel expense for OPG-operated stations including hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures (excluding the Darlington Refurbishment project and other generation development projects) incurred during the period, divided by total electricity generation from OPG-operated generating stations plus electricity generation forgone due to SBG conditions during the period.

(millions of dollars – except where noted) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Enterprise TGC				
Total OM&A expenses	**635**	666	**2,054**	2,061
Total fuel expense	**185**	187	**518**	541
Total capital expenditures	**476**	444	**1,335**	1,162
Less: Darlington Refurbishment capital and OM&A costs	**(328)**	(269)	**(943)**	(717)
Less: Other generation development project capital and OM&A costs	**(17)**	(42)	**(53)**	(121)
Add (Less): OM&A and fuel expenses (refundable through) deferred in regulatory variance and deferral accounts	**4**	35	**(19)**	76
Less: Nuclear fuel expense for non OPG-operated stations	**(13)**	(18)	**(42)**	(50)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**13**	5	**47**	38
Less: OM&A expenses ancillary to electricity generation business	**(4)**	(5)	**(13)**	(17)
Other adjustments	**(3)**	(12)	**(7)**	(15)
	948	991	**2,877**	2,958
Adjusted electricity generation *(TWh)*				
Total OPG electricity generation	**19.4**	19.5	**56.0**	59.9
Adjust for electricity generation forgone due to SBG conditions and OPG's share of electricity generation from co-owned facilities	**0.9**	0.1	**4.2**	3.4
	20.3	19.6	**60.2**	63.3
Enterprise TGC per MWh *($/MWh)* [1]	**46.65**	50.72	**47.77**	46.74

[1] Amounts may not calculate due to rounding.

(4) **Nuclear Total Generating Cost per MWh** is used to measure the cost performance of OPG's nuclear generating assets. Nuclear TGC per MWh is defined as OM&A expenses of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the nuclear electricity generation business), nuclear fuel expense for OPG-operated stations (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs) incurred during the period, divided by nuclear electricity generation for the period.

(millions of dollars – except where noted) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Nuclear TGC				
Regulated – Nuclear Generation OM&A expenses	**511**	521	**1,693**	1,665
Regulated – Nuclear Generation fuel expense	**81**	79	**217**	239
Regulated – Nuclear Generation capital expenditures	**409**	339	**1,150**	896
Less: Darlington Refurbishment capital and OM&A costs	**(328)**	(269)	**(943)**	(717)
Add: Regulated – Nuclear Generation OM&A and fuel expenses deferred in regulatory variance and deferral accounts	**5**	31	**6**	84
Less: Nuclear fuel expense for non OPG-operated stations	**(13)**	(18)	**(42)**	(50)
Less: Regulated - Nuclear Generation OM&A expenses ancillary to nuclear electricity generation business	**(1)**	(1)	**(3)**	(4)
Other adjustments	**1**	3	**(1)**	(1)
	665	685	**2,077**	2,112
Nuclear electricity generation (TWh)	**11.3**	11.7	**30.6**	34.6
Nuclear TGC per MWh (*$/MWh*) [1]	**58.75**	58.55	**67.87**	61.07

[1] Amounts may not calculate due to rounding.

(5) **Hydroelectric Total Generating Cost per MWh** is used to measure the cost performance of OPG's hydroelectric generating assets. Hydroelectric TGC per MWh is defined as OM&A expenses of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the hydroelectric electricity generation business), hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding expenditures related to the Peter Sutherland Sr. GS, Ranney Falls GS, and other hydroelectric generation development projects) incurred during the period, divided by total hydroelectric electricity generation plus hydroelectric electricity generation forgone due to SBG conditions during the period. OPG reports hydroelectric gross revenue charge and water rental payments as fuel expense.

(millions of dollars – except where noted) (unaudited)	**Three Months Ended September 30**		**Nine Months Ended September 30**	
	2017	**2016**	**2017**	**2016**
Hydroelectric TGC				
Regulated – Hydroelectric OM&A expenses	**81**	87	**232**	238
Regulated – Hydroelectric fuel expense	**88**	88	**258**	259
Contracted Generation Portfolio OM&A expenses	**39**	44	**118**	129
Contracted Generation Portfolio fuel expense	**15**	19	**42**	42
Regulated – Hydroelectric and Contracted Generation Portfolio capital expenditures	**56**	92	**141**	231
Less: Regulated – Hydroelectric and Contracted Generation Portfolio generation development project capital and OM&A costs	**(17)**	(41)	**(52)**	(117)
Less: Thermal OM&A and fuel expenses and capital expenditures in the Contracted Generation Portfolio	**(39)**	(51)	**(119)**	(126)
(Less) Add: Regulated – Hydroelectric OM&A and fuel expenses refundable through regulatory variance and deferral accounts	**(1)**	4	**(25)**	(8)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**13**	5	**47**	38
Other adjustments	**(1)**	(1)	**-**	(1)
	234	246	**642**	685
Adjusted hydroelectric electricity generation *(TWh)*				
Regulated – Hydroelectric electricity generation	**7.3**	6.9	**23.5**	22.8
Contracted Generation Portfolio electricity generation	**0.8**	0.9	**1.9**	2.5
Adjust for hydroelectric electricity generation forgone due to SBG conditions and non-hydroelectric electricity generation of the Contracted Generation Portfolio, including OPG's share of electricity generation from co-owned facilities	**0.8**	0.1	**4.1**	3.4
	8.9	7.9	**29.5**	28.7
Hydroelectric TGC per MWh *($/MWh)* [1]	**26.20**	31.01	**21.74**	23.99

[1] Amounts may not calculate due to rounding.

(6) **Gross margin** is defined as revenue less fuel expense.

For further information, please contact: Investor Relations 416-592-6700

webmaster@opg.com

Media Relations 416-592-4008

1-877-592-4008

www.opg.com
www.sedar.com

From: Ronald Kwan
To: "HO Philip -FIN & C CTRL"; John Kim
Cc: MAK Ricky -FIN & C CTRL; DYKXHOORN Sandra -STAKEREL; GORE Michael -FIN & C CTRL
Subject: RE: EXTERNAL – RE: OPG Q3 2017 Submission to Province
Date: Wednesday, November 08, 2017 5:28:59 PM

Thanks Philip, John.

Ron

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To: John Kim <John.Kim@ofina.on.ca>
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Date:	Wednesday, November 08, 2017 2:03:40 PM
Attachments:	Q3 2017 OPG MDA - DRAFT - PROVINCE MAILING_EFB_CommentsV4_addressed by OPG_Markup2.docx

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ONTARIO POWER GENERATION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

2017 THIRD QUARTER REPORT

[DRAFT]

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ONTARIO POWER GENERATION

ONTARIO POWER GENERATION INC.
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This Management's Discussion and Analysis (MD&A) should be read in conjunction with the unaudited interim consolidated financial statements and accompanying notes of Ontario Power Generation Inc. (OPG or Company) as at and for the three and nine months ended September 30, 2017. OPG's unaudited interim consolidated financial statements are prepared in accordance with United States generally accepted accounting principles (US GAAP) and are presented in Canadian dollars.

For a complete description of OPG's corporate strategies, risk management, corporate governance, and the effect of critical accounting policies and estimates on OPG's results of operations and financial condition, this MD&A should also be read in conjunction with OPG's audited consolidated financial statements, accompanying notes, the Annual Information Form, and the MD&A as at and for the year ended December 31, 2016.

As required by *Ontario Regulation 395/11*, as amended, a regulation under the *Financial Administration Act* (Ontario), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. In 2014, the Ontario Securities Commission approved an exemption which allows OPG to apply US GAAP up to January 1, 2019. The term of the exemption is subject to certain conditions, which may result in the expiry of the exemption prior to January 1, 2019. For details, refer to the section, *Critical Accounting Policies and Estimates* under the heading, *Exemptive Relief for Reporting under US GAAP,* in OPG's 2016 annual MD&A. This MD&A is dated November 9, 2017.

FORWARD-LOOKING STATEMENTS

The MD&A contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could", and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

All forward-looking statements involve inherent assumptions, risks, and uncertainties, including those set out in the section, *Risk Management,* and forecasts discussed in the section, *Core Business, Strategy, and Outlook.* All forward-looking statements could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's generating station performance and availability, fuel costs, surplus baseload generation (SBG), cost of fixed asset removal and nuclear waste management, performance and earnings of investment funds, refurbishment of existing facilities, development and construction of new facilities, pension and other post-employment benefit (OPEB) obligations and funds, income taxes, proposed new legislation, the ongoing evolution of Ontario's electricity industry, environmental and other regulatory requirements, health, safety and environmental developments, business continuity events, the weather, financing and liquidity, applications to the Ontario Energy Board (OEB) for regulatory prices, the impact of regulatory decisions by the OEB, and forecasts of earnings, cash flows, Funds from Operations (FFO) Adjusted Interest Coverage, Return on Common Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI), Total Generating Cost (TGC) and capital expenditures. Accordingly, undue reliance should not be placed on any forward-looking statement. The forward-looking statements included in this MD&A are made only as of the date of this MD&A. Except as required by applicable securities laws, OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events, or otherwise.

THE COMPANY

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG was established under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (Province or Shareholder).

As at September 30, 2017, OPG's electricity generation portfolio had an in-service capacity of 16,210 megawatts (MW). OPG operates two nuclear generating stations, 66 hydroelectric generating stations, three thermal generating stations, and one wind power turbine. In addition, OPG and TransCanada Energy Ltd. co-own the 550 MW Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS). OPG and ATCO Power Canada Ltd. co-own the 560 MW Brighton Beach gas-fired combined cycle GS (Brighton Beach). OPG's 50 percent share of the in-service capacity and generation volume of these co-owned facilities is included in the generation portfolio statistics set out in this report. The income from the co-owned facilities is accounted for using the equity method of accounting, and OPG's share of income is presented as income from investments subject to significant influence in the Contracted Generation Portfolio segment.

OPG also owns two other nuclear generating stations, the Bruce A GS and the Bruce B GS, which are leased on a long-term basis to Bruce Power LP (Bruce Power). Income from these leased stations is included in revenue under the Regulated – Nuclear Generation segment. The leased stations are not included in the generation portfolio statistics set out in this report.

All of OPG's owned and co-owned generating facilities are located in Ontario. OPG does not operate PEC, Brighton Beach, the Bruce A GS and the Bruce B GS.

A description of OPG's segments is provided in OPG's 2016 annual MD&A in the section, *Business Segments*.

In-Service Generating Capacity

OPG's in-service generating capacity by business segment as at September 30, 2017 and December 31, 2016 was as follows:

	As at	
(MW)	**September 30 2017**	**December 31 2016**
Regulated – Nuclear Generation [1]	**5,728**	5,728
Regulated – Hydroelectric	**6,426**	6,421
Contracted Generation Portfolio [2]	**4,056**	4,028
Total	**16,210**	16,177

[1] The in-service generating capacity as of September 30, 2017 and December 31, 2016 excludes Unit 2 of the Darlington GS. The unit, which has a generating capacity of 878 MW, was taken offline in mid-October 2016 and is currently undergoing refurbishment.

[2] Includes OPG's share of in-service generating capacity of 275 MW for PEC and 280 MW for Brighton Beach.

During the nine months ended September 30, 2017, the total in-service capacity increased by 33 MW. The increase was primarily due to the completion of the Peter Sutherland Sr. hydroelectric GS, which was placed in-service at the end of the first quarter of 2017, and the upgrade of Unit 10 of the Sir Adam Beck 1 hydroelectric GS, which was completed in June 2017.

HIGHLIGHTS

Overview of Results

This section provides an overview of OPG's unaudited interim consolidated operating results. Significant factors which contributed to OPG's results during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, are discussed below.

(millions of dollars – except where noted) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Revenue	**1,217**	1,400	**3,539**	4,265
Fuel expense	**185**	187	**518**	541
Gross margin	**1,032**	1,213	**3,021**	3,724
Operations, maintenance and administration	**635**	666	**2,054**	2,061
Depreciation and amortization	**178**	313	**517**	941
Accretion on fixed asset removal and nuclear waste management liabilities	**235**	232	**709**	696
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(196)**	(248)	**(579)**	(620)
Income from investments subject to significant influence	**(11)**	(11)	**(29)**	(28)
Property taxes	**8**	12	**30**	35
	849	964	**2,702**	3,085
Income before other losses (gains), interest and income taxes	**183**	249	**319**	639
Other losses (gains)	**3**	1	**(380)**	(23)
Income before interest and income taxes	**180**	248	**699**	662
Net interest expense	**21**	28	**56**	92
Income before income taxes	**159**	220	**643**	570
Income tax expense	**19**	22	**128**	109
Net income	**140**	198	**515**	461
Net income attributable to the Shareholder	**131**	194	**498**	449
Net income attributable to non-controlling interest [1]	**9**	4	**17**	12
Electricity production (TWh) [2]	**19.4**	19.5	**56.0**	59.9
Cash flow provided by operating activities	**485**	530	**698**	1,211

[1] Relates to the 25 percent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in the Lower Mattagami Limited Partnership, the 33 percent interest of Coral Rapids Power Corporation, a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership, and the 10 percent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP.

[2] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

Third Quarter

Net income attributable to the Shareholder was $131 million for the third quarter of 2017, a decrease of $63 million compared to the same quarter in 2016. Income before interest and income taxes for the third quarter of 2017 was $180 million, a decrease of $68 million compared to the same quarter in 2016.

Commented [A1]:
Wondering if this should be 437?
Since:
Q3 9-mos ended – Q2 6-mos ended = 698-261 = 437

Was Q2 "6-month ended June 30" number for Cash flow provided by operating activities revised?

OPG: In Q3 2017, adjustments for non-cash balances related to Darlington Refurbishment capital expenditures have been reclassified from the "Net changes in non-cash working capital balances" line to the "Investment in property, plant and equipment and intangible assets" line. Comparative amounts have been reclassified accordingly.

Significant factors that reduced income before interest and income taxes:

- Lower earnings from the nuclear base regulated price of approximately $24 million reflecting lower electricity generation of 0.4 terawatt hours (TWh) from the Regulated – Nuclear Generation segment and the continuation of existing base regulated prices set by the OEB in 2014. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS since October 2016, largely offset by an increase in generation from Pickering GS. The increase in generation from the Pickering GS was primarily due to outage optimization, favourable unit conditions and execution of planned outage work. The base regulated prices set in 2014 continue to be in effect pending the OEB's decision on OPG's current application for new regulated prices, expected later in 2017. **[MONITOR]** The existing nuclear base regulated price was set to allow the Company to recover its approved nuclear costs over a higher nuclear production volume, based on the 2014 and 2015 outage profile that did not include a refurbishment outage. OPG has requested January 1, 2017 as the effective date of the new regulated prices.
- Lower earnings on the nuclear fixed asset removal and nuclear waste management funds (Nuclear Segregated Funds) of $52 million.
- Higher depreciation and amortization expense of $16 million in the Regulated – Nuclear Generation segment, excluding amortization expense related to balances in OEB-authorized regulatory variance and deferral accounts (regulatory accounts), primarily due to new assets in service.

The expiry of rate riders for the recovery of approved balances in OEB-authorized regulatory accounts on December 31, 2016 contributed to the decrease in revenue for the three months ended September 30, 2017, compared to the same period in 2016, but was largely offset by a decrease in the amortization expense related to these balances. OPG has requested new rate riders in its current application to the OEB for new regulated prices, with a proposed effective date of January 1, 2017.

Significant factor that increased income before interest and income taxes:

- Lower operations, maintenance and administration (OM&A) expenses of $31 million, mainly in the Regulated – Nuclear Generation segment, as a result of a higher materials and supplies obsolescence charge recognized in the third quarter of 2016, Services, Trading and Other Non-Generation segment due to project expenditures incurred in the third quarter of 2016, and Regulated – Hydroelectric segment due to the timing of repairs and maintenance work in 2017 and a deferral of outages during the high water period.

Net interest expense decreased by $7 million during the third quarter of 2017, compared to the same quarter in 2016, primarily due to a higher amount of interest costs capitalized for the Darlington Refurbishment project expenditures and a higher amount of interest costs deferred in OEB-authorized regulatory accounts.

Income tax expense for the three months ended September 30, 2017 was $19 million, compared to $22 million for the same period in 2016. The decrease in income tax expense was primarily due to lower income before taxes and a higher change in reserves from the resolution of uncertainties, partially offset by a lower amount of tax expense deferred in regulatory assets.

Year-To-Date

Net income attributable to the Shareholder was $498 million for the first nine months of 2017, an increase of $49 million compared to the same period in 2016. Income before interest and income taxes for the first nine months of 2017 was $699 million, an increase of $37 million compared to the same period in 2016.

Significant factor that increased income before interest and income taxes:

- Higher earnings of $390 million from the Services, Trading, and Other Non-Generation segment, primarily reflecting the gain on sale of OPG's head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street that was recognized in the second quarter of 2017. The sale of the

Commented [A2]: If approved by OEB (during Q4), would this result in a higher regulated price and a revenue/net income pick up for 2017 reported in OPG's Q4?

OPG – It depends on the effective date of the decision on the base regulated prices. If the OEB decision on the new base regulated prices are retrospectively effective as of Jan 1, 2017 for example, then it should result in a higher revenue/net income pick up for 2017 assuming the new regulated prices are higher.

assets was required by a Shareholder Declaration and a Shareholder Resolution. The gain on sale was $283 million, which is net of tax effects of $95 million.

Significant factors that reduced income before interest and income taxes:

- Lower earnings from the nuclear base regulated price of approximately $230 million, partially offset by a decrease in nuclear fuel expense of $22 million, reflecting lower electricity generation of 4.0 TWh from the Regulated – Nuclear Generation segment and the continuation of existing base regulated prices set by the OEB in 2014. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS, partially offset by an increase in generation from Pickering GS.
- Lower earnings on the Nuclear Segregated Funds of $41 million.
- Higher depreciation and amortization expense of $30 million in the Regulated – Nuclear Generation segment, excluding amortization expense related to regulatory account balances, primarily due to new assets in service.
- A gain of $22 million recorded in the first quarter of 2016 to reflect the OEB's decision on OPG's motion asking the OEB to review and vary parts of its November 2014 decision on OPG's regulated prices.

The expiry of rate riders for the recovery of approved balances in OEB-authorized regulatory accounts on December 31, 2016 contributed to the decrease in revenue for the nine months ended September 30, 2017, compared to the same period in 2016, but was primarily offset by a decrease in the amortization expense related to these balances.

Net interest expense decreased by $36 million for the nine months ended September 30, 2017, compared to the same period in 2016, primarily due to a higher amount of interest costs capitalized for the Darlington Refurbishment project expenditures and a higher amount of interest costs deferred in OEB-authorized regulatory accounts.

Commented [A3]: Does this imply there were interest costs related to Darlington Refurb previously (same quarter previous year), that were not capitalized, but were able to be capitalized this year?

OPG – There were higher Darlington Refurb project expenditures in 2017, compared to 2016.

Income tax expense for the nine months ended September 30, 2017 was $128 million, compared to $109 million for the same period in 2016. The increase in income tax expense was primarily due to higher income before income taxes.

Segment Results

The following table summarizes OPG's income before interest and income taxes by business segment. A detailed discussion of OPG's performance by reportable segment is included in the section, *Discussion of Operating Results by Business Segment*.

(millions of dollars)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Income (loss) before interest and income taxes				
Regulated – Nuclear Generation	**20**	47	**(267)**	17
Regulated – Hydroelectric	**122**	117	**474**	500
Contracted Generation Portfolio	**75**	74	**229**	219
Total electricity generation business segments	**217**	238	**436**	736
Regulated – Nuclear Waste Management	**(36)**	18	**(123)**	(70)
Services, Trading, and Other Non-Generation	**(1)**	(8)	**386**	(4)
	180	248	**699**	662

Electricity Generation

Electricity generation for the three and nine month periods ended September 30, 2017 and 2016 was as follows:

(TWh)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Regulated – Nuclear Generation	**11.3**	11.7	**30.6**	34.6
Regulated – Hydroelectric	**7.3**	6.9	**23.5**	22.8
Contracted Generation Portfolio [1]	**0.8**	0.9	**1.9**	2.5
Total OPG electricity generation	**19.4**	19.5	**56.0**	59.9
Total electricity generation by all other generators in Ontario [2]	**16.6**	19.5	**51.7**	53.8

[1] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.
[2] Non-OPG generation is calculated as the Ontario electricity demand plus net exports, as published by the Independent Electricity System Operator (IESO), minus OPG electricity generation.

Total OPG electricity generation decreased by 0.1 TWh during the third quarter of 2017, compared to the same quarter in 2016, and by 3.9 TWh during the nine months ended September 30, 2017, compared to the same period in 2016. As expected, the lower electricity generation from the Regulated – Nuclear Generation segment was primarily the result of the removal from service of Unit 2 at the Darlington GS for the duration of the unit's refurbishment, which began in October 2016. This decrease in electricity generation was largely offset by an increase in generation from the Pickering GS, primarily due to outage optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station, and higher hydroelectric generation from the Regulated – Hydroelectric segment.

The higher electricity generation of 0.4 TWh and 0.7 TWh from the Regulated – Hydroelectric segment for the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016, was due to higher water flows primarily on the eastern Ontario river systems, net of water spilled as a result of SBG conditions, discussed below.

The lower electricity generation of 0.6 TWh from the Contracted Generation Portfolio segment for the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to higher SBG conditions. The electricity generation from the Contracted Generation Portfolio segment for the three months ended September 30, 2017 was comparable to the same period in 2016.

OPG's operating results are impacted by changes in grid-supplied electricity demand resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. For the three and nine month periods ended September 30, 2017, Ontario's electricity demand as reported by the IESO was 33.6 TWh and 98.5 TWh, respectively, compared to 36.7 TWh and 103.8 TWh for the same periods in 2016, respectively, excluding electricity exports out of the province.

Power that is surplus to the Ontario market is managed by the IESO, mainly through generation reductions at hydroelectric, other grid-connected renewable resources and nuclear stations. Reducing hydroelectric production is the first measure used by the IESO to manage SBG conditions. Low demand conditions in Ontario continued to be prevalent in 2017, resulting in forgone hydroelectric generation for OPG of 1.1 TWh and 4.5 TWh due to SBG conditions in the three and nine month periods ended September 30, 2017, respectively, compared to 0.5 TWh and 3.9 TWh during the same periods in 2016, respectively. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions during these periods was offset by the impact of a regulatory variance account authorized by the OEB. OPG did not forgo any electricity production at its nuclear stations due to SBG conditions.

Average Sales Prices

The majority of OPG's generation is from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments. The same base regulated prices for electricity generated by these segments, authorized by the OEB effective November 1, 2014, were in effect during the first nine months of 2017 as in 2016. These prices will remain in effect until such time as the OEB approves new regulated prices based on OPG's current application. **[MONITOR]** The base regulated prices established in 2014 are discussed in OPG's 2016 annual MD&A in the section, *Revenue Mechanisms for Regulated and Non-Regulated Generation*.

The average sales price for the Regulated – Nuclear Generation segment was 5.8 cents per kilowatt hour (¢/kWh) during the three and nine month periods ended September 30, 2017, respectively, compared to 6.9 ¢/kWh during the same periods in 2016. The decrease in the average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized nuclear rate rider of $10.84 per megawatt hour (MWh) for the recovery of variance and deferral account balances. The average sales price for the Regulated – Hydroelectric segment was 4.1 ¢/kWh during the three and nine month periods ended September 30, 2017, respectively, compared to 4.4 ¢/kWh during the same periods in 2016. The decrease in the average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized regulated hydroelectric rate rider of $3.19/MWh for the recovery of variance and deferral account balances. The rate riders were established to recover approved balances recorded in the variance and deferral accounts in prior years. As such, the year-over-year changes in revenue from the rate riders were largely offset by changes in amortization expense related to these balances. There were no rate riders in effect during the nine months ended September 30, 2017 for either nuclear or regulated hydroelectric generation, pending the outcome of OPG's current application with the OEB for new regulated prices.

Cash Flow from Operations

Cash flow provided by operating activities was $485 million for the three months ended September 30, 2017 and $698 million for the nine months ended September 30, 2017, compared to $530 million and $1,211 million for the same periods in 2016, respectively. The decrease in cash flow provided by operating activities was expected and primarily due to lower generation revenue receipts reflecting lower generation from the Regulated – Nuclear Generation segment as a result of the ongoing refurbishment of Unit 2 at the Darlington GS and the expiry, on December 31, 2016, of the OEB-authorized rate riders for nuclear and regulated hydroelectric generation. The decrease in cash flow during the nine months ended September 30, 2017 was also due to higher income tax instalments.

The decrease in cash flow provided by operating activities for the three and nine month periods ended September 30, 2017 was partly offset by lower OM&A expenditures and lower contributions to the Used Fuel Segregated Fund in 2017. Both the Used Fuel Segregated Fund and the Decommissioning Segregated Fund were determined to be fully funded based on an updated estimate of OPG's nuclear waste management and nuclear facilities decommissioning obligations pursuant to a reference plan approved by the Province ~~for years 2017 to 2021~~ under the Ontario Nuclear Funds Agreement (ONFA), effective January 1, 2017. Pursuant to the ONFA, the reference plan is required to be updated at least once every five years. Contributions to either or both of the Nuclear Segregated Funds may be required in the future should the funds be in an underfunded position at the time of the next ONFA reference plan update. The year-over-year decrease in cash flow also was partially offset by the payment of a supplemental rent rebate to Bruce Power in the first quarter of 2016 in relation to a period in 2015. The lease agreement for the Bruce nuclear generating stations was amended in late 2015 to eliminate this rebate provision going forward.

Return on Common Equity Excluding Accumulated Other Comprehensive Income

ROE Excluding AOCI is an indicator of OPG's performance consistent with the Company's strategy to provide value to the Shareholder. ROE Excluding AOCI is measured over a 12-month period.

Commented [A4]: OPG: no change as this was previously disclosed as is in Q2 2017.

Commented [A5R4]: The Reference Plan is a lifecycle plan. The years should be omitted. It implies to the naïve reader that the Reference Plan approval only covers the period 2017-2021, whereas the reference plan goes out more than a century (don't need to say that.)

The following sentence conveys that the Reference Plan needs to be refreshed at least every five years.

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ROE Excluding AOCI was 4.4 percent for the 12 months ended September 30, 2017, compared to 4.2 percent for the 12 months ended December 31, 2016. The increase was primarily due to higher net income attributable to the Shareholder for the 12 months ended September 30, 2017, which reflected the gain on sale of OPG's head office premises and associated parking facility recorded in the second quarter of 2017, partially offset by the lower earnings from the decrease in nuclear electricity generation reflecting the Unit 2 refurbishment outage at the Darlington GS without a corresponding increase in the nuclear base regulated price, as expected. The lower nuclear generation as a result of the refurbishment outage will continue to negatively affect OPG's ROE Excluding AOCI until such time as new regulated prices are approved by the OEB, anticipated in the fourth quarter of 2017. **[MONITOR]**

Funds from Operations Adjusted Interest Coverage

FFO Adjusted Interest Coverage is an indicator of OPG's ability to meet interest obligations from operating cash flows. The indicator is measured over a 12-month period. FFO Adjusted Interest Coverage for the 12 months ended September 30, 2017 was 4.2 times, compared to 5.1 times for the 12 months ended December 31, 2016. FFO Adjusted Interest Coverage in 2017 reflected a year-over-year decrease in FFO before interest due to lower cash flow provided by operating activities, partially offset by the impact of a lower adjusted interest expense due to a decrease in the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets.

The decrease in the excess of interest on pension and OPEB benefit obligations over expected return on pension plan assets in the nine months of 2017 was primarily due to the change in the method used to estimate the interest cost and service cost components of pension and OPEB costs. Effective January 1, 2017, OPG adopted a full yield curve approach to the estimation of these cost components, by applying the specific spot rates along the yield curve used in the determination of the projected benefit obligations to the relevant projected cash flows. Under the previous method, these components of pension and OPEB costs were calculated using the same single weighted-average discount rates as reflected in the calculation of the benefit obligations. This change in the method was accounted for prospectively, as a change in estimate. The resulting reduction in pension and OPEB costs for the three and nine month periods ended September 30, 2017 did not have a material impact on net income as it was largely offset by the impact of OEB-authorized variance and deferral accounts in the regulated business segments. Further details on the full yield curve approach can be found in the 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Pension and Other Post-Employment Benefits*.

Commented [A6]: Does this have any implications for the methodology used for the IFRS adjustments for the purposes of the Province's Public Accounts?

OPG response - Since the full yield curve approach is applied to the determination of pension and OPEB costs under both US GAAP and IFRS, it will not create a US GAAP and IFRS difference. Therefore it is not expected to have any implications for the methodology used for the IFRS adjustments for the purposes of the Province's Public Accounts.

Enterprise Total Generating Cost per MWh

The Enterprise TGC per MWh decreased to $46.65 for the three months ended September 30, 2017, compared to $50.72 for the same quarter in 2016. The decrease was mainly due to lower OM&A expenses before the impact of regulatory accounts and higher SBG-adjusted hydroelectric generation reflecting higher water flows.

The Enterprise TGC per MWh was $47.77 for the nine months ended September 30, 2017, an increase compared to $46.74 for the same period in 2016. The increase was expected and mainly a result of lower electricity generation due to the Unit 2 refurbishment outage at the Darlington GS, largely offset by lower OM&A expenses before the impact of regulatory accounts and higher SBG-adjusted hydroelectric generation reflecting higher water flows.

If Unit 2 at the Darlington GS was not currently undergoing refurbishment and had continued to operate in a manner consistent with the performance of the remaining units at the Darlington GS, adjusting for generation constraints on these units related to the transition of the station toward refurbishment, the Enterprise TGC would have been approximately $4 per MWh lower for both the three and nine month periods ended September 30, 2017. This sensitivity was calculated using the estimated incremental electricity and associated fuel cost that are expected to have resulted in the absence of the refurbishment.

Nuclear Total Generating Cost per MWh

The Nuclear TGC per MWh was $58.75 for the three months ended September 30, 2017, which was comparable to $58.55 for the same quarter in 2016. For the three months ended September 30, 2017, the higher generation at the Pickering GS and the impact of lower OM&A expenses before the impact of regulatory accounts was mostly offset by the expected decrease in nuclear electricity generation reflecting the Unit 2 refurbishment outage at the Darlington GS and higher sustaining capital expenditures. The Nuclear TGC per MWh was $67.87 for the nine months ended September 30, 2017, compared to $61.07 for the same period in 2016. The increase in the Nuclear TGC per MWh for the nine months ended September 30, 2017 was expected and primarily due to the decrease in nuclear electricity generation, partially offset by lower OM&A expenses before the impact of regulatory accounts.

Hydroelectric Total Generating Cost per MWh

The Hydroelectric TGC per MWh was $26.20 for the three months ended September 30, 2017, compared to $31.01 for the same quarter in 2016. The decrease was primarily due to higher SBG-adjusted hydroelectric electricity generation reflecting higher water flows. The Hydroelectric TGC per MWh was $21.74 for the nine months ended September 30, 2017, compared to $23.99 for the same period in 2016. The decrease was primarily due to lower OM&A expenses before the impact of regulatory accounts and lower sustaining capital expenditures.

ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are not measurements in accordance with US GAAP and should not be considered alternative measures to net income, cash flow provided by operating activities, or any other performance measure under US GAAP. OPG believes that these non-GAAP financial measures are effective indicators of its performance and are consistent with the Company's strategic imperatives and related objectives. The definition and calculation of ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are found in the section, *Supplementary Non-GAAP Financial Measures*.

Recent Developments

Ontario's 2017 Long Term Energy Plan

On October 26, 2017, Ontario's Ministry of Energy issued the 2017 Long Term Energy Plan. The Plan is currently being analyzed by OPG but is not expected to significantly impact OPG's business. There are no fundamental changes from the principles in the 2013 Long Term Energy Plan, which include cost effectiveness, reliability, clean energy and community engagement. The 2017 Long Term Energy Plan fully supports nuclear refurbishment projects in Ontario and the extension of commercial operation of all Pickering units to 2024. **[MONITOR & UPDATE DETAILS FOLLOWING RELEASE]**

OEB's Decision on New Regulated Prices **[MONITOR]**

Ontario's Fair Hydro Plan

OPG continues to prepare for its involvement as the Financial Services Manager for Ontario's Fair Hydro Plan (the Fair Hydro Plan) on a commercial basis. Accordingly, the financing entity was established in XX 2017 as the Fair Hydro Trust (the Trust), following the execution of its constating documents. The majority unitholder and beneficiary of the Trust is a wholly-owned subsidiary of OPG. Through this ownership and OPG's control over the key activities of the Trust, the Company will consolidate the Trust for accounting purposes commencing in the fourth quarter of 2017. **[MONITOR]**

In order for the Trust to ~~provide~~ financ~~eing for~~ the deferred Global Adjustment costs, the Trust will incur senior debt from capital markets and subordinated debt from OPG. The Trust is structured to be bankruptcy remote and ring fenced from OPG to protect the Company's assets and operations. In support of the Fair Hydro Plan, the following developments have transpired:

Commented [A7]: Why not rephrase as acquiring the investment asset related to the deferred GA costs (right to future recovery)?

OPG response: No change made.

It is easier to understand for the general public the notion of a financing transaction vs. acquiring an investment interest

Commented [A8R7]: Suggested wording change.

- In October 2017, *Ontario Regulation 206/17 General* was amended to establish details of the recovery mechanism for the monthly carrying costs incurred by the Trust from June 1, 2017 to July 31, 2021 payable by the IESO to the Trust. Originally established in June 2017, this regulation provides more details on the funding obligations incurred by the Trust and the fair allocation amount, the determination and collection of clean energy adjustments, the determination of the finance amount, the true up amount, and the regulatory asset, as well as principles and assumptions relating to the financing plan.
- A plan to amend the Company's Articles of Amalgamation to allow for the creation and issuance of Class A shares to be issued to the Province for its equity investment through OPG in the Fair Hydro Plan is in progress. The Province is expected to provide 44 percent of the total funding requirement related to the deferred Global Adjustment costs, which OPG will invest as subordinated debt into the Trust. OPG's Board approval and a Shareholder Resolution are expected later in the year to authorize the amendment.
- OPG is expected to provide five percent of the total funding requirement of the Trust related to the deferred Global Adjustment costs of the Fair Hydro Plan. OPG issued senior notes payable in October 2017 under a short form base shelf prospectus for general corporate purposes and to fund OPG's subordinated debt investment in the Trust. Further details of the debt offering can be found in the section, *Liquidity and Capital Resources* under the heading, *Financing Activities*.

Commented [A9]: Are any other details available to be released at this time?

OPG – Not for Q3 2017 reporting.

The first set of transactions of the Trust are expected to take place in the fourth quarter of 2017.

Canadian Nuclear Safety Commission Safety Rating for the Darlington GS and the Pickering GS

The Canadian Nuclear Safety Commission (CNSC) publishes an annual report on the safety performance of Canada's nuclear power plants. The report assesses how well plant operators are meeting regulatory requirements and program expectations in the areas of operational performance, safety analysis, radiation protection, waste management and conventional health and safety. On September 8, 2017, the CNSC issued an executive summary of its 2016 annual report. The CNSC gave both the Darlington GS and the Pickering GS the highest possible safety rating of "Fully Satisfactory". The Darlington GS achieved this rating for the eighth consecutive year, while the Pickering GS achieved this rating for the second consecutive year.

CORE BUSINESS, STRATEGY, AND OUTLOOK

The discussion in this section is qualified in its entirety by the cautionary statements included in the section, *Forward-Looking Statements,* at the beginning of the MD&A.

OPG's mission is to provide low cost power in a safe, clean, reliable and sustainable manner for the benefit of customers and its Shareholder. OPG also seeks to pursue, on a commercial basis, generation development projects and other business growth opportunities.

The following sections provide an update to OPG's disclosures in the 2016 annual MD&A related to its four key strategic imperatives – operational excellence, project excellence, financial strength, and social licence. A detailed discussion of these strategic imperatives is included in the 2016 annual MD&A in the section, *Core Business, Strategy, and Outlook*.

Operational Excellence

Operational excellence at OPG is accomplished by the safe and environmentally responsible generation of reliable and cost-effective electricity from the Company's generating assets through a highly trained and engaged workforce.

Electricity Generation Production and Reliability

- As part of the plan to extend Pickering operations, OPG is continuing to undertake the required technical work to confirm that the station's pressure tubes, a key life-limiting component of the station, will remain fit for service for operation to 2024. OPG is also nearing completion of component condition assessments to identify the work required to support the continued operation of the station. The accounting end of life assumptions for the Pickering GS, currently set at the end of 2020, will be reassessed based on the fuel channel analysis and safety case consistent with submissions for the CNSC approval, discussed below. The activities completed to date have had positive results, which will go towards re-confirming Pickering operations past 2020 are technically feasible. The Periodic Safety Review (PSR) is in progress and will confirm that extending operations of the Pickering units will be safe to the public, workers and the environment. The PSR consists of Safety Factor Reports (SFRs), a Global Assessment Report (GAR), and the Integration Improvement Plan (IIP). SFRs have been submitted to the CNSC and the GAR and IIP are on track for CNSC submission in October and November 2017, respectively. Other technical feasibility activities continue to progress as planned. Completion of various technical feasibility assessments are required to reach a high confidence conclusion to allow the station end of life to change for depreciation purposes. OPG's current application with the OEB for new base regulated prices, currently pending the OEB's decision, reflects OPG's plans to extend Pickering operations to 2024 and requests inclusion of the corresponding cost and generation impacts in the determination of the nuclear regulated price.
- OPG's current five-year operating licence for the Pickering GS was approved by the CNSC in 2013 and expires on August 31, 2018. This licence was issued assuming that the station would shut down in 2020. On June 28, 2017, OPG confirmed to the CNSC that it intends to cease commercial operation of all Pickering units on December 31, 2024. On August 28, 2017, OPG submitted a ten-year licence renewal application to the CNSC. The licence term spans the planned extended operations period, through to the end of commercial operation, defueling, dewatering and the start of placing the station in a safe storage state.
- Work continues on the rehabilitation of Unit 2 of the DeCew Falls hydroelectric GS and the rehabilitation and overhaul of Unit 2 of the Lower Notch hydroelectric GS.
- During the third quarter, a new control centre was opened at Saunders GS to merge its operations with Chenaux GS. The new control centre will overlook power production at ten hydroelectric stations along the Madawaska, Ottawa and St. Lawrence rivers.
- As part of the process to decommission the Nanticoke and Lambton generating stations, OPG has begun executing demolition plans that will ensure that the stations are closed safely, securely and in an environmentally responsible manner. The demolition of the Nanticoke coal yard equipment and structures is in progress, with a contract issued in July 2017 for the demolition of the Nanticoke powerhouse and associated structures. Project milestones for the Nanticoke site during the remainder of 2017 include completing the removal of coal yard equipment and structures, demolition of the ash silos, and mobilization of the contractor to prepare for removal of the stacks, powerhouse and associated structures. A competitive bidding process for the demolition of the Lambton GS has been completed, with a contract for the removal of the powerhouse and associated buildings expected to be awarded in 2018. An update of the associated asset retirement obligations related to the Nanticoke and Lambton sites is expected to be finalized in the fourth quarter of 2017.

Environmental Performance

There were no significant changes to environmental legislation affecting the Company during the third quarter of 2017. Disclosures related to the Company's environmental policy and environmental risks can be found in OPG's 2016 annual MD&A.

OPG communicates its environmental performance internally to employees and to external stakeholders, including the Ontario Ministry of the Environment and Climate Change, Environment and Climate Change Canada, the CNSC, and local communities. Details of OPG's environmental performance and initiatives to fulfill the Company's Environmental Policy can be found in OPG's 2016 Sustainability Report, available on the Company's website at www.opg.com. **[MONITOR]**

Project Excellence

OPG is pursuing a number of generation development and other major projects in support of Ontario's electricity planning initiatives. OPG remains focused on delivering projects safely, on time, on budget and with high quality. The status updates for OPG's major projects as at September 30, 2017 are outlined in the following table, with further details below.

Project	Capital expenditures		Approved budget	Expected in-service date	Current status
(millions of dollars)	**Year-to-date**	**Life-to-date**			
Darlington Refurbishment	924	4,109	12,800 [1]	First unit - 2020 Last unit - 2026	The setup of specialized tooling and equipment needed for the removal of reactor components was completed in the third quarter of 2017. All feeder tubes have been removed safely, and the pressure tubes have been severed in preparation for their removal. The Re-tube Waste Processing Building will be available for use in the fourth quarter of 2017. The project is tracking on schedule and on budget.
Peter Sutherland Sr. Hydroelectric GS	38	274	300	2017	The station was placed in-service on March 31, 2017, ahead of the originally planned schedule, and is expected to close below the approved budget. Project close-out activities are in progress.
Ranney Falls Hydroelectric GS	17	20	77	2019	Work is progressing on the expanded forebay, forebay wall concrete replacement, powerhouse and spillway areas. The project is tracking on schedule and on budget.
Nanticoke Solar Facility	1	2	107 **[MONITOR]**	2019	Project definition work is continuing, with construction planned to commence in the first quarter of 2018.
Deep Geologic Repository for low and intermediate level radioactive waste (L&ILW)	7 [2]	202 [2]			On August 21, 2017, the federal Minister of Environment and Climate Change requested further information on the project's environmental assessment (EA). OPG is reviewing the new request and will notify the Canadian Environmental Assessment Agency (CEAA) when it has a timeline for submission of that information.

[1] The total project budget of $12.8 billion is for the refurbishment of all four units at the Darlington GS.
[2] Expenditures are charged against the nuclear fixed asset removal and nuclear waste management liabilities (Nuclear Liabilities).

Commented [A10]: Does this imply that only 700M further is anticipated to be spent by the time Unit 2 gets completed? (Eg. 4.8B in Capital Expenditure)

Eg. from above:
"Once refurbished, Unit 2 is scheduled to be returned to service in the first quarter of 2020, at which time capital expenditures of approximately $4.8 billion are planned to be placed in service."

OPG – No, the LTD in the table includes prerequisite projects already declared in-service. The $4.8B was the OEB submitted estimate of a future in-service amount for Unit 2 refurbishment.

Please see updated wording below:

OPG's current application with the OEB for new regulated prices seeks an increase in the nuclear rate base, effective in the first quarter of 2020, to reflect the planned placement in service of the $4.8 billion in capital expenditures upon return to service of Unit 2, which includes expenditures incurred during the definition and planning phase of the project. Based on OPG's proposal in the application, the revenue requirement impact of the differences between the Unit 2 in-service amount included in the regulated prices and the actual amounts placed in service would be subject to true up via the Capacity Refurbishment Variance Account established by the OEB pursuant to *Ontario Regulation 53/05*. OPG's application proposes that the recovery of the HWSF's costs through regulated prices be subject to a separate prudence review by the OEB, to be conducted as part of a future OEB application.

Darlington Refurbishment

The Darlington generating units are approaching their originally designed end-of-life. Refurbishment of the four generating units is expected to extend the operating life of the station by approximately 30 years. OPG commenced the planning of the refurbishment in 2010.

In 2016, the Darlington Refurbishment project transitioned from the planning phase to the execution phase, as OPG commenced the refurbishment of the first unit, Unit 2, in October 2016, as planned. The unit was taken offline on October 15, 2016. De-fuelling of the reactor, the first critical refurbishment activity undertaken once the unit is removed from service, was completed safely in January 2017, with a total of 480 fuel channels de-fuelled. Islanding of Unit 2, the physical separation of the unit under refurbishment from the three operating units, was completed in April 2017, signifying the completion of the first major segment of the project.

The second major segment includes preparatory work to support the removal of feeder tubes and fuel channel assemblies and the removal of reactor components. The preparatory work was completed in the second quarter of 2017. The Re-tube Tooling Platform for hosting the tooling for the removal, inspection, and installation activities and the setup of specialized tooling and equipment needed for the removal and replacement of the reactor components were completed in the third quarter of 2017. The disassembly of reactor components commenced in August 2017, with the removal of all 960 feeder tubes completed safely in September 2017. This was followed by the severing of pressure tubes, with the severing of bellows and the removal of end fittings expected to commence thereafter and through the end of 2017. Other key project activities executed during the second segment include the completion of the primary side steam generator layup, installation of steam generator access ports to support future inspections, continuation of the major turbine generator overhaul and continued execution of the major electrical scope. OPG is also continuing to execute work to support the requirements set out in the CNSC approved IIP for the station.

Once refurbished, Unit 2 is scheduled to be returned to service in the first quarter of 2020, at which time capital expenditures of approximately $4.8 billion are planned to be placed in service. This includes expenditures incurred during the definition and planning phase of the overall project. The project is tracking on schedule and on budget.

With the substantial completion of the Re-tube Waste Processing Building in November 2017, 17 out of 18 pre-requisite projects in support of the execution phase of the project, including construction of facilities, infrastructure upgrades and installation of safety enhancements, have been completed and placed in service. Completion of the Heavy Water Storage and Drum Handling Facility (HWSF) has been delayed due to challenges with construction. OPG suspended the project in the second quarter of 2017 to evaluate the best approach to optimize cost and schedule and complete the project. Construction activities for the HWSF recommenced in the fourth quarter of 2017 following substantial completion of the Re-tube Waste Processing Building. This plan ensures that the necessary resources are available for both projects and, through resource levelling, improves their execution and cost efficiency. The delay in the completion of the HWSF will not impact the overall Darlington Refurbishment project schedule, as the HWSF is not on the project's critical path. This also will not impact the overall project budget of $12.8 billion, as the costs of the HWSF are included in this total figure. The recovery of HWSF costs through regulated prices will be subject to a prudence review by the OEB, which OPG has proposed be conducted as part of a future OEB application.

In addition to the execution of refurbishment activities on Unit 2, OPG is continuing planning activities for the refurbishment of the second unit, Unit 3, and is entering into associated commitments to procure major components that require long lead times. As of September 30, 2017, $70 million has been invested in planning activities related to the refurbishment of the second unit, Unit 3. These planning activities are being undertaken in accordance with the refurbishment project schedule.

The Financial Accountability Office of Ontario has issued a report titled "*An Assessment of the Financial Risks of the Nuclear Refurbishment Plan*". The report assesses both OPG and Bruce Power's refurbishment activities and the method in which those refurbishments and subsequent nuclear generation is provided to the marketplace. The report

concludes that the base case of refurbishing the six units at the Bruce nuclear GS and the four units at the Darlington nuclear GS provide the most cost effective, low emission generation source available to meet Ontario's baseload electricity requirements. This report re-affirms the positive economic and societal benefits associated with a strong nuclear program in the Province. **[MONITOR]**

Commented [A11]: Not yet released.

OPG – We put MONITOR to ensure status next Thursday before we release.

Ranney Falls Hydroelectric GS

During the third quarter of 2017, OPG continued construction work for a 10 MW single-unit powerhouse on the existing Ranney Falls GS site, as part of the Regulated – Hydroelectric segment. The new unit will replace an existing unit that reached its end of life in 2014. The existing forebay structure demolition has been completed and the upstream cofferdam has been constructed ahead of schedule. Construction continues on the expanded forebay, powerhouse and spillway. Excavation work is substantially complete and forebay wall concrete replacement is in progress. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget.

Nanticoke Solar Facility

The construction of a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands under a Large Renewable Procurement contract with the IESO, through Nanticoke Solar LP, a partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation, is planned to commence in the first quarter of 2018. During the third quarter of 2017, the partnership continued work to obtain approvals and permits required to enable the commencement of construction, and progressed procurement activities for equipment and for engineering and construction services. The facility is expected to be completed in the first quarter of 2019.

Deep Geologic Repository for Low and Intermediate Level Waste

OPG has proposed a deep geologic repository as the preferred solution for the safe long-term management of the L&ILW produced from the continued operation of OPG-owned nuclear generating stations. Agreement has been reached with local municipalities for OPG to develop the L&ILW Deep Geologic Repository (DGR) on lands adjacent to the Western Waste Management Facility (WWMF) in Kincardine, Ontario. The environmental effects of the proposed L&ILW DGR were examined by the CNSC and CEAA-appointed Joint Review Panel (JRP) to meet the requirements of the Canadian Environmental Assessment Act. The JRP submitted its report on the EA to the federal Minister of Environment in May 2015, concluding that, given mitigation, there is unlikely to be significant environmental impact from the project and recommending that the Minister approve the EA. In December 2016, at the request of the federal Minister of Environment and Climate Change, OPG submitted additional information on certain aspects of the EA, including information related to alternate locations for the project. Following its review of OPG's submission and a period of public comment, the CEAA requested further information that OPG subsequently provided in May 2017. In June 2017, the CEAA notified OPG that it had sufficient and adequate information to proceed with the next step of the environmental assessment process and advised that a draft report and updated terms and conditions will be prepared for public review.

On August 21, 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of potential cumulative effects of the project on the Saugeen Ojibway Nations' (SON) physical and cultural heritage, including a description of the potential effects of the project on the Nation's spiritual and cultural connection to the land. OPG is assessing the request and will notify the CEAA when it has determined the timeline for developing a response. The CEAA's draft report for public review will not be issued until this update is provided. The L&ILW DGR at the WWMF site remains OPG's preferred solution for the safe long-term management of the L&ILW.

OPG continues its engagement with the SON toward securing community support for the L&ILW DGR. The in-service date of the L&ILW DGR is expected to be approximately six to seven years from the start of construction.

Financial Strength

As a commercial enterprise, OPG's financial priority is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future growth.

Increase Revenue, Reduce Costs and Achieve Appropriate Return

In May 2016, OPG filed a 5-year application with the OEB for new regulated prices for production from its regulated hydroelectric and nuclear facilities, with a proposed effective date of January 1, 2017. Consistent with the requirements of *Ontario Regulation 53/05*, the application incorporates a rate smoothing proposal that would defer, for future collection, a portion of the approved annual nuclear revenue requirement for the period from January 1, 2017 to the end of the Darlington Refurbishment project, with a view to making changes in OPG's regulated prices more stable year-over-year. The application seeks to ensure that nuclear regulated prices under the rate smoothing approach allow for sufficient cash flow to meet the Company's liquidity needs, support cost effective funding for the Darlington Refurbishment project and other expenditures, and maintain the Company's investment grade credit rating, while taking into account both near-term and future impacts on customers. OPG expects to recognize amounts deferred under rate smoothing as income in the periods to which the underlying approved revenue requirements relate.

The application will further challenge and incentivize OPG to find additional cost reductions and efficiencies within its operations, as a result of greater de-coupling of nuclear and hydroelectric regulated prices from costs and a longer rate-setting period under the OEB's incentive ratemaking framework, which forms the basis for the ratemaking methodologies reflected in the application.

The application seeks an increase in the nuclear rate base, effective in early 2020, to reflect the planned placement in service of approximately $4.8 billion of capital expenditures upon the scheduled return to service of Unit 2 at the Darlington GS as part of the Darlington Refurbishment project and, effective in 2017, an increase in the deemed capital structure applied to the total regulated rate base to 49 percent equity and 51 percent debt, from 45 percent equity and 55 percent debt reflected in the existing regulated prices. The application also requests new rate riders, effective January 1, 2017, to recover or repay the December 31, 2015 balances in all of the Company's OEB-authorized variance and deferral accounts, with the exception of the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the portion of these balances previously approved for recovery or repayment through rate riders that were in effect during 2016.

The OEB's decision on the application, including the effective date of approved new regulated prices, is expected later in 2017. **[MONITOR]**

For generation assets that do not form part of the assets regulated by the OEB, OPG's strategy has been to secure appropriate long-term revenue arrangements. In line with this strategy, virtually all of OPG's non-regulated operating facilities and assets under construction are subject to long-term Energy Supply Agreements (ESAs) or other long-term contracts with the IESO.

Ensure Availability of Cost Effective Funding

In April 2017, DBRS Limited (DBRS) re-affirmed the long-term credit rating on OPG's debt at 'A (low)' and OPG's commercial paper rating at 'R-1 (low)'. All ratings from DBRS have a stable outlook. In July 2017, S&P Global Ratings (S&P) re-affirmed OPG's long-term credit rating at 'BBB+' with a stable outlook. S&P's commercial paper rating for OPG is 'A-1 (low)'.

Social Licence

As the largest electricity generator in Ontario with diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust. OPG is committed to maintaining high standards of public safety and corporate citizenship, including environmental stewardship, transparency, community engagement, and Indigenous relations.

OPG is focused on building long-term, mutually beneficial working relationships with Indigenous communities, businesses and organizations across Ontario, and continues to support procurement, employment and educational opportunities with its Indigenous community partners. The Company seeks to establish these relationships based on a foundation of respect for the languages, customs, and political, social and cultural organizations of the Indigenous communities.

In June 2017, OPG launched an Indigenous Business Engagement (IBE) Initiative. The purpose of this initiative is to increase access to procurement opportunities for Indigenous businesses interested in supplying materials and services to OPG. The IBE Initiative is based on a strategy that will identify opportunities in contracts, scopes of work and business plans for potential Indigenous business engagement; include criteria related to suppliers' ability to engage or partner with Indigenous people or businesses in assessing procurement proposals; and invest in relationships with Indigenous communities by increasing outreach efforts to enhance understanding of how to do business with OPG. OPG has continued to engage with various Indigenous business and communities as well as its suppliers to promote the IBE Initiative. In September 2017, OPG presented the IBE to the Mohawk Council of Akwesanse (Akwesanse). As a result, Akwesanse plans to create a database of businesses in the community that will participate in contracting and supply opportunities with OPG. In September 2017, OPG also hosted a similar presentation to the Williams Treaties First Nations, located proximate to the Pickering and Darlington Nuclear Generating Stations, at the quarterly meeting for these communities.

OPG is developing recruitment plans targeting Indigenous people. In October 2017, OPG participated in five Indigenous-specific career fairs to attract such talent. **[MONITOR]**

OPG has a transportation electrification strategy that will help position OPG as a leader in transportation electrification in Ontario. This strategy is intended to leverage OPG's clean electricity to support action on climate change, create growth opportunities for OPG, and enhance OPG's brand and social licence.

Commented [A12]: Sp. "Akwesasne" ?

OPG – fixed spelling to as follows:

In September 2017, OPG presented the IBE to the Mohawk Council of Akwesasne (Akwesasne). As a result, the Akwesasne plan to create a database of businesses in the community that will participate in contracting and supply opportunities with OPG.

Commented [A13]: Does this deal with OPG owned fleet and other vehicles, or in line with the infrastructure for EV vehicles.

Can further details be provided in particular on the point of 'creating growth opportunities for OPG'.

OPG – revised wording for this paragraph as follows:

OPG has a strategy to help position the Company as a leader in transportation electrification in the province. The strategy aims to leverage the Company's clean, reliable and cost-effective electricity to power transportation, capitalize on future commercial growth opportunities, and enhance the Company's social licence. OPG is pursuing initiatives to increase the use of electric vehicles within its operations, and is assessing vehicle grid integration and hydrogen applications for the transportation sector.

Outlook

The financial performance of OPG's regulated operations is driven, in large part, by the outcome of applications for regulated prices to the OEB. The existing base regulated prices were established by the OEB effective November 1, 2014 based on a forecast of costs and production for the regulated facilities for the 2014 to 2015 period. The future outcome of OPG's current application for new regulated prices, currently pending the OEB's decision, is expected to provide substantial price certainty for the regulated business for the 2017 to 2021 period.

In its application, OPG has requested January 1, 2017 as the effective date for the new regulated prices. In December 2016, the OEB issued an order declaring the existing base regulated prices interim, which preserves the OEB's ability to make the new regulated prices effective as early as January 1, 2017. Considering the timing of OPG's application and OPG's procedural adherence throughout the proceeding, the Company believes that the OEB could make the new regulated prices effective January 1, 2017. This would allow OPG to recover the difference between the approved new regulated prices and the existing regulated prices for the period between January 1, 2017 and the implementation date of the new prices based on the OEB's order. The OEB's decision on the application, including the effective date of the new regulated prices, is expected in the fourth quarter of 2017. **[MONITOR]** The continuation of existing regulated prices until the issuance of the OEB's decision is expected to continue to contribute to lower income, particularly from the Regulated – Nuclear Generation segment, and, excluding the gain on sale of the Company's head office premises and associated parking facility recorded in the second quarter of 2017, lower

ROE Excluding AOCI during 2017, compared to 2016. In large part, this is due to the year-over-year reduction in nuclear electricity generation resulting from the Unit 2 refurbishment outage at the Darlington GS, given that the existing nuclear regulated prices were determined in 2014 based on a higher production forecast that reflected the operation of all four units at the station. As such, the OEB's decision on the effective date of the new regulated prices, as well as the timing of the decision issuance, could have a significant impact on OPG's financial results during 2017.

Nuclear base regulated prices resulting from OPG's current application will be subject to a rate smoothing mechanism that defers collection of a portion of OEB-approved revenues to future periods. As expected, combined with the expiry of rate riders in effect to the end of 2016, a year-over-year reduction in nuclear generation due to the Unit 2 refurbishment outage at the Darlington GS and the continuation of existing regulated prices until such time as new prices are implemented by the OEB, this will result in lower cash flow from operating activities in 2017, compared to 2016. OPG expects to continue to have the necessary financial capacity and sufficient access to cost effective financing sources to continue to fund its capital requirements and other disbursements.

Lower nuclear generation due to the Darlington Refurbishment outages will continue, as planned, to negatively impact the Enterprise TGC metric for the duration of the refurbishment project. Variability in sustaining capital investment expenditures, including major sustaining projects for the hydroelectric operations, also will impact the Enterprise TGC in future periods.

Several OEB-authorized regulatory variance and deferral accounts currently in place contribute to reducing the relative variability of the Company's income and ROE Excluding AOCI. Among others, the regulatory accounts include those related to the revenue impact of variability in water flows and forgone production due to SBG conditions at the regulated hydroelectric stations. As there are no variance or deferral accounts in place related to the impact of generation performance of the nuclear stations on revenue from base regulated prices, the Regulated – Hydroelectric segment generally is expected to produce overall more predictable earnings. OPG continues to operate and maintain its nuclear facilities with a view to optimize their performance and availability, while focusing on improving the overall reliability and predictability of the fleet.

Electricity generated from most of OPG's non-regulated assets is subject to ESAs with the IESO. Based on these agreements, OPG expects the Contracted Generation Portfolio segment to continue to contribute a generally stable level of earnings and cash flow from operations going forward.

OPG's total forecast capital expenditures for the 2017 year are approximately $2.0 billion. This includes amounts for the Darlington Refurbishment project, hydroelectric and other development projects including the completion of the Peter Sutherland Sr. GS and the expansion of the Ranney Falls GS, and sustaining capital investments across the generating fleet. OPG's major projects are discussed in the section, *Project Excellence*.

In addition to the operating and financial performance of the electricity generation business, OPG's results are affected by the earnings on the Nuclear Segregated Funds, which are reported in the Regulated – Nuclear Waste Management segment. While the Nuclear Segregated Funds are managed to achieve, in the long term, the target rate of return based on the discount rate specified in the ONFA, the rates of return earned in a given period can be subject to various external factors including financial market conditions and, for the portion of the Used Fuel Segregated Fund guaranteed by the Province under the ONFA, changes in the Ontario consumer price index (CPI). In the near term, these factors can be volatile and cause fluctuations in the Company's income. This volatility is partially mitigated by the impact of the OEB-authorized Bruce Lease Net Revenues Variance Account and, as discussed below, the funded status of the two segregated funds.

As OPG does not have the right to withdraw surplus amounts from the Nuclear Segregated Funds, OPG limits the amount of Nuclear Segregated Funds assets reported on the balance sheet to the present value of such life cycle funding liability. This reduces the volatility of earnings on the Nuclear Segregated Funds reflected in net income when the funds are in a fully funded or overfunded position. As at September 30, 2017, the Decommissioning

Segregated Fund was overfunded by approximately 23 percent, and the Used Fuel Segregated Fund was marginally overfunded, by less than one percent, based on the 2017 ONFA Reference Plan. Variability in asset performance due to volatility inherent in financial markets and changes in Ontario CPI, or changes in funding liability estimates, may result in either or both funds becoming underfunded in the future.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

Regulated – Nuclear Generation Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue	**739**	885	**2,000**	2,631
Fuel expense	**81**	79	**217**	239
Gross margin	**658**	806	**1,783**	2,392
Operations, maintenance and administration	**511**	521	**1,693**	1,665
Depreciation and amortization	**116**	230	**333**	691
Property taxes	**7**	6	**20**	19
Income (loss) before other losses, interest, and income taxes	**24**	49	**(263)**	17
Other losses	**4**	2	**4**	-
Income (loss) before interest and income taxes	**20**	47	**(267)**	17

For the three and nine month periods ended September 30, 2017, the segment earnings decreased by $27 million and $284 million, respectively, compared to the same periods in 2016. The decrease in earnings was expected and primarily due to reduced revenue from the nuclear base regulated price of approximately $24 million and $230 million, respectively. The decrease was partially offset by an associated year-over-year decrease in fuel expense. The decrease in revenue during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, reflected lower electricity generation of 0.4 TWh and 4.0 TWh, respectively, primarily due to the ongoing Unit 2 refurbishment outage at the Darlington GS that began in October 2016, without a corresponding increase in the base regulated price. The existing nuclear base regulated price set by the OEB in 2014 continues to be in effect pending the OEB's decision on OPG's application for new regulated prices, proposed to be effective on January 1, 2017. The existing price does not reflect the lower generation as a result of the Darlington Refurbishment project, as it was set to allow the Company to recover its approved nuclear costs over a higher nuclear production volume, based on the 2014 and 2015 outage profile that did not include a refurbishment outage. The reduction in nuclear electricity generation for the three months ended September 30, 2017 was largely offset by the higher electricity generation from the Pickering GS.

OM&A expenses decreased by $10 million during the third quarter of 2017, compared to the same period in 2016, as a result of a higher materials and supplies obsolescence charge recognized in 2016. OM&A expenses increased by $28 million during the nine months ended September 30, 2017, compared to the same period in 2016, due to planned maintenance activities in 2017.

Depreciation and amortization expense, excluding amortization expense related to regulatory account balances, increased by $16 million and $30 million during the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016, primarily due to new assets in service.

The expiry of an OEB-authorized nuclear rate rider on December 31, 2016 contributed to the decrease in segment revenue for the three and nine month periods ended September 30, 2017, compared to the same periods in 2016. As rate riders allow for recovery of approved balances in OEB-authorized regulatory accounts, this decrease in revenue was largely offset by a decrease in amortization expense related to these balances. There was no rate rider

in effect during the nine months ended September 30, 2017, pending the outcome of OPG's current application to the OEB for new regulated prices.

The Unit Capability Factors for the Darlington and Pickering generating stations were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Unit Capability Factor *(%)* [1]				
Darlington GS	**96.2**	89.6	**82.1**	87.6
Pickering GS	**88.7**	77.3	**83.8**	73.8

[1] The nuclear Unit Capability Factor excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS was excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

The Unit Capability Factor at the Darlington GS increased in the third quarter of 2017, compared to the same quarter in 2016, primarily due to the lower number of planned outage days during the third quarter of 2017. The lower Unit Capability Factor at the Darlington GS for the nine months ended September 30, 2017, compared to the same period in 2016, reflected the higher number of planned outage days, largely driven by constraints related to the transition of the station toward refurbishment.

The increase in Unit Capability Factor at the Pickering GS for the three and nine month periods ended September 30, 2017 was primarily due to outage optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station compared to 2016.

Regulated – Nuclear Waste Management Segment

(millions of dollars) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Revenue	**33**	36	**90**	102
Operations, maintenance and administration	**35**	38	**96**	108
Accretion on nuclear fixed asset removal and nuclear waste management liabilities	**230**	228	**696**	684
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(196)**	(248)	**(579)**	(620)
(Loss) Income before interest and income taxes	**(36)**	18	**(123)**	(70)

The segment loss before interest and income taxes was $36 million and $123 million during the three and nine months ended September 30, 2017, respectively, a decrease in earnings of $54 million and $53 million compared to the same periods in 2016. The decline in earnings was primarily due to lower earnings from the Nuclear Segregated Funds, net of the impact of the impact of the Bruce Lease Net Revenues Variance Account, reflecting higher earnings from market returns on fund assets and the CPI-adjusted rate of return guaranteed by the Province for the portion of the Used Fuel Segregated Fund related to the initial 2.23 million used fuel bundles (committed return) in the third quarter of 2016.

As both the Decommissioning Segregated Fund and the Used Fuel Fund were in an overfunded position during the three and nine months period ended September 30, 2017, compared to the underlying funding liabilities per the approved ONFA Reference Plan, the earnings on the funds during these periods reflected the growth rate in the present value of the funding liabilities and were not impacted by market returns and committed return. The higher earnings on both funds during the three and nine months periods ended September 30, 2016 reflected market returns and committed return, as the Decommissioning Segregated Fund became over 120 percent funded during the third quarter of 2016 while the Used Fuel Fund was underfunded, compared to the corresponding funding liabilities.

Higher market returns and committed return in the third quarter of 2016 in relation to the funding liabilities' growth rate reflected in fund earnings during 2017 resulted in a year-over-year decrease in the amount of earnings on the Nuclear Segregated Funds.

As of December 31, 2016, OPG recorded a decrease of approximately $1,570 million to the Nuclear Liabilities and associated asset retirement costs capitalized as part of the carrying value of the nuclear generating stations. The resulting year-over-year decreases in accretion on fixed asset removal and nuclear waste management liabilities recorded in the Regulated – Nuclear Waste Management segment and depreciation and fuel expenses recorded in the Regulated – Nuclear Generation segment during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, were offset by the impact of the Bruce Lease Net Revenues Variance Account and the Nuclear Liability Deferral Account authorized by the OEB.

Under the current OEB-approved cost recovery methodology, these changes in expenses also are not expected to materially affect OPG's income during the rest of 2017, as they are expected to continue to be largely offset by the impact of the regulatory accounts until such time as the OEB implements corresponding changes to OPG's nuclear regulated prices, and subsequently by the impact of such new regulated prices. Further details on the change in the estimate of the Nuclear Liabilities as of December 31, 2016 are described in OPG's 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Asset Retirement Obligation*. **[MONITOR]**

Regulated – Hydroelectric Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue [1]	**327**	350	**1,069**	1,148
Fuel expense	**88**	88	**258**	259
Gross margin	**239**	262	**811**	889
Operations, maintenance and administration	**81**	87	**232**	238
Depreciation and amortization	**34**	56	**103**	169
Property tax	**1**	1	**1**	1
Income before other losses (gains), interest and income taxes	**123**	118	**475**	481
Other losses (gains)	**1**	1	**1**	(19)
Income before interest and income taxes	**122**	117	**474**	500

[1] During the three and nine month periods ended September 30, 2017, the Regulated – Hydroelectric segment revenue included incentive payments of $4 million and $9 million, respectively, related to the OEB-approved hydroelectric incentive mechanism (three and nine month periods ended September 30, 2016 – incentive payments of $6 million and $8 million, respectively). The mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers. The incentive payments are reduced to remove incentive revenues arising in connection with SBG conditions.

The increase in segment income before interest and income taxes of $5 million during the third quarter of 2017, compared to the same quarter in 2016, was primarily the result of a decrease in OM&A expenses, mainly due to the timing of repairs and maintenance work in 2017 and a deferral of outages during the high water period.

The decrease in segment income before interest and income taxes of $26 million during the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to a gain of $22 million recognized during the first quarter of 2016 to reflect the OEB's January 2016 decision to reverse a portion of an earlier capital cost disallowance related to the Niagara Tunnel project expenditures, in response to a motion by OPG. The income impact of OEB-approved variance accounts also contributed to the year-over-year decrease in income for the period. These factors were partially offset by the decrease in OM&A expenses related to the timing of repairs and maintenance work in 2017 and a deferral of outages during the high water period.

The decrease in revenue from the segment for the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was largely due to the expiry of an OEB-authorized rate rider on

December 31, 2016. As the rider allowed for the recovery of approved balances in OEB-authorized regulatory accounts, the resulting reduction in revenue was largely offset by lower amortization expense related to these balances. There was no rate rider in effect during the first nine months of 2017 pending the outcome of OPG's current application to the OEB for new regulated prices.

The Hydroelectric Availability for the stations included in the Regulated – Hydroelectric segment was as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Hydroelectric Availability *(%)*	**87.6**	84.1	**89.0**	89.8

The Hydroelectric Availability in the third quarter of 2017 was higher compared to the same period in 2016, primarily due to a higher number of planned outages in 2016 as a result of the refurbishment of the Sir Adam Beck Pump GS reservoir between April 2016 and February 2017. The marginal decrease in Hydroelectric Availability during the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to a higher number of unplanned outage days at the Northwestern Ontario and Niagara region hydroelectric stations, partially offset by higher availability from the Sir Adam Beck Pump GS.

Contracted Generation Portfolio Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue	**141**	149	**431**	431
Fuel expense	**15**	19	**42**	42
Gross margin	**126**	130	**389**	389
Operations, maintenance and administration	**39**	44	**118**	129
Depreciation and amortization	**20**	19	**59**	56
Accretion on fixed asset removal liabilities	**3**	2	**7**	6
Property taxes	**-**	1	**5**	6
Income from investments subject to significant influence	**(11)**	(11)	**(29)**	(28)
Income before other loss, interest and income taxes	**75**	75	**229**	220
Other loss	**-**	1	**-**	1
Income before interest and income taxes	**75**	74	**229**	219

Income before interest and income taxes from the segment increased by $1 million and $10 million during the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016. The increase in earnings for the three months ended September 30, 2017 mainly resulted from revenues from the Peter Sutherland Sr. GS that was placed in-service at the end of the first quarter of 2017 and lower OM&A expenses, partially offset by lower revenue from the Atikokan GS. The decrease in revenue from the Atikokan GS was primarily due to higher revenues in 2016, when the station was called upon to provide the needed support to the electricity system in Northwestern Ontario as a result of an outage at a local transformer station. For the nine months ended September 30, 2017, the increase in earnings was primarily due to lower OM&A expenses. The lower OM&A expenses for the three and nine month periods ended September 30, 2017 were mainly due to the prospective adoption of the full yield curve approach to the estimation of the service and interest cost components of pension and OPEB costs starting in 2017.

The Hydroelectric Availability and the Thermal Equivalent Forced Outage Rate (EFOR) for the Contracted Generation Portfolio segment were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Hydroelectric Availability *(%)*	**66.1**	68.2	**76.9**	79.6
Thermal EFOR *(%)*	**2.6**	2.1	**6.0**	1.3

Lower Hydroelectric Availability during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was primarily due to an increase in the number of planned outage days at the Lower Mattagami River hydroelectric generating stations.

The higher Thermal EFOR during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was primarily due to a higher number of unplanned outage days at a Lennox GS unit as a result of a transmission outage and a generator cooling water system outage in 2017.

Services, Trading, and Other Non-Generation Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue	**9**	15	**36**	52
Fuel expense	**1**	1	**1**	1
Gross margin	**8**	14	**35**	51
Operations, maintenance and administration	**1**	11	**2**	20
Depreciation and amortization	**8**	8	**22**	25
Accretion on fixed asset removal liabilities	**2**	2	**6**	6
Property taxes	**-**	4	**4**	9
(Loss) income before other gains, interest, and income taxes	**(3)**	(11)	**1**	(9)
Other gains	**(2)**	(3)	**(385)**	(5)
Income (loss) before interest and income taxes	**(1)**	(8)	**386**	(4)

Segment earnings improved by $7 million during the third quarter of 2017, compared to the same quarter in 2016. The improvement in earnings was primarily due to lower OM&A expenses reflecting project expenditures incurred in the third quarter of 2016, and OPG's decision, in the fourth quarter of 2016, to proceed with the decommissioning of Lambton GS.

Segment income before interest and income taxes increased by $390 million for the nine months ended September 30, 2017, compared to the same period in 2016. The increase in earnings mainly reflected the gain on the sale of OPG's head office premises and associated parking facility recorded during the second quarter of 2017.

LIQUIDITY AND CAPITAL RESOURCES

OPG's primary sources of liquidity and capital are funds generated from operations, bank financing, credit facilities provided by the Ontario Electricity Financial Corporation (OEFC), long-term corporate debt, and capital market financing. These sources are used for multiple purposes including: to invest in plants and technologies, to undertake major projects, to fund long-term obligations such as contributions to the pension fund and the Nuclear Segregated Funds, to make payments under the OPEB plans, to fund expenditures on Nuclear Liabilities not reimbursable from the Nuclear Segregated Funds, to service and repay long-term debt, to provide general working capital, and to fund OPG's investment in the Fair Hydro Plan.

Changes in cash and cash equivalents for the three and nine month periods ended September 30 are as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Cash and cash equivalents, beginning of period	**242**	295	**186**	464
Cash flow provided by operating activities	**485**	530	**698**	1,211
Cash flow used in investing activities	**(463)**	(390)	**(720)**	(1,253)
Cash flow provided by (used in) financing activities	**16**	(9)	**116**	4
Net increase (decrease)	**38**	131	**94**	(38)
Cash and cash equivalents, end of period	**280**	426	**280**	426

For a discussion of cash flow provided by operating activities and the FFO Adjusted Interest Coverage ratio, refer to the details in the section, *Highlights* under the heading, *Overview of Results*.

Investing Activities

Electricity generation is a capital-intensive business. It requires continued investment in plants and technologies to maintain and improve operating performance including asset reliability, safety and environmental performance, to increase the generating capacity of existing stations, and to invest in the development of new generating stations, emerging technologies and other business growth opportunities.

Cash flow used in investing activities during the third quarter of 2017 was $463 million, compared to $390 million for the same period in 2016. The increase in cash flow used for investing activities mainly resulted from higher expenditures on the Darlington Refurbishment project in the third quarter of 2017.

Cash flow used in investing activities decreased by $533 million for the nine months ended September 30, 2017, compared to the same period in 2016. The decrease in net cash flow used in investing activities was primarily due to the receipt of proceeds from the sale of OPG's head office premises and associated parking facility in the second quarter of 2017 pursuant to a Shareholder Declaration and Shareholder Resolution, and the acquisition of nine million common shares of Hydro One Limited (Hydro One) in the second quarter of 2016, partially offset by higher expenditures on the Darlington Refurbishment project in 2017. OPG acquired the Hydro One shares for investment purposes, to mitigate the risk of future price volatility related to the Company's future share delivery obligations under the collective agreements with the Power Workers' Union and The Society of Energy Professionals.

Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from the sale of head office premises and associated parking facility, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. OPG expects that the amount of designated proceeds to be transferred into the Consolidated Revenue Fund will be largely consistent with the after-tax gain on sale. The transfer is expected to take place later in 2017.

Financing Activities

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. In the second quarter of 2017, OPG renewed and extended the expiry date of both tranches from May 2021 to May 2022. There were no amounts outstanding under the bank credit facility as at September 30, 2017.

There was $160 million of commercial paper outstanding under OPG's commercial paper program as at September 30, 2017.

As at September 30, 2017, OPG also maintained $25 million of short-term, uncommitted overdraft facilities, and a further $463 million of short-term, uncommitted credit facilities, which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other general corporate purposes. As at September 30, 2017, a total of $388 million of Letters of Credit had been issued under these facilities. This included $349 million for the supplementary pension plans, $38 million for general corporate purposes, and $1 million related to the operation of the PEC.

The Company has an agreement to sell an undivided co-ownership interest in its current and future accounts receivable to an independent trust, expiring on November 30, 2018. The maximum amount of co-ownership interest that can be sold under this agreement is $150 million. As at September 30, 2017, no borrowings were issued under this agreement and there were Letters of Credit outstanding under this agreement of $150 million, which were issued in support of OPG's supplementary pension plans.

As at September 30, 2017, Lower Mattagami Energy Limited Partnership (LME) maintained a $400 million bank credit facility to support the funding requirements for the Lower Mattagami River project including support for LME's commercial paper program and the issuance of the Letters of Credit. The facility consists of a $300 million tranche which, in the third quarter of 2017, was extended to mature in August 2022 and a $100 million tranche which, in the third quarter of 2017, was reduced from $200 million and extended to mature in August 2018. As at September 30, 2017, there was no external commercial paper outstanding under LME's commercial paper program. A letter of credit of $55 million was issued in July 2017 and remains outstanding as at September 30, 2017 under the $300 million tranche of the credit facility.

In June 2016, OPG entered into a $700 million general corporate credit facility agreement with the OEFC, which expires on December 31, 2017. In the third quarter of 2017, the agreement was amended to increase the credit facility to $2,350 million and to extend its expiry date to December 31, 2018.

In February 2017, OPG issued senior notes payable to the OEFC totalling $200 million and maturing in February 2047. The effective interest rate and coupon interest rate of these notes was 4.12 percent. In June 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in June 2047. The effective interest rate and coupon interest rate of these notes was 3.65 percent. In August 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in August 2047. The effective interest rate and coupon interest rate of these notes was 3.86 percent. In September 2017, OPG issued senior notes payable to the OEFC totalling $400 million and maturing in September 2047. The effective interest rate and coupon interest rate of these notes was 4.07 percent. As at September 30, 2017, there were outstanding long-term borrowings of $800 million under this credit facility.

In October 2017, OPG issued $500 million of senior notes payable under a Medium Term Note Program. The notes bear a coupon interest rate of 3.32 percent and an effective rate of 3.43 percent, payable semi-annually until maturity on October 4, 2027. The offering was made under OPG's $2 billion short form base shelf prospectus dated September 12, 2017. The net proceeds will be used for general corporate purposes, including the financing of OPG's subordinated debt investment in the Fair Hydro Plan.

As at September 30, 2017, OPG's long-term debt outstanding was $5,482 million, including $628 million due within one year.

OPG continues to evaluate arrangements that would appropriately support the Company's financing needs and capital expenditure programs.

Contractual and Commercial Commitments

Pension Plan Actuarial Valuation

A new actuarial valuation of the OPG registered pension plan was filed with the Financial Services Commission of Ontario in September 2017 with an effective date of January 1, 2017. The annual funding requirements in accordance with the new actuarial valuation are $212 million for 2017, $215 million for 2018, and $219 million for 2019. The next actuarial valuation must have an effective date no later than January 1, 2020.

BALANCE SHEET HIGHLIGHTS

The following section provides highlights of OPG's unaudited interim consolidated financial position using selected balance sheet data:

(millions of dollars) (unaudited)	As At September 30 2017	As At December 31 2016
Property, plant and equipment - net	**20,801**	19,998
The increase was primarily due to capital expenditures on the Darlington Refurbishment project, partially offset by depreciation expense.		
Nuclear fixed asset removal and nuclear waste management funds *(current and non-current portions)*	**16,534**	15,984
The increase was primarily due to earnings on the Nuclear Segregated Funds, partially offset by reimbursements of eligible expenditures on nuclear fixed asset removal and nuclear waste management activities.		
Short-term debt	**160**	2
The increase was due to commercial paper issued under OPG's commercial paper program during the third quarter of 2017.		
Fixed asset removal and nuclear waste management liabilities	**20,075**	19,484
The increase was primarily a result of accretion expense representing the increase in the liabilities due to the passage of time, partially offset by expenditures on nuclear fixed asset removal and waste management activities.		

Off-Balance Sheet Arrangements

In the normal course of operations, OPG engages in a variety of transactions that, under US GAAP, are either not recorded in the Company's interim consolidated financial statements or are recorded in the Company's interim consolidated financial statements using amounts that differ from the full contract amounts. Principal off-balance sheet activities for OPG include guarantees and long-term contracts.

CHANGES IN ACCOUNTING POLICIES AND ESTIMATES

OPG's significant accounting policies are outlined in Note 3 to the audited consolidated financial statements as at and for the year ended December 31, 2016. A discussion of recent accounting pronouncements and change in accounting estimate are included in Note 2 to OPG's unaudited interim consolidated financial statements as at and for the three and nine month periods ended September 30, 2017 under the heading, *Significant Accounting Policies and Estimates*. Disclosure regarding OPG's critical accounting policies is included in OPG's 2016 annual MD&A.

RISK MANAGEMENT

The following provides an update to the discussion of the Company's risks and risk management activities included in OPG's 2016 annual MD&A. As such, the disclosure in this section should be read in conjunction with the *Risk Management* section included in the annual MD&A.

Risks to Achieving Project Excellence

Deep Geologic Repository for Low and Intermediate Level Waste

In August 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of the potential cumulative effects of the DGR project on the physical and cultural heritage of the SON, taking into account the results of the SON Community Process. OPG continues to work with the SON, however the timing and outcome of the SON Community Process and the EA decision by the Minister are uncertain.

Risks to Maintaining Financial Strength

Commodity Markets

Changes in the market price of fuels used to produce electricity can adversely impact OPG's earnings and cash flow from operations.

To manage the risk of unpredictable increases in the price of fuels, the Company has fuel hedging programs, which include fixed price and indexed contracts.

The percentages hedged of OPG's fuel requirements are shown in the following table. These amounts are based on yearly forecasts of generation and supply mix, and as such, are subject to change as these forecasts are updated.

	2017 [1]	2018	2019
Estimated fuel requirements hedged [2]	73%	73%	69%

[1] Based on actual fuel requirements hedged for the nine months ended September 30, 2017 and forecast for the remainder of the year.

[2] Represents the approximate portion of megawatt-hours of expected generation production (and year-end inventory targets) from each type of OPG-operated facility (nuclear, hydroelectric and thermal) for which the Company has entered into contractual arrangements or obligations in order to secure the price of fuel, or which is subject to regulation. In the case of hydroelectric generation, this represents the gross revenue charge and water rental charges. Excess fuel inventories (nuclear and thermal) in a given year are attributed to the next year for the purpose of measuring hedge ratios.

Foreign Exchange

OPG's earnings and cash flow can be affected by movements in the United States dollar (USD) relative to the Canadian dollar.

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are denominated in, or tied to, USD. To manage this risk, OPG periodically employs various financial instruments such as forwards and other

derivative contracts, in accordance with approved risk management policies. As at September 30, 2017, OPG had no foreign exchange contracts outstanding.

Trading

OPG's financial performance can be affected by its trading activities.

OPG's electricity trading operations are closely monitored, with total exposures measured and reported to senior management on a daily basis. The main metric used to measure the financial risk of trading activity is Value at Risk (VaR). VaR is defined as a probabilistic maximum potential future loss expressed in monetary terms for a portfolio based on normal market conditions over a set period of time. For the third quarter of 2017, the VaR utilization ranged between $0.2 million and $0.3 million.

Credit

Deterioration in energy markets counterparty credit and non-performance by suppliers and contractors can adversely impact OPG's earnings and cash flow from operations.

OPG manages its exposure to suppliers or counterparties by evaluating their financial condition and negotiating appropriate collateral or other forms of security. OPG's credit exposure relating to energy markets transactions as at September 30, 2017 was $356 million, including $346 million with the IESO. Management considers the Company's risk exposure relating to electricity sales through the IESO-administered spot market to be low as the IESO oversees the credit worthiness of all market participants. In accordance with the IESO's prudential support requirements, market participants are required to provide collateral to cover funds that they might owe to the market. Of the $10 million remaining exposure as at September 30, 2017, over 95 percent was related to investment grade counterparties.

Fair Hydro Plan

OPG's role in connection with the Fair Hydro Plan could have reputational impacts on the Company.

The *Ontario Fair Hydro Plan Act, 2017* received Royal Assent on June 1, 2017 and its attendant regulations came into force in June, July, and October 2017. **[UPDATE]** The regulations clarify aspects of the structure and program logistics required for ~~OPG, as~~ the Financial Services Manager of the Fair Hydro Plan, which OPG is planning to undertake, to refinance a portion of the Global Adjustment through the Trust. OPG's reputation could potentially be adversely impacted through its involvement with the Fair Hydro Plan and through stakeholder opinions related to this involvement.

Commented [A14]: Not sure this is the right wording. OPG's role as FSM is required under the Act, but not the refinancing through the Trust – the OPG Financing Entity's (or entities) role is discretionary.

OPG – please see changes to this paragraph as follows:

The *Ontario Fair Hydro Plan Act, 2017* received Royal Assent on June 1, 2017 and the associated general regulation came into force in June 2017. As the Financial Services Manager of the Fair Hydro Plan, OPG's reputation could potentially be adversely impacted through this involvement and through stakeholder opinions related to this involvement.

Recovery of Pension and OPEB Costs

On September 14, 2017, the OEB issued its final report on the guiding principles and the policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the electricity and natural gas sectors. The report reaffirmed the conclusions of the initial report issued in May 2017, including the establishment of the accrual basis of accounting as the default rate-setting method and the establishment of a variance account to record asymmetric carrying charges in favour of ratepayers on the differences between the accrual costs recovered and cash payments made by a utility for pension and OPEB plans. The report requires OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the Pension & OPEB Cash Versus Accrual Differential Deferral Account that has been in effect since November 1, 2014, until such time as the OEB approves the resumption of the accrual basis of recovery. The future recovery of amounts recorded in the account will be subject to this approval. The report confirmed that OPG would become subject to the carrying charges on the differences between accrual costs and cash payments going back to November 1, 2014, with the charges calculated on the portion of such differences that have been recovered through regulated prices. The carrying charges will be determined at prescribed interest rate set quarterly by the OEB based on the quarterly return of a mid-term corporate bond index yield. This outcome has reduced OPG's risk related to the recovery of actual pension and OPEB accrual

costs and the recovery of the balance in the Pension & OPEB Cash Versus Accrual Differential Deferral Account. The account had a balance of $552 million as at September 30, 2017 and is recognized on the Company's consolidated balance sheet as a regulatory asset. OPG's financial results for the three and nine month periods ended September 30, 2017 were not impacted by the issuance of the OEB's report.

RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One, the IESO and the OEFC. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions are summarized below:

	Three Months Ended September 30			
	2017		2016	
(millions of dollars) (unaudited)	**Revenue**	**Expense**	**Revenue**	**Expense**
Hydro One				
Electricity sales	**2**	**-**	1	-
Services	**-**	**3**	-	3
Dividends	**2**	**-**	-	2
Province of Ontario				
Decommissioning Fund excess funding [1]	**-**	**(44)**	-	201
Used Fuel Fund rate of return guarantee and excess funding [1]	**-**	**(39)**	-	295
Gross revenue charges	**-**	**27**	-	28
ONFA guarantee fee	**-**	**2**	-	2
Other	**-**	**2**	-	-
OEFC				
Gross revenue charges	**-**	**62**	-	57
Interest expense on long-term notes	**-**	**40**	-	42
Income taxes, net of investment tax credits	**-**	**23**	-	28
IESO				
Electricity related revenue	**1,126**	**4**	1,293	7
	1,130	**80**	1,294	665

(millions of dollars) (unaudited)	Nine Months Ended September 30 2017 Revenue	2017 Expense	2016 Revenue	2016 Expense
Hydro One				
Electricity sales	**7**	**-**	4	-
Services	**1**	**8**	1	12
Dividends	**6**	**-**	-	4
Province of Ontario				
Decommissioning Fund excess funding [1]	**-**	**164**	-	137
Used Fuel Fund rate of return guarantee and excess funding [1]	**-**	**217**	-	190
Gross revenue charges	**-**	**84**	-	91
ONFA guarantee fee	**-**	**6**	-	6
Other	**-**	**3**	-	-
OEFC				
Gross revenue charges	**-**	**156**	-	147
Interest expense on long-term notes	**-**	**122**	-	127
Income taxes, net of investment tax credits	**-**	**132**	-	112
IESO				
Electricity related revenue	**3,228**	**11**	3,894	22
	3,242	**903**	3,899	848

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at September 30, 2017 and December 31, 2016, the Nuclear Segregated Funds were reported net of amounts due to the Province of $3,796 million and $3,415 million, respectively. The details of accounting for the Nuclear Segregated Funds are described in OPG's 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

The receivable, available-for-sale securities, payable and long-term debt balances between OPG and its related parties are summarized below:

(millions of dollars) (unaudited)	September 30 2017	December 31 2016
Receivables from related parties		
Hydro One	**1**	1
IESO	**346**	421
OEFC	**3**	1
PEC	**2**	4
Province of Ontario	**5**	2
Available-for-sale securities		
Hydro One shares	**190**	212
Accounts payable and accrued charges		
OEFC	**37**	61
Province of Ontario	**6**	2
IESO	**2**	2
Long-term debt (including current portion)		
Notes payable to OEFC	**3,245**	3,295

OPG holds interest-bearing Province of Ontario bonds in the Nuclear Segregated Funds and the OPG registered pension fund. As at September 30, 2017, the Nuclear Segregated Funds held $1,498 million of interest-bearing Province of Ontario bonds, while the registered pension fund had no such holdings. As at December 31, 2016, the Nuclear Segregated Funds and the registered pension fund held $1,652 million and $284 million of interest-bearing Province of Ontario bonds, respectively. These bonds are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

There have been no related party transactions related to the Fair Hydro Plan and associated financing activities. The first transaction between the Trust and the IESO is expected later in 2017.

INTERNAL CONTROLS OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

The Company maintains a comprehensive system of policies, procedures, and processes that represents its framework for internal controls over financial reporting and for its disclosure controls and procedures (together, ICOFR). There were no changes in the Company's internal control system during the current interim period that has or is reasonably likely to have a material impact to the ICOFR.

QUARTERLY FINANCIAL HIGHLIGHTS

The following tables set out selected financial information from OPG's unaudited interim consolidated financial statements for each of the eight most recently completed quarters.

(millions of dollars - except where noted) (unaudited)	**September 30 2017**	**June 30 2017**	**March 31 2017**	**December 31 2016**
Revenue	**1,217**	1,146	1,176	1,388
Net income (loss)	**140**	307	68	(8)
Less: Net income attributable to non-controlling interest	**9**	4	4	5
Net income (loss) attributable to the Shareholder	**131**	303	64	(13)
Per common share, attributable to the Shareholder *(dollars)*	**$0.51**	$1.18	$0.25	($0.05)

(millions of dollars - except where noted) (unaudited)	**September 30 2016**	**June 30 2016**	**March 31 2016**	**December 31 2015**
Revenue	1,400	1,387	1,478	1,312
Net income (loss)	198	135	128	(100)
Less: Net income attribute to the non-controlling interest	4	3	5	1
Net income (loss) attributable to the Shareholder	194	132	123	(101)
Per common share, attributable to the Shareholder *(dollars)*	$0.76	$0.51	$0.48	($0.39)

Trends

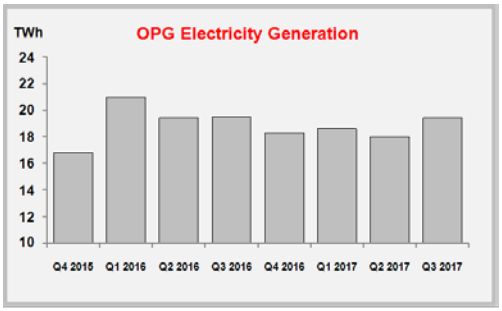
OPG's quarterly results are affected by changes in grid-supplied electricity demand, primarily resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. Weather conditions affect water flows, electricity demand, and prevalence of SBG conditions. Historically, OPG's revenues have been higher in the first

quarter of a fiscal year as a result of winter heating demands and in the third quarter due to air conditioning and cooling demands. The financial impact of forgone production due to SBG conditions at the regulated hydroelectric stations and the financial impact of differences between forecast water flows reflected in OEB-approved regulated prices and the actual water flows are mitigated by regulatory variance accounts authorized by the OEB.

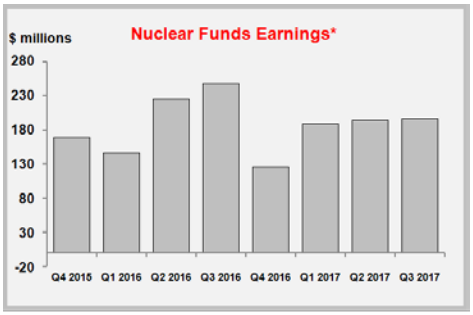
The timing of planned outages at a nuclear generating station during the year can cause variability in year-over-year operating results for partial periods of a fiscal year, including the impact on revenue and OM&A expenses, but is not a significant driver of variability for full fiscal year results.

OPG's electricity generation was reduced as a result of the Unit 2 refurbishment outage at the Darlington GS, which began in October 2016 and is expected to continue until early 2020.

OPG's financial results are also affected by the earnings on the Nuclear Segregated Funds, net of the impact of the Bruce Lease Net Revenues Variance Account.



Additional items that affected net income in certain quarters above are described in OPG's 2016 annual MD&A under



*net of regulatory variance account

the section, *Quarterly Financial Highlights*.

SUPPLEMENTARY NON-GAAP FINANCIAL MEASURES

In addition to providing net income and other financial information in accordance with US GAAP, certain non-GAAP financial measures are also presented in OPG's MD&A. These non-GAAP measures do not have any standardized meaning prescribed by US GAAP and, therefore, may not be comparable to similar measures presented by other issuers. OPG utilizes these measures to make operating decisions and assess performance. Readers of the MD&A would utilize these measures in assessing the Company's financial performance from ongoing operations. The Company believes that these indicators are important since they provide additional information about OPG's performance, facilitate comparison of results over different periods, and present measures consistent with the Company's strategies to provide value to the Shareholder, improve cost performance, and ensure availability of cost effective funding. These non-GAAP financial measures have not been presented as an alternative to net income, cash flow provided by operating activities, or any other measure in accordance with US GAAP, but as indicators of operating performance.

The definitions of the non-GAAP financial measures are as follows:

(1) **ROE Excluding AOCI** is defined as net income attributable to the Shareholder divided by average equity attributable to the Shareholder excluding AOCI, for the period. ROE Excluding AOCI is measured over a 12-month period and is calculated as follows:

	Twelve Months Ended	
(millions of dollars – except where noted) (unaudited)	**September 30 2017**	**December 31 2016**
ROE Excluding AOCI		
Net income attributable to the Shareholder	**485**	436
Divided by: Average equity attributable to the Shareholder, excluding AOCI	**11,055**	10,442
ROE Excluding AOCI *(percent)*	**4.4**	4.2

(2) **FFO Adjusted Interest Coverage** is defined as FFO before interest divided by adjusted interest expense. FFO before interest is defined as cash flow provided by operating activities adjusted for interest paid, interest capitalized to fixed and intangible assets, and changes to non-cash working capital balances for the period. Adjusted interest expense is calculated as net interest expense plus interest income, interest capitalized to fixed and intangible assets, interest related to regulatory assets and liabilities, and the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets, for the period.

FFO Adjusted Interest Coverage is measured over a 12-month period and is calculated as follows:

	Twelve Months Ended	
(millions of dollars – except where noted) (unaudited)	**September 30 2017**	**December 31 2016**
FFO before interest		
Cash flow provided by operating activities	**1,082**	1,595
Add: Interest paid	**270**	269
Less: Interest capitalized to fixed and intangible assets	**(161)**	(141)
Less: Changes to non-cash working capital balances	**38**	42
FFO before interest	**1,229**	1,765
Adjusted interest expense		
Net interest expense	**84**	120
Add: Interest income	**8**	7
Add: Interest capitalized to fixed and intangible assets	**161**	141
Add: Interest related to regulatory assets and liabilities	**43**	30
Add: Excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets [1]	**-**	45
Adjusted interest expense	**296**	343
FFO Adjusted Interest Coverage *(times)*	**4.2**	5.1

[1] A value of nil is used in the calculation when interest on pension and OPEB projected benefit obligations is equal to, or lower than, expected return on pension plan assets.

(3) **Enterprise Total Generating Cost per MWh** is used to measure OPG's overall organizational cost performance. Enterprise TGC per MWh is defined as OM&A expenses (excluding the Darlington Refurbishment project and other generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to OPG's electricity generation business), fuel expense for OPG-operated stations including hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures (excluding the Darlington Refurbishment project and other generation development projects) incurred during the period, divided by total electricity generation from OPG-operated generating stations plus electricity generation forgone due to SBG conditions during the period.

(millions of dollars – except where noted) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Enterprise TGC				
Total OM&A expenses	**635**	666	**2,054**	2,061
Total fuel expense	**185**	187	**518**	541
Total capital expenditures	**476**	444	**1,335**	1,162
Less: Darlington Refurbishment capital and OM&A costs	**(328)**	(269)	**(943)**	(717)
Less: Other generation development project capital and OM&A costs	**(17)**	(42)	**(53)**	(121)
Add (Less): OM&A and fuel expenses (refundable through) deferred in regulatory variance and deferral accounts	**4**	35	**(19)**	76
Less: Nuclear fuel expense for non OPG-operated stations	**(13)**	(18)	**(42)**	(50)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**13**	5	**47**	38
Less: OM&A expenses ancillary to electricity generation business	**(4)**	(5)	**(13)**	(17)
Other adjustments	**(3)**	(12)	**(7)**	(15)
	948	991	**2,877**	2,958
Adjusted electricity generation *(TWh)*				
Total OPG electricity generation	**19.4**	19.5	**56.0**	59.9
Adjust for electricity generation forgone due to SBG conditions and OPG's share of electricity generation from co-owned facilities	**0.9**	0.1	**4.2**	3.4
	20.3	19.6	**60.2**	63.3
Enterprise TGC per MWh *($/MWh)* [1]	**46.65**	50.72	**47.77**	46.74

[1] Amounts may not calculate due to rounding.

(4) **Nuclear Total Generating Cost per MWh** is used to measure the cost performance of OPG's nuclear generating assets. Nuclear TGC per MWh is defined as OM&A expenses of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the nuclear electricity generation business), nuclear fuel expense for OPG-operated stations (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs) incurred during the period, divided by nuclear electricity generation for the period.

(millions of dollars – except where noted) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Nuclear TGC				
Regulated – Nuclear Generation OM&A expenses	**511**	521	**1,693**	1,665
Regulated – Nuclear Generation fuel expense	**81**	79	**217**	239
Regulated – Nuclear Generation capital expenditures	**409**	339	**1,150**	896
Less: Darlington Refurbishment capital and OM&A costs	**(328)**	(269)	**(943)**	(717)
Add: Regulated – Nuclear Generation OM&A and fuel expenses deferred in regulatory variance and deferral accounts	**5**	31	**6**	84
Less: Nuclear fuel expense for non OPG-operated stations	**(13)**	(18)	**(42)**	(50)
Less: Regulated - Nuclear Generation OM&A expenses ancillary to nuclear electricity generation business	**(1)**	(1)	**(3)**	(4)
Other adjustments	**1**	3	**(1)**	(1)
	665	685	**2,077**	2,112
Nuclear electricity generation (TWh)	**11.3**	11.7	**30.6**	34.6
Nuclear TGC per MWh (*$/MWh*) [1]	**58.75**	58.55	**67.87**	61.07

[1] Amounts may not calculate due to rounding.

(5) **Hydroelectric Total Generating Cost per MWh** is used to measure the cost performance of OPG's hydroelectric generating assets. Hydroelectric TGC per MWh is defined as OM&A expenses of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the hydroelectric electricity generation business), hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding expenditures related to the Peter Sutherland Sr. GS, Ranney Falls GS, and other hydroelectric generation development projects) incurred during the period, divided by total hydroelectric electricity generation plus hydroelectric electricity generation forgone due to SBG conditions during the period. OPG reports hydroelectric gross revenue charge and water rental payments as fuel expense.

(millions of dollars – except where noted) (unaudited)	**Three Months Ended September 30**		**Nine Months Ended September 30**	
	2017	**2016**	**2017**	**2016**
Hydroelectric TGC				
Regulated – Hydroelectric OM&A expenses	**81**	87	**232**	238
Regulated – Hydroelectric fuel expense	**88**	88	**258**	259
Contracted Generation Portfolio OM&A expenses	**39**	44	**118**	129
Contracted Generation Portfolio fuel expense	**15**	19	**42**	42
Regulated – Hydroelectric and Contracted Generation Portfolio capital expenditures	**56**	92	**141**	231
Less: Regulated – Hydroelectric and Contracted Generation Portfolio generation development project capital and OM&A costs	**(17)**	(41)	**(52)**	(117)
Less: Thermal OM&A and fuel expenses and capital expenditures in the Contracted Generation Portfolio	**(39)**	(51)	**(119)**	(126)
(Less) Add: Regulated – Hydroelectric OM&A and fuel expenses refundable through regulatory variance and deferral accounts	**(1)**	4	**(25)**	(8)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**13**	5	**47**	38
Other adjustments	**(1)**	(1)	**-**	(1)
	234	246	**642**	685
Adjusted hydroelectric electricity generation *(TWh)*				
Regulated – Hydroelectric electricity generation	**7.3**	6.9	**23.5**	22.8
Contracted Generation Portfolio electricity generation	**0.8**	0.9	**1.9**	2.5
Adjust for hydroelectric electricity generation forgone due to SBG conditions and non-hydroelectric electricity generation of the Contracted Generation Portfolio, including OPG's share of electricity generation from co-owned facilities	**0.8**	0.1	**4.1**	3.4
	8.9	7.9	**29.5**	28.7
Hydroelectric TGC per MWh *($/MWh)* [1]	**26.20**	31.01	**21.74**	23.99

[1] Amounts may not calculate due to rounding.

(6) **Gross margin** is defined as revenue less fuel expense.

For further information, please contact: Investor Relations 416-592-6700

webmaster@opg.com

Media Relations 416-592-4008

1-877-592-4008

www.opg.com
www.sedar.com

From:	Ronald Kwan
To:	John Kim
Subject:	RE: EXTERNAL – RE: OPG Q3 2017 Submission to Province
Date:	Wednesday, November 08, 2017 1:42:32 PM
Attachments:	Q3 2017 OPG MDA - DRAFT - PROVINCE MAILING_EFB_CommentsV4_addressed by OPG_Markup2.docx

Hi John,

A comment on p.8, and a suggestion on p.10.

Ron

From: HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
Sent: November-08-17 13:30
To: John Kim <John.Kim@ofina.on.ca>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Subject: RE: EXTERNAL – RE: OPG Q3 2017 Submission to Province

Hi John,

Please see our responses to your three additional comments. Thank you.

Philip

From: John Kim [mailto:John.Kim@ofina.on.ca]
Sent: Monday, November 06, 2017 7:35 PM
To: HO Philip -FIN & C CTRL <philip.ho@opg.com>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Subject: RE: EXTERNAL – RE: OPG Q3 2017 Submission to Province

Hi Philip,

We have gone through again and some additional comment boxes and edits.

Thanks,

John

From: HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
Sent: Monday, November 06, 2017 6:19 PM
To: John Kim <John.Kim@ofina.on.ca>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; Ronald Kwan

<Ronald.Kwan@ofina.on.ca>
Subject: RE: EXTERNAL – RE: OPG Q3 2017 Submission to Province

Hi John,

Please see our responses to your comments. Let us know if you have any others. Thank you.

Regards,

Philip

Philip Ho, CPA, CA | Senior Manager, External Reporting & Accounting Policy | Ontario Power Generation
700 University Avenue, Toronto ON M5G 1X6 | Phone: (416) 592-3320| E-mail: philip.ho@opg.com

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From: John Kim [mailto:John.Kim@ofina.on.ca]
Sent: Monday, October 30, 2017 6:16 PM
To: HO Philip -FIN & C CTRL <philip.ho@opg.com>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Subject: EXTERNAL – RE: OPG Q3 2017 Submission to Province

*** Exercise caution. This is an EXTERNAL email. DO NOT open attachments or click links from unknown senders or unexpected email. ***

Hi Philip,

See attached with our comments on the MD&A.

These are staff level comments as Ron has not had a chance to review.

Thanks,

John

From: HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
Sent: Wednesday, October 25, 2017 12:22 PM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>; 'Montgomery, Kaitlin (MOF)' <Kaitlin.Montgomery@ontario.ca>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>
Subject: OPG Q3 2017 Submission to Province

Hi All,

Please find attached OPG's draft Q3 2017 Financial Results Press Release, Management's Discussion and Analysis (MD&A), and Financial Statements for the Province's review.

We would greatly appreciate comments on the above **no later than Monday, Oct 30th**.

These documents will be filed with the Ontario Securities Commission on **Thursday, November 9th** following OPG's Board of Directors meeting.

Kindly forward all comments directly to Philip Ho – philip.ho@opg.com.

To assist the review process, the following are the key items in the Q3 2017 MD&A:

Highlights	
Recent Developments	MD&A p.10-11
Darlington Refurbishment	MD&A p.13-15
Ontario's Fair Hydro Plan	MD&A p.10-11

Philip Ho, CPA, CA | Senior Manager, External Reporting & Accounting Policy | Ontario Power Generation
700 University Avenue, Toronto ON M5G 1X6 | Phone: (416) 592-3320| E-mail: philip.ho@opg.com

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ONTARIO POWER GENERATION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

2017 THIRD QUARTER REPORT

[DRAFT]

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ONTARIO POWER GENERATION

ONTARIO POWER GENERATION INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) should be read in conjunction with the unaudited interim consolidated financial statements and accompanying notes of Ontario Power Generation Inc. (OPG or Company) as at and for the three and nine months ended September 30, 2017. OPG's unaudited interim consolidated financial statements are prepared in accordance with United States generally accepted accounting principles (US GAAP) and are presented in Canadian dollars.

For a complete description of OPG's corporate strategies, risk management, corporate governance, and the effect of critical accounting policies and estimates on OPG's results of operations and financial condition, this MD&A should also be read in conjunction with OPG's audited consolidated financial statements, accompanying notes, the Annual Information Form, and the MD&A as at and for the year ended December 31, 2016.

As required by *Ontario Regulation 395/11*, as amended, a regulation under the *Financial Administration Act* (Ontario), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. In 2014, the Ontario Securities Commission approved an exemption which allows OPG to apply US GAAP up to January 1, 2019. The term of the exemption is subject to certain conditions, which may result in the expiry of the exemption prior to January 1, 2019. For details, refer to the section, *Critical Accounting Policies and Estimates* under the heading, *Exemptive Relief for Reporting under US GAAP,* in OPG's 2016 annual MD&A. This MD&A is dated November 9, 2017.

FORWARD-LOOKING STATEMENTS

The MD&A contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could", and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

All forward-looking statements involve inherent assumptions, risks, and uncertainties, including those set out in the section, *Risk Management,* and forecasts discussed in the section, *Core Business, Strategy, and Outlook.* All forward-looking statements could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's generating station performance and availability, fuel costs, surplus baseload generation (SBG), cost of fixed asset removal and nuclear waste management, performance and earnings of investment funds, refurbishment of existing facilities, development and construction of new facilities, pension and other post-employment benefit (OPEB) obligations and funds, income taxes, proposed new legislation, the ongoing evolution of Ontario's electricity industry, environmental and other regulatory requirements, health, safety and environmental developments, business continuity events, the weather, financing and liquidity, applications to the Ontario Energy Board (OEB) for regulatory prices, the impact of regulatory decisions by the OEB, and forecasts of earnings, cash flows, Funds from Operations (FFO) Adjusted Interest Coverage, Return on Common Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI), Total Generating Cost (TGC) and capital expenditures. Accordingly, undue reliance should not be placed on any forward-looking statement. The forward-looking statements included in this MD&A are made only as of the date of this MD&A. Except as required by applicable securities laws, OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events, or otherwise.

THE COMPANY

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG was established under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (Province or Shareholder).

As at September 30, 2017, OPG's electricity generation portfolio had an in-service capacity of 16,210 megawatts (MW). OPG operates two nuclear generating stations, 66 hydroelectric generating stations, three thermal generating stations, and one wind power turbine. In addition, OPG and TransCanada Energy Ltd. co-own the 550 MW Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS). OPG and ATCO Power Canada Ltd. co-own the 560 MW Brighton Beach gas-fired combined cycle GS (Brighton Beach). OPG's 50 percent share of the in-service capacity and generation volume of these co-owned facilities is included in the generation portfolio statistics set out in this report. The income from the co-owned facilities is accounted for using the equity method of accounting, and OPG's share of income is presented as income from investments subject to significant influence in the Contracted Generation Portfolio segment.

OPG also owns two other nuclear generating stations, the Bruce A GS and the Bruce B GS, which are leased on a long-term basis to Bruce Power LP (Bruce Power). Income from these leased stations is included in revenue under the Regulated – Nuclear Generation segment. The leased stations are not included in the generation portfolio statistics set out in this report.

All of OPG's owned and co-owned generating facilities are located in Ontario. OPG does not operate PEC, Brighton Beach, the Bruce A GS and the Bruce B GS.

A description of OPG's segments is provided in OPG's 2016 annual MD&A in the section, *Business Segments*.

In-Service Generating Capacity

OPG's in-service generating capacity by business segment as at September 30, 2017 and December 31, 2016 was as follows:

	As at	
(MW)	**September 30 2017**	**December 31 2016**
Regulated – Nuclear Generation [1]	**5,728**	5,728
Regulated – Hydroelectric	**6,426**	6,421
Contracted Generation Portfolio [2]	**4,056**	4,028
Total	**16,210**	16,177

[1] The in-service generating capacity as of September 30, 2017 and December 31, 2016 excludes Unit 2 of the Darlington GS. The unit, which has a generating capacity of 878 MW, was taken offline in mid-October 2016 and is currently undergoing refurbishment.

[2] Includes OPG's share of in-service generating capacity of 275 MW for PEC and 280 MW for Brighton Beach.

During the nine months ended September 30, 2017, the total in-service capacity increased by 33 MW. The increase was primarily due to the completion of the Peter Sutherland Sr. hydroelectric GS, which was placed in-service at the end of the first quarter of 2017, and the upgrade of Unit 10 of the Sir Adam Beck 1 hydroelectric GS, which was completed in June 2017.

HIGHLIGHTS

Overview of Results

This section provides an overview of OPG's unaudited interim consolidated operating results. Significant factors which contributed to OPG's results during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, are discussed below.

(millions of dollars – except where noted) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Revenue	**1,217**	1,400	**3,539**	4,265
Fuel expense	**185**	187	**518**	541
Gross margin	**1,032**	1,213	**3,021**	3,724
Operations, maintenance and administration	**635**	666	**2,054**	2,061
Depreciation and amortization	**178**	313	**517**	941
Accretion on fixed asset removal and nuclear waste management liabilities	**235**	232	**709**	696
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(196)**	(248)	**(579)**	(620)
Income from investments subject to significant influence	**(11)**	(11)	**(29)**	(28)
Property taxes	**8**	12	**30**	35
	849	964	**2,702**	3,085
Income before other losses (gains), interest and income taxes	**183**	249	**319**	639
Other losses (gains)	**3**	1	**(380)**	(23)
Income before interest and income taxes	**180**	248	**699**	662
Net interest expense	**21**	28	**56**	92
Income before income taxes	**159**	220	**643**	570
Income tax expense	**19**	22	**128**	109
Net income	**140**	198	**515**	461
Net income attributable to the Shareholder	**131**	194	**498**	449
Net income attributable to non-controlling interest [1]	**9**	4	**17**	12
Electricity production (TWh) [2]	**19.4**	19.5	**56.0**	59.9
Cash flow provided by operating activities	**485**	530	**698**	1,211

[1] Relates to the 25 percent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in the Lower Mattagami Limited Partnership, the 33 percent interest of Coral Rapids Power Corporation, a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership, and the 10 percent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP.

[2] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

Third Quarter

Net income attributable to the Shareholder was $131 million for the third quarter of 2017, a decrease of $63 million compared to the same quarter in 2016. Income before interest and income taxes for the third quarter of 2017 was $180 million, a decrease of $68 million compared to the same quarter in 2016.

Commented [A1]:
Wondering if this should be 437?
Since:
Q3 9-mos ended – Q2 6-mos ended = 698-261 = 437

Was Q2 "6-month ended June 30" number for Cash flow provided by operating activities revised?

OPG: In Q3 2017, adjustments for non-cash balances related to Darlington Refurbishment capital expenditures have been reclassified from the "Net changes in non-cash working capital balances" line to the "Investment in property, plant and equipment and intangible assets" line. Comparative amounts have been reclassified accordingly.

Significant factors that reduced income before interest and income taxes:

- Lower earnings from the nuclear base regulated price of approximately $24 million reflecting lower electricity generation of 0.4 terawatt hours (TWh) from the Regulated – Nuclear Generation segment and the continuation of existing base regulated prices set by the OEB in 2014. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS since October 2016, largely offset by an increase in generation from Pickering GS. The increase in generation from the Pickering GS was primarily due to outage optimization, favourable unit conditions and execution of planned outage work. The base regulated prices set in 2014 continue to be in effect pending the OEB's decision on OPG's current application for new regulated prices, expected later in 2017. **[MONITOR]** The existing nuclear base regulated price was set to allow the Company to recover its approved nuclear costs over a higher nuclear production volume, based on the 2014 and 2015 outage profile that did not include a refurbishment outage. OPG has requested January 1, 2017 as the effective date of the new regulated prices.
- Lower earnings on the nuclear fixed asset removal and nuclear waste management funds (Nuclear Segregated Funds) of $52 million.
- Higher depreciation and amortization expense of $16 million in the Regulated – Nuclear Generation segment, excluding amortization expense related to balances in OEB-authorized regulatory variance and deferral accounts (regulatory accounts), primarily due to new assets in service.

The expiry of rate riders for the recovery of approved balances in OEB-authorized regulatory accounts on December 31, 2016 contributed to the decrease in revenue for the three months ended September 30, 2017, compared to the same period in 2016, but was largely offset by a decrease in the amortization expense related to these balances. OPG has requested new rate riders in its current application to the OEB for new regulated prices, with a proposed effective date of January 1, 2017.

Significant factor that increased income before interest and income taxes:

- Lower operations, maintenance and administration (OM&A) expenses of $31 million, mainly in the Regulated – Nuclear Generation segment, as a result of a higher materials and supplies obsolescence charge recognized in the third quarter of 2016, Services, Trading and Other Non-Generation segment due to project expenditures incurred in the third quarter of 2016, and Regulated – Hydroelectric segment due to the timing of repairs and maintenance work in 2017 and a deferral of outages during the high water period.

Net interest expense decreased by $7 million during the third quarter of 2017, compared to the same quarter in 2016, primarily due to a higher amount of interest costs capitalized for the Darlington Refurbishment project expenditures and a higher amount of interest costs deferred in OEB-authorized regulatory accounts.

Income tax expense for the three months ended September 30, 2017 was $19 million, compared to $22 million for the same period in 2016. The decrease in income tax expense was primarily due to lower income before taxes and a higher change in reserves from the resolution of uncertainties, partially offset by a lower amount of tax expense deferred in regulatory assets.

Year-To-Date

Net income attributable to the Shareholder was $498 million for the first nine months of 2017, an increase of $49 million compared to the same period in 2016. Income before interest and income taxes for the first nine months of 2017 was $699 million, an increase of $37 million compared to the same period in 2016.

Significant factor that increased income before interest and income taxes:

- Higher earnings of $390 million from the Services, Trading, and Other Non-Generation segment, primarily reflecting the gain on sale of OPG's head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street that was recognized in the second quarter of 2017. The sale of the

Commented [A2]: If approved by OEB (during Q4), would this result in a higher regulated price and a revenue/net income pick up for 2017 reported in OPG's Q4?

OPG – It depends on the effective date of the decision on the base regulated prices. If the OEB decision on the new base regulated prices are retrospectively effective as of Jan 1, 2017 for example, then it should result in a higher revenue/net income pick up for 2017 assuming the new regulated prices are higher.

assets was required by a Shareholder Declaration and a Shareholder Resolution. The gain on sale was $283 million, which is net of tax effects of $95 million.

Significant factors that reduced income before interest and income taxes:

- Lower earnings from the nuclear base regulated price of approximately $230 million, partially offset by a decrease in nuclear fuel expense of $22 million, reflecting lower electricity generation of 4.0 TWh from the Regulated – Nuclear Generation segment and the continuation of existing base regulated prices set by the OEB in 2014. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS, partially offset by an increase in generation from Pickering GS.
- Lower earnings on the Nuclear Segregated Funds of $41 million.
- Higher depreciation and amortization expense of $30 million in the Regulated – Nuclear Generation segment, excluding amortization expense related to regulatory account balances, primarily due to new assets in service.
- A gain of $22 million recorded in the first quarter of 2016 to reflect the OEB's decision on OPG's motion asking the OEB to review and vary parts of its November 2014 decision on OPG's regulated prices.

The expiry of rate riders for the recovery of approved balances in OEB-authorized regulatory accounts on December 31, 2016 contributed to the decrease in revenue for the nine months ended September 30, 2017, compared to the same period in 2016, but was primarily offset by a decrease in the amortization expense related to these balances.

Net interest expense decreased by $36 million for the nine months ended September 30, 2017, compared to the same period in 2016, primarily due to a higher amount of interest costs capitalized for the Darlington Refurbishment project expenditures and a higher amount of interest costs deferred in OEB-authorized regulatory accounts.

Commented [A3]: Does this imply there were interest costs related to Darlington Refurb previously (same quarter previous year), that were not capitalized, but were able to be capitalized this year?

OPG – There were higher Darlington Refurb project expenditures in 2017, compared to 2016.

Income tax expense for the nine months ended September 30, 2017 was $128 million, compared to $109 million for the same period in 2016. The increase in income tax expense was primarily due to higher income before income taxes.

Segment Results

The following table summarizes OPG's income before interest and income taxes by business segment. A detailed discussion of OPG's performance by reportable segment is included in the section, *Discussion of Operating Results by Business Segment*.

(millions of dollars)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Income (loss) before interest and income taxes				
Regulated – Nuclear Generation	**20**	47	**(267)**	17
Regulated – Hydroelectric	**122**	117	**474**	500
Contracted Generation Portfolio	**75**	74	**229**	219
Total electricity generation business segments	**217**	238	**436**	736
Regulated – Nuclear Waste Management	**(36)**	18	**(123)**	(70)
Services, Trading, and Other Non-Generation	**(1)**	(8)	**386**	(4)
	180	248	**699**	662

Electricity Generation

Electricity generation for the three and nine month periods ended September 30, 2017 and 2016 was as follows:

(TWh)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Regulated – Nuclear Generation	**11.3**	11.7	**30.6**	34.6
Regulated – Hydroelectric	**7.3**	6.9	**23.5**	22.8
Contracted Generation Portfolio [1]	**0.8**	0.9	**1.9**	2.5
Total OPG electricity generation	**19.4**	19.5	**56.0**	59.9
Total electricity generation by all other generators in Ontario [2]	**16.6**	19.5	**51.7**	53.8

[1] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.
[2] Non-OPG generation is calculated as the Ontario electricity demand plus net exports, as published by the Independent Electricity System Operator (IESO), minus OPG electricity generation.

Total OPG electricity generation decreased by 0.1 TWh during the third quarter of 2017, compared to the same quarter in 2016, and by 3.9 TWh during the nine months ended September 30, 2017, compared to the same period in 2016. As expected, the lower electricity generation from the Regulated – Nuclear Generation segment was primarily the result of the removal from service of Unit 2 at the Darlington GS for the duration of the unit's refurbishment, which began in October 2016. This decrease in electricity generation was largely offset by an increase in generation from the Pickering GS, primarily due to outage optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station, and higher hydroelectric generation from the Regulated – Hydroelectric segment.

The higher electricity generation of 0.4 TWh and 0.7 TWh from the Regulated – Hydroelectric segment for the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016, was due to higher water flows primarily on the eastern Ontario river systems, net of water spilled as a result of SBG conditions, discussed below.

The lower electricity generation of 0.6 TWh from the Contracted Generation Portfolio segment for the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to higher SBG conditions. The electricity generation from the Contracted Generation Portfolio segment for the three months ended September 30, 2017 was comparable to the same period in 2016.

OPG's operating results are impacted by changes in grid-supplied electricity demand resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. For the three and nine month periods ended September 30, 2017, Ontario's electricity demand as reported by the IESO was 33.6 TWh and 98.5 TWh, respectively, compared to 36.7 TWh and 103.8 TWh for the same periods in 2016, respectively, excluding electricity exports out of the province.

Power that is surplus to the Ontario market is managed by the IESO, mainly through generation reductions at hydroelectric, other grid-connected renewable resources and nuclear stations. Reducing hydroelectric production is the first measure used by the IESO to manage SBG conditions. Low demand conditions in Ontario continued to be prevalent in 2017, resulting in forgone hydroelectric generation for OPG of 1.1 TWh and 4.5 TWh due to SBG conditions in the three and nine month periods ended September 30, 2017, respectively, compared to 0.5 TWh and 3.9 TWh during the same periods in 2016, respectively. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions during these periods was offset by the impact of a regulatory variance account authorized by the OEB. OPG did not forgo any electricity production at its nuclear stations due to SBG conditions.

Average Sales Prices

The majority of OPG's generation is from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments. The same base regulated prices for electricity generated by these segments, authorized by the OEB effective November 1, 2014, were in effect during the first nine months of 2017 as in 2016. These prices will remain in effect until such time as the OEB approves new regulated prices based on OPG's current application. **[MONITOR]** The base regulated prices established in 2014 are discussed in OPG's 2016 annual MD&A in the section, *Revenue Mechanisms for Regulated and Non-Regulated Generation*.

The average sales price for the Regulated – Nuclear Generation segment was 5.8 cents per kilowatt hour (¢/kWh) during the three and nine month periods ended September 30, 2017, respectively, compared to 6.9 ¢/kWh during the same periods in 2016. The decrease in the average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized nuclear rate rider of $10.84 per megawatt hour (MWh) for the recovery of variance and deferral account balances. The average sales price for the Regulated – Hydroelectric segment was 4.1 ¢/kWh during the three and nine month periods ended September 30, 2017, respectively, compared to 4.4 ¢/kWh during the same periods in 2016. The decrease in the average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized regulated hydroelectric rate rider of $3.19/MWh for the recovery of variance and deferral account balances. The rate riders were established to recover approved balances recorded in the variance and deferral accounts in prior years. As such, the year-over-year changes in revenue from the rate riders were largely offset by changes in amortization expense related to these balances. There were no rate riders in effect during the nine months ended September 30, 2017 for either nuclear or regulated hydroelectric generation, pending the outcome of OPG's current application with the OEB for new regulated prices.

Cash Flow from Operations

Cash flow provided by operating activities was $485 million for the three months ended September 30, 2017 and $698 million for the nine months ended September 30, 2017, compared to $530 million and $1,211 million for the same periods in 2016, respectively. The decrease in cash flow provided by operating activities was expected and primarily due to lower generation revenue receipts reflecting lower generation from the Regulated – Nuclear Generation segment as a result of the ongoing refurbishment of Unit 2 at the Darlington GS and the expiry, on December 31, 2016, of the OEB-authorized rate riders for nuclear and regulated hydroelectric generation. The decrease in cash flow during the nine months ended September 30, 2017 was also due to higher income tax instalments.

The decrease in cash flow provided by operating activities for the three and nine month periods ended September 30, 2017 was partly offset by lower OM&A expenditures and lower contributions to the Used Fuel Segregated Fund in 2017. Both the Used Fuel Segregated Fund and the Decommissioning Segregated Fund were determined to be fully funded based on an updated estimate of OPG's nuclear waste management and nuclear facilities decommissioning obligations pursuant to a reference plan approved by the Province ~~for years 2017 to 2021~~ under the Ontario Nuclear Funds Agreement (ONFA), effective January 1, 2017. Pursuant to the ONFA, the reference plan is required to be updated at least once every five years. Contributions to either or both of the Nuclear Segregated Funds may be required in the future should the funds be in an underfunded position at the time of the next ONFA reference plan update. The year-over-year decrease in cash flow also was partially offset by the payment of a supplemental rent rebate to Bruce Power in the first quarter of 2016 in relation to a period in 2015. The lease agreement for the Bruce nuclear generating stations was amended in late 2015 to eliminate this rebate provision going forward.

Return on Common Equity Excluding Accumulated Other Comprehensive Income

ROE Excluding AOCI is an indicator of OPG's performance consistent with the Company's strategy to provide value to the Shareholder. ROE Excluding AOCI is measured over a 12-month period.

Commented [A4]: OPG: no change as this was previously disclosed as is in Q2 2017.

Commented [A5R4]: The Reference Plan is a lifecycle plan. The years should be omitted. It implies to the naïve reader that the Reference Plan approval only covers the period 2017-2021, whereas the reference plan goes out more than a century (don't need to say that.)

The following sentence conveys that the Reference Plan needs to be refreshed at least every five years.

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ROE Excluding AOCI was 4.4 percent for the 12 months ended September 30, 2017, compared to 4.2 percent for the 12 months ended December 31, 2016. The increase was primarily due to higher net income attributable to the Shareholder for the 12 months ended September 30, 2017, which reflected the gain on sale of OPG's head office premises and associated parking facility recorded in the second quarter of 2017, partially offset by the lower earnings from the decrease in nuclear electricity generation reflecting the Unit 2 refurbishment outage at the Darlington GS without a corresponding increase in the nuclear base regulated price, as expected. The lower nuclear generation as a result of the refurbishment outage will continue to negatively affect OPG's ROE Excluding AOCI until such time as new regulated prices are approved by the OEB, anticipated in the fourth quarter of 2017. **[MONITOR]**

Funds from Operations Adjusted Interest Coverage

FFO Adjusted Interest Coverage is an indicator of OPG's ability to meet interest obligations from operating cash flows. The indicator is measured over a 12-month period. FFO Adjusted Interest Coverage for the 12 months ended September 30, 2017 was 4.2 times, compared to 5.1 times for the 12 months ended December 31, 2016. FFO Adjusted Interest Coverage in 2017 reflected a year-over-year decrease in FFO before interest due to lower cash flow provided by operating activities, partially offset by the impact of a lower adjusted interest expense due to a decrease in the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets.

The decrease in the excess of interest on pension and OPEB benefit obligations over expected return on pension plan assets in the nine months of 2017 was primarily due to the change in the method used to estimate the interest cost and service cost components of pension and OPEB costs. Effective January 1, 2017, OPG adopted a full yield curve approach to the estimation of these cost components, by applying the specific spot rates along the yield curve used in the determination of the projected benefit obligations to the relevant projected cash flows. Under the previous method, these components of pension and OPEB costs were calculated using the same single weighted-average discount rates as reflected in the calculation of the benefit obligations. This change in the method was accounted for prospectively, as a change in estimate. The resulting reduction in pension and OPEB costs for the three and nine month periods ended September 30, 2017 did not have a material impact on net income as it was largely offset by the impact of OEB-authorized variance and deferral accounts in the regulated business segments. Further details on the full yield curve approach can be found in the 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Pension and Other Post-Employment Benefits*.

Commented [A6]: Does this have any implications for the methodology used for the IFRS adjustments for the purposes of the Province's Public Accounts?

OPG response - Since the full yield curve approach is applied to the determination of pension and OPEB costs under both US GAAP and IFRS, it will not create a US GAAP and IFRS difference. Therefore it is not expected to have any implications for the methodology used for the IFRS adjustments for the purposes of the Province's Public Accounts.

Enterprise Total Generating Cost per MWh

The Enterprise TGC per MWh decreased to $46.65 for the three months ended September 30, 2017, compared to $50.72 for the same quarter in 2016. The decrease was mainly due to lower OM&A expenses before the impact of regulatory accounts and higher SBG-adjusted hydroelectric generation reflecting higher water flows.

The Enterprise TGC per MWh was $47.77 for the nine months ended September 30, 2017, an increase compared to $46.74 for the same period in 2016. The increase was expected and mainly a result of lower electricity generation due to the Unit 2 refurbishment outage at the Darlington GS, largely offset by lower OM&A expenses before the impact of regulatory accounts and higher SBG-adjusted hydroelectric generation reflecting higher water flows.

If Unit 2 at the Darlington GS was not currently undergoing refurbishment and had continued to operate in a manner consistent with the performance of the remaining units at the Darlington GS, adjusting for generation constraints on these units related to the transition of the station toward refurbishment, the Enterprise TGC would have been approximately $4 per MWh lower for both the three and nine month periods ended September 30, 2017. This sensitivity was calculated using the estimated incremental electricity and associated fuel cost that are expected to have resulted in the absence of the refurbishment.

Nuclear Total Generating Cost per MWh

The Nuclear TGC per MWh was $58.75 for the three months ended September 30, 2017, which was comparable to $58.55 for the same quarter in 2016. For the three months ended September 30, 2017, the higher generation at the Pickering GS and the impact of lower OM&A expenses before the impact of regulatory accounts was mostly offset by the expected decrease in nuclear electricity generation reflecting the Unit 2 refurbishment outage at the Darlington GS and higher sustaining capital expenditures. The Nuclear TGC per MWh was $67.87 for the nine months ended September 30, 2017, compared to $61.07 for the same period in 2016. The increase in the Nuclear TGC per MWh for the nine months ended September 30, 2017 was expected and primarily due to the decrease in nuclear electricity generation, partially offset by lower OM&A expenses before the impact of regulatory accounts.

Hydroelectric Total Generating Cost per MWh

The Hydroelectric TGC per MWh was $26.20 for the three months ended September 30, 2017, compared to $31.01 for the same quarter in 2016. The decrease was primarily due to higher SBG-adjusted hydroelectric electricity generation reflecting higher water flows. The Hydroelectric TGC per MWh was $21.74 for the nine months ended September 30, 2017, compared to $23.99 for the same period in 2016. The decrease was primarily due to lower OM&A expenses before the impact of regulatory accounts and lower sustaining capital expenditures.

ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are not measurements in accordance with US GAAP and should not be considered alternative measures to net income, cash flow provided by operating activities, or any other performance measure under US GAAP. OPG believes that these non-GAAP financial measures are effective indicators of its performance and are consistent with the Company's strategic imperatives and related objectives. The definition and calculation of ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are found in the section, *Supplementary Non-GAAP Financial Measures*.

Recent Developments

Ontario's 2017 Long Term Energy Plan

On October 26, 2017, Ontario's Ministry of Energy issued the 2017 Long Term Energy Plan. The Plan is currently being analyzed by OPG but is not expected to significantly impact OPG's business. There are no fundamental changes from the principles in the 2013 Long Term Energy Plan, which include cost effectiveness, reliability, clean energy and community engagement. The 2017 Long Term Energy Plan fully supports nuclear refurbishment projects in Ontario and the extension of commercial operation of all Pickering units to 2024. **[MONITOR & UPDATE DETAILS FOLLOWING RELEASE]**

OEB's Decision on New Regulated Prices **[MONITOR]**

Ontario's Fair Hydro Plan

OPG continues to prepare for its involvement as the Financial Services Manager for Ontario's Fair Hydro Plan (the Fair Hydro Plan) on a commercial basis. Accordingly, the financing entity was established in XX 2017 as the Fair Hydro Trust (the Trust), following the execution of its constating documents. The majority unitholder and beneficiary of the Trust is a wholly-owned subsidiary of OPG. Through this ownership and OPG's control over the key activities of the Trust, the Company will consolidate the Trust for accounting purposes commencing in the fourth quarter of 2017. **[MONITOR]**

In order for the Trust to ~~provide~~ financ~~eing for~~ the deferred Global Adjustment costs, the Trust will incur senior debt from capital markets and subordinated debt from OPG. The Trust is structured to be bankruptcy remote and ring fenced from OPG to protect the Company's assets and operations. In support of the Fair Hydro Plan, the following developments have transpired:

Commented [A7]: Why not rephrase as acquiring the investment asset related to the deferred GA costs (right to future recovery)?

OPG response: No change made.

It is easier to understand for the general public the notion of a financing transaction vs. acquiring an investment interest

Commented [A8R7]: Suggested wording change.

- In October 2017, *Ontario Regulation 206/17 General* was amended to establish details of the recovery mechanism for the monthly carrying costs incurred by the Trust from June 1, 2017 to July 31, 2021 payable by the IESO to the Trust. Originally established in June 2017, this regulation provides more details on the funding obligations incurred by the Trust and the fair allocation amount, the determination and collection of clean energy adjustments, the determination of the finance amount, the true up amount, and the regulatory asset, as well as principles and assumptions relating to the financing plan.
- A plan to amend the Company's Articles of Amalgamation to allow for the creation and issuance of Class A shares to be issued to the Province for its equity investment through OPG in the Fair Hydro Plan is in progress. The Province is expected to provide 44 percent of the total funding requirement related to the deferred Global Adjustment costs, which OPG will invest as subordinated debt into the Trust. OPG's Board approval and a Shareholder Resolution are expected later in the year to authorize the amendment.
- OPG is expected to provide five percent of the total funding requirement of the Trust related to the deferred Global Adjustment costs of the Fair Hydro Plan. OPG issued senior notes payable in October 2017 under a short form base shelf prospectus for general corporate purposes and to fund OPG's subordinated debt investment in the Trust. Further details of the debt offering can be found in the section, *Liquidity and Capital Resources* under the heading, *Financing Activities*.

Commented [A9]: Are any other details available to be released at this time?

OPG – Not for Q3 2017 reporting.

The first set of transactions of the Trust are expected to take place in the fourth quarter of 2017.

Canadian Nuclear Safety Commission Safety Rating for the Darlington GS and the Pickering GS

The Canadian Nuclear Safety Commission (CNSC) publishes an annual report on the safety performance of Canada's nuclear power plants. The report assesses how well plant operators are meeting regulatory requirements and program expectations in the areas of operational performance, safety analysis, radiation protection, waste management and conventional health and safety. On September 8, 2017, the CNSC issued an executive summary of its 2016 annual report. The CNSC gave both the Darlington GS and the Pickering GS the highest possible safety rating of "Fully Satisfactory". The Darlington GS achieved this rating for the eighth consecutive year, while the Pickering GS achieved this rating for the second consecutive year.

CORE BUSINESS, STRATEGY, AND OUTLOOK

The discussion in this section is qualified in its entirety by the cautionary statements included in the section, *Forward-Looking Statements,* at the beginning of the MD&A.

OPG's mission is to provide low cost power in a safe, clean, reliable and sustainable manner for the benefit of customers and its Shareholder. OPG also seeks to pursue, on a commercial basis, generation development projects and other business growth opportunities.

The following sections provide an update to OPG's disclosures in the 2016 annual MD&A related to its four key strategic imperatives – operational excellence, project excellence, financial strength, and social licence. A detailed discussion of these strategic imperatives is included in the 2016 annual MD&A in the section, *Core Business, Strategy, and Outlook*.

Operational Excellence

Operational excellence at OPG is accomplished by the safe and environmentally responsible generation of reliable and cost-effective electricity from the Company's generating assets through a highly trained and engaged workforce.

Electricity Generation Production and Reliability

- As part of the plan to extend Pickering operations, OPG is continuing to undertake the required technical work to confirm that the station's pressure tubes, a key life-limiting component of the station, will remain fit for service for operation to 2024. OPG is also nearing completion of component condition assessments to identify the work required to support the continued operation of the station. The accounting end of life assumptions for the Pickering GS, currently set at the end of 2020, will be reassessed based on the fuel channel analysis and safety case consistent with submissions for the CNSC approval, discussed below. The activities completed to date have had positive results, which will go towards re-confirming Pickering operations past 2020 are technically feasible. The Periodic Safety Review (PSR) is in progress and will confirm that extending operations of the Pickering units will be safe to the public, workers and the environment. The PSR consists of Safety Factor Reports (SFRs), a Global Assessment Report (GAR), and the Integration Improvement Plan (IIP). SFRs have been submitted to the CNSC and the GAR and IIP are on track for CNSC submission in October and November 2017, respectively. Other technical feasibility activities continue to progress as planned. Completion of various technical feasibility assessments are required to reach a high confidence conclusion to allow the station end of life to change for depreciation purposes. OPG's current application with the OEB for new base regulated prices, currently pending the OEB's decision, reflects OPG's plans to extend Pickering operations to 2024 and requests inclusion of the corresponding cost and generation impacts in the determination of the nuclear regulated price.
- OPG's current five-year operating licence for the Pickering GS was approved by the CNSC in 2013 and expires on August 31, 2018. This licence was issued assuming that the station would shut down in 2020. On June 28, 2017, OPG confirmed to the CNSC that it intends to cease commercial operation of all Pickering units on December 31, 2024. On August 28, 2017, OPG submitted a ten-year licence renewal application to the CNSC. The licence term spans the planned extended operations period, through to the end of commercial operation, defueling, dewatering and the start of placing the station in a safe storage state.
- Work continues on the rehabilitation of Unit 2 of the DeCew Falls hydroelectric GS and the rehabilitation and overhaul of Unit 2 of the Lower Notch hydroelectric GS.
- During the third quarter, a new control centre was opened at Saunders GS to merge its operations with Chenaux GS. The new control centre will overlook power production at ten hydroelectric stations along the Madawaska, Ottawa and St. Lawrence rivers.
- As part of the process to decommission the Nanticoke and Lambton generating stations, OPG has begun executing demolition plans that will ensure that the stations are closed safely, securely and in an environmentally responsible manner. The demolition of the Nanticoke coal yard equipment and structures is in progress, with a contract issued in July 2017 for the demolition of the Nanticoke powerhouse and associated structures. Project milestones for the Nanticoke site during the remainder of 2017 include completing the removal of coal yard equipment and structures, demolition of the ash silos, and mobilization of the contractor to prepare for removal of the stacks, powerhouse and associated structures. A competitive bidding process for the demolition of the Lambton GS has been completed, with a contract for the removal of the powerhouse and associated buildings expected to be awarded in 2018. An update of the associated asset retirement obligations related to the Nanticoke and Lambton sites is expected to be finalized in the fourth quarter of 2017.

Environmental Performance

There were no significant changes to environmental legislation affecting the Company during the third quarter of 2017. Disclosures related to the Company's environmental policy and environmental risks can be found in OPG's 2016 annual MD&A.

OPG communicates its environmental performance internally to employees and to external stakeholders, including the Ontario Ministry of the Environment and Climate Change, Environment and Climate Change Canada, the CNSC, and local communities. Details of OPG's environmental performance and initiatives to fulfill the Company's Environmental Policy can be found in OPG's 2016 Sustainability Report, available on the Company's website at www.opg.com. **[MONITOR]**

Project Excellence

OPG is pursuing a number of generation development and other major projects in support of Ontario's electricity planning initiatives. OPG remains focused on delivering projects safely, on time, on budget and with high quality. The status updates for OPG's major projects as at September 30, 2017 are outlined in the following table, with further details below.

Project	Capital expenditures		Approved budget	Expected in-service date	Current status
(millions of dollars)	**Year-to-date**	**Life-to-date**			
Darlington Refurbishment	924	4,109	12,800 [1]	First unit - 2020 Last unit - 2026	The setup of specialized tooling and equipment needed for the removal of reactor components was completed in the third quarter of 2017. All feeder tubes have been removed safely, and the pressure tubes have been severed in preparation for their removal. The Re-tube Waste Processing Building will be available for use in the fourth quarter of 2017. The project is tracking on schedule and on budget.
Peter Sutherland Sr. Hydroelectric GS	38	274	300	2017	The station was placed in-service on March 31, 2017, ahead of the originally planned schedule, and is expected to close below the approved budget. Project close-out activities are in progress.
Ranney Falls Hydroelectric GS	17	20	77	2019	Work is progressing on the expanded forebay, forebay wall concrete replacement, powerhouse and spillway areas. The project is tracking on schedule and on budget.
Nanticoke Solar Facility	1	2	107 **[MONITOR]**	2019	Project definition work is continuing, with construction planned to commence in the first quarter of 2018.
Deep Geologic Repository for low and intermediate level radioactive waste (L&ILW)	7 [2]	202 [2]			On August 21, 2017, the federal Minister of Environment and Climate Change requested further information on the project's environmental assessment (EA). OPG is reviewing the new request and will notify the Canadian Environmental Assessment Agency (CEAA) when it has a timeline for submission of that information.

[1] The total project budget of $12.8 billion is for the refurbishment of all four units at the Darlington GS.
[2] Expenditures are charged against the nuclear fixed asset removal and nuclear waste management liabilities (Nuclear Liabilities).

Commented [A10]: Does this imply that only 700M further is anticipated to be spent by the time Unit 2 gets completed? (Eg. 4.8B in Capital Expenditure)

Eg. from above:
"Once refurbished, Unit 2 is scheduled to be returned to service in the first quarter of 2020, at which time capital expenditures of approximately $4.8 billion are planned to be placed in service."

OPG – No, the LTD in the table includes prerequisite projects already declared in-service. The $4.8B was the OEB submitted estimate of a future in-service amount for Unit 2 refurbishment.

Please see updated wording below:

OPG's current application with the OEB for new regulated prices seeks an increase in the nuclear rate base, effective in the first quarter of 2020, to reflect the planned placement in service of the $4.8 billion in capital expenditures upon return to service of Unit 2, which includes expenditures incurred during the definition and planning phase of the project. Based on OPG's proposal in the application, the revenue requirement impact of the differences between the Unit 2 in-service amount included in the regulated prices and the actual amounts placed in service would be subject to true up via the Capacity Refurbishment Variance Account established by the OEB pursuant to *Ontario Regulation 53/05*. OPG's application proposes that the recovery of the HWSF's costs through regulated prices be subject to a separate prudence review by the OEB, to be conducted as part of a future OEB application.

Darlington Refurbishment

The Darlington generating units are approaching their originally designed end-of-life. Refurbishment of the four generating units is expected to extend the operating life of the station by approximately 30 years. OPG commenced the planning of the refurbishment in 2010.

In 2016, the Darlington Refurbishment project transitioned from the planning phase to the execution phase, as OPG commenced the refurbishment of the first unit, Unit 2, in October 2016, as planned. The unit was taken offline on October 15, 2016. De-fuelling of the reactor, the first critical refurbishment activity undertaken once the unit is removed from service, was completed safely in January 2017, with a total of 480 fuel channels de-fuelled. Islanding of Unit 2, the physical separation of the unit under refurbishment from the three operating units, was completed in April 2017, signifying the completion of the first major segment of the project.

The second major segment includes preparatory work to support the removal of feeder tubes and fuel channel assemblies and the removal of reactor components. The preparatory work was completed in the second quarter of 2017. The Re-tube Tooling Platform for hosting the tooling for the removal, inspection, and installation activities and the setup of specialized tooling and equipment needed for the removal and replacement of the reactor components were completed in the third quarter of 2017. The disassembly of reactor components commenced in August 2017, with the removal of all 960 feeder tubes completed safely in September 2017. This was followed by the severing of pressure tubes, with the severing of bellows and the removal of end fittings expected to commence thereafter and through the end of 2017. Other key project activities executed during the second segment include the completion of the primary side steam generator layup, installation of steam generator access ports to support future inspections, continuation of the major turbine generator overhaul and continued execution of the major electrical scope. OPG is also continuing to execute work to support the requirements set out in the CNSC approved IIP for the station.

Once refurbished, Unit 2 is scheduled to be returned to service in the first quarter of 2020, at which time capital expenditures of approximately $4.8 billion are planned to be placed in service. This includes expenditures incurred during the definition and planning phase of the overall project. The project is tracking on schedule and on budget.

With the substantial completion of the Re-tube Waste Processing Building in November 2017, 17 out of 18 pre-requisite projects in support of the execution phase of the project, including construction of facilities, infrastructure upgrades and installation of safety enhancements, have been completed and placed in service. Completion of the Heavy Water Storage and Drum Handling Facility (HWSF) has been delayed due to challenges with construction. OPG suspended the project in the second quarter of 2017 to evaluate the best approach to optimize cost and schedule and complete the project. Construction activities for the HWSF recommenced in the fourth quarter of 2017 following substantial completion of the Re-tube Waste Processing Building. This plan ensures that the necessary resources are available for both projects and, through resource levelling, improves their execution and cost efficiency. The delay in the completion of the HWSF will not impact the overall Darlington Refurbishment project schedule, as the HWSF is not on the project's critical path. This also will not impact the overall project budget of $12.8 billion, as the costs of the HWSF are included in this total figure. The recovery of HWSF costs through regulated prices will be subject to a prudence review by the OEB, which OPG has proposed be conducted as part of a future OEB application.

In addition to the execution of refurbishment activities on Unit 2, OPG is continuing planning activities for the refurbishment of the second unit, Unit 3, and is entering into associated commitments to procure major components that require long lead times. As of September 30, 2017, $70 million has been invested in planning activities related to the refurbishment of the second unit, Unit 3. These planning activities are being undertaken in accordance with the refurbishment project schedule.

The Financial Accountability Office of Ontario has issued a report titled "*An Assessment of the Financial Risks of the Nuclear Refurbishment Plan*". The report assesses both OPG and Bruce Power's refurbishment activities and the method in which those refurbishments and subsequent nuclear generation is provided to the marketplace. The report

concludes that the base case of refurbishing the six units at the Bruce nuclear GS and the four units at the Darlington nuclear GS provide the most cost effective, low emission generation source available to meet Ontario's baseload electricity requirements. This report re-affirms the positive economic and societal benefits associated with a strong nuclear program in the Province. **[MONITOR]**

Commented [A11]: Not yet released.

OPG – We put MONITOR to ensure status next Thursday before we release.

Ranney Falls Hydroelectric GS

During the third quarter of 2017, OPG continued construction work for a 10 MW single-unit powerhouse on the existing Ranney Falls GS site, as part of the Regulated – Hydroelectric segment. The new unit will replace an existing unit that reached its end of life in 2014. The existing forebay structure demolition has been completed and the upstream cofferdam has been constructed ahead of schedule. Construction continues on the expanded forebay, powerhouse and spillway. Excavation work is substantially complete and forebay wall concrete replacement is in progress. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget.

Nanticoke Solar Facility

The construction of a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands under a Large Renewable Procurement contract with the IESO, through Nanticoke Solar LP, a partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation, is planned to commence in the first quarter of 2018. During the third quarter of 2017, the partnership continued work to obtain approvals and permits required to enable the commencement of construction, and progressed procurement activities for equipment and for engineering and construction services. The facility is expected to be completed in the first quarter of 2019.

Deep Geologic Repository for Low and Intermediate Level Waste

OPG has proposed a deep geologic repository as the preferred solution for the safe long-term management of the L&ILW produced from the continued operation of OPG-owned nuclear generating stations. Agreement has been reached with local municipalities for OPG to develop the L&ILW Deep Geologic Repository (DGR) on lands adjacent to the Western Waste Management Facility (WWMF) in Kincardine, Ontario. The environmental effects of the proposed L&ILW DGR were examined by the CNSC and CEAA-appointed Joint Review Panel (JRP) to meet the requirements of the Canadian Environmental Assessment Act. The JRP submitted its report on the EA to the federal Minister of Environment in May 2015, concluding that, given mitigation, there is unlikely to be significant environmental impact from the project and recommending that the Minister approve the EA. In December 2016, at the request of the federal Minister of Environment and Climate Change, OPG submitted additional information on certain aspects of the EA, including information related to alternate locations for the project. Following its review of OPG's submission and a period of public comment, the CEAA requested further information that OPG subsequently provided in May 2017. In June 2017, the CEAA notified OPG that it had sufficient and adequate information to proceed with the next step of the environmental assessment process and advised that a draft report and updated terms and conditions will be prepared for public review.

On August 21, 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of potential cumulative effects of the project on the Saugeen Ojibway Nations' (SON) physical and cultural heritage, including a description of the potential effects of the project on the Nation's spiritual and cultural connection to the land. OPG is assessing the request and will notify the CEAA when it has determined the timeline for developing a response. The CEAA's draft report for public review will not be issued until this update is provided. The L&ILW DGR at the WWMF site remains OPG's preferred solution for the safe long-term management of the L&ILW.

OPG continues its engagement with the SON toward securing community support for the L&ILW DGR. The in-service date of the L&ILW DGR is expected to be approximately six to seven years from the start of construction.

Financial Strength

As a commercial enterprise, OPG's financial priority is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future growth.

Increase Revenue, Reduce Costs and Achieve Appropriate Return

In May 2016, OPG filed a 5-year application with the OEB for new regulated prices for production from its regulated hydroelectric and nuclear facilities, with a proposed effective date of January 1, 2017. Consistent with the requirements of *Ontario Regulation 53/05*, the application incorporates a rate smoothing proposal that would defer, for future collection, a portion of the approved annual nuclear revenue requirement for the period from January 1, 2017 to the end of the Darlington Refurbishment project, with a view to making changes in OPG's regulated prices more stable year-over-year. The application seeks to ensure that nuclear regulated prices under the rate smoothing approach allow for sufficient cash flow to meet the Company's liquidity needs, support cost effective funding for the Darlington Refurbishment project and other expenditures, and maintain the Company's investment grade credit rating, while taking into account both near-term and future impacts on customers. OPG expects to recognize amounts deferred under rate smoothing as income in the periods to which the underlying approved revenue requirements relate.

The application will further challenge and incentivize OPG to find additional cost reductions and efficiencies within its operations, as a result of greater de-coupling of nuclear and hydroelectric regulated prices from costs and a longer rate-setting period under the OEB's incentive ratemaking framework, which forms the basis for the ratemaking methodologies reflected in the application.

The application seeks an increase in the nuclear rate base, effective in early 2020, to reflect the planned placement in service of approximately $4.8 billion of capital expenditures upon the scheduled return to service of Unit 2 at the Darlington GS as part of the Darlington Refurbishment project and, effective in 2017, an increase in the deemed capital structure applied to the total regulated rate base to 49 percent equity and 51 percent debt, from 45 percent equity and 55 percent debt reflected in the existing regulated prices. The application also requests new rate riders, effective January 1, 2017, to recover or repay the December 31, 2015 balances in all of the Company's OEB-authorized variance and deferral accounts, with the exception of the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the portion of these balances previously approved for recovery or repayment through rate riders that were in effect during 2016.

The OEB's decision on the application, including the effective date of approved new regulated prices, is expected later in 2017. **[MONITOR]**

For generation assets that do not form part of the assets regulated by the OEB, OPG's strategy has been to secure appropriate long-term revenue arrangements. In line with this strategy, virtually all of OPG's non-regulated operating facilities and assets under construction are subject to long-term Energy Supply Agreements (ESAs) or other long-term contracts with the IESO.

Ensure Availability of Cost Effective Funding

In April 2017, DBRS Limited (DBRS) re-affirmed the long-term credit rating on OPG's debt at 'A (low)' and OPG's commercial paper rating at 'R-1 (low)'. All ratings from DBRS have a stable outlook. In July 2017, S&P Global Ratings (S&P) re-affirmed OPG's long-term credit rating at 'BBB+' with a stable outlook. S&P's commercial paper rating for OPG is 'A-1 (low)'.

Social Licence

As the largest electricity generator in Ontario with diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust. OPG is committed to maintaining high standards of public safety and corporate citizenship, including environmental stewardship, transparency, community engagement, and Indigenous relations.

OPG is focused on building long-term, mutually beneficial working relationships with Indigenous communities, businesses and organizations across Ontario, and continues to support procurement, employment and educational opportunities with its Indigenous community partners. The Company seeks to establish these relationships based on a foundation of respect for the languages, customs, and political, social and cultural organizations of the Indigenous communities.

In June 2017, OPG launched an Indigenous Business Engagement (IBE) Initiative. The purpose of this initiative is to increase access to procurement opportunities for Indigenous businesses interested in supplying materials and services to OPG. The IBE Initiative is based on a strategy that will identify opportunities in contracts, scopes of work and business plans for potential Indigenous business engagement; include criteria related to suppliers' ability to engage or partner with Indigenous people or businesses in assessing procurement proposals; and invest in relationships with Indigenous communities by increasing outreach efforts to enhance understanding of how to do business with OPG. OPG has continued to engage with various Indigenous business and communities as well as its suppliers to promote the IBE Initiative. In September 2017, OPG presented the IBE to the Mohawk Council of Akwesanse (Akwesanse). As a result, Akwesanse plans to create a database of businesses in the community that will participate in contracting and supply opportunities with OPG. In September 2017, OPG also hosted a similar presentation to the Williams Treaties First Nations, located proximate to the Pickering and Darlington Nuclear Generating Stations, at the quarterly meeting for these communities.

OPG is developing recruitment plans targeting Indigenous people. In October 2017, OPG participated in five Indigenous-specific career fairs to attract such talent. **[MONITOR]**

OPG has a transportation electrification strategy that will help position OPG as a leader in transportation electrification in Ontario. This strategy is intended to leverage OPG's clean electricity to support action on climate change, create growth opportunities for OPG, and enhance OPG's brand and social licence.

Commented [A12]: Sp. "Akwesasne" ?

OPG – fixed spelling to as follows:

In September 2017, OPG presented the IBE to the Mohawk Council of Akwesasne (Akwesasne). As a result, the Akwesasne plan to create a database of businesses in the community that will participate in contracting and supply opportunities with OPG.

Commented [A13]: Does this deal with OPG owned fleet and other vehicles, or in line with the infrastructure for EV vehicles.

Can further details be provided in particular on the point of 'creating growth opportunities for OPG'.

OPG – revised wording for this paragraph as follows:

OPG has a strategy to help position the Company as a leader in transportation electrification in the province. The strategy aims to leverage the Company's clean, reliable and cost-effective electricity to power transportation, capitalize on future commercial growth opportunities, and enhance the Company's social licence. OPG is pursuing initiatives to increase the use of electric vehicles within its operations, and is assessing vehicle grid integration and hydrogen applications for the transportation sector.

Outlook

The financial performance of OPG's regulated operations is driven, in large part, by the outcome of applications for regulated prices to the OEB. The existing base regulated prices were established by the OEB effective November 1, 2014 based on a forecast of costs and production for the regulated facilities for the 2014 to 2015 period. The future outcome of OPG's current application for new regulated prices, currently pending the OEB's decision, is expected to provide substantial price certainty for the regulated business for the 2017 to 2021 period.

In its application, OPG has requested January 1, 2017 as the effective date for the new regulated prices. In December 2016, the OEB issued an order declaring the existing base regulated prices interim, which preserves the OEB's ability to make the new regulated prices effective as early as January 1, 2017. Considering the timing of OPG's application and OPG's procedural adherence throughout the proceeding, the Company believes that the OEB could make the new regulated prices effective January 1, 2017. This would allow OPG to recover the difference between the approved new regulated prices and the existing regulated prices for the period between January 1, 2017 and the implementation date of the new prices based on the OEB's order. The OEB's decision on the application, including the effective date of the new regulated prices, is expected in the fourth quarter of 2017. **[MONITOR]** The continuation of existing regulated prices until the issuance of the OEB's decision is expected to continue to contribute to lower income, particularly from the Regulated – Nuclear Generation segment, and, excluding the gain on sale of the Company's head office premises and associated parking facility recorded in the second quarter of 2017, lower

ROE Excluding AOCI during 2017, compared to 2016. In large part, this is due to the year-over-year reduction in nuclear electricity generation resulting from the Unit 2 refurbishment outage at the Darlington GS, given that the existing nuclear regulated prices were determined in 2014 based on a higher production forecast that reflected the operation of all four units at the station. As such, the OEB's decision on the effective date of the new regulated prices, as well as the timing of the decision issuance, could have a significant impact on OPG's financial results during 2017.

Nuclear base regulated prices resulting from OPG's current application will be subject to a rate smoothing mechanism that defers collection of a portion of OEB-approved revenues to future periods. As expected, combined with the expiry of rate riders in effect to the end of 2016, a year-over-year reduction in nuclear generation due to the Unit 2 refurbishment outage at the Darlington GS and the continuation of existing regulated prices until such time as new prices are implemented by the OEB, this will result in lower cash flow from operating activities in 2017, compared to 2016. OPG expects to continue to have the necessary financial capacity and sufficient access to cost effective financing sources to continue to fund its capital requirements and other disbursements.

Lower nuclear generation due to the Darlington Refurbishment outages will continue, as planned, to negatively impact the Enterprise TGC metric for the duration of the refurbishment project. Variability in sustaining capital investment expenditures, including major sustaining projects for the hydroelectric operations, also will impact the Enterprise TGC in future periods.

Several OEB-authorized regulatory variance and deferral accounts currently in place contribute to reducing the relative variability of the Company's income and ROE Excluding AOCI. Among others, the regulatory accounts include those related to the revenue impact of variability in water flows and forgone production due to SBG conditions at the regulated hydroelectric stations. As there are no variance or deferral accounts in place related to the impact of generation performance of the nuclear stations on revenue from base regulated prices, the Regulated – Hydroelectric segment generally is expected to produce overall more predictable earnings. OPG continues to operate and maintain its nuclear facilities with a view to optimize their performance and availability, while focusing on improving the overall reliability and predictability of the fleet.

Electricity generated from most of OPG's non-regulated assets is subject to ESAs with the IESO. Based on these agreements, OPG expects the Contracted Generation Portfolio segment to continue to contribute a generally stable level of earnings and cash flow from operations going forward.

OPG's total forecast capital expenditures for the 2017 year are approximately $2.0 billion. This includes amounts for the Darlington Refurbishment project, hydroelectric and other development projects including the completion of the Peter Sutherland Sr. GS and the expansion of the Ranney Falls GS, and sustaining capital investments across the generating fleet. OPG's major projects are discussed in the section, *Project Excellence*.

In addition to the operating and financial performance of the electricity generation business, OPG's results are affected by the earnings on the Nuclear Segregated Funds, which are reported in the Regulated – Nuclear Waste Management segment. While the Nuclear Segregated Funds are managed to achieve, in the long term, the target rate of return based on the discount rate specified in the ONFA, the rates of return earned in a given period can be subject to various external factors including financial market conditions and, for the portion of the Used Fuel Segregated Fund guaranteed by the Province under the ONFA, changes in the Ontario consumer price index (CPI). In the near term, these factors can be volatile and cause fluctuations in the Company's income. This volatility is partially mitigated by the impact of the OEB-authorized Bruce Lease Net Revenues Variance Account and, as discussed below, the funded status of the two segregated funds.

As OPG does not have the right to withdraw surplus amounts from the Nuclear Segregated Funds, OPG limits the amount of Nuclear Segregated Funds assets reported on the balance sheet to the present value of such life cycle funding liability. This reduces the volatility of earnings on the Nuclear Segregated Funds reflected in net income when the funds are in a fully funded or overfunded position. As at September 30, 2017, the Decommissioning

Segregated Fund was overfunded by approximately 23 percent, and the Used Fuel Segregated Fund was marginally overfunded, by less than one percent, based on the 2017 ONFA Reference Plan. Variability in asset performance due to volatility inherent in financial markets and changes in Ontario CPI, or changes in funding liability estimates, may result in either or both funds becoming underfunded in the future.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

Regulated – Nuclear Generation Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue	**739**	885	**2,000**	2,631
Fuel expense	**81**	79	**217**	239
Gross margin	**658**	806	**1,783**	2,392
Operations, maintenance and administration	**511**	521	**1,693**	1,665
Depreciation and amortization	**116**	230	**333**	691
Property taxes	**7**	6	**20**	19
Income (loss) before other losses, interest, and income taxes	**24**	49	**(263)**	17
Other losses	**4**	2	**4**	-
Income (loss) before interest and income taxes	**20**	47	**(267)**	17

For the three and nine month periods ended September 30, 2017, the segment earnings decreased by $27 million and $284 million, respectively, compared to the same periods in 2016. The decrease in earnings was expected and primarily due to reduced revenue from the nuclear base regulated price of approximately $24 million and $230 million, respectively. The decrease was partially offset by an associated year-over-year decrease in fuel expense. The decrease in revenue during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, reflected lower electricity generation of 0.4 TWh and 4.0 TWh, respectively, primarily due to the ongoing Unit 2 refurbishment outage at the Darlington GS that began in October 2016, without a corresponding increase in the base regulated price. The existing nuclear base regulated price set by the OEB in 2014 continues to be in effect pending the OEB's decision on OPG's application for new regulated prices, proposed to be effective on January 1, 2017. The existing price does not reflect the lower generation as a result of the Darlington Refurbishment project, as it was set to allow the Company to recover its approved nuclear costs over a higher nuclear production volume, based on the 2014 and 2015 outage profile that did not include a refurbishment outage. The reduction in nuclear electricity generation for the three months ended September 30, 2017 was largely offset by the higher electricity generation from the Pickering GS.

OM&A expenses decreased by $10 million during the third quarter of 2017, compared to the same period in 2016, as a result of a higher materials and supplies obsolescence charge recognized in 2016. OM&A expenses increased by $28 million during the nine months ended September 30, 2017, compared to the same period in 2016, due to planned maintenance activities in 2017.

Depreciation and amortization expense, excluding amortization expense related to regulatory account balances, increased by $16 million and $30 million during the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016, primarily due to new assets in service.

The expiry of an OEB-authorized nuclear rate rider on December 31, 2016 contributed to the decrease in segment revenue for the three and nine month periods ended September 30, 2017, compared to the same periods in 2016. As rate riders allow for recovery of approved balances in OEB-authorized regulatory accounts, this decrease in revenue was largely offset by a decrease in amortization expense related to these balances. There was no rate rider

in effect during the nine months ended September 30, 2017, pending the outcome of OPG's current application to the OEB for new regulated prices.

The Unit Capability Factors for the Darlington and Pickering generating stations were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Unit Capability Factor *(%)* [1]				
Darlington GS	**96.2**	89.6	**82.1**	87.6
Pickering GS	**88.7**	77.3	**83.8**	73.8

[1] The nuclear Unit Capability Factor excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS was excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

The Unit Capability Factor at the Darlington GS increased in the third quarter of 2017, compared to the same quarter in 2016, primarily due to the lower number of planned outage days during the third quarter of 2017. The lower Unit Capability Factor at the Darlington GS for the nine months ended September 30, 2017, compared to the same period in 2016, reflected the higher number of planned outage days, largely driven by constraints related to the transition of the station toward refurbishment.

The increase in Unit Capability Factor at the Pickering GS for the three and nine month periods ended September 30, 2017 was primarily due to outage optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station compared to 2016.

Regulated – Nuclear Waste Management Segment

(millions of dollars) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Revenue	**33**	36	**90**	102
Operations, maintenance and administration	**35**	38	**96**	108
Accretion on nuclear fixed asset removal and nuclear waste management liabilities	**230**	228	**696**	684
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(196)**	(248)	**(579)**	(620)
(Loss) Income before interest and income taxes	**(36)**	18	**(123)**	(70)

The segment loss before interest and income taxes was $36 million and $123 million during the three and nine months ended September 30, 2017, respectively, a decrease in earnings of $54 million and $53 million compared to the same periods in 2016. The decline in earnings was primarily due to lower earnings from the Nuclear Segregated Funds, net of the impact of the impact of the Bruce Lease Net Revenues Variance Account, reflecting higher earnings from market returns on fund assets and the CPI-adjusted rate of return guaranteed by the Province for the portion of the Used Fuel Segregated Fund related to the initial 2.23 million used fuel bundles (committed return) in the third quarter of 2016.

As both the Decommissioning Segregated Fund and the Used Fuel Fund were in an overfunded position during the three and nine months period ended September 30, 2017, compared to the underlying funding liabilities per the approved ONFA Reference Plan, the earnings on the funds during these periods reflected the growth rate in the present value of the funding liabilities and were not impacted by market returns and committed return. The higher earnings on both funds during the three and nine months periods ended September 30, 2016 reflected market returns and committed return, as the Decommissioning Segregated Fund became over 120 percent funded during the third quarter of 2016 while the Used Fuel Fund was underfunded, compared to the corresponding funding liabilities.

Higher market returns and committed return in the third quarter of 2016 in relation to the funding liabilities' growth rate reflected in fund earnings during 2017 resulted in a year-over-year decrease in the amount of earnings on the Nuclear Segregated Funds.

As of December 31, 2016, OPG recorded a decrease of approximately $1,570 million to the Nuclear Liabilities and associated asset retirement costs capitalized as part of the carrying value of the nuclear generating stations. The resulting year-over-year decreases in accretion on fixed asset removal and nuclear waste management liabilities recorded in the Regulated – Nuclear Waste Management segment and depreciation and fuel expenses recorded in the Regulated – Nuclear Generation segment during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, were offset by the impact of the Bruce Lease Net Revenues Variance Account and the Nuclear Liability Deferral Account authorized by the OEB.

Under the current OEB-approved cost recovery methodology, these changes in expenses also are not expected to materially affect OPG's income during the rest of 2017, as they are expected to continue to be largely offset by the impact of the regulatory accounts until such time as the OEB implements corresponding changes to OPG's nuclear regulated prices, and subsequently by the impact of such new regulated prices. Further details on the change in the estimate of the Nuclear Liabilities as of December 31, 2016 are described in OPG's 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Asset Retirement Obligation*. **[MONITOR]**

Regulated – Hydroelectric Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue [1]	**327**	350	**1,069**	1,148
Fuel expense	**88**	88	**258**	259
Gross margin	**239**	262	**811**	889
Operations, maintenance and administration	**81**	87	**232**	238
Depreciation and amortization	**34**	56	**103**	169
Property tax	**1**	1	**1**	1
Income before other losses (gains), interest and income taxes	**123**	118	**475**	481
Other losses (gains)	**1**	1	**1**	(19)
Income before interest and income taxes	**122**	117	**474**	500

[1] During the three and nine month periods ended September 30, 2017, the Regulated – Hydroelectric segment revenue included incentive payments of $4 million and $9 million, respectively, related to the OEB-approved hydroelectric incentive mechanism (three and nine month periods ended September 30, 2016 – incentive payments of $6 million and $8 million, respectively). The mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers. The incentive payments are reduced to remove incentive revenues arising in connection with SBG conditions.

The increase in segment income before interest and income taxes of $5 million during the third quarter of 2017, compared to the same quarter in 2016, was primarily the result of a decrease in OM&A expenses, mainly due to the timing of repairs and maintenance work in 2017 and a deferral of outages during the high water period.

The decrease in segment income before interest and income taxes of $26 million during the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to a gain of $22 million recognized during the first quarter of 2016 to reflect the OEB's January 2016 decision to reverse a portion of an earlier capital cost disallowance related to the Niagara Tunnel project expenditures, in response to a motion by OPG. The income impact of OEB-approved variance accounts also contributed to the year-over-year decrease in income for the period. These factors were partially offset by the decrease in OM&A expenses related to the timing of repairs and maintenance work in 2017 and a deferral of outages during the high water period.

The decrease in revenue from the segment for the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was largely due to the expiry of an OEB-authorized rate rider on

December 31, 2016. As the rider allowed for the recovery of approved balances in OEB-authorized regulatory accounts, the resulting reduction in revenue was largely offset by lower amortization expense related to these balances. There was no rate rider in effect during the first nine months of 2017 pending the outcome of OPG's current application to the OEB for new regulated prices.

The Hydroelectric Availability for the stations included in the Regulated – Hydroelectric segment was as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Hydroelectric Availability *(%)*	**87.6**	84.1	**89.0**	89.8

The Hydroelectric Availability in the third quarter of 2017 was higher compared to the same period in 2016, primarily due to a higher number of planned outages in 2016 as a result of the refurbishment of the Sir Adam Beck Pump GS reservoir between April 2016 and February 2017. The marginal decrease in Hydroelectric Availability during the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to a higher number of unplanned outage days at the Northwestern Ontario and Niagara region hydroelectric stations, partially offset by higher availability from the Sir Adam Beck Pump GS.

Contracted Generation Portfolio Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue	**141**	149	**431**	431
Fuel expense	**15**	19	**42**	42
Gross margin	**126**	130	**389**	389
Operations, maintenance and administration	**39**	44	**118**	129
Depreciation and amortization	**20**	19	**59**	56
Accretion on fixed asset removal liabilities	**3**	2	**7**	6
Property taxes	**-**	1	**5**	6
Income from investments subject to significant influence	**(11)**	(11)	**(29)**	(28)
Income before other loss, interest and income taxes	**75**	75	**229**	220
Other loss	**-**	1	**-**	1
Income before interest and income taxes	**75**	74	**229**	219

Income before interest and income taxes from the segment increased by $1 million and $10 million during the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016. The increase in earnings for the three months ended September 30, 2017 mainly resulted from revenues from the Peter Sutherland Sr. GS that was placed in-service at the end of the first quarter of 2017 and lower OM&A expenses, partially offset by lower revenue from the Atikokan GS. The decrease in revenue from the Atikokan GS was primarily due to higher revenues in 2016, when the station was called upon to provide the needed support to the electricity system in Northwestern Ontario as a result of an outage at a local transformer station. For the nine months ended September 30, 2017, the increase in earnings was primarily due to lower OM&A expenses. The lower OM&A expenses for the three and nine month periods ended September 30, 2017 were mainly due to the prospective adoption of the full yield curve approach to the estimation of the service and interest cost components of pension and OPEB costs starting in 2017.

The Hydroelectric Availability and the Thermal Equivalent Forced Outage Rate (EFOR) for the Contracted Generation Portfolio segment were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Hydroelectric Availability *(%)*	**66.1**	68.2	**76.9**	79.6
Thermal EFOR *(%)*	**2.6**	2.1	**6.0**	1.3

Lower Hydroelectric Availability during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was primarily due to an increase in the number of planned outage days at the Lower Mattagami River hydroelectric generating stations.

The higher Thermal EFOR during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was primarily due to a higher number of unplanned outage days at a Lennox GS unit as a result of a transmission outage and a generator cooling water system outage in 2017.

Services, Trading, and Other Non-Generation Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue	**9**	15	**36**	52
Fuel expense	**1**	1	**1**	1
Gross margin	**8**	14	**35**	51
Operations, maintenance and administration	**1**	11	**2**	20
Depreciation and amortization	**8**	8	**22**	25
Accretion on fixed asset removal liabilities	**2**	2	**6**	6
Property taxes	**-**	4	**4**	9
(Loss) income before other gains, interest, and income taxes	**(3)**	(11)	**1**	(9)
Other gains	**(2)**	(3)	**(385)**	(5)
Income (loss) before interest and income taxes	**(1)**	(8)	**386**	(4)

Segment earnings improved by $7 million during the third quarter of 2017, compared to the same quarter in 2016. The improvement in earnings was primarily due to lower OM&A expenses reflecting project expenditures incurred in the third quarter of 2016, and OPG's decision, in the fourth quarter of 2016, to proceed with the decommissioning of Lambton GS.

Segment income before interest and income taxes increased by $390 million for the nine months ended September 30, 2017, compared to the same period in 2016. The increase in earnings mainly reflected the gain on the sale of OPG's head office premises and associated parking facility recorded during the second quarter of 2017.

LIQUIDITY AND CAPITAL RESOURCES

OPG's primary sources of liquidity and capital are funds generated from operations, bank financing, credit facilities provided by the Ontario Electricity Financial Corporation (OEFC), long-term corporate debt, and capital market financing. These sources are used for multiple purposes including: to invest in plants and technologies, to undertake major projects, to fund long-term obligations such as contributions to the pension fund and the Nuclear Segregated Funds, to make payments under the OPEB plans, to fund expenditures on Nuclear Liabilities not reimbursable from the Nuclear Segregated Funds, to service and repay long-term debt, to provide general working capital, and to fund OPG's investment in the Fair Hydro Plan.

Changes in cash and cash equivalents for the three and nine month periods ended September 30 are as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Cash and cash equivalents, beginning of period	**242**	295	**186**	464
Cash flow provided by operating activities	**485**	530	**698**	1,211
Cash flow used in investing activities	**(463)**	(390)	**(720)**	(1,253)
Cash flow provided by (used in) financing activities	**16**	(9)	**116**	4
Net increase (decrease)	**38**	131	**94**	(38)
Cash and cash equivalents, end of period	**280**	426	**280**	426

For a discussion of cash flow provided by operating activities and the FFO Adjusted Interest Coverage ratio, refer to the details in the section, *Highlights* under the heading, *Overview of Results*.

Investing Activities

Electricity generation is a capital-intensive business. It requires continued investment in plants and technologies to maintain and improve operating performance including asset reliability, safety and environmental performance, to increase the generating capacity of existing stations, and to invest in the development of new generating stations, emerging technologies and other business growth opportunities.

Cash flow used in investing activities during the third quarter of 2017 was $463 million, compared to $390 million for the same period in 2016. The increase in cash flow used for investing activities mainly resulted from higher expenditures on the Darlington Refurbishment project in the third quarter of 2017.

Cash flow used in investing activities decreased by $533 million for the nine months ended September 30, 2017, compared to the same period in 2016. The decrease in net cash flow used in investing activities was primarily due to the receipt of proceeds from the sale of OPG's head office premises and associated parking facility in the second quarter of 2017 pursuant to a Shareholder Declaration and Shareholder Resolution, and the acquisition of nine million common shares of Hydro One Limited (Hydro One) in the second quarter of 2016, partially offset by higher expenditures on the Darlington Refurbishment project in 2017. OPG acquired the Hydro One shares for investment purposes, to mitigate the risk of future price volatility related to the Company's future share delivery obligations under the collective agreements with the Power Workers' Union and The Society of Energy Professionals.

Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from the sale of head office premises and associated parking facility, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. OPG expects that the amount of designated proceeds to be transferred into the Consolidated Revenue Fund will be largely consistent with the after-tax gain on sale. The transfer is expected to take place later in 2017.

Financing Activities

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. In the second quarter of 2017, OPG renewed and extended the expiry date of both tranches from May 2021 to May 2022. There were no amounts outstanding under the bank credit facility as at September 30, 2017.

There was $160 million of commercial paper outstanding under OPG's commercial paper program as at September 30, 2017.

As at September 30, 2017, OPG also maintained $25 million of short-term, uncommitted overdraft facilities, and a further $463 million of short-term, uncommitted credit facilities, which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other general corporate purposes. As at September 30, 2017, a total of $388 million of Letters of Credit had been issued under these facilities. This included $349 million for the supplementary pension plans, $38 million for general corporate purposes, and $1 million related to the operation of the PEC.

The Company has an agreement to sell an undivided co-ownership interest in its current and future accounts receivable to an independent trust, expiring on November 30, 2018. The maximum amount of co-ownership interest that can be sold under this agreement is $150 million. As at September 30, 2017, no borrowings were issued under this agreement and there were Letters of Credit outstanding under this agreement of $150 million, which were issued in support of OPG's supplementary pension plans.

As at September 30, 2017, Lower Mattagami Energy Limited Partnership (LME) maintained a $400 million bank credit facility to support the funding requirements for the Lower Mattagami River project including support for LME's commercial paper program and the issuance of the Letters of Credit. The facility consists of a $300 million tranche which, in the third quarter of 2017, was extended to mature in August 2022 and a $100 million tranche which, in the third quarter of 2017, was reduced from $200 million and extended to mature in August 2018. As at September 30, 2017, there was no external commercial paper outstanding under LME's commercial paper program. A letter of credit of $55 million was issued in July 2017 and remains outstanding as at September 30, 2017 under the $300 million tranche of the credit facility.

In June 2016, OPG entered into a $700 million general corporate credit facility agreement with the OEFC, which expires on December 31, 2017. In the third quarter of 2017, the agreement was amended to increase the credit facility to $2,350 million and to extend its expiry date to December 31, 2018.

In February 2017, OPG issued senior notes payable to the OEFC totalling $200 million and maturing in February 2047. The effective interest rate and coupon interest rate of these notes was 4.12 percent. In June 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in June 2047. The effective interest rate and coupon interest rate of these notes was 3.65 percent. In August 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in August 2047. The effective interest rate and coupon interest rate of these notes was 3.86 percent. In September 2017, OPG issued senior notes payable to the OEFC totalling $400 million and maturing in September 2047. The effective interest rate and coupon interest rate of these notes was 4.07 percent. As at September 30, 2017, there were outstanding long-term borrowings of $800 million under this credit facility.

In October 2017, OPG issued $500 million of senior notes payable under a Medium Term Note Program. The notes bear a coupon interest rate of 3.32 percent and an effective rate of 3.43 percent, payable semi-annually until maturity on October 4, 2027. The offering was made under OPG's $2 billion short form base shelf prospectus dated September 12, 2017. The net proceeds will be used for general corporate purposes, including the financing of OPG's subordinated debt investment in the Fair Hydro Plan.

As at September 30, 2017, OPG's long-term debt outstanding was $5,482 million, including $628 million due within one year.

OPG continues to evaluate arrangements that would appropriately support the Company's financing needs and capital expenditure programs.

Contractual and Commercial Commitments

Pension Plan Actuarial Valuation

A new actuarial valuation of the OPG registered pension plan was filed with the Financial Services Commission of Ontario in September 2017 with an effective date of January 1, 2017. The annual funding requirements in accordance with the new actuarial valuation are $212 million for 2017, $215 million for 2018, and $219 million for 2019. The next actuarial valuation must have an effective date no later than January 1, 2020.

BALANCE SHEET HIGHLIGHTS

The following section provides highlights of OPG's unaudited interim consolidated financial position using selected balance sheet data:

(millions of dollars) (unaudited)	As At September 30 2017	As At December 31 2016
Property, plant and equipment - net	**20,801**	19,998
The increase was primarily due to capital expenditures on the Darlington Refurbishment project, partially offset by depreciation expense.		
Nuclear fixed asset removal and nuclear waste management funds *(current and non-current portions)*	**16,534**	15,984
The increase was primarily due to earnings on the Nuclear Segregated Funds, partially offset by reimbursements of eligible expenditures on nuclear fixed asset removal and nuclear waste management activities.		
Short-term debt	**160**	2
The increase was due to commercial paper issued under OPG's commercial paper program during the third quarter of 2017.		
Fixed asset removal and nuclear waste management liabilities	**20,075**	19,484
The increase was primarily a result of accretion expense representing the increase in the liabilities due to the passage of time, partially offset by expenditures on nuclear fixed asset removal and waste management activities.		

Off-Balance Sheet Arrangements

In the normal course of operations, OPG engages in a variety of transactions that, under US GAAP, are either not recorded in the Company's interim consolidated financial statements or are recorded in the Company's interim consolidated financial statements using amounts that differ from the full contract amounts. Principal off-balance sheet activities for OPG include guarantees and long-term contracts.

CHANGES IN ACCOUNTING POLICIES AND ESTIMATES

OPG's significant accounting policies are outlined in Note 3 to the audited consolidated financial statements as at and for the year ended December 31, 2016. A discussion of recent accounting pronouncements and change in accounting estimate are included in Note 2 to OPG's unaudited interim consolidated financial statements as at and for the three and nine month periods ended September 30, 2017 under the heading, *Significant Accounting Policies and Estimates*. Disclosure regarding OPG's critical accounting policies is included in OPG's 2016 annual MD&A.

RISK MANAGEMENT

The following provides an update to the discussion of the Company's risks and risk management activities included in OPG's 2016 annual MD&A. As such, the disclosure in this section should be read in conjunction with the *Risk Management* section included in the annual MD&A.

Risks to Achieving Project Excellence

Deep Geologic Repository for Low and Intermediate Level Waste

In August 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of the potential cumulative effects of the DGR project on the physical and cultural heritage of the SON, taking into account the results of the SON Community Process. OPG continues to work with the SON, however the timing and outcome of the SON Community Process and the EA decision by the Minister are uncertain.

Risks to Maintaining Financial Strength

Commodity Markets

Changes in the market price of fuels used to produce electricity can adversely impact OPG's earnings and cash flow from operations.

To manage the risk of unpredictable increases in the price of fuels, the Company has fuel hedging programs, which include fixed price and indexed contracts.

The percentages hedged of OPG's fuel requirements are shown in the following table. These amounts are based on yearly forecasts of generation and supply mix, and as such, are subject to change as these forecasts are updated.

	2017 [1]	2018	2019
Estimated fuel requirements hedged [2]	73%	73%	69%

[1] Based on actual fuel requirements hedged for the nine months ended September 30, 2017 and forecast for the remainder of the year.

[2] Represents the approximate portion of megawatt-hours of expected generation production (and year-end inventory targets) from each type of OPG-operated facility (nuclear, hydroelectric and thermal) for which the Company has entered into contractual arrangements or obligations in order to secure the price of fuel, or which is subject to regulation. In the case of hydroelectric generation, this represents the gross revenue charge and water rental charges. Excess fuel inventories (nuclear and thermal) in a given year are attributed to the next year for the purpose of measuring hedge ratios.

Foreign Exchange

OPG's earnings and cash flow can be affected by movements in the United States dollar (USD) relative to the Canadian dollar.

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are denominated in, or tied to, USD. To manage this risk, OPG periodically employs various financial instruments such as forwards and other

derivative contracts, in accordance with approved risk management policies. As at September 30, 2017, OPG had no foreign exchange contracts outstanding.

Trading

OPG's financial performance can be affected by its trading activities.

OPG's electricity trading operations are closely monitored, with total exposures measured and reported to senior management on a daily basis. The main metric used to measure the financial risk of trading activity is Value at Risk (VaR). VaR is defined as a probabilistic maximum potential future loss expressed in monetary terms for a portfolio based on normal market conditions over a set period of time. For the third quarter of 2017, the VaR utilization ranged between $0.2 million and $0.3 million.

Credit

Deterioration in energy markets counterparty credit and non-performance by suppliers and contractors can adversely impact OPG's earnings and cash flow from operations.

OPG manages its exposure to suppliers or counterparties by evaluating their financial condition and negotiating appropriate collateral or other forms of security. OPG's credit exposure relating to energy markets transactions as at September 30, 2017 was $356 million, including $346 million with the IESO. Management considers the Company's risk exposure relating to electricity sales through the IESO-administered spot market to be low as the IESO oversees the credit worthiness of all market participants. In accordance with the IESO's prudential support requirements, market participants are required to provide collateral to cover funds that they might owe to the market. Of the $10 million remaining exposure as at September 30, 2017, over 95 percent was related to investment grade counterparties.

Fair Hydro Plan

OPG's role in connection with the Fair Hydro Plan could have reputational impacts on the Company.

The *Ontario Fair Hydro Plan Act, 2017* received Royal Assent on June 1, 2017 and its attendant regulations came into force in June, July, and October 2017. **[UPDATE]** The regulations clarify aspects of the structure and program logistics required for ~~OPG, as~~ the Financial Services Manager of the Fair Hydro Plan, which OPG is planning to undertake, to refinance a portion of the Global Adjustment through the Trust. OPG's reputation could potentially be adversely impacted through its involvement with the Fair Hydro Plan and through stakeholder opinions related to this involvement.

Commented [A14]: Not sure this is the right wording. OPG's role as FSM is required under the Act, but not the refinancing through the Trust – the OPG Financing Entity's (or entities) role is discretionary.

OPG – please see changes to this paragraph as follows:

The *Ontario Fair Hydro Plan Act, 2017* received Royal Assent on June 1, 2017 and the associated general regulation came into force in June 2017. As the Financial Services Manager of the Fair Hydro Plan, OPG's reputation could potentially be adversely impacted through this involvement and through stakeholder opinions related to this involvement.

Recovery of Pension and OPEB Costs

On September 14, 2017, the OEB issued its final report on the guiding principles and the policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the electricity and natural gas sectors. The report reaffirmed the conclusions of the initial report issued in May 2017, including the establishment of the accrual basis of accounting as the default rate-setting method and the establishment of a variance account to record asymmetric carrying charges in favour of ratepayers on the differences between the accrual costs recovered and cash payments made by a utility for pension and OPEB plans. The report requires OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the Pension & OPEB Cash Versus Accrual Differential Deferral Account that has been in effect since November 1, 2014, until such time as the OEB approves the resumption of the accrual basis of recovery. The future recovery of amounts recorded in the account will be subject to this approval. The report confirmed that OPG would become subject to the carrying charges on the differences between accrual costs and cash payments going back to November 1, 2014, with the charges calculated on the portion of such differences that have been recovered through regulated prices. The carrying charges will be determined at prescribed interest rate set quarterly by the OEB based on the quarterly return of a mid-term corporate bond index yield. This outcome has reduced OPG's risk related to the recovery of actual pension and OPEB accrual

costs and the recovery of the balance in the Pension & OPEB Cash Versus Accrual Differential Deferral Account. The account had a balance of $552 million as at September 30, 2017 and is recognized on the Company's consolidated balance sheet as a regulatory asset. OPG's financial results for the three and nine month periods ended September 30, 2017 were not impacted by the issuance of the OEB's report.

RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One, the IESO and the OEFC. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions are summarized below:

	Three Months Ended September 30			
	2017		2016	
(millions of dollars) (unaudited)	**Revenue**	**Expense**	**Revenue**	**Expense**
Hydro One				
Electricity sales	**2**	**-**	1	-
Services	**-**	**3**	-	3
Dividends	**2**	**-**	-	2
Province of Ontario				
Decommissioning Fund excess funding [1]	**-**	**(44)**	-	201
Used Fuel Fund rate of return guarantee and excess funding [1]	**-**	**(39)**	-	295
Gross revenue charges	**-**	**27**	-	28
ONFA guarantee fee	**-**	**2**	-	2
Other	**-**	**2**	-	-
OEFC				
Gross revenue charges	**-**	**62**	-	57
Interest expense on long-term notes	**-**	**40**	-	42
Income taxes, net of investment tax credits	**-**	**23**	-	28
IESO				
Electricity related revenue	**1,126**	**4**	1,293	7
	1,130	**80**	1,294	665

(millions of dollars) (unaudited)	Nine Months Ended September 30 2017 Revenue	2017 Expense	2016 Revenue	2016 Expense
Hydro One				
Electricity sales	**7**	**-**	4	-
Services	**1**	**8**	1	12
Dividends	**6**	**-**	-	4
Province of Ontario				
Decommissioning Fund excess funding [1]	**-**	**164**	-	137
Used Fuel Fund rate of return guarantee and excess funding [1]	**-**	**217**	-	190
Gross revenue charges	**-**	**84**	-	91
ONFA guarantee fee	**-**	**6**	-	6
Other	**-**	**3**	-	-
OEFC				
Gross revenue charges	**-**	**156**	-	147
Interest expense on long-term notes	**-**	**122**	-	127
Income taxes, net of investment tax credits	**-**	**132**	-	112
IESO				
Electricity related revenue	**3,228**	**11**	3,894	22
	3,242	**903**	3,899	848

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at September 30, 2017 and December 31, 2016, the Nuclear Segregated Funds were reported net of amounts due to the Province of $3,796 million and $3,415 million, respectively. The details of accounting for the Nuclear Segregated Funds are described in OPG's 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

The receivable, available-for-sale securities, payable and long-term debt balances between OPG and its related parties are summarized below:

(millions of dollars) (unaudited)	September 30 2017	December 31 2016
Receivables from related parties		
Hydro One	**1**	1
IESO	**346**	421
OEFC	**3**	1
PEC	**2**	4
Province of Ontario	**5**	2
Available-for-sale securities		
Hydro One shares	**190**	212
Accounts payable and accrued charges		
OEFC	**37**	61
Province of Ontario	**6**	2
IESO	**2**	2
Long-term debt (including current portion)		
Notes payable to OEFC	**3,245**	3,295

OPG holds interest-bearing Province of Ontario bonds in the Nuclear Segregated Funds and the OPG registered pension fund. As at September 30, 2017, the Nuclear Segregated Funds held $1,498 million of interest-bearing Province of Ontario bonds, while the registered pension fund had no such holdings. As at December 31, 2016, the Nuclear Segregated Funds and the registered pension fund held $1,652 million and $284 million of interest-bearing Province of Ontario bonds, respectively. These bonds are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

There have been no related party transactions related to the Fair Hydro Plan and associated financing activities. The first transaction between the Trust and the IESO is expected later in 2017.

INTERNAL CONTROLS OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

The Company maintains a comprehensive system of policies, procedures, and processes that represents its framework for internal controls over financial reporting and for its disclosure controls and procedures (together, ICOFR). There were no changes in the Company's internal control system during the current interim period that has or is reasonably likely to have a material impact to the ICOFR.

QUARTERLY FINANCIAL HIGHLIGHTS

The following tables set out selected financial information from OPG's unaudited interim consolidated financial statements for each of the eight most recently completed quarters.

(millions of dollars - except where noted) (unaudited)	**September 30 2017**	**June 30 2017**	**March 31 2017**	**December 31 2016**
Revenue	**1,217**	1,146	1,176	1,388
Net income (loss)	**140**	307	68	(8)
Less: Net income attributable to non-controlling interest	**9**	4	4	5
Net income (loss) attributable to the Shareholder	**131**	303	64	(13)
Per common share, attributable to the Shareholder *(dollars)*	**$0.51**	$1.18	$0.25	($0.05)

(millions of dollars - except where noted) (unaudited)	**September 30 2016**	**June 30 2016**	**March 31 2016**	**December 31 2015**
Revenue	1,400	1,387	1,478	1,312
Net income (loss)	198	135	128	(100)
Less: Net income attribute to the non-controlling interest	4	3	5	1
Net income (loss) attributable to the Shareholder	194	132	123	(101)
Per common share, attributable to the Shareholder *(dollars)*	$0.76	$0.51	$0.48	($0.39)

Trends

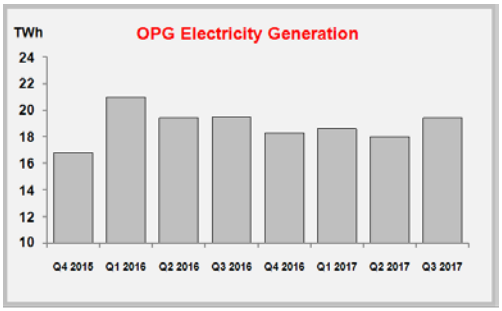
OPG's quarterly results are affected by changes in grid-supplied electricity demand, primarily resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. Weather conditions affect water flows, electricity demand, and prevalence of SBG conditions. Historically, OPG's revenues have been higher in the first

quarter of a fiscal year as a result of winter heating demands and in the third quarter due to air conditioning and cooling demands. The financial impact of forgone production due to SBG conditions at the regulated hydroelectric stations and the financial impact of differences between forecast water flows reflected in OEB-approved regulated prices and the actual water flows are mitigated by regulatory variance accounts authorized by the OEB.

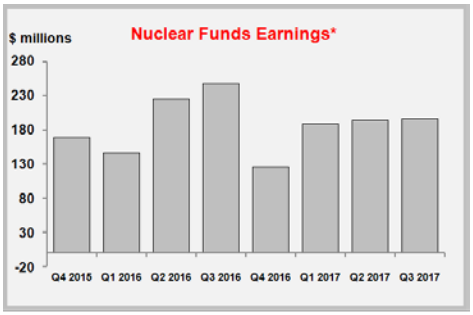
The timing of planned outages at a nuclear generating station during the year can cause variability in year-over-year operating results for partial periods of a fiscal year, including the impact on revenue and OM&A expenses, but is not a significant driver of variability for full fiscal year results.

OPG's electricity generation was reduced as a result of the Unit 2 refurbishment outage at the Darlington GS, which began in October 2016 and is expected to continue until early 2020.

OPG's financial results are also affected by the earnings on the Nuclear Segregated Funds, net of the impact of the Bruce Lease Net Revenues Variance Account.



Additional items that affected net income in certain quarters above are described in OPG's 2016 annual MD&A under



*net of regulatory variance account

the section, *Quarterly Financial Highlights*.

SUPPLEMENTARY NON-GAAP FINANCIAL MEASURES

In addition to providing net income and other financial information in accordance with US GAAP, certain non-GAAP financial measures are also presented in OPG's MD&A. These non-GAAP measures do not have any standardized meaning prescribed by US GAAP and, therefore, may not be comparable to similar measures presented by other issuers. OPG utilizes these measures to make operating decisions and assess performance. Readers of the MD&A would utilize these measures in assessing the Company's financial performance from ongoing operations. The Company believes that these indicators are important since they provide additional information about OPG's performance, facilitate comparison of results over different periods, and present measures consistent with the Company's strategies to provide value to the Shareholder, improve cost performance, and ensure availability of cost effective funding. These non-GAAP financial measures have not been presented as an alternative to net income, cash flow provided by operating activities, or any other measure in accordance with US GAAP, but as indicators of operating performance.

The definitions of the non-GAAP financial measures are as follows:

(1) **ROE Excluding AOCI** is defined as net income attributable to the Shareholder divided by average equity attributable to the Shareholder excluding AOCI, for the period. ROE Excluding AOCI is measured over a 12-month period and is calculated as follows:

	Twelve Months Ended	
(millions of dollars – except where noted) (unaudited)	**September 30 2017**	**December 31 2016**
ROE Excluding AOCI		
Net income attributable to the Shareholder	**485**	436
Divided by: Average equity attributable to the Shareholder, excluding AOCI	**11,055**	10,442
ROE Excluding AOCI *(percent)*	**4.4**	4.2

(2) **FFO Adjusted Interest Coverage** is defined as FFO before interest divided by adjusted interest expense. FFO before interest is defined as cash flow provided by operating activities adjusted for interest paid, interest capitalized to fixed and intangible assets, and changes to non-cash working capital balances for the period. Adjusted interest expense is calculated as net interest expense plus interest income, interest capitalized to fixed and intangible assets, interest related to regulatory assets and liabilities, and the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets, for the period.

FFO Adjusted Interest Coverage is measured over a 12-month period and is calculated as follows:

	Twelve Months Ended	
(millions of dollars – except where noted) (unaudited)	**September 30 2017**	**December 31 2016**
FFO before interest		
Cash flow provided by operating activities	**1,082**	1,595
Add: Interest paid	**270**	269
Less: Interest capitalized to fixed and intangible assets	**(161)**	(141)
Less: Changes to non-cash working capital balances	**38**	42
FFO before interest	**1,229**	1,765
Adjusted interest expense		
Net interest expense	**84**	120
Add: Interest income	**8**	7
Add: Interest capitalized to fixed and intangible assets	**161**	141
Add: Interest related to regulatory assets and liabilities	**43**	30
Add: Excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets [1]	**-**	45
Adjusted interest expense	**296**	343
FFO Adjusted Interest Coverage *(times)*	**4.2**	5.1

[1] A value of nil is used in the calculation when interest on pension and OPEB projected benefit obligations is equal to, or lower than, expected return on pension plan assets.

(3) **Enterprise Total Generating Cost per MWh** is used to measure OPG's overall organizational cost performance. Enterprise TGC per MWh is defined as OM&A expenses (excluding the Darlington Refurbishment project and other generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to OPG's electricity generation business), fuel expense for OPG-operated stations including hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures (excluding the Darlington Refurbishment project and other generation development projects) incurred during the period, divided by total electricity generation from OPG-operated generating stations plus electricity generation forgone due to SBG conditions during the period.

(millions of dollars – except where noted) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Enterprise TGC				
Total OM&A expenses	**635**	666	**2,054**	2,061
Total fuel expense	**185**	187	**518**	541
Total capital expenditures	**476**	444	**1,335**	1,162
Less: Darlington Refurbishment capital and OM&A costs	**(328)**	(269)	**(943)**	(717)
Less: Other generation development project capital and OM&A costs	**(17)**	(42)	**(53)**	(121)
Add (Less): OM&A and fuel expenses (refundable through) deferred in regulatory variance and deferral accounts	**4**	35	**(19)**	76
Less: Nuclear fuel expense for non OPG-operated stations	**(13)**	(18)	**(42)**	(50)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**13**	5	**47**	38
Less: OM&A expenses ancillary to electricity generation business	**(4)**	(5)	**(13)**	(17)
Other adjustments	**(3)**	(12)	**(7)**	(15)
	948	991	**2,877**	2,958
Adjusted electricity generation *(TWh)*				
Total OPG electricity generation	**19.4**	19.5	**56.0**	59.9
Adjust for electricity generation forgone due to SBG conditions and OPG's share of electricity generation from co-owned facilities	**0.9**	0.1	**4.2**	3.4
	20.3	19.6	**60.2**	63.3
Enterprise TGC per MWh *($/MWh)* [1]	**46.65**	50.72	**47.77**	46.74

[1] Amounts may not calculate due to rounding.

(4) **Nuclear Total Generating Cost per MWh** is used to measure the cost performance of OPG's nuclear generating assets. Nuclear TGC per MWh is defined as OM&A expenses of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the nuclear electricity generation business), nuclear fuel expense for OPG-operated stations (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs) incurred during the period, divided by nuclear electricity generation for the period.

(millions of dollars – except where noted) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Nuclear TGC				
Regulated – Nuclear Generation OM&A expenses	**511**	521	**1,693**	1,665
Regulated – Nuclear Generation fuel expense	**81**	79	**217**	239
Regulated – Nuclear Generation capital expenditures	**409**	339	**1,150**	896
Less: Darlington Refurbishment capital and OM&A costs	**(328)**	(269)	**(943)**	(717)
Add: Regulated – Nuclear Generation OM&A and fuel expenses deferred in regulatory variance and deferral accounts	**5**	31	**6**	84
Less: Nuclear fuel expense for non OPG-operated stations	**(13)**	(18)	**(42)**	(50)
Less: Regulated - Nuclear Generation OM&A expenses ancillary to nuclear electricity generation business	**(1)**	(1)	**(3)**	(4)
Other adjustments	**1**	3	**(1)**	(1)
	665	685	**2,077**	2,112
Nuclear electricity generation (TWh)	**11.3**	11.7	**30.6**	34.6
Nuclear TGC per MWh (*$/MWh*) [1]	**58.75**	58.55	**67.87**	61.07

[1] Amounts may not calculate due to rounding.

(5) **Hydroelectric Total Generating Cost per MWh** is used to measure the cost performance of OPG's hydroelectric generating assets. Hydroelectric TGC per MWh is defined as OM&A expenses of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the hydroelectric electricity generation business), hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding expenditures related to the Peter Sutherland Sr. GS, Ranney Falls GS, and other hydroelectric generation development projects) incurred during the period, divided by total hydroelectric electricity generation plus hydroelectric electricity generation forgone due to SBG conditions during the period. OPG reports hydroelectric gross revenue charge and water rental payments as fuel expense.

(millions of dollars – except where noted) (unaudited)	**Three Months Ended September 30**		**Nine Months Ended September 30**	
	2017	**2016**	**2017**	**2016**
Hydroelectric TGC				
Regulated – Hydroelectric OM&A expenses	**81**	87	**232**	238
Regulated – Hydroelectric fuel expense	**88**	88	**258**	259
Contracted Generation Portfolio OM&A expenses	**39**	44	**118**	129
Contracted Generation Portfolio fuel expense	**15**	19	**42**	42
Regulated – Hydroelectric and Contracted Generation Portfolio capital expenditures	**56**	92	**141**	231
Less: Regulated – Hydroelectric and Contracted Generation Portfolio generation development project capital and OM&A costs	**(17)**	(41)	**(52)**	(117)
Less: Thermal OM&A and fuel expenses and capital expenditures in the Contracted Generation Portfolio	**(39)**	(51)	**(119)**	(126)
(Less) Add: Regulated – Hydroelectric OM&A and fuel expenses refundable through regulatory variance and deferral accounts	**(1)**	4	**(25)**	(8)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**13**	5	**47**	38
Other adjustments	**(1)**	(1)	**-**	(1)
	234	246	**642**	685
Adjusted hydroelectric electricity generation *(TWh)*				
Regulated – Hydroelectric electricity generation	**7.3**	6.9	**23.5**	22.8
Contracted Generation Portfolio electricity generation	**0.8**	0.9	**1.9**	2.5
Adjust for hydroelectric electricity generation forgone due to SBG conditions and non-hydroelectric electricity generation of the Contracted Generation Portfolio, including OPG's share of electricity generation from co-owned facilities	**0.8**	0.1	**4.1**	3.4
	8.9	7.9	**29.5**	28.7
Hydroelectric TGC per MWh *($/MWh)* [1]	**26.20**	31.01	**21.74**	23.99

[1] Amounts may not calculate due to rounding.

(6) **Gross margin** is defined as revenue less fuel expense.

For further information, please contact: Investor Relations 416-592-6700

webmaster@opg.com

Media Relations 416-592-4008

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From:	HO Philip -FIN & C CTRL
To:	John Kim
Cc:	MAK Ricky -FIN & C CTRL; DYKXHOORN Sandra -STAKEREL; GORE Michael -FIN & C CTRL; Ronald Kwan
Subject:	RE: EXTERNAL – RE: OPG Q3 2017 Submission to Province
Date:	Wednesday, November 08, 2017 1:30:14 PM
Attachments:	Q3 2017 OPG MDA - DRAFT - PROVINCE MAILING_EFB_CommentsV4_addressed by OPG_Markup.docx

Hi John,

Please see our responses to your three additional comments. Thank you.

Philip

From: John Kim [mailto:John.Kim@ofina.on.ca]
Sent: Monday, November 06, 2017 7:35 PM
To: HO Philip -FIN & C CTRL <philip.ho@opg.com>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Subject: RE: EXTERNAL – RE: OPG Q3 2017 Submission to Province

Hi Philip,

We have gone through again and some additional comment boxes and edits.

Thanks,

John

From: HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
Sent: Monday, November 06, 2017 6:19 PM
To: John Kim <John.Kim@ofina.on.ca>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Subject: RE: EXTERNAL – RE: OPG Q3 2017 Submission to Province

Hi John,

Please see our responses to your comments. Let us know if you have any others. Thank you.

Regards,

Philip

Philip Ho, CPA, CA | Senior Manager, External Reporting & Accounting Policy | Ontario Power Generation
700 University Avenue, Toronto ON M5G 1X6 | Phone: (416) 592-3320| E-mail: philip.ho@opg.com

From: John Kim [mailto:John.Kim@ofina.on.ca]
Sent: Monday, October 30, 2017 6:16 PM
To: HO Philip -FIN & C CTRL <philip.ho@opg.com>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Subject: EXTERNAL – RE: OPG Q3 2017 Submission to Province

*** Exercise caution. This is an EXTERNAL email. DO NOT open attachments or click links from unknown senders or unexpected email. ***

Hi Philip,

See attached with our comments on the MD&A.

These are staff level comments as Ron has not had a chance to review.

Thanks,

John

From: HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
Sent: Wednesday, October 25, 2017 12:22 PM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>; 'Montgomery, Kaitlin (MOF)' <Kaitlin.Montgomery@ontario.ca>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>
Subject: OPG Q3 2017 Submission to Province

Hi All,

Please find attached OPG's draft Q3 2017 Financial Results Press Release, Management's Discussion and Analysis (MD&A), and Financial Statements for the Province's review.

We would greatly appreciate comments on the above **no later than Monday, Oct 30th**.

These documents will be filed with the Ontario Securities Commission on **Thursday, November 9th** following OPG's Board of Directors meeting.

Kindly forward all comments directly to Philip Ho – philip.ho@opg.com.

To assist the review process, the following are the key items in the Q3 2017 MD&A:

Highlights	
Recent Developments	MD&A p.10-11
Darlington Refurbishment	MD&A p.13-15
Ontario's Fair Hydro Plan	MD&A p.10-11

Philip Ho, CPA, CA | Senior Manager, External Reporting & Accounting Policy | Ontario Power Generation
700 University Avenue, Toronto ON M5G 1X6 | Phone: (416) 592-3320| E-mail: philip.ho@opg.com

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ONTARIO POWER GENERATION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

2017 THIRD QUARTER REPORT

[DRAFT]

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ONTARIO POWER GENERATION

ONTARIO POWER GENERATION INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) should be read in conjunction with the unaudited interim consolidated financial statements and accompanying notes of Ontario Power Generation Inc. (OPG or Company) as at and for the three and nine months ended September 30, 2017. OPG's unaudited interim consolidated financial statements are prepared in accordance with United States generally accepted accounting principles (US GAAP) and are presented in Canadian dollars.

For a complete description of OPG's corporate strategies, risk management, corporate governance, and the effect of critical accounting policies and estimates on OPG's results of operations and financial condition, this MD&A should also be read in conjunction with OPG's audited consolidated financial statements, accompanying notes, the Annual Information Form, and the MD&A as at and for the year ended December 31, 2016.

As required by *Ontario Regulation 395/11*, as amended, a regulation under the *Financial Administration Act* (Ontario), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. In 2014, the Ontario Securities Commission approved an exemption which allows OPG to apply US GAAP up to January 1, 2019. The term of the exemption is subject to certain conditions, which may result in the expiry of the exemption prior to January 1, 2019. For details, refer to the section, *Critical Accounting Policies and Estimates* under the heading, *Exemptive Relief for Reporting under US GAAP,* in OPG's 2016 annual MD&A. This MD&A is dated November 9, 2017.

FORWARD-LOOKING STATEMENTS

The MD&A contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could", and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

All forward-looking statements involve inherent assumptions, risks, and uncertainties, including those set out in the section, *Risk Management,* and forecasts discussed in the section, *Core Business, Strategy, and Outlook.* All forward-looking statements could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's generating station performance and availability, fuel costs, surplus baseload generation (SBG), cost of fixed asset removal and nuclear waste management, performance and earnings of investment funds, refurbishment of existing facilities, development and construction of new facilities, pension and other post-employment benefit (OPEB) obligations and funds, income taxes, proposed new legislation, the ongoing evolution of Ontario's electricity industry, environmental and other regulatory requirements, health, safety and environmental developments, business continuity events, the weather, financing and liquidity, applications to the Ontario Energy Board (OEB) for regulatory prices, the impact of regulatory decisions by the OEB, and forecasts of earnings, cash flows, Funds from Operations (FFO) Adjusted Interest Coverage, Return on Common Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI), Total Generating Cost (TGC) and capital expenditures. Accordingly, undue reliance should not be placed on any forward-looking statement. The forward-looking statements included in this MD&A are made only as of the date of this MD&A. Except as required by applicable securities laws, OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events, or otherwise.

THE COMPANY

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG was established under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (Province or Shareholder).

As at September 30, 2017, OPG's electricity generation portfolio had an in-service capacity of 16,210 megawatts (MW). OPG operates two nuclear generating stations, 66 hydroelectric generating stations, three thermal generating stations, and one wind power turbine. In addition, OPG and TransCanada Energy Ltd. co-own the 550 MW Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS). OPG and ATCO Power Canada Ltd. co-own the 560 MW Brighton Beach gas-fired combined cycle GS (Brighton Beach). OPG's 50 percent share of the in-service capacity and generation volume of these co-owned facilities is included in the generation portfolio statistics set out in this report. The income from the co-owned facilities is accounted for using the equity method of accounting, and OPG's share of income is presented as income from investments subject to significant influence in the Contracted Generation Portfolio segment.

OPG also owns two other nuclear generating stations, the Bruce A GS and the Bruce B GS, which are leased on a long-term basis to Bruce Power LP (Bruce Power). Income from these leased stations is included in revenue under the Regulated – Nuclear Generation segment. The leased stations are not included in the generation portfolio statistics set out in this report.

All of OPG's owned and co-owned generating facilities are located in Ontario. OPG does not operate PEC, Brighton Beach, the Bruce A GS and the Bruce B GS.

A description of OPG's segments is provided in OPG's 2016 annual MD&A in the section, *Business Segments*.

In-Service Generating Capacity

OPG's in-service generating capacity by business segment as at September 30, 2017 and December 31, 2016 was as follows:

	As at	
(MW)	**September 30 2017**	**December 31 2016**
Regulated – Nuclear Generation [1]	**5,728**	5,728
Regulated – Hydroelectric	**6,426**	6,421
Contracted Generation Portfolio [2]	**4,056**	4,028
Total	**16,210**	16,177

[1] The in-service generating capacity as of September 30, 2017 and December 31, 2016 excludes Unit 2 of the Darlington GS. The unit, which has a generating capacity of 878 MW, was taken offline in mid-October 2016 and is currently undergoing refurbishment.

[2] Includes OPG's share of in-service generating capacity of 275 MW for PEC and 280 MW for Brighton Beach.

During the nine months ended September 30, 2017, the total in-service capacity increased by 33 MW. The increase was primarily due to the completion of the Peter Sutherland Sr. hydroelectric GS, which was placed in-service at the end of the first quarter of 2017, and the upgrade of Unit 10 of the Sir Adam Beck 1 hydroelectric GS, which was completed in June 2017.

HIGHLIGHTS

Overview of Results

This section provides an overview of OPG's unaudited interim consolidated operating results. Significant factors which contributed to OPG's results during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, are discussed below.

(millions of dollars – except where noted) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Revenue	**1,217**	1,400	**3,539**	4,265
Fuel expense	**185**	187	**518**	541
Gross margin	**1,032**	1,213	**3,021**	3,724
Operations, maintenance and administration	**635**	666	**2,054**	2,061
Depreciation and amortization	**178**	313	**517**	941
Accretion on fixed asset removal and nuclear waste management liabilities	**235**	232	**709**	696
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(196)**	(248)	**(579)**	(620)
Income from investments subject to significant influence	**(11)**	(11)	**(29)**	(28)
Property taxes	**8**	12	**30**	35
	849	964	**2,702**	3,085
Income before other losses (gains), interest and income taxes	**183**	249	**319**	639
Other losses (gains)	**3**	1	**(380)**	(23)
Income before interest and income taxes	**180**	248	**699**	662
Net interest expense	**21**	28	**56**	92
Income before income taxes	**159**	220	**643**	570
Income tax expense	**19**	22	**128**	109
Net income	**140**	198	**515**	461
Net income attributable to the Shareholder	**131**	194	**498**	449
Net income attributable to non-controlling interest [1]	**9**	4	**17**	12
Electricity production (TWh) [2]	**19.4**	19.5	**56.0**	59.9
Cash flow provided by operating activities	**485**	530	**698**	1,211

[1] Relates to the 25 percent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in the Lower Mattagami Limited Partnership, the 33 percent interest of Coral Rapids Power Corporation, a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership, and the 10 percent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP.

[2] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

Third Quarter

Net income attributable to the Shareholder was $131 million for the third quarter of 2017, a decrease of $63 million compared to the same quarter in 2016. Income before interest and income taxes for the third quarter of 2017 was $180 million, a decrease of $68 million compared to the same quarter in 2016.

Commented [A1]:
Wondering if this should be 437?
Since:
Q3 9-mos ended – Q2 6-mos ended = 698-261 = 437

Was Q2 "6-month ended June 30" number for Cash flow provided by operating activities revised?

OPG: In Q3 2017, adjustments for non-cash balances related to Darlington Refurbishment capital expenditures have been reclassified from the "Net changes in non-cash working capital balances" line to the "Investment in property, plant and equipment and intangible assets" line. Comparative amounts have been reclassified accordingly.

Significant factors that reduced income before interest and income taxes:

- Lower earnings from the nuclear base regulated price of approximately $24 million reflecting lower electricity generation of 0.4 terawatt hours (TWh) from the Regulated – Nuclear Generation segment and the continuation of existing base regulated prices set by the OEB in 2014. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS since October 2016, largely offset by an increase in generation from Pickering GS. The increase in generation from the Pickering GS was primarily due to outage optimization, favourable unit conditions and execution of planned outage work. The base regulated prices set in 2014 continue to be in effect pending the OEB's decision on OPG's current application for new regulated prices, expected later in 2017. **[MONITOR]** The existing nuclear base regulated price was set to allow the Company to recover its approved nuclear costs over a higher nuclear production volume, based on the 2014 and 2015 outage profile that did not include a refurbishment outage. OPG has requested January 1, 2017 as the effective date of the new regulated prices.
- Lower earnings on the nuclear fixed asset removal and nuclear waste management funds (Nuclear Segregated Funds) of $52 million.
- Higher depreciation and amortization expense of $16 million in the Regulated – Nuclear Generation segment, excluding amortization expense related to balances in OEB-authorized regulatory variance and deferral accounts (regulatory accounts), primarily due to new assets in service.

The expiry of rate riders for the recovery of approved balances in OEB-authorized regulatory accounts on December 31, 2016 contributed to the decrease in revenue for the three months ended September 30, 2017, compared to the same period in 2016, but was largely offset by a decrease in the amortization expense related to these balances. OPG has requested new rate riders in its current application to the OEB for new regulated prices, with a proposed effective date of January 1, 2017.

Significant factor that increased income before interest and income taxes:

- Lower operations, maintenance and administration (OM&A) expenses of $31 million, mainly in the Regulated – Nuclear Generation segment, as a result of a higher materials and supplies obsolescence charge recognized in the third quarter of 2016, Services, Trading and Other Non-Generation segment due to project expenditures incurred in the third quarter of 2016, and Regulated – Hydroelectric segment due to the timing of repairs and maintenance work in 2017 and a deferral of outages during the high water period.

Net interest expense decreased by $7 million during the third quarter of 2017, compared to the same quarter in 2016, primarily due to a higher amount of interest costs capitalized for the Darlington Refurbishment project expenditures and a higher amount of interest costs deferred in OEB-authorized regulatory accounts.

Income tax expense for the three months ended September 30, 2017 was $19 million, compared to $22 million for the same period in 2016. The decrease in income tax expense was primarily due to lower income before taxes and a higher change in reserves from the resolution of uncertainties, partially offset by a lower amount of tax expense deferred in regulatory assets.

Year-To-Date

Net income attributable to the Shareholder was $498 million for the first nine months of 2017, an increase of $49 million compared to the same period in 2016. Income before interest and income taxes for the first nine months of 2017 was $699 million, an increase of $37 million compared to the same period in 2016.

Significant factor that increased income before interest and income taxes:

- Higher earnings of $390 million from the Services, Trading, and Other Non-Generation segment, primarily reflecting the gain on sale of OPG's head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street that was recognized in the second quarter of 2017. The sale of the

Commented [A2]: If approved by OEB (during Q4), would this result in a higher regulated price and a revenue/net income pick up for 2017 reported in OPG's Q4?

OPG – It depends on the effective date of the decision on the base regulated prices. If the OEB decision on the new base regulated prices are retrospectively effective as of Jan 1, 2017 for example, then it should result in a higher revenue/net income pick up for 2017 assuming the new regulated prices are higher.

assets was required by a Shareholder Declaration and a Shareholder Resolution. The gain on sale was $283 million, which is net of tax effects of $95 million.

Significant factors that reduced income before interest and income taxes:

- Lower earnings from the nuclear base regulated price of approximately $230 million, partially offset by a decrease in nuclear fuel expense of $22 million, reflecting lower electricity generation of 4.0 TWh from the Regulated – Nuclear Generation segment and the continuation of existing base regulated prices set by the OEB in 2014. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS, partially offset by an increase in generation from Pickering GS.
- Lower earnings on the Nuclear Segregated Funds of $41 million.
- Higher depreciation and amortization expense of $30 million in the Regulated – Nuclear Generation segment, excluding amortization expense related to regulatory account balances, primarily due to new assets in service.
- A gain of $22 million recorded in the first quarter of 2016 to reflect the OEB's decision on OPG's motion asking the OEB to review and vary parts of its November 2014 decision on OPG's regulated prices.

The expiry of rate riders for the recovery of approved balances in OEB-authorized regulatory accounts on December 31, 2016 contributed to the decrease in revenue for the nine months ended September 30, 2017, compared to the same period in 2016, but was primarily offset by a decrease in the amortization expense related to these balances.

Net interest expense decreased by $36 million for the nine months ended September 30, 2017, compared to the same period in 2016, primarily due to a higher amount of interest costs capitalized for the Darlington Refurbishment project expenditures and a higher amount of interest costs deferred in OEB-authorized regulatory accounts.

Commented [A3]: Does this imply there were interest costs related to Darlington Refurb previously (same quarter previous year), that were not capitalized, but were able to be capitalized this year?

OPG – There were higher Darlington Refurb project expenditures in 2017, compared to 2016.

Income tax expense for the nine months ended September 30, 2017 was $128 million, compared to $109 million for the same period in 2016. The increase in income tax expense was primarily due to higher income before income taxes.

Segment Results

The following table summarizes OPG's income before interest and income taxes by business segment. A detailed discussion of OPG's performance by reportable segment is included in the section, *Discussion of Operating Results by Business Segment*.

(millions of dollars)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Income (loss) before interest and income taxes				
Regulated – Nuclear Generation	**20**	47	**(267)**	17
Regulated – Hydroelectric	**122**	117	**474**	500
Contracted Generation Portfolio	**75**	74	**229**	219
Total electricity generation business segments	**217**	238	**436**	736
Regulated – Nuclear Waste Management	**(36)**	18	**(123)**	(70)
Services, Trading, and Other Non-Generation	**(1)**	(8)	**386**	(4)
	180	248	**699**	662

Electricity Generation

Electricity generation for the three and nine month periods ended September 30, 2017 and 2016 was as follows:

(TWh)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Regulated – Nuclear Generation	**11.3**	11.7	**30.6**	34.6
Regulated – Hydroelectric	**7.3**	6.9	**23.5**	22.8
Contracted Generation Portfolio [1]	**0.8**	0.9	**1.9**	2.5
Total OPG electricity generation	**19.4**	19.5	**56.0**	59.9
Total electricity generation by all other generators in Ontario [2]	**16.6**	19.5	**51.7**	53.8

[1] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.
[2] Non-OPG generation is calculated as the Ontario electricity demand plus net exports, as published by the Independent Electricity System Operator (IESO), minus OPG electricity generation.

Total OPG electricity generation decreased by 0.1 TWh during the third quarter of 2017, compared to the same quarter in 2016, and by 3.9 TWh during the nine months ended September 30, 2017, compared to the same period in 2016. As expected, the lower electricity generation from the Regulated – Nuclear Generation segment was primarily the result of the removal from service of Unit 2 at the Darlington GS for the duration of the unit's refurbishment, which began in October 2016. This decrease in electricity generation was largely offset by an increase in generation from the Pickering GS, primarily due to outage optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station, and higher hydroelectric generation from the Regulated – Hydroelectric segment.

The higher electricity generation of 0.4 TWh and 0.7 TWh from the Regulated – Hydroelectric segment for the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016, was due to higher water flows primarily on the eastern Ontario river systems, net of water spilled as a result of SBG conditions, discussed below.

The lower electricity generation of 0.6 TWh from the Contracted Generation Portfolio segment for the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to higher SBG conditions. The electricity generation from the Contracted Generation Portfolio segment for the three months ended September 30, 2017 was comparable to the same period in 2016.

OPG's operating results are impacted by changes in grid-supplied electricity demand resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. For the three and nine month periods ended September 30, 2017, Ontario's electricity demand as reported by the IESO was 33.6 TWh and 98.5 TWh, respectively, compared to 36.7 TWh and 103.8 TWh for the same periods in 2016, respectively, excluding electricity exports out of the province.

Power that is surplus to the Ontario market is managed by the IESO, mainly through generation reductions at hydroelectric, other grid-connected renewable resources and nuclear stations. Reducing hydroelectric production is the first measure used by the IESO to manage SBG conditions. Low demand conditions in Ontario continued to be prevalent in 2017, resulting in forgone hydroelectric generation for OPG of 1.1 TWh and 4.5 TWh due to SBG conditions in the three and nine month periods ended September 30, 2017, respectively, compared to 0.5 TWh and 3.9 TWh during the same periods in 2016, respectively. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions during these periods was offset by the impact of a regulatory variance account authorized by the OEB. OPG did not forgo any electricity production at its nuclear stations due to SBG conditions.

Average Sales Prices

The majority of OPG's generation is from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments. The same base regulated prices for electricity generated by these segments, authorized by the OEB effective November 1, 2014, were in effect during the first nine months of 2017 as in 2016. These prices will remain in effect until such time as the OEB approves new regulated prices based on OPG's current application. **[MONITOR]** The base regulated prices established in 2014 are discussed in OPG's 2016 annual MD&A in the section, *Revenue Mechanisms for Regulated and Non-Regulated Generation*.

The average sales price for the Regulated – Nuclear Generation segment was 5.8 cents per kilowatt hour (¢/kWh) during the three and nine month periods ended September 30, 2017, respectively, compared to 6.9 ¢/kWh during the same periods in 2016. The decrease in the average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized nuclear rate rider of $10.84 per megawatt hour (MWh) for the recovery of variance and deferral account balances. The average sales price for the Regulated – Hydroelectric segment was 4.1 ¢/kWh during the three and nine month periods ended September 30, 2017, respectively, compared to 4.4 ¢/kWh during the same periods in 2016. The decrease in the average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized regulated hydroelectric rate rider of $3.19/MWh for the recovery of variance and deferral account balances. The rate riders were established to recover approved balances recorded in the variance and deferral accounts in prior years. As such, the year-over-year changes in revenue from the rate riders were largely offset by changes in amortization expense related to these balances. There were no rate riders in effect during the nine months ended September 30, 2017 for either nuclear or regulated hydroelectric generation, pending the outcome of OPG's current application with the OEB for new regulated prices.

Cash Flow from Operations

Cash flow provided by operating activities was $485 million for the three months ended September 30, 2017 and $698 million for the nine months ended September 30, 2017, compared to $530 million and $1,211 million for the same periods in 2016, respectively. The decrease in cash flow provided by operating activities was expected and primarily due to lower generation revenue receipts reflecting lower generation from the Regulated – Nuclear Generation segment as a result of the ongoing refurbishment of Unit 2 at the Darlington GS and the expiry, on December 31, 2016, of the OEB-authorized rate riders for nuclear and regulated hydroelectric generation. The decrease in cash flow during the nine months ended September 30, 2017 was also due to higher income tax instalments.

The decrease in cash flow provided by operating activities for the three and nine month periods ended September 30, 2017 was partly offset by lower OM&A expenditures and lower contributions to the Used Fuel Segregated Fund in 2017. Both the Used Fuel Segregated Fund and the Decommissioning Segregated Fund were determined to be fully funded based on an updated estimate of OPG's nuclear waste management and nuclear facilities decommissioning obligations pursuant to a reference plan approved by the Province ~~for years 2017 to 2021~~ under the Ontario Nuclear Funds Agreement (ONFA), effective January 1, 2017. Pursuant to the ONFA, the reference plan is required to be updated at least once every five years. Contributions to either or both of the Nuclear Segregated Funds may be required in the future should the funds be in an underfunded position at the time of the next ONFA reference plan update. The year-over-year decrease in cash flow also was partially offset by the payment of a supplemental rent rebate to Bruce Power in the first quarter of 2016 in relation to a period in 2015. The lease agreement for the Bruce nuclear generating stations was amended in late 2015 to eliminate this rebate provision going forward.

Commented [A4]: OPG: no change as this was previously disclosed as is in Q2 2017.

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Return on Common Equity Excluding Accumulated Other Comprehensive Income

ROE Excluding AOCI is an indicator of OPG's performance consistent with the Company's strategy to provide value to the Shareholder. ROE Excluding AOCI is measured over a 12-month period.

ROE Excluding AOCI was 4.4 percent for the 12 months ended September 30, 2017, compared to 4.2 percent for the 12 months ended December 31, 2016. The increase was primarily due to higher net income attributable to the Shareholder for the 12 months ended September 30, 2017, which reflected the gain on sale of OPG's head office premises and associated parking facility recorded in the second quarter of 2017, partially offset by the lower earnings from the decrease in nuclear electricity generation reflecting the Unit 2 refurbishment outage at the Darlington GS without a corresponding increase in the nuclear base regulated price, as expected. The lower nuclear generation as a result of the refurbishment outage will continue to negatively affect OPG's ROE Excluding AOCI until such time as new regulated prices are approved by the OEB, anticipated in the fourth quarter of 2017. **[MONITOR]**

Funds from Operations Adjusted Interest Coverage

FFO Adjusted Interest Coverage is an indicator of OPG's ability to meet interest obligations from operating cash flows. The indicator is measured over a 12-month period. FFO Adjusted Interest Coverage for the 12 months ended September 30, 2017 was 4.2 times, compared to 5.1 times for the 12 months ended December 31, 2016. FFO Adjusted Interest Coverage in 2017 reflected a year-over-year decrease in FFO before interest due to lower cash flow provided by operating activities, partially offset by the impact of a lower adjusted interest expense due to a decrease in the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets.

The decrease in the excess of interest on pension and OPEB benefit obligations over expected return on pension plan assets in the nine months of 2017 was primarily due to the change in the method used to estimate the interest cost and service cost components of pension and OPEB costs. Effective January 1, 2017, OPG adopted a full yield curve approach to the estimation of these cost components, by applying the specific spot rates along the yield curve used in the determination of the projected benefit obligations to the relevant projected cash flows. Under the previous method, these components of pension and OPEB costs were calculated using the same single weighted-average discount rates as reflected in the calculation of the benefit obligations. This change in the method was accounted for prospectively, as a change in estimate. The resulting reduction in pension and OPEB costs for the three and nine month periods ended September 30, 2017 did not have a material impact on net income as it was largely offset by the impact of OEB-authorized variance and deferral accounts in the regulated business segments. Further details on the full yield curve approach can be found in the 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Pension and Other Post-Employment Benefits*.

Commented [A5]: Does this have any implications for the methodology used for the IFRS adjustments for the purposes of the Province's Public Accounts?

OPG response - Since the full yield curve approach is applied to the determination of pension and OPEB costs under both US GAAP and IFRS, it will not create a US GAAP and IFRS difference. Therefore it is not expected to have any implications for the methodology used for the IFRS adjustments for the purposes of the Province's Public Accounts.

Enterprise Total Generating Cost per MWh

The Enterprise TGC per MWh decreased to $46.65 for the three months ended September 30, 2017, compared to $50.72 for the same quarter in 2016. The decrease was mainly due to lower OM&A expenses before the impact of regulatory accounts and higher SBG-adjusted hydroelectric generation reflecting higher water flows.

The Enterprise TGC per MWh was $47.77 for the nine months ended September 30, 2017, an increase compared to $46.74 for the same period in 2016. The increase was expected and mainly a result of lower electricity generation due to the Unit 2 refurbishment outage at the Darlington GS, largely offset by lower OM&A expenses before the impact of regulatory accounts and higher SBG-adjusted hydroelectric generation reflecting higher water flows.

If Unit 2 at the Darlington GS was not currently undergoing refurbishment and had continued to operate in a manner consistent with the performance of the remaining units at the Darlington GS, adjusting for generation constraints on these units related to the transition of the station toward refurbishment, the Enterprise TGC would have been approximately $4 per MWh lower for both the three and nine month periods ended September 30, 2017. This sensitivity was calculated using the estimated incremental electricity and associated fuel cost that are expected to have resulted in the absence of the refurbishment.

Nuclear Total Generating Cost per MWh

The Nuclear TGC per MWh was $58.75 for the three months ended September 30, 2017, which was comparable to $58.55 for the same quarter in 2016. For the three months ended September 30, 2017, the higher generation at the Pickering GS and the impact of lower OM&A expenses before the impact of regulatory accounts was mostly offset by the expected decrease in nuclear electricity generation reflecting the Unit 2 refurbishment outage at the Darlington GS and higher sustaining capital expenditures. The Nuclear TGC per MWh was $67.87 for the nine months ended September 30, 2017, compared to $61.07 for the same period in 2016. The increase in the Nuclear TGC per MWh for the nine months ended September 30, 2017 was expected and primarily due to the decrease in nuclear electricity generation, partially offset by lower OM&A expenses before the impact of regulatory accounts.

Hydroelectric Total Generating Cost per MWh

The Hydroelectric TGC per MWh was $26.20 for the three months ended September 30, 2017, compared to $31.01 for the same quarter in 2016. The decrease was primarily due to higher SBG-adjusted hydroelectric electricity generation reflecting higher water flows. The Hydroelectric TGC per MWh was $21.74 for the nine months ended September 30, 2017, compared to $23.99 for the same period in 2016. The decrease was primarily due to lower OM&A expenses before the impact of regulatory accounts and lower sustaining capital expenditures.

ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are not measurements in accordance with US GAAP and should not be considered alternative measures to net income, cash flow provided by operating activities, or any other performance measure under US GAAP. OPG believes that these non-GAAP financial measures are effective indicators of its performance and are consistent with the Company's strategic imperatives and related objectives. The definition and calculation of ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are found in the section, *Supplementary Non-GAAP Financial Measures*.

Recent Developments

Ontario's 2017 Long Term Energy Plan

On October 26, 2017, Ontario's Ministry of Energy issued the 2017 Long Term Energy Plan. The Plan is currently being analyzed by OPG but is not expected to significantly impact OPG's business. There are no fundamental changes from the principles in the 2013 Long Term Energy Plan, which include cost effectiveness, reliability, clean energy and community engagement. The 2017 Long Term Energy Plan fully supports nuclear refurbishment projects in Ontario and the extension of commercial operation of all Pickering units to 2024. **[MONITOR & UPDATE DETAILS FOLLOWING RELEASE]**

OEB's Decision on New Regulated Prices **[MONITOR]**

Ontario's Fair Hydro Plan

OPG continues to prepare for its involvement as the Financial Services Manager for Ontario's Fair Hydro Plan (the Fair Hydro Plan) on a commercial basis. Accordingly, the financing entity was established in XX 2017 as the Fair Hydro Trust (the Trust), following the execution of its constating documents. The majority unitholder and beneficiary of the Trust is a wholly-owned subsidiary of OPG. Through this ownership and OPG's control over the key activities of the Trust, the Company will consolidate the Trust for accounting purposes commencing in the fourth quarter of 2017. **[MONITOR]**

In order for the Trust to provide financing for the deferred Global Adjustment costs, the Trust will incur senior debt from capital markets and subordinated debt from OPG. The Trust is structured to be bankruptcy remote and ring fenced from OPG to protect the Company's assets and operations. In support of the Fair Hydro Plan, the following developments have transpired:

Commented [A6]: Why not rephrase as acquiring the investment asset related to the deferred GA costs (right to future recovery)?

OPG response: No change made.

It is easier to understand for the general public the notion of a financing transaction vs. acquiring an investment interest

- In October 2017, *Ontario Regulation 206/17 General* was amended to establish details of the recovery mechanism for the monthly carrying costs incurred by the Trust from June 1, 2017 to July 31, 2021 payable by the IESO to the Trust. Originally established in June 2017, this regulation provides more details on the funding obligations incurred by the Trust and the fair allocation amount, the determination and collection of clean energy adjustments, the determination of the finance amount, the true up amount, and the regulatory asset, as well as principles and assumptions relating to the financing plan.
- A plan to amend the Company's Articles of Amalgamation to allow for the creation and issuance of Class A shares to be issued to the Province for its equity investment through OPG in the Fair Hydro Plan is in progress. The Province is expected to provide 44 percent of the total funding requirement related to the deferred Global Adjustment costs, which OPG will invest as subordinated debt into the Trust. OPG's Board approval and a Shareholder Resolution are expected later in the year to authorize the amendment.
- OPG is expected to provide five percent of the total funding requirement of the Trust related to the deferred Global Adjustment costs of the Fair Hydro Plan. OPG issued senior notes payable in October 2017 under a short form base shelf prospectus for general corporate purposes and to fund OPG's subordinated debt investment in the Trust. Further details of the debt offering can be found in the section, *Liquidity and Capital Resources* under the heading, *Financing Activities*.

Commented [A7]: Are any other details available to be released at this time?

OPG – Not for Q3 2017 reporting.

The first set of transactions of the Trust are expected to take place in the fourth quarter of 2017.

Canadian Nuclear Safety Commission Safety Rating for the Darlington GS and the Pickering GS

The Canadian Nuclear Safety Commission (CNSC) publishes an annual report on the safety performance of Canada's nuclear power plants. The report assesses how well plant operators are meeting regulatory requirements and program expectations in the areas of operational performance, safety analysis, radiation protection, waste management and conventional health and safety. On September 8, 2017, the CNSC issued an executive summary of its 2016 annual report. The CNSC gave both the Darlington GS and the Pickering GS the highest possible safety rating of "Fully Satisfactory". The Darlington GS achieved this rating for the eighth consecutive year, while the Pickering GS achieved this rating for the second consecutive year.

CORE BUSINESS, STRATEGY, AND OUTLOOK

The discussion in this section is qualified in its entirety by the cautionary statements included in the section, *Forward-Looking Statements,* at the beginning of the MD&A.

OPG's mission is to provide low cost power in a safe, clean, reliable and sustainable manner for the benefit of customers and its Shareholder. OPG also seeks to pursue, on a commercial basis, generation development projects and other business growth opportunities.

The following sections provide an update to OPG's disclosures in the 2016 annual MD&A related to its four key strategic imperatives – operational excellence, project excellence, financial strength, and social licence. A detailed discussion of these strategic imperatives is included in the 2016 annual MD&A in the section, *Core Business, Strategy, and Outlook*.

Operational Excellence

Operational excellence at OPG is accomplished by the safe and environmentally responsible generation of reliable and cost-effective electricity from the Company's generating assets through a highly trained and engaged workforce.

Electricity Generation Production and Reliability

- As part of the plan to extend Pickering operations, OPG is continuing to undertake the required technical work to confirm that the station's pressure tubes, a key life-limiting component of the station, will remain fit for service for operation to 2024. OPG is also nearing completion of component condition assessments to identify the work required to support the continued operation of the station. The accounting end of life assumptions for the Pickering GS, currently set at the end of 2020, will be reassessed based on the fuel channel analysis and safety case consistent with submissions for the CNSC approval, discussed below. The activities completed to date have had positive results, which will go towards re-confirming Pickering operations past 2020 are technically feasible. The Periodic Safety Review (PSR) is in progress and will confirm that extending operations of the Pickering units will be safe to the public, workers and the environment. The PSR consists of Safety Factor Reports (SFRs), a Global Assessment Report (GAR), and the Integration Improvement Plan (IIP). SFRs have been submitted to the CNSC and the GAR and IIP are on track for CNSC submission in October and November 2017, respectively. Other technical feasibility activities continue to progress as planned. Completion of various technical feasibility assessments are required to reach a high confidence conclusion to allow the station end of life to change for depreciation purposes. OPG's current application with the OEB for new base regulated prices, currently pending the OEB's decision, reflects OPG's plans to extend Pickering operations to 2024 and requests inclusion of the corresponding cost and generation impacts in the determination of the nuclear regulated price.
- OPG's current five-year operating licence for the Pickering GS was approved by the CNSC in 2013 and expires on August 31, 2018. This licence was issued assuming that the station would shut down in 2020. On June 28, 2017, OPG confirmed to the CNSC that it intends to cease commercial operation of all Pickering units on December 31, 2024. On August 28, 2017, OPG submitted a ten-year licence renewal application to the CNSC. The licence term spans the planned extended operations period, through to the end of commercial operation, defueling, dewatering and the start of placing the station in a safe storage state.
- Work continues on the rehabilitation of Unit 2 of the DeCew Falls hydroelectric GS and the rehabilitation and overhaul of Unit 2 of the Lower Notch hydroelectric GS.
- During the third quarter, a new control centre was opened at Saunders GS to merge its operations with Chenaux GS. The new control centre will overlook power production at ten hydroelectric stations along the Madawaska, Ottawa and St. Lawrence rivers.
- As part of the process to decommission the Nanticoke and Lambton generating stations, OPG has begun executing demolition plans that will ensure that the stations are closed safely, securely and in an environmentally responsible manner. The demolition of the Nanticoke coal yard equipment and structures is in progress, with a contract issued in July 2017 for the demolition of the Nanticoke powerhouse and associated structures. Project milestones for the Nanticoke site during the remainder of 2017 include completing the removal of coal yard equipment and structures, demolition of the ash silos, and mobilization of the contractor to prepare for removal of the stacks, powerhouse and associated structures. A competitive bidding process for the demolition of the Lambton GS has been completed, with a contract for the removal of the powerhouse and associated buildings expected to be awarded in 2018. An update of the associated asset retirement obligations related to the Nanticoke and Lambton sites is expected to be finalized in the fourth quarter of 2017.

Environmental Performance

There were no significant changes to environmental legislation affecting the Company during the third quarter of 2017. Disclosures related to the Company's environmental policy and environmental risks can be found in OPG's 2016 annual MD&A.

OPG communicates its environmental performance internally to employees and to external stakeholders, including the Ontario Ministry of the Environment and Climate Change, Environment and Climate Change Canada, the CNSC, and local communities. Details of OPG's environmental performance and initiatives to fulfill the Company's Environmental Policy can be found in OPG's 2016 Sustainability Report, available on the Company's website at www.opg.com. **[MONITOR]**

Project Excellence

OPG is pursuing a number of generation development and other major projects in support of Ontario's electricity planning initiatives. OPG remains focused on delivering projects safely, on time, on budget and with high quality. The status updates for OPG's major projects as at September 30, 2017 are outlined in the following table, with further details below.

Project	Capital expenditures		Approved budget	Expected in-service date	Current status
(millions of dollars)	**Year-to-date**	**Life-to-date**			
Darlington Refurbishment	924	4,109	12,800 [1]	First unit - 2020 Last unit - 2026	The setup of specialized tooling and equipment needed for the removal of reactor components was completed in the third quarter of 2017. All feeder tubes have been removed safely, and the pressure tubes have been severed in preparation for their removal. The Re-tube Waste Processing Building will be available for use in the fourth quarter of 2017. The project is tracking on schedule and on budget.
Peter Sutherland Sr. Hydroelectric GS	38	274	300	2017	The station was placed in-service on March 31, 2017, ahead of the originally planned schedule, and is expected to close below the approved budget. Project close-out activities are in progress.
Ranney Falls Hydroelectric GS	17	20	77	2019	Work is progressing on the expanded forebay, forebay wall concrete replacement, powerhouse and spillway areas. The project is tracking on schedule and on budget.
Nanticoke Solar Facility	1	2	107 **[MONITOR]**	2019	Project definition work is continuing, with construction planned to commence in the first quarter of 2018.
Deep Geologic Repository for low and intermediate level radioactive waste (L&ILW)	7 [2]	202 [2]			On August 21, 2017, the federal Minister of Environment and Climate Change requested further information on the project's environmental assessment (EA). OPG is reviewing the new request and will notify the Canadian Environmental Assessment Agency (CEAA) when it has a timeline for submission of that information.

[1] The total project budget of $12.8 billion is for the refurbishment of all four units at the Darlington GS.
[2] Expenditures are charged against the nuclear fixed asset removal and nuclear waste management liabilities (Nuclear Liabilities).

Commented [A8]: Does this imply that only 700M further is anticipated to be spent by the time Unit 2 gets completed? (Eg. 4.8B in Capital Expenditure)

Eg. from above:
"Once refurbished, Unit 2 is scheduled to be returned to service in the first quarter of 2020, at which time capital expenditures of approximately $4.8 billion are planned to be placed in service."

OPG – No, the LTD in the table includes prerequisite projects already declared in-service. The $4.8B was the OEB submitted estimate of a future in-service amount for Unit 2 refurbishment.

Please see updated wording below:

OPG's current application with the OEB for new regulated prices seeks an increase in the nuclear rate base, effective in the first quarter of 2020, to reflect the planned placement in service of the $4.8 billion in capital expenditures upon return to service of Unit 2, which includes expenditures incurred during the definition and planning phase of the project. Based on OPG's proposal in the application, the revenue requirement impact of the differences between the Unit 2 in-service amount included in the regulated prices and the actual amounts placed in service would be subject to true up via the Capacity Refurbishment Variance Account established by the OEB pursuant to *Ontario Regulation 53/05*. OPG's application proposes that the recovery of the HWSF's costs through regulated prices be subject to a separate prudence review by the OEB, to be conducted as part of a future OEB application.

Darlington Refurbishment

The Darlington generating units are approaching their originally designed end-of-life. Refurbishment of the four generating units is expected to extend the operating life of the station by approximately 30 years. OPG commenced the planning of the refurbishment in 2010.

In 2016, the Darlington Refurbishment project transitioned from the planning phase to the execution phase, as OPG commenced the refurbishment of the first unit, Unit 2, in October 2016, as planned. The unit was taken offline on October 15, 2016. De-fuelling of the reactor, the first critical refurbishment activity undertaken once the unit is removed from service, was completed safely in January 2017, with a total of 480 fuel channels de-fuelled. Islanding of Unit 2, the physical separation of the unit under refurbishment from the three operating units, was completed in April 2017, signifying the completion of the first major segment of the project.

The second major segment includes preparatory work to support the removal of feeder tubes and fuel channel assemblies and the removal of reactor components. The preparatory work was completed in the second quarter of 2017. The Re-tube Tooling Platform for hosting the tooling for the removal, inspection, and installation activities and the setup of specialized tooling and equipment needed for the removal and replacement of the reactor components were completed in the third quarter of 2017. The disassembly of reactor components commenced in August 2017, with the removal of all 960 feeder tubes completed safely in September 2017. This was followed by the severing of pressure tubes, with the severing of bellows and the removal of end fittings expected to commence thereafter and through the end of 2017. Other key project activities executed during the second segment include the completion of the primary side steam generator layup, installation of steam generator access ports to support future inspections, continuation of the major turbine generator overhaul and continued execution of the major electrical scope. OPG is also continuing to execute work to support the requirements set out in the CNSC approved IIP for the station.

Once refurbished, Unit 2 is scheduled to be returned to service in the first quarter of 2020, at which time capital expenditures of approximately $4.8 billion are planned to be placed in service. This includes expenditures incurred during the definition and planning phase of the overall project. The project is tracking on schedule and on budget.

With the substantial completion of the Re-tube Waste Processing Building in November 2017, 17 out of 18 pre-requisite projects in support of the execution phase of the project, including construction of facilities, infrastructure upgrades and installation of safety enhancements, have been completed and placed in service. Completion of the Heavy Water Storage and Drum Handling Facility (HWSF) has been delayed due to challenges with construction. OPG suspended the project in the second quarter of 2017 to evaluate the best approach to optimize cost and schedule and complete the project. Construction activities for the HWSF recommenced in the fourth quarter of 2017 following substantial completion of the Re-tube Waste Processing Building. This plan ensures that the necessary resources are available for both projects and, through resource levelling, improves their execution and cost efficiency. The delay in the completion of the HWSF will not impact the overall Darlington Refurbishment project schedule, as the HWSF is not on the project's critical path. This also will not impact the overall project budget of $12.8 billion, as the costs of the HWSF are included in this total figure. The recovery of HWSF costs through regulated prices will be subject to a prudence review by the OEB, which OPG has proposed be conducted as part of a future OEB application.

In addition to the execution of refurbishment activities on Unit 2, OPG is continuing planning activities for the refurbishment of the second unit, Unit 3, and is entering into associated commitments to procure major components that require long lead times. As of September 30, 2017, $70 million has been invested in planning activities related to the refurbishment of the second unit, Unit 3. These planning activities are being undertaken in accordance with the refurbishment project schedule.

The Financial Accountability Office of Ontario has issued a report titled "*An Assessment of the Financial Risks of the Nuclear Refurbishment Plan*". The report assesses both OPG and Bruce Power's refurbishment activities and the method in which those refurbishments and subsequent nuclear generation is provided to the marketplace. The report

concludes that the base case of refurbishing the six units at the Bruce nuclear GS and the four units at the Darlington nuclear GS provide the most cost effective, low emission generation source available to meet Ontario's baseload electricity requirements. This report re-affirms the positive economic and societal benefits associated with a strong nuclear program in the Province. **[MONITOR]**

Commented [A9]: Not yet released.

OPG – We put MONITOR to ensure status next Thursday before we release.

Ranney Falls Hydroelectric GS

During the third quarter of 2017, OPG continued construction work for a 10 MW single-unit powerhouse on the existing Ranney Falls GS site, as part of the Regulated – Hydroelectric segment. The new unit will replace an existing unit that reached its end of life in 2014. The existing forebay structure demolition has been completed and the upstream cofferdam has been constructed ahead of schedule. Construction continues on the expanded forebay, powerhouse and spillway. Excavation work is substantially complete and forebay wall concrete replacement is in progress. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget.

Nanticoke Solar Facility

The construction of a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands under a Large Renewable Procurement contract with the IESO, through Nanticoke Solar LP, a partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation, is planned to commence in the first quarter of 2018. During the third quarter of 2017, the partnership continued work to obtain approvals and permits required to enable the commencement of construction, and progressed procurement activities for equipment and for engineering and construction services. The facility is expected to be completed in the first quarter of 2019.

Deep Geologic Repository for Low and Intermediate Level Waste

OPG has proposed a deep geologic repository as the preferred solution for the safe long-term management of the L&ILW produced from the continued operation of OPG-owned nuclear generating stations. Agreement has been reached with local municipalities for OPG to develop the L&ILW Deep Geologic Repository (DGR) on lands adjacent to the Western Waste Management Facility (WWMF) in Kincardine, Ontario. The environmental effects of the proposed L&ILW DGR were examined by the CNSC and CEAA-appointed Joint Review Panel (JRP) to meet the requirements of the Canadian Environmental Assessment Act. The JRP submitted its report on the EA to the federal Minister of Environment in May 2015, concluding that, given mitigation, there is unlikely to be significant environmental impact from the project and recommending that the Minister approve the EA. In December 2016, at the request of the federal Minister of Environment and Climate Change, OPG submitted additional information on certain aspects of the EA, including information related to alternate locations for the project. Following its review of OPG's submission and a period of public comment, the CEAA requested further information that OPG subsequently provided in May 2017. In June 2017, the CEAA notified OPG that it had sufficient and adequate information to proceed with the next step of the environmental assessment process and advised that a draft report and updated terms and conditions will be prepared for public review.

On August 21, 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of potential cumulative effects of the project on the Saugeen Ojibway Nations' (SON) physical and cultural heritage, including a description of the potential effects of the project on the Nation's spiritual and cultural connection to the land. OPG is assessing the request and will notify the CEAA when it has determined the timeline for developing a response. The CEAA's draft report for public review will not be issued until this update is provided. The L&ILW DGR at the WWMF site remains OPG's preferred solution for the safe long-term management of the L&ILW.

OPG continues its engagement with the SON toward securing community support for the L&ILW DGR. The in-service date of the L&ILW DGR is expected to be approximately six to seven years from the start of construction.

Financial Strength

As a commercial enterprise, OPG's financial priority is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future growth.

Increase Revenue, Reduce Costs and Achieve Appropriate Return

In May 2016, OPG filed a 5-year application with the OEB for new regulated prices for production from its regulated hydroelectric and nuclear facilities, with a proposed effective date of January 1, 2017. Consistent with the requirements of *Ontario Regulation 53/05*, the application incorporates a rate smoothing proposal that would defer, for future collection, a portion of the approved annual nuclear revenue requirement for the period from January 1, 2017 to the end of the Darlington Refurbishment project, with a view to making changes in OPG's regulated prices more stable year-over-year. The application seeks to ensure that nuclear regulated prices under the rate smoothing approach allow for sufficient cash flow to meet the Company's liquidity needs, support cost effective funding for the Darlington Refurbishment project and other expenditures, and maintain the Company's investment grade credit rating, while taking into account both near-term and future impacts on customers. OPG expects to recognize amounts deferred under rate smoothing as income in the periods to which the underlying approved revenue requirements relate.

The application will further challenge and incentivize OPG to find additional cost reductions and efficiencies within its operations, as a result of greater de-coupling of nuclear and hydroelectric regulated prices from costs and a longer rate-setting period under the OEB's incentive ratemaking framework, which forms the basis for the ratemaking methodologies reflected in the application.

The application seeks an increase in the nuclear rate base, effective in early 2020, to reflect the planned placement in service of approximately $4.8 billion of capital expenditures upon the scheduled return to service of Unit 2 at the Darlington GS as part of the Darlington Refurbishment project and, effective in 2017, an increase in the deemed capital structure applied to the total regulated rate base to 49 percent equity and 51 percent debt, from 45 percent equity and 55 percent debt reflected in the existing regulated prices. The application also requests new rate riders, effective January 1, 2017, to recover or repay the December 31, 2015 balances in all of the Company's OEB-authorized variance and deferral accounts, with the exception of the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the portion of these balances previously approved for recovery or repayment through rate riders that were in effect during 2016.

The OEB's decision on the application, including the effective date of approved new regulated prices, is expected later in 2017. **[MONITOR]**

For generation assets that do not form part of the assets regulated by the OEB, OPG's strategy has been to secure appropriate long-term revenue arrangements. In line with this strategy, virtually all of OPG's non-regulated operating facilities and assets under construction are subject to long-term Energy Supply Agreements (ESAs) or other long-term contracts with the IESO.

Ensure Availability of Cost Effective Funding

In April 2017, DBRS Limited (DBRS) re-affirmed the long-term credit rating on OPG's debt at 'A (low)' and OPG's commercial paper rating at 'R-1 (low)'. All ratings from DBRS have a stable outlook. In July 2017, S&P Global Ratings (S&P) re-affirmed OPG's long-term credit rating at 'BBB+' with a stable outlook. S&P's commercial paper rating for OPG is 'A-1 (low)'.

Social Licence

As the largest electricity generator in Ontario with diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust. OPG is committed to maintaining high standards of public safety and corporate citizenship, including environmental stewardship, transparency, community engagement, and Indigenous relations.

OPG is focused on building long-term, mutually beneficial working relationships with Indigenous communities, businesses and organizations across Ontario, and continues to support procurement, employment and educational opportunities with its Indigenous community partners. The Company seeks to establish these relationships based on a foundation of respect for the languages, customs, and political, social and cultural organizations of the Indigenous communities.

In June 2017, OPG launched an Indigenous Business Engagement (IBE) Initiative. The purpose of this initiative is to increase access to procurement opportunities for Indigenous businesses interested in supplying materials and services to OPG. The IBE Initiative is based on a strategy that will identify opportunities in contracts, scopes of work and business plans for potential Indigenous business engagement; include criteria related to suppliers' ability to engage or partner with Indigenous people or businesses in assessing procurement proposals; and invest in relationships with Indigenous communities by increasing outreach efforts to enhance understanding of how to do business with OPG. OPG has continued to engage with various Indigenous business and communities as well as its suppliers to promote the IBE Initiative. In September 2017, OPG presented the IBE to the Mohawk Council of Akwesanse (Akwesanse). As a result, Akwesanse plans to create a database of businesses in the community that will participate in contracting and supply opportunities with OPG. In September 2017, OPG also hosted a similar presentation to the Williams Treaties First Nations, located proximate to the Pickering and Darlington Nuclear Generating Stations, at the quarterly meeting for these communities.

OPG is developing recruitment plans targeting Indigenous people. In October 2017, OPG participated in five Indigenous-specific career fairs to attract such talent. **[MONITOR]**

OPG has a transportation electrification strategy that will help position OPG as a leader in transportation electrification in Ontario. This strategy is intended to leverage OPG's clean electricity to support action on climate change, create growth opportunities for OPG, and enhance OPG's brand and social licence.

Outlook

The financial performance of OPG's regulated operations is driven, in large part, by the outcome of applications for regulated prices to the OEB. The existing base regulated prices were established by the OEB effective November 1, 2014 based on a forecast of costs and production for the regulated facilities for the 2014 to 2015 period. The future outcome of OPG's current application for new regulated prices, currently pending the OEB's decision, is expected to provide substantial price certainty for the regulated business for the 2017 to 2021 period.

In its application, OPG has requested January 1, 2017 as the effective date for the new regulated prices. In December 2016, the OEB issued an order declaring the existing base regulated prices interim, which preserves the OEB's ability to make the new regulated prices effective as early as January 1, 2017. Considering the timing of OPG's application and OPG's procedural adherence throughout the proceeding, the Company believes that the OEB could make the new regulated prices effective January 1, 2017. This would allow OPG to recover the difference between the approved new regulated prices and the existing regulated prices for the period between January 1, 2017 and the implementation date of the new prices based on the OEB's order. The OEB's decision on the application, including the effective date of the new regulated prices, is expected in the fourth quarter of 2017. **[MONITOR]** The continuation of existing regulated prices until the issuance of the OEB's decision is expected to continue to contribute to lower income, particularly from the Regulated – Nuclear Generation segment, and, excluding the gain on sale of the Company's head office premises and associated parking facility recorded in the second quarter of 2017, lower

Commented [A10]: Sp. "Akwesasne" ?

OPG – fixed spelling to as follows:

In September 2017, OPG presented the IBE to the Mohawk Council of Akwesasne (Akwesasne). As a result, the Akwesasne plan to create a database of businesses in the community that will participate in contracting and supply opportunities with OPG.

Commented [A11]: Does this deal with OPG owned fleet and other vehicles, or in line with the infrastructure for EV vehicles.

Can further details be provided in particular on the point of 'creating growth opportunities for OPG'.

OPG – revised wording for this paragraph as follows:

OPG has a strategy to help position the Company as a leader in transportation electrification in the province. The strategy aims to leverage the Company's clean, reliable and cost-effective electricity to power transportation, capitalize on future commercial growth opportunities, and enhance the Company's social licence. OPG is pursuing initiatives to increase the use of electric vehicles within its operations, and is assessing vehicle grid integration and hydrogen applications for the transportation sector.

ROE Excluding AOCI during 2017, compared to 2016. In large part, this is due to the year-over-year reduction in nuclear electricity generation resulting from the Unit 2 refurbishment outage at the Darlington GS, given that the existing nuclear regulated prices were determined in 2014 based on a higher production forecast that reflected the operation of all four units at the station. As such, the OEB's decision on the effective date of the new regulated prices, as well as the timing of the decision issuance, could have a significant impact on OPG's financial results during 2017.

Nuclear base regulated prices resulting from OPG's current application will be subject to a rate smoothing mechanism that defers collection of a portion of OEB-approved revenues to future periods. As expected, combined with the expiry of rate riders in effect to the end of 2016, a year-over-year reduction in nuclear generation due to the Unit 2 refurbishment outage at the Darlington GS and the continuation of existing regulated prices until such time as new prices are implemented by the OEB, this will result in lower cash flow from operating activities in 2017, compared to 2016. OPG expects to continue to have the necessary financial capacity and sufficient access to cost effective financing sources to continue to fund its capital requirements and other disbursements.

Lower nuclear generation due to the Darlington Refurbishment outages will continue, as planned, to negatively impact the Enterprise TGC metric for the duration of the refurbishment project. Variability in sustaining capital investment expenditures, including major sustaining projects for the hydroelectric operations, also will impact the Enterprise TGC in future periods.

Several OEB-authorized regulatory variance and deferral accounts currently in place contribute to reducing the relative variability of the Company's income and ROE Excluding AOCI. Among others, the regulatory accounts include those related to the revenue impact of variability in water flows and forgone production due to SBG conditions at the regulated hydroelectric stations. As there are no variance or deferral accounts in place related to the impact of generation performance of the nuclear stations on revenue from base regulated prices, the Regulated – Hydroelectric segment generally is expected to produce overall more predictable earnings. OPG continues to operate and maintain its nuclear facilities with a view to optimize their performance and availability, while focusing on improving the overall reliability and predictability of the fleet.

Electricity generated from most of OPG's non-regulated assets is subject to ESAs with the IESO. Based on these agreements, OPG expects the Contracted Generation Portfolio segment to continue to contribute a generally stable level of earnings and cash flow from operations going forward.

OPG's total forecast capital expenditures for the 2017 year are approximately $2.0 billion. This includes amounts for the Darlington Refurbishment project, hydroelectric and other development projects including the completion of the Peter Sutherland Sr. GS and the expansion of the Ranney Falls GS, and sustaining capital investments across the generating fleet. OPG's major projects are discussed in the section, *Project Excellence*.

In addition to the operating and financial performance of the electricity generation business, OPG's results are affected by the earnings on the Nuclear Segregated Funds, which are reported in the Regulated – Nuclear Waste Management segment. While the Nuclear Segregated Funds are managed to achieve, in the long term, the target rate of return based on the discount rate specified in the ONFA, the rates of return earned in a given period can be subject to various external factors including financial market conditions and, for the portion of the Used Fuel Segregated Fund guaranteed by the Province under the ONFA, changes in the Ontario consumer price index (CPI). In the near term, these factors can be volatile and cause fluctuations in the Company's income. This volatility is partially mitigated by the impact of the OEB-authorized Bruce Lease Net Revenues Variance Account and, as discussed below, the funded status of the two segregated funds.

As OPG does not have the right to withdraw surplus amounts from the Nuclear Segregated Funds, OPG limits the amount of Nuclear Segregated Funds assets reported on the balance sheet to the present value of such life cycle funding liability. This reduces the volatility of earnings on the Nuclear Segregated Funds reflected in net income when the funds are in a fully funded or overfunded position. As at September 30, 2017, the Decommissioning

Segregated Fund was overfunded by approximately 23 percent, and the Used Fuel Segregated Fund was marginally overfunded, by less than one percent, based on the 2017 ONFA Reference Plan. Variability in asset performance due to volatility inherent in financial markets and changes in Ontario CPI, or changes in funding liability estimates, may result in either or both funds becoming underfunded in the future.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

Regulated – Nuclear Generation Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue	**739**	885	**2,000**	2,631
Fuel expense	**81**	79	**217**	239
Gross margin	**658**	806	**1,783**	2,392
Operations, maintenance and administration	**511**	521	**1,693**	1,665
Depreciation and amortization	**116**	230	**333**	691
Property taxes	**7**	6	**20**	19
Income (loss) before other losses, interest, and income taxes	**24**	49	**(263)**	17
Other losses	**4**	2	**4**	-
Income (loss) before interest and income taxes	**20**	47	**(267)**	17

For the three and nine month periods ended September 30, 2017, the segment earnings decreased by $27 million and $284 million, respectively, compared to the same periods in 2016. The decrease in earnings was expected and primarily due to reduced revenue from the nuclear base regulated price of approximately $24 million and $230 million, respectively. The decrease was partially offset by an associated year-over-year decrease in fuel expense. The decrease in revenue during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, reflected lower electricity generation of 0.4 TWh and 4.0 TWh, respectively, primarily due to the ongoing Unit 2 refurbishment outage at the Darlington GS that began in October 2016, without a corresponding increase in the base regulated price. The existing nuclear base regulated price set by the OEB in 2014 continues to be in effect pending the OEB's decision on OPG's application for new regulated prices, proposed to be effective on January 1, 2017. The existing price does not reflect the lower generation as a result of the Darlington Refurbishment project, as it was set to allow the Company to recover its approved nuclear costs over a higher nuclear production volume, based on the 2014 and 2015 outage profile that did not include a refurbishment outage. The reduction in nuclear electricity generation for the three months ended September 30, 2017 was largely offset by the higher electricity generation from the Pickering GS.

OM&A expenses decreased by $10 million during the third quarter of 2017, compared to the same period in 2016, as a result of a higher materials and supplies obsolescence charge recognized in 2016. OM&A expenses increased by $28 million during the nine months ended September 30, 2017, compared to the same period in 2016, due to planned maintenance activities in 2017.

Depreciation and amortization expense, excluding amortization expense related to regulatory account balances, increased by $16 million and $30 million during the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016, primarily due to new assets in service.

The expiry of an OEB-authorized nuclear rate rider on December 31, 2016 contributed to the decrease in segment revenue for the three and nine month periods ended September 30, 2017, compared to the same periods in 2016. As rate riders allow for recovery of approved balances in OEB-authorized regulatory accounts, this decrease in revenue was largely offset by a decrease in amortization expense related to these balances. There was no rate rider

in effect during the nine months ended September 30, 2017, pending the outcome of OPG's current application to the OEB for new regulated prices.

The Unit Capability Factors for the Darlington and Pickering generating stations were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Unit Capability Factor *(%)* [1]				
Darlington GS	**96.2**	89.6	**82.1**	87.6
Pickering GS	**88.7**	77.3	**83.8**	73.8

[1] The nuclear Unit Capability Factor excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS was excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

The Unit Capability Factor at the Darlington GS increased in the third quarter of 2017, compared to the same quarter in 2016, primarily due to the lower number of planned outage days during the third quarter of 2017. The lower Unit Capability Factor at the Darlington GS for the nine months ended September 30, 2017, compared to the same period in 2016, reflected the higher number of planned outage days, largely driven by constraints related to the transition of the station toward refurbishment.

The increase in Unit Capability Factor at the Pickering GS for the three and nine month periods ended September 30, 2017 was primarily due to outage optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station compared to 2016.

Regulated – Nuclear Waste Management Segment

(millions of dollars) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Revenue	**33**	36	**90**	102
Operations, maintenance and administration	**35**	38	**96**	108
Accretion on nuclear fixed asset removal and nuclear waste management liabilities	**230**	228	**696**	684
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(196)**	(248)	**(579)**	(620)
(Loss) Income before interest and income taxes	**(36)**	18	**(123)**	(70)

The segment loss before interest and income taxes was $36 million and $123 million during the three and nine months ended September 30, 2017, respectively, a decrease in earnings of $54 million and $53 million compared to the same periods in 2016. The decline in earnings was primarily due to lower earnings from the Nuclear Segregated Funds, net of the impact of the impact of the Bruce Lease Net Revenues Variance Account, reflecting higher earnings from market returns on fund assets and the CPI-adjusted rate of return guaranteed by the Province for the portion of the Used Fuel Segregated Fund related to the initial 2.23 million used fuel bundles (committed return) in the third quarter of 2016.

As both the Decommissioning Segregated Fund and the Used Fuel Fund were in an overfunded position during the three and nine months period ended September 30, 2017, compared to the underlying funding liabilities per the approved ONFA Reference Plan, the earnings on the funds during these periods reflected the growth rate in the present value of the funding liabilities and were not impacted by market returns and committed return. The higher earnings on both funds during the three and nine months periods ended September 30, 2016 reflected market returns and committed return, as the Decommissioning Segregated Fund became over 120 percent funded during the third quarter of 2016 while the Used Fuel Fund was underfunded, compared to the corresponding funding liabilities.

Higher market returns and committed return in the third quarter of 2016 in relation to the funding liabilities' growth rate reflected in fund earnings during 2017 resulted in a year-over-year decrease in the amount of earnings on the Nuclear Segregated Funds.

As of December 31, 2016, OPG recorded a decrease of approximately $1,570 million to the Nuclear Liabilities and associated asset retirement costs capitalized as part of the carrying value of the nuclear generating stations. The resulting year-over-year decreases in accretion on fixed asset removal and nuclear waste management liabilities recorded in the Regulated – Nuclear Waste Management segment and depreciation and fuel expenses recorded in the Regulated – Nuclear Generation segment during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, were offset by the impact of the Bruce Lease Net Revenues Variance Account and the Nuclear Liability Deferral Account authorized by the OEB.

Under the current OEB-approved cost recovery methodology, these changes in expenses also are not expected to materially affect OPG's income during the rest of 2017, as they are expected to continue to be largely offset by the impact of the regulatory accounts until such time as the OEB implements corresponding changes to OPG's nuclear regulated prices, and subsequently by the impact of such new regulated prices. Further details on the change in the estimate of the Nuclear Liabilities as of December 31, 2016 are described in OPG's 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Asset Retirement Obligation*. **[MONITOR]**

Regulated – Hydroelectric Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue [1]	**327**	350	**1,069**	1,148
Fuel expense	**88**	88	**258**	259
Gross margin	**239**	262	**811**	889
Operations, maintenance and administration	**81**	87	**232**	238
Depreciation and amortization	**34**	56	**103**	169
Property tax	**1**	1	**1**	1
Income before other losses (gains), interest and income taxes	**123**	118	**475**	481
Other losses (gains)	**1**	1	**1**	(19)
Income before interest and income taxes	**122**	117	**474**	500

[1] During the three and nine month periods ended September 30, 2017, the Regulated – Hydroelectric segment revenue included incentive payments of $4 million and $9 million, respectively, related to the OEB-approved hydroelectric incentive mechanism (three and nine month periods ended September 30, 2016 – incentive payments of $6 million and $8 million, respectively). The mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers. The incentive payments are reduced to remove incentive revenues arising in connection with SBG conditions.

The increase in segment income before interest and income taxes of $5 million during the third quarter of 2017, compared to the same quarter in 2016, was primarily the result of a decrease in OM&A expenses, mainly due to the timing of repairs and maintenance work in 2017 and a deferral of outages during the high water period.

The decrease in segment income before interest and income taxes of $26 million during the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to a gain of $22 million recognized during the first quarter of 2016 to reflect the OEB's January 2016 decision to reverse a portion of an earlier capital cost disallowance related to the Niagara Tunnel project expenditures, in response to a motion by OPG. The income impact of OEB-approved variance accounts also contributed to the year-over-year decrease in income for the period. These factors were partially offset by the decrease in OM&A expenses related to the timing of repairs and maintenance work in 2017 and a deferral of outages during the high water period.

The decrease in revenue from the segment for the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was largely due to the expiry of an OEB-authorized rate rider on

December 31, 2016. As the rider allowed for the recovery of approved balances in OEB-authorized regulatory accounts, the resulting reduction in revenue was largely offset by lower amortization expense related to these balances. There was no rate rider in effect during the first nine months of 2017 pending the outcome of OPG's current application to the OEB for new regulated prices.

The Hydroelectric Availability for the stations included in the Regulated – Hydroelectric segment was as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Hydroelectric Availability *(%)*	**87.6**	84.1	**89.0**	89.8

The Hydroelectric Availability in the third quarter of 2017 was higher compared to the same period in 2016, primarily due to a higher number of planned outages in 2016 as a result of the refurbishment of the Sir Adam Beck Pump GS reservoir between April 2016 and February 2017. The marginal decrease in Hydroelectric Availability during the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to a higher number of unplanned outage days at the Northwestern Ontario and Niagara region hydroelectric stations, partially offset by higher availability from the Sir Adam Beck Pump GS.

Contracted Generation Portfolio Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue	**141**	149	**431**	431
Fuel expense	**15**	19	**42**	42
Gross margin	**126**	130	**389**	389
Operations, maintenance and administration	**39**	44	**118**	129
Depreciation and amortization	**20**	19	**59**	56
Accretion on fixed asset removal liabilities	**3**	2	**7**	6
Property taxes	**-**	1	**5**	6
Income from investments subject to significant influence	**(11)**	(11)	**(29)**	(28)
Income before other loss, interest and income taxes	**75**	75	**229**	220
Other loss	**-**	1	**-**	1
Income before interest and income taxes	**75**	74	**229**	219

Income before interest and income taxes from the segment increased by $1 million and $10 million during the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016. The increase in earnings for the three months ended September 30, 2017 mainly resulted from revenues from the Peter Sutherland Sr. GS that was placed in-service at the end of the first quarter of 2017 and lower OM&A expenses, partially offset by lower revenue from the Atikokan GS. The decrease in revenue from the Atikokan GS was primarily due to higher revenues in 2016, when the station was called upon to provide the needed support to the electricity system in Northwestern Ontario as a result of an outage at a local transformer station. For the nine months ended September 30, 2017, the increase in earnings was primarily due to lower OM&A expenses. The lower OM&A expenses for the three and nine month periods ended September 30, 2017 were mainly due to the prospective adoption of the full yield curve approach to the estimation of the service and interest cost components of pension and OPEB costs starting in 2017.

The Hydroelectric Availability and the Thermal Equivalent Forced Outage Rate (EFOR) for the Contracted Generation Portfolio segment were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Hydroelectric Availability *(%)*	**66.1**	68.2	**76.9**	79.6
Thermal EFOR *(%)*	**2.6**	2.1	**6.0**	1.3

Lower Hydroelectric Availability during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was primarily due to an increase in the number of planned outage days at the Lower Mattagami River hydroelectric generating stations.

The higher Thermal EFOR during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was primarily due to a higher number of unplanned outage days at a Lennox GS unit as a result of a transmission outage and a generator cooling water system outage in 2017.

Services, Trading, and Other Non-Generation Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue	**9**	15	**36**	52
Fuel expense	**1**	1	**1**	1
Gross margin	**8**	14	**35**	51
Operations, maintenance and administration	**1**	11	**2**	20
Depreciation and amortization	**8**	8	**22**	25
Accretion on fixed asset removal liabilities	**2**	2	**6**	6
Property taxes	**-**	4	**4**	9
(Loss) income before other gains, interest, and income taxes	**(3)**	(11)	**1**	(9)
Other gains	**(2)**	(3)	**(385)**	(5)
Income (loss) before interest and income taxes	**(1)**	(8)	**386**	(4)

Segment earnings improved by $7 million during the third quarter of 2017, compared to the same quarter in 2016. The improvement in earnings was primarily due to lower OM&A expenses reflecting project expenditures incurred in the third quarter of 2016, and OPG's decision, in the fourth quarter of 2016, to proceed with the decommissioning of Lambton GS.

Segment income before interest and income taxes increased by $390 million for the nine months ended September 30, 2017, compared to the same period in 2016. The increase in earnings mainly reflected the gain on the sale of OPG's head office premises and associated parking facility recorded during the second quarter of 2017.

LIQUIDITY AND CAPITAL RESOURCES

OPG's primary sources of liquidity and capital are funds generated from operations, bank financing, credit facilities provided by the Ontario Electricity Financial Corporation (OEFC), long-term corporate debt, and capital market financing. These sources are used for multiple purposes including: to invest in plants and technologies, to undertake major projects, to fund long-term obligations such as contributions to the pension fund and the Nuclear Segregated Funds, to make payments under the OPEB plans, to fund expenditures on Nuclear Liabilities not reimbursable from the Nuclear Segregated Funds, to service and repay long-term debt, to provide general working capital, and to fund OPG's investment in the Fair Hydro Plan.

Changes in cash and cash equivalents for the three and nine month periods ended September 30 are as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Cash and cash equivalents, beginning of period	**242**	295	**186**	464
Cash flow provided by operating activities	**485**	530	**698**	1,211
Cash flow used in investing activities	**(463)**	(390)	**(720)**	(1,253)
Cash flow provided by (used in) financing activities	**16**	(9)	**116**	4
Net increase (decrease)	**38**	131	**94**	(38)
Cash and cash equivalents, end of period	**280**	426	**280**	426

For a discussion of cash flow provided by operating activities and the FFO Adjusted Interest Coverage ratio, refer to the details in the section, *Highlights* under the heading, *Overview of Results*.

Investing Activities

Electricity generation is a capital-intensive business. It requires continued investment in plants and technologies to maintain and improve operating performance including asset reliability, safety and environmental performance, to increase the generating capacity of existing stations, and to invest in the development of new generating stations, emerging technologies and other business growth opportunities.

Cash flow used in investing activities during the third quarter of 2017 was $463 million, compared to $390 million for the same period in 2016. The increase in cash flow used for investing activities mainly resulted from higher expenditures on the Darlington Refurbishment project in the third quarter of 2017.

Cash flow used in investing activities decreased by $533 million for the nine months ended September 30, 2017, compared to the same period in 2016. The decrease in net cash flow used in investing activities was primarily due to the receipt of proceeds from the sale of OPG's head office premises and associated parking facility in the second quarter of 2017 pursuant to a Shareholder Declaration and Shareholder Resolution, and the acquisition of nine million common shares of Hydro One Limited (Hydro One) in the second quarter of 2016, partially offset by higher expenditures on the Darlington Refurbishment project in 2017. OPG acquired the Hydro One shares for investment purposes, to mitigate the risk of future price volatility related to the Company's future share delivery obligations under the collective agreements with the Power Workers' Union and The Society of Energy Professionals.

Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from the sale of head office premises and associated parking facility, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. OPG expects that the amount of designated proceeds to be transferred into the Consolidated Revenue Fund will be largely consistent with the after-tax gain on sale. The transfer is expected to take place later in 2017.

Financing Activities

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. In the second quarter of 2017, OPG renewed and extended the expiry date of both tranches from May 2021 to May 2022. There were no amounts outstanding under the bank credit facility as at September 30, 2017.

There was $160 million of commercial paper outstanding under OPG's commercial paper program as at September 30, 2017.

As at September 30, 2017, OPG also maintained $25 million of short-term, uncommitted overdraft facilities, and a further $463 million of short-term, uncommitted credit facilities, which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other general corporate purposes. As at September 30, 2017, a total of $388 million of Letters of Credit had been issued under these facilities. This included $349 million for the supplementary pension plans, $38 million for general corporate purposes, and $1 million related to the operation of the PEC.

The Company has an agreement to sell an undivided co-ownership interest in its current and future accounts receivable to an independent trust, expiring on November 30, 2018. The maximum amount of co-ownership interest that can be sold under this agreement is $150 million. As at September 30, 2017, no borrowings were issued under this agreement and there were Letters of Credit outstanding under this agreement of $150 million, which were issued in support of OPG's supplementary pension plans.

As at September 30, 2017, Lower Mattagami Energy Limited Partnership (LME) maintained a $400 million bank credit facility to support the funding requirements for the Lower Mattagami River project including support for LME's commercial paper program and the issuance of the Letters of Credit. The facility consists of a $300 million tranche which, in the third quarter of 2017, was extended to mature in August 2022 and a $100 million tranche which, in the third quarter of 2017, was reduced from $200 million and extended to mature in August 2018. As at September 30, 2017, there was no external commercial paper outstanding under LME's commercial paper program. A letter of credit of $55 million was issued in July 2017 and remains outstanding as at September 30, 2017 under the $300 million tranche of the credit facility.

In June 2016, OPG entered into a $700 million general corporate credit facility agreement with the OEFC, which expires on December 31, 2017. In the third quarter of 2017, the agreement was amended to increase the credit facility to $2,350 million and to extend its expiry date to December 31, 2018.

In February 2017, OPG issued senior notes payable to the OEFC totalling $200 million and maturing in February 2047. The effective interest rate and coupon interest rate of these notes was 4.12 percent. In June 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in June 2047. The effective interest rate and coupon interest rate of these notes was 3.65 percent. In August 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in August 2047. The effective interest rate and coupon interest rate of these notes was 3.86 percent. In September 2017, OPG issued senior notes payable to the OEFC totalling $400 million and maturing in September 2047. The effective interest rate and coupon interest rate of these notes was 4.07 percent. As at September 30, 2017, there were outstanding long-term borrowings of $800 million under this credit facility.

In October 2017, OPG issued $500 million of senior notes payable under a Medium Term Note Program. The notes bear a coupon interest rate of 3.32 percent and an effective rate of 3.43 percent, payable semi-annually until maturity on October 4, 2027. The offering was made under OPG's $2 billion short form base shelf prospectus dated September 12, 2017. The net proceeds will be used for general corporate purposes, including the financing of OPG's subordinated debt investment in the Fair Hydro Plan.

As at September 30, 2017, OPG's long-term debt outstanding was $5,482 million, including $628 million due within one year.

OPG continues to evaluate arrangements that would appropriately support the Company's financing needs and capital expenditure programs.

Contractual and Commercial Commitments

Pension Plan Actuarial Valuation

A new actuarial valuation of the OPG registered pension plan was filed with the Financial Services Commission of Ontario in September 2017 with an effective date of January 1, 2017. The annual funding requirements in accordance with the new actuarial valuation are $212 million for 2017, $215 million for 2018, and $219 million for 2019. The next actuarial valuation must have an effective date no later than January 1, 2020.

BALANCE SHEET HIGHLIGHTS

The following section provides highlights of OPG's unaudited interim consolidated financial position using selected balance sheet data:

(millions of dollars) (unaudited)	As At September 30 2017	As At December 31 2016
Property, plant and equipment - net	**20,801**	19,998
The increase was primarily due to capital expenditures on the Darlington Refurbishment project, partially offset by depreciation expense.		
Nuclear fixed asset removal and nuclear waste management funds *(current and non-current portions)*	**16,534**	15,984
The increase was primarily due to earnings on the Nuclear Segregated Funds, partially offset by reimbursements of eligible expenditures on nuclear fixed asset removal and nuclear waste management activities.		
Short-term debt	**160**	2
The increase was due to commercial paper issued under OPG's commercial paper program during the third quarter of 2017.		
Fixed asset removal and nuclear waste management liabilities	**20,075**	19,484
The increase was primarily a result of accretion expense representing the increase in the liabilities due to the passage of time, partially offset by expenditures on nuclear fixed asset removal and waste management activities.		

Off-Balance Sheet Arrangements

In the normal course of operations, OPG engages in a variety of transactions that, under US GAAP, are either not recorded in the Company's interim consolidated financial statements or are recorded in the Company's interim consolidated financial statements using amounts that differ from the full contract amounts. Principal off-balance sheet activities for OPG include guarantees and long-term contracts.

CHANGES IN ACCOUNTING POLICIES AND ESTIMATES

OPG's significant accounting policies are outlined in Note 3 to the audited consolidated financial statements as at and for the year ended December 31, 2016. A discussion of recent accounting pronouncements and change in accounting estimate are included in Note 2 to OPG's unaudited interim consolidated financial statements as at and for the three and nine month periods ended September 30, 2017 under the heading, *Significant Accounting Policies and Estimates*. Disclosure regarding OPG's critical accounting policies is included in OPG's 2016 annual MD&A.

RISK MANAGEMENT

The following provides an update to the discussion of the Company's risks and risk management activities included in OPG's 2016 annual MD&A. As such, the disclosure in this section should be read in conjunction with the *Risk Management* section included in the annual MD&A.

Risks to Achieving Project Excellence

Deep Geologic Repository for Low and Intermediate Level Waste

In August 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of the potential cumulative effects of the DGR project on the physical and cultural heritage of the SON, taking into account the results of the SON Community Process. OPG continues to work with the SON, however the timing and outcome of the SON Community Process and the EA decision by the Minister are uncertain.

Risks to Maintaining Financial Strength

Commodity Markets

Changes in the market price of fuels used to produce electricity can adversely impact OPG's earnings and cash flow from operations.

To manage the risk of unpredictable increases in the price of fuels, the Company has fuel hedging programs, which include fixed price and indexed contracts.

The percentages hedged of OPG's fuel requirements are shown in the following table. These amounts are based on yearly forecasts of generation and supply mix, and as such, are subject to change as these forecasts are updated.

	2017 [1]	2018	2019
Estimated fuel requirements hedged [2]	73%	73%	69%

[1] Based on actual fuel requirements hedged for the nine months ended September 30, 2017 and forecast for the remainder of the year.

[2] Represents the approximate portion of megawatt-hours of expected generation production (and year-end inventory targets) from each type of OPG-operated facility (nuclear, hydroelectric and thermal) for which the Company has entered into contractual arrangements or obligations in order to secure the price of fuel, or which is subject to regulation. In the case of hydroelectric generation, this represents the gross revenue charge and water rental charges. Excess fuel inventories (nuclear and thermal) in a given year are attributed to the next year for the purpose of measuring hedge ratios.

Foreign Exchange

OPG's earnings and cash flow can be affected by movements in the United States dollar (USD) relative to the Canadian dollar.

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are denominated in, or tied to, USD. To manage this risk, OPG periodically employs various financial instruments such as forwards and other

derivative contracts, in accordance with approved risk management policies. As at September 30, 2017, OPG had no foreign exchange contracts outstanding.

Trading

OPG's financial performance can be affected by its trading activities.

OPG's electricity trading operations are closely monitored, with total exposures measured and reported to senior management on a daily basis. The main metric used to measure the financial risk of trading activity is Value at Risk (VaR). VaR is defined as a probabilistic maximum potential future loss expressed in monetary terms for a portfolio based on normal market conditions over a set period of time. For the third quarter of 2017, the VaR utilization ranged between $0.2 million and $0.3 million.

Credit

Deterioration in energy markets counterparty credit and non-performance by suppliers and contractors can adversely impact OPG's earnings and cash flow from operations.

OPG manages its exposure to suppliers or counterparties by evaluating their financial condition and negotiating appropriate collateral or other forms of security. OPG's credit exposure relating to energy markets transactions as at September 30, 2017 was $356 million, including $346 million with the IESO. Management considers the Company's risk exposure relating to electricity sales through the IESO-administered spot market to be low as the IESO oversees the credit worthiness of all market participants. In accordance with the IESO's prudential support requirements, market participants are required to provide collateral to cover funds that they might owe to the market. Of the $10 million remaining exposure as at September 30, 2017, over 95 percent was related to investment grade counterparties.

Fair Hydro Plan

OPG's role in connection with the Fair Hydro Plan could have reputational impacts on the Company.

The *Ontario Fair Hydro Plan Act, 2017* received Royal Assent on June 1, 2017 and its attendant regulations came into force in June, July, and October 2017. **[UPDATE]** The regulations clarify aspects of the structure and program logistics required for ~~OPG, as~~ the Financial Services Manager of the Fair Hydro Plan, which OPG is planning to undertake, to refinance a portion of the Global Adjustment through the Trust. OPG's reputation could potentially be adversely impacted through its involvement with the Fair Hydro Plan and through stakeholder opinions related to this involvement.

Commented [A12]: Not sure this is the right wording. OPG's role as FSM is required under the Act, but not the refinancing through the Trust – the OPG Financing Entity's (or entities) role is discretionary.

OPG – please see changes to this paragraph as follows:

The *Ontario Fair Hydro Plan Act, 2017* received Royal Assent on June 1, 2017 and the associated general regulation came into force in June 2017. As the Financial Services Manager of the Fair Hydro Plan, OPG's reputation could potentially be adversely impacted through this involvement and through stakeholder opinions related to this involvement.

Recovery of Pension and OPEB Costs

On September 14, 2017, the OEB issued its final report on the guiding principles and the policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the electricity and natural gas sectors. The report reaffirmed the conclusions of the initial report issued in May 2017, including the establishment of the accrual basis of accounting as the default rate-setting method and the establishment of a variance account to record asymmetric carrying charges in favour of ratepayers on the differences between the accrual costs recovered and cash payments made by a utility for pension and OPEB plans. The report requires OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the Pension & OPEB Cash Versus Accrual Differential Deferral Account that has been in effect since November 1, 2014, until such time as the OEB approves the resumption of the accrual basis of recovery. The future recovery of amounts recorded in the account will be subject to this approval. The report confirmed that OPG would become subject to the carrying charges on the differences between accrual costs and cash payments going back to November 1, 2014, with the charges calculated on the portion of such differences that have been recovered through regulated prices. The carrying charges will be determined at prescribed interest rate set quarterly by the OEB based on the quarterly return of a mid-term corporate bond index yield. This outcome has reduced OPG's risk related to the recovery of actual pension and OPEB accrual

costs and the recovery of the balance in the Pension & OPEB Cash Versus Accrual Differential Deferral Account. The account had a balance of $552 million as at September 30, 2017 and is recognized on the Company's consolidated balance sheet as a regulatory asset. OPG's financial results for the three and nine month periods ended September 30, 2017 were not impacted by the issuance of the OEB's report.

RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One, the IESO and the OEFC. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions are summarized below:

	Three Months Ended September 30			
	2017		2016	
(millions of dollars) (unaudited)	**Revenue**	**Expense**	**Revenue**	**Expense**
Hydro One				
Electricity sales	**2**	**-**	1	-
Services	**-**	**3**	-	3
Dividends	**2**	**-**	-	2
Province of Ontario				
Decommissioning Fund excess funding [1]	**-**	**(44)**	-	201
Used Fuel Fund rate of return guarantee and excess funding [1]	**-**	**(39)**	-	295
Gross revenue charges	**-**	**27**	-	28
ONFA guarantee fee	**-**	**2**	-	2
Other	**-**	**2**	-	-
OEFC				
Gross revenue charges	**-**	**62**	-	57
Interest expense on long-term notes	**-**	**40**	-	42
Income taxes, net of investment tax credits	**-**	**23**	-	28
IESO				
Electricity related revenue	**1,126**	**4**	1,293	7
	1,130	**80**	1,294	665

(millions of dollars) (unaudited)	Nine Months Ended September 30 2017 Revenue	2017 Expense	2016 Revenue	2016 Expense
Hydro One				
Electricity sales	**7**	**-**	4	-
Services	**1**	**8**	1	12
Dividends	**6**	**-**	-	4
Province of Ontario				
Decommissioning Fund excess funding [1]	**-**	**164**	-	137
Used Fuel Fund rate of return guarantee and excess funding [1]	**-**	**217**	-	190
Gross revenue charges	**-**	**84**	-	91
ONFA guarantee fee	**-**	**6**	-	6
Other	**-**	**3**	-	-
OEFC				
Gross revenue charges	**-**	**156**	-	147
Interest expense on long-term notes	**-**	**122**	-	127
Income taxes, net of investment tax credits	**-**	**132**	-	112
IESO				
Electricity related revenue	**3,228**	**11**	3,894	22
	3,242	**903**	3,899	848

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at September 30, 2017 and December 31, 2016, the Nuclear Segregated Funds were reported net of amounts due to the Province of $3,796 million and $3,415 million, respectively. The details of accounting for the Nuclear Segregated Funds are described in OPG's 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

The receivable, available-for-sale securities, payable and long-term debt balances between OPG and its related parties are summarized below:

(millions of dollars) (unaudited)	September 30 2017	December 31 2016
Receivables from related parties		
Hydro One	**1**	1
IESO	**346**	421
OEFC	**3**	1
PEC	**2**	4
Province of Ontario	**5**	2
Available-for-sale securities		
Hydro One shares	**190**	212
Accounts payable and accrued charges		
OEFC	**37**	61
Province of Ontario	**6**	2
IESO	**2**	2
Long-term debt (including current portion)		
Notes payable to OEFC	**3,245**	3,295

OPG holds interest-bearing Province of Ontario bonds in the Nuclear Segregated Funds and the OPG registered pension fund. As at September 30, 2017, the Nuclear Segregated Funds held $1,498 million of interest-bearing Province of Ontario bonds, while the registered pension fund had no such holdings. As at December 31, 2016, the Nuclear Segregated Funds and the registered pension fund held $1,652 million and $284 million of interest-bearing Province of Ontario bonds, respectively. These bonds are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

There have been no related party transactions related to the Fair Hydro Plan and associated financing activities. The first transaction between the Trust and the IESO is expected later in 2017.

INTERNAL CONTROLS OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

The Company maintains a comprehensive system of policies, procedures, and processes that represents its framework for internal controls over financial reporting and for its disclosure controls and procedures (together, ICOFR). There were no changes in the Company's internal control system during the current interim period that has or is reasonably likely to have a material impact to the ICOFR.

QUARTERLY FINANCIAL HIGHLIGHTS

The following tables set out selected financial information from OPG's unaudited interim consolidated financial statements for each of the eight most recently completed quarters.

(millions of dollars - except where noted) (unaudited)	**September 30 2017**	**June 30 2017**	**March 31 2017**	**December 31 2016**
Revenue	**1,217**	1,146	1,176	1,388
Net income (loss)	**140**	307	68	(8)
Less: Net income attributable to non-controlling interest	**9**	4	4	5
Net income (loss) attributable to the Shareholder	**131**	303	64	(13)
Per common share, attributable to the Shareholder *(dollars)*	**$0.51**	$1.18	$0.25	($0.05)

(millions of dollars - except where noted) (unaudited)	**September 30 2016**	**June 30 2016**	**March 31 2016**	**December 31 2015**
Revenue	1,400	1,387	1,478	1,312
Net income (loss)	198	135	128	(100)
Less: Net income attribute to the non-controlling interest	4	3	5	1
Net income (loss) attributable to the Shareholder	194	132	123	(101)
Per common share, attributable to the Shareholder *(dollars)*	$0.76	$0.51	$0.48	($0.39)

Trends

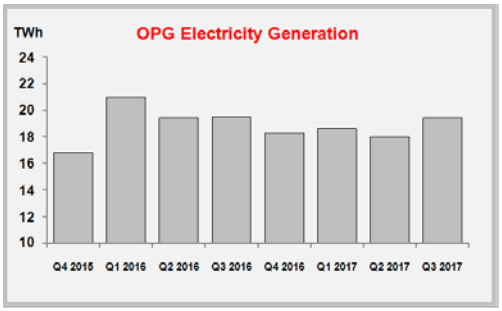
OPG's quarterly results are affected by changes in grid-supplied electricity demand, primarily resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. Weather conditions affect water flows, electricity demand, and prevalence of SBG conditions. Historically, OPG's revenues have been higher in the first

quarter of a fiscal year as a result of winter heating demands and in the third quarter due to air conditioning and cooling demands. The financial impact of forgone production due to SBG conditions at the regulated hydroelectric stations and the financial impact of differences between forecast water flows reflected in OEB-approved regulated prices and the actual water flows are mitigated by regulatory variance accounts authorized by the OEB.

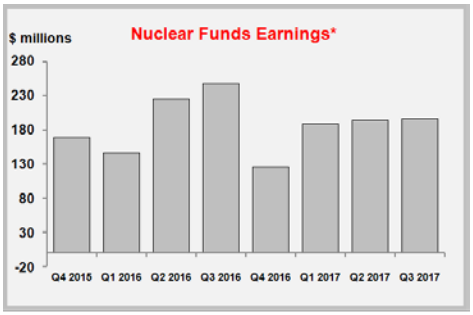
The timing of planned outages at a nuclear generating station during the year can cause variability in year-over-year operating results for partial periods of a fiscal year, including the impact on revenue and OM&A expenses, but is not a significant driver of variability for full fiscal year results.

OPG's electricity generation was reduced as a result of the Unit 2 refurbishment outage at the Darlington GS, which began in October 2016 and is expected to continue until early 2020.

OPG's financial results are also affected by the earnings on the Nuclear Segregated Funds, net of the impact of the Bruce Lease Net Revenues Variance Account.



Additional items that affected net income in certain quarters above are described in OPG's 2016 annual MD&A under



*net of regulatory variance account

the section, *Quarterly Financial Highlights*.

SUPPLEMENTARY NON-GAAP FINANCIAL MEASURES

In addition to providing net income and other financial information in accordance with US GAAP, certain non-GAAP financial measures are also presented in OPG's MD&A. These non-GAAP measures do not have any standardized meaning prescribed by US GAAP and, therefore, may not be comparable to similar measures presented by other issuers. OPG utilizes these measures to make operating decisions and assess performance. Readers of the MD&A would utilize these measures in assessing the Company's financial performance from ongoing operations. The Company believes that these indicators are important since they provide additional information about OPG's performance, facilitate comparison of results over different periods, and present measures consistent with the Company's strategies to provide value to the Shareholder, improve cost performance, and ensure availability of cost effective funding. These non-GAAP financial measures have not been presented as an alternative to net income, cash flow provided by operating activities, or any other measure in accordance with US GAAP, but as indicators of operating performance.

The definitions of the non-GAAP financial measures are as follows:

(1) **ROE Excluding AOCI** is defined as net income attributable to the Shareholder divided by average equity attributable to the Shareholder excluding AOCI, for the period. ROE Excluding AOCI is measured over a 12-month period and is calculated as follows:

	Twelve Months Ended	
(millions of dollars – except where noted) (unaudited)	**September 30 2017**	**December 31 2016**
ROE Excluding AOCI		
Net income attributable to the Shareholder	**485**	436
Divided by: Average equity attributable to the Shareholder, excluding AOCI	**11,055**	10,442
ROE Excluding AOCI *(percent)*	**4.4**	4.2

(2) **FFO Adjusted Interest Coverage** is defined as FFO before interest divided by adjusted interest expense. FFO before interest is defined as cash flow provided by operating activities adjusted for interest paid, interest capitalized to fixed and intangible assets, and changes to non-cash working capital balances for the period. Adjusted interest expense is calculated as net interest expense plus interest income, interest capitalized to fixed and intangible assets, interest related to regulatory assets and liabilities, and the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets, for the period.

FFO Adjusted Interest Coverage is measured over a 12-month period and is calculated as follows:

	Twelve Months Ended	
(millions of dollars – except where noted) (unaudited)	**September 30 2017**	**December 31 2016**
FFO before interest		
Cash flow provided by operating activities	**1,082**	1,595
Add: Interest paid	**270**	269
Less: Interest capitalized to fixed and intangible assets	**(161)**	(141)
Less: Changes to non-cash working capital balances	**38**	42
FFO before interest	**1,229**	1,765
Adjusted interest expense		
Net interest expense	**84**	120
Add: Interest income	**8**	7
Add: Interest capitalized to fixed and intangible assets	**161**	141
Add: Interest related to regulatory assets and liabilities	**43**	30
Add: Excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets [1]	**-**	45
Adjusted interest expense	**296**	343
FFO Adjusted Interest Coverage *(times)*	**4.2**	5.1

[1] A value of nil is used in the calculation when interest on pension and OPEB projected benefit obligations is equal to, or lower than, expected return on pension plan assets.

(3) **Enterprise Total Generating Cost per MWh** is used to measure OPG's overall organizational cost performance. Enterprise TGC per MWh is defined as OM&A expenses (excluding the Darlington Refurbishment project and other generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to OPG's electricity generation business), fuel expense for OPG-operated stations including hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures (excluding the Darlington Refurbishment project and other generation development projects) incurred during the period, divided by total electricity generation from OPG-operated generating stations plus electricity generation forgone due to SBG conditions during the period.

(millions of dollars – except where noted) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Enterprise TGC				
Total OM&A expenses	**635**	666	**2,054**	2,061
Total fuel expense	**185**	187	**518**	541
Total capital expenditures	**476**	444	**1,335**	1,162
Less: Darlington Refurbishment capital and OM&A costs	**(328)**	(269)	**(943)**	(717)
Less: Other generation development project capital and OM&A costs	**(17)**	(42)	**(53)**	(121)
Add (Less): OM&A and fuel expenses (refundable through) deferred in regulatory variance and deferral accounts	**4**	35	**(19)**	76
Less: Nuclear fuel expense for non OPG-operated stations	**(13)**	(18)	**(42)**	(50)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**13**	5	**47**	38
Less: OM&A expenses ancillary to electricity generation business	**(4)**	(5)	**(13)**	(17)
Other adjustments	**(3)**	(12)	**(7)**	(15)
	948	991	**2,877**	2,958
Adjusted electricity generation *(TWh)*				
Total OPG electricity generation	**19.4**	19.5	**56.0**	59.9
Adjust for electricity generation forgone due to SBG conditions and OPG's share of electricity generation from co-owned facilities	**0.9**	0.1	**4.2**	3.4
	20.3	19.6	**60.2**	63.3
Enterprise TGC per MWh *($/MWh)* [1]	**46.65**	50.72	**47.77**	46.74

[1] Amounts may not calculate due to rounding.

(4) **Nuclear Total Generating Cost per MWh** is used to measure the cost performance of OPG's nuclear generating assets. Nuclear TGC per MWh is defined as OM&A expenses of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the nuclear electricity generation business), nuclear fuel expense for OPG-operated stations (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs) incurred during the period, divided by nuclear electricity generation for the period.

(millions of dollars – except where noted) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Nuclear TGC				
Regulated – Nuclear Generation OM&A expenses	**511**	521	**1,693**	1,665
Regulated – Nuclear Generation fuel expense	**81**	79	**217**	239
Regulated – Nuclear Generation capital expenditures	**409**	339	**1,150**	896
Less: Darlington Refurbishment capital and OM&A costs	**(328)**	(269)	**(943)**	(717)
Add: Regulated – Nuclear Generation OM&A and fuel expenses deferred in regulatory variance and deferral accounts	**5**	31	**6**	84
Less: Nuclear fuel expense for non OPG-operated stations	**(13)**	(18)	**(42)**	(50)
Less: Regulated - Nuclear Generation OM&A expenses ancillary to nuclear electricity generation business	**(1)**	(1)	**(3)**	(4)
Other adjustments	**1**	3	**(1)**	(1)
	665	685	**2,077**	2,112
Nuclear electricity generation (TWh)	**11.3**	11.7	**30.6**	34.6
Nuclear TGC per MWh (*$/MWh*) [1]	**58.75**	58.55	**67.87**	61.07

[1] Amounts may not calculate due to rounding.

(5) **Hydroelectric Total Generating Cost per MWh** is used to measure the cost performance of OPG's hydroelectric generating assets. Hydroelectric TGC per MWh is defined as OM&A expenses of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the hydroelectric electricity generation business), hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding expenditures related to the Peter Sutherland Sr. GS, Ranney Falls GS, and other hydroelectric generation development projects) incurred during the period, divided by total hydroelectric electricity generation plus hydroelectric electricity generation forgone due to SBG conditions during the period. OPG reports hydroelectric gross revenue charge and water rental payments as fuel expense.

(millions of dollars – except where noted) (unaudited)	**Three Months Ended September 30**		**Nine Months Ended September 30**	
	2017	**2016**	**2017**	**2016**
Hydroelectric TGC				
Regulated – Hydroelectric OM&A expenses	**81**	87	**232**	238
Regulated – Hydroelectric fuel expense	**88**	88	**258**	259
Contracted Generation Portfolio OM&A expenses	**39**	44	**118**	129
Contracted Generation Portfolio fuel expense	**15**	19	**42**	42
Regulated – Hydroelectric and Contracted Generation Portfolio capital expenditures	**56**	92	**141**	231
Less: Regulated – Hydroelectric and Contracted Generation Portfolio generation development project capital and OM&A costs	**(17)**	(41)	**(52)**	(117)
Less: Thermal OM&A and fuel expenses and capital expenditures in the Contracted Generation Portfolio	**(39)**	(51)	**(119)**	(126)
(Less) Add: Regulated – Hydroelectric OM&A and fuel expenses refundable through regulatory variance and deferral accounts	**(1)**	4	**(25)**	(8)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**13**	5	**47**	38
Other adjustments	**(1)**	(1)	**-**	(1)
	234	246	**642**	685
Adjusted hydroelectric electricity generation *(TWh)*				
Regulated – Hydroelectric electricity generation	**7.3**	6.9	**23.5**	22.8
Contracted Generation Portfolio electricity generation	**0.8**	0.9	**1.9**	2.5
Adjust for hydroelectric electricity generation forgone due to SBG conditions and non-hydroelectric electricity generation of the Contracted Generation Portfolio, including OPG's share of electricity generation from co-owned facilities	**0.8**	0.1	**4.1**	3.4
	8.9	7.9	**29.5**	28.7
Hydroelectric TGC per MWh *($/MWh)* [1]	**26.20**	31.01	**21.74**	23.99

[1] Amounts may not calculate due to rounding.

(6) **Gross margin** is defined as revenue less fuel expense.

For further information, please contact: Investor Relations 416-592-6700

webmaster@opg.com

Media Relations 416-592-4008

1-877-592-4008

www.opg.com
www.sedar.com

From: Ronald Kwan
To: John Kim
Subject: RE: EXTERNAL – RE: OPG Q3 2017 Submission to Province
Date: Monday, November 06, 2017 7:39:13 PM

Thanks John.

Ron

From: John Kim
Sent: November-06-17 19:35
To: 'HO Philip -FIN & C CTRL' <philip.ho@opg.com>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Subject: RE: EXTERNAL – RE: OPG Q3 2017 Submission to Province

Hi Philip,

We have gone through again and some additional comment boxes and edits.

Thanks,

John

From: HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
Sent: Monday, November 06, 2017 6:19 PM
To: John Kim <John.Kim@ofina.on.ca>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
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Please see our responses to your comments. Let us know if you have any others. Thank you.

Regards,

Philip

Philip Ho, CPA, CA | Senior Manager, External Reporting & Accounting Policy | Ontario Power Generation
700 University Avenue, Toronto ON M5G 1X6 | Phone: (416) 592-3320| E-mail: philip.ho@opg.com

From: John Kim [mailto:John.Kim@ofina.on.ca]
Sent: Monday, October 30, 2017 6:16 PM
To: HO Philip -FIN & C CTRL <philip.ho@opg.com>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
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See attached with our comments on the MD&A.

These are staff level comments as Ron has not had a chance to review.

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John

From: HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
Sent: Wednesday, October 25, 2017 12:22 PM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>; 'Montgomery, Kaitlin (MOF)' <Kaitlin.Montgomery@ontario.ca>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>
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We would greatly appreciate comments on the above **no later than Monday, Oct 30th**.

These documents will be filed with the Ontario Securities Commission on **Thursday, November 9th** following OPG's Board of Directors meeting.

Kindly forward all comments directly to Philip Ho – philip.ho@opg.com.

To assist the review process, the following are the key items in the Q3 2017 MD&A:

Highlights

Recent Developments	MD&A p.10-11
Darlington Refurbishment	MD&A p.13-15
Ontario's Fair Hydro Plan	MD&A p.10-11

Philip Ho, CPA, CA | Senior Manager, External Reporting & Accounting Policy | Ontario Power Generation
700 University Avenue, Toronto ON M5G 1X6 | Phone: (416) 592-3320| E-mail: philip.ho@opg.com

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From:	John Kim
To:	"HO Philip -FIN & C CTRL"
Cc:	MAK Ricky -FIN & C CTRL; DYKXHOORN Sandra -STAKEREL; GORE Michael -FIN & C CTRL; Ronald Kwan
Subject:	RE: EXTERNAL – RE: OPG Q3 2017 Submission to Province
Date:	Monday, November 06, 2017 7:35:15 PM
Attachments:	Q3 2017 OPG MDA - DRAFT - PROVINCE MAILING_EFB_CommentsV4_addressed by OPG_Markup.docx

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700 University Avenue, Toronto ON M5G 1X6 | Phone: (416) 592-3320| E-mail: philip.ho@opg.com

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ONTARIO POWER GENERATION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

2017 THIRD QUARTER REPORT

[DRAFT]

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ONTARIO POWER GENERATION

ONTARIO POWER GENERATION INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) should be read in conjunction with the unaudited interim consolidated financial statements and accompanying notes of Ontario Power Generation Inc. (OPG or Company) as at and for the three and nine months ended September 30, 2017. OPG's unaudited interim consolidated financial statements are prepared in accordance with United States generally accepted accounting principles (US GAAP) and are presented in Canadian dollars.

For a complete description of OPG's corporate strategies, risk management, corporate governance, and the effect of critical accounting policies and estimates on OPG's results of operations and financial condition, this MD&A should also be read in conjunction with OPG's audited consolidated financial statements, accompanying notes, the Annual Information Form, and the MD&A as at and for the year ended December 31, 2016.

As required by *Ontario Regulation 395/11*, as amended, a regulation under the *Financial Administration Act* (Ontario), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. In 2014, the Ontario Securities Commission approved an exemption which allows OPG to apply US GAAP up to January 1, 2019. The term of the exemption is subject to certain conditions, which may result in the expiry of the exemption prior to January 1, 2019. For details, refer to the section, *Critical Accounting Policies and Estimates* under the heading, *Exemptive Relief for Reporting under US GAAP,* in OPG's 2016 annual MD&A. This MD&A is dated November 9, 2017.

FORWARD-LOOKING STATEMENTS

The MD&A contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could", and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

All forward-looking statements involve inherent assumptions, risks, and uncertainties, including those set out in the section, *Risk Management,* and forecasts discussed in the section, *Core Business, Strategy, and Outlook.* All forward-looking statements could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's generating station performance and availability, fuel costs, surplus baseload generation (SBG), cost of fixed asset removal and nuclear waste management, performance and earnings of investment funds, refurbishment of existing facilities, development and construction of new facilities, pension and other post-employment benefit (OPEB) obligations and funds, income taxes, proposed new legislation, the ongoing evolution of Ontario's electricity industry, environmental and other regulatory requirements, health, safety and environmental developments, business continuity events, the weather, financing and liquidity, applications to the Ontario Energy Board (OEB) for regulatory prices, the impact of regulatory decisions by the OEB, and forecasts of earnings, cash flows, Funds from Operations (FFO) Adjusted Interest Coverage, Return on Common Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI), Total Generating Cost (TGC) and capital expenditures. Accordingly, undue reliance should not be placed on any forward-looking statement. The forward-looking statements included in this MD&A are made only as of the date of this MD&A. Except as required by applicable securities laws, OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events, or otherwise.

THE COMPANY

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG was established under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (Province or Shareholder).

As at September 30, 2017, OPG's electricity generation portfolio had an in-service capacity of 16,210 megawatts (MW). OPG operates two nuclear generating stations, 66 hydroelectric generating stations, three thermal generating stations, and one wind power turbine. In addition, OPG and TransCanada Energy Ltd. co-own the 550 MW Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS). OPG and ATCO Power Canada Ltd. co-own the 560 MW Brighton Beach gas-fired combined cycle GS (Brighton Beach). OPG's 50 percent share of the in-service capacity and generation volume of these co-owned facilities is included in the generation portfolio statistics set out in this report. The income from the co-owned facilities is accounted for using the equity method of accounting, and OPG's share of income is presented as income from investments subject to significant influence in the Contracted Generation Portfolio segment.

OPG also owns two other nuclear generating stations, the Bruce A GS and the Bruce B GS, which are leased on a long-term basis to Bruce Power LP (Bruce Power). Income from these leased stations is included in revenue under the Regulated – Nuclear Generation segment. The leased stations are not included in the generation portfolio statistics set out in this report.

All of OPG's owned and co-owned generating facilities are located in Ontario. OPG does not operate PEC, Brighton Beach, the Bruce A GS and the Bruce B GS.

A description of OPG's segments is provided in OPG's 2016 annual MD&A in the section, *Business Segments*.

In-Service Generating Capacity

OPG's in-service generating capacity by business segment as at September 30, 2017 and December 31, 2016 was as follows:

	As at	
(MW)	**September 30 2017**	**December 31 2016**
Regulated – Nuclear Generation [1]	**5,728**	5,728
Regulated – Hydroelectric	**6,426**	6,421
Contracted Generation Portfolio [2]	**4,056**	4,028
Total	**16,210**	16,177

[1] The in-service generating capacity as of September 30, 2017 and December 31, 2016 excludes Unit 2 of the Darlington GS. The unit, which has a generating capacity of 878 MW, was taken offline in mid-October 2016 and is currently undergoing refurbishment.

[2] Includes OPG's share of in-service generating capacity of 275 MW for PEC and 280 MW for Brighton Beach.

During the nine months ended September 30, 2017, the total in-service capacity increased by 33 MW. The increase was primarily due to the completion of the Peter Sutherland Sr. hydroelectric GS, which was placed in-service at the end of the first quarter of 2017, and the upgrade of Unit 10 of the Sir Adam Beck 1 hydroelectric GS, which was completed in June 2017.

HIGHLIGHTS

Overview of Results

This section provides an overview of OPG's unaudited interim consolidated operating results. Significant factors which contributed to OPG's results during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, are discussed below.

(millions of dollars – except where noted) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Revenue	**1,217**	1,400	**3,539**	4,265
Fuel expense	**185**	187	**518**	541
Gross margin	**1,032**	1,213	**3,021**	3,724
Operations, maintenance and administration	**635**	666	**2,054**	2,061
Depreciation and amortization	**178**	313	**517**	941
Accretion on fixed asset removal and nuclear waste management liabilities	**235**	232	**709**	696
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(196)**	(248)	**(579)**	(620)
Income from investments subject to significant influence	**(11)**	(11)	**(29)**	(28)
Property taxes	**8**	12	**30**	35
	849	964	**2,702**	3,085
Income before other losses (gains), interest and income taxes	**183**	249	**319**	639
Other losses (gains)	**3**	1	**(380)**	(23)
Income before interest and income taxes	**180**	248	**699**	662
Net interest expense	**21**	28	**56**	92
Income before income taxes	**159**	220	**643**	570
Income tax expense	**19**	22	**128**	109
Net income	**140**	198	**515**	461
Net income attributable to the Shareholder	**131**	194	**498**	449
Net income attributable to non-controlling interest [1]	**9**	4	**17**	12
Electricity production (TWh) [2]	**19.4**	19.5	**56.0**	59.9
Cash flow provided by operating activities	**485**	530	**698**	1,211

[1] Relates to the 25 percent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in the Lower Mattagami Limited Partnership, the 33 percent interest of Coral Rapids Power Corporation, a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership, and the 10 percent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP.

[2] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

Third Quarter

Net income attributable to the Shareholder was $131 million for the third quarter of 2017, a decrease of $63 million compared to the same quarter in 2016. Income before interest and income taxes for the third quarter of 2017 was $180 million, a decrease of $68 million compared to the same quarter in 2016.

Commented [A1]:
Wondering if this should be 437?
Since:
Q3 9-mos ended – Q2 6-mos ended = 698-261 = 437

Was Q2 "6-month ended June 30" number for Cash flow provided by operating activities revised?

OPG: In Q3 2017, adjustments for non-cash balances related to Darlington Refurbishment capital expenditures have been reclassified from the "Net changes in non-cash working capital balances" line to the "Investment in property, plant and equipment and intangible assets" line. Comparative amounts have been reclassified accordingly.

Significant factors that reduced income before interest and income taxes:

- Lower earnings from the nuclear base regulated price of approximately $24 million reflecting lower electricity generation of 0.4 terawatt hours (TWh) from the Regulated – Nuclear Generation segment and the continuation of existing base regulated prices set by the OEB in 2014. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS since October 2016, largely offset by an increase in generation from Pickering GS. The increase in generation from the Pickering GS was primarily due to outage optimization, favourable unit conditions and execution of planned outage work. The base regulated prices set in 2014 continue to be in effect pending the OEB's decision on OPG's current application for new regulated prices, expected later in 2017. **[MONITOR]** The existing nuclear base regulated price was set to allow the Company to recover its approved nuclear costs over a higher nuclear production volume, based on the 2014 and 2015 outage profile that did not include a refurbishment outage. OPG has requested January 1, 2017 as the effective date of the new regulated prices.
- Lower earnings on the nuclear fixed asset removal and nuclear waste management funds (Nuclear Segregated Funds) of $52 million.
- Higher depreciation and amortization expense of $16 million in the Regulated – Nuclear Generation segment, excluding amortization expense related to balances in OEB-authorized regulatory variance and deferral accounts (regulatory accounts), primarily due to new assets in service.

The expiry of rate riders for the recovery of approved balances in OEB-authorized regulatory accounts on December 31, 2016 contributed to the decrease in revenue for the three months ended September 30, 2017, compared to the same period in 2016, but was largely offset by a decrease in the amortization expense related to these balances. OPG has requested new rate riders in its current application to the OEB for new regulated prices, with a proposed effective date of January 1, 2017.

Significant factor that increased income before interest and income taxes:

- Lower operations, maintenance and administration (OM&A) expenses of $31 million, mainly in the Regulated – Nuclear Generation segment, as a result of a higher materials and supplies obsolescence charge recognized in the third quarter of 2016, Services, Trading and Other Non-Generation segment due to project expenditures incurred in the third quarter of 2016, and Regulated – Hydroelectric segment due to the timing of repairs and maintenance work in 2017 and a deferral of outages during the high water period.

Net interest expense decreased by $7 million during the third quarter of 2017, compared to the same quarter in 2016, primarily due to a higher amount of interest costs capitalized for the Darlington Refurbishment project expenditures and a higher amount of interest costs deferred in OEB-authorized regulatory accounts.

Income tax expense for the three months ended September 30, 2017 was $19 million, compared to $22 million for the same period in 2016. The decrease in income tax expense was primarily due to lower income before taxes and a higher change in reserves from the resolution of uncertainties, partially offset by a lower amount of tax expense deferred in regulatory assets.

Year-To-Date

Net income attributable to the Shareholder was $498 million for the first nine months of 2017, an increase of $49 million compared to the same period in 2016. Income before interest and income taxes for the first nine months of 2017 was $699 million, an increase of $37 million compared to the same period in 2016.

Significant factor that increased income before interest and income taxes:

- Higher earnings of $390 million from the Services, Trading, and Other Non-Generation segment, primarily reflecting the gain on sale of OPG's head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street that was recognized in the second quarter of 2017. The sale of the

Commented [A2]: If approved by OEB (during Q4), would this result in a higher regulated price and a revenue/net income pick up for 2017 reported in OPG's Q4?

OPG – It depends on the effective date of the decision on the base regulated prices. If the OEB decision on the new base regulated prices are retrospectively effective as of Jan 1, 2017 for example, then it should result in a higher revenue/net income pick up for 2017 assuming the new regulated prices are higher.

assets was required by a Shareholder Declaration and a Shareholder Resolution. The gain on sale was $283 million, which is net of tax effects of $95 million.

Significant factors that reduced income before interest and income taxes:

- Lower earnings from the nuclear base regulated price of approximately $230 million, partially offset by a decrease in nuclear fuel expense of $22 million, reflecting lower electricity generation of 4.0 TWh from the Regulated – Nuclear Generation segment and the continuation of existing base regulated prices set by the OEB in 2014. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS, partially offset by an increase in generation from Pickering GS.
- Lower earnings on the Nuclear Segregated Funds of $41 million.
- Higher depreciation and amortization expense of $30 million in the Regulated – Nuclear Generation segment, excluding amortization expense related to regulatory account balances, primarily due to new assets in service.
- A gain of $22 million recorded in the first quarter of 2016 to reflect the OEB's decision on OPG's motion asking the OEB to review and vary parts of its November 2014 decision on OPG's regulated prices.

The expiry of rate riders for the recovery of approved balances in OEB-authorized regulatory accounts on December 31, 2016 contributed to the decrease in revenue for the nine months ended September 30, 2017, compared to the same period in 2016, but was primarily offset by a decrease in the amortization expense related to these balances.

Net interest expense decreased by $36 million for the nine months ended September 30, 2017, compared to the same period in 2016, primarily due to a higher amount of interest costs capitalized for the Darlington Refurbishment project expenditures and a higher amount of interest costs deferred in OEB-authorized regulatory accounts.

Commented [A3]: Does this imply there were interest costs related to Darlington Refurb previously (same quarter previous year), that were not capitalized, but were able to be capitalized this year?

OPG – There were higher Darlington Refurb project expenditures in 2017, compared to 2016.

Income tax expense for the nine months ended September 30, 2017 was $128 million, compared to $109 million for the same period in 2016. The increase in income tax expense was primarily due to higher income before income taxes.

Segment Results

The following table summarizes OPG's income before interest and income taxes by business segment. A detailed discussion of OPG's performance by reportable segment is included in the section, *Discussion of Operating Results by Business Segment*.

(millions of dollars)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Income (loss) before interest and income taxes				
Regulated – Nuclear Generation	**20**	47	**(267)**	17
Regulated – Hydroelectric	**122**	117	**474**	500
Contracted Generation Portfolio	**75**	74	**229**	219
Total electricity generation business segments	**217**	238	**436**	736
Regulated – Nuclear Waste Management	**(36)**	18	**(123)**	(70)
Services, Trading, and Other Non-Generation	**(1)**	(8)	**386**	(4)
	180	248	**699**	662

Electricity Generation

Electricity generation for the three and nine month periods ended September 30, 2017 and 2016 was as follows:

(TWh)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Regulated – Nuclear Generation	**11.3**	11.7	**30.6**	34.6
Regulated – Hydroelectric	**7.3**	6.9	**23.5**	22.8
Contracted Generation Portfolio [1]	**0.8**	0.9	**1.9**	2.5
Total OPG electricity generation	**19.4**	19.5	**56.0**	59.9
Total electricity generation by all other generators in Ontario [2]	**16.6**	19.5	**51.7**	53.8

[1] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.
[2] Non-OPG generation is calculated as the Ontario electricity demand plus net exports, as published by the Independent Electricity System Operator (IESO), minus OPG electricity generation.

Total OPG electricity generation decreased by 0.1 TWh during the third quarter of 2017, compared to the same quarter in 2016, and by 3.9 TWh during the nine months ended September 30, 2017, compared to the same period in 2016. As expected, the lower electricity generation from the Regulated – Nuclear Generation segment was primarily the result of the removal from service of Unit 2 at the Darlington GS for the duration of the unit's refurbishment, which began in October 2016. This decrease in electricity generation was largely offset by an increase in generation from the Pickering GS, primarily due to outage optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station, and higher hydroelectric generation from the Regulated – Hydroelectric segment.

The higher electricity generation of 0.4 TWh and 0.7 TWh from the Regulated – Hydroelectric segment for the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016, was due to higher water flows primarily on the eastern Ontario river systems, net of water spilled as a result of SBG conditions, discussed below.

The lower electricity generation of 0.6 TWh from the Contracted Generation Portfolio segment for the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to higher SBG conditions. The electricity generation from the Contracted Generation Portfolio segment for the three months ended September 30, 2017 was comparable to the same period in 2016.

OPG's operating results are impacted by changes in grid-supplied electricity demand resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. For the three and nine month periods ended September 30, 2017, Ontario's electricity demand as reported by the IESO was 33.6 TWh and 98.5 TWh, respectively, compared to 36.7 TWh and 103.8 TWh for the same periods in 2016, respectively, excluding electricity exports out of the province.

Power that is surplus to the Ontario market is managed by the IESO, mainly through generation reductions at hydroelectric, other grid-connected renewable resources and nuclear stations. Reducing hydroelectric production is the first measure used by the IESO to manage SBG conditions. Low demand conditions in Ontario continued to be prevalent in 2017, resulting in forgone hydroelectric generation for OPG of 1.1 TWh and 4.5 TWh due to SBG conditions in the three and nine month periods ended September 30, 2017, respectively, compared to 0.5 TWh and 3.9 TWh during the same periods in 2016, respectively. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions during these periods was offset by the impact of a regulatory variance account authorized by the OEB. OPG did not forgo any electricity production at its nuclear stations due to SBG conditions.

Average Sales Prices

The majority of OPG's generation is from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments. The same base regulated prices for electricity generated by these segments, authorized by the OEB effective November 1, 2014, were in effect during the first nine months of 2017 as in 2016. These prices will remain in effect until such time as the OEB approves new regulated prices based on OPG's current application. **[MONITOR]** The base regulated prices established in 2014 are discussed in OPG's 2016 annual MD&A in the section, *Revenue Mechanisms for Regulated and Non-Regulated Generation*.

The average sales price for the Regulated – Nuclear Generation segment was 5.8 cents per kilowatt hour (¢/kWh) during the three and nine month periods ended September 30, 2017, respectively, compared to 6.9 ¢/kWh during the same periods in 2016. The decrease in the average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized nuclear rate rider of $10.84 per megawatt hour (MWh) for the recovery of variance and deferral account balances. The average sales price for the Regulated – Hydroelectric segment was 4.1 ¢/kWh during the three and nine month periods ended September 30, 2017, respectively, compared to 4.4 ¢/kWh during the same periods in 2016. The decrease in the average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized regulated hydroelectric rate rider of $3.19/MWh for the recovery of variance and deferral account balances. The rate riders were established to recover approved balances recorded in the variance and deferral accounts in prior years. As such, the year-over-year changes in revenue from the rate riders were largely offset by changes in amortization expense related to these balances. There were no rate riders in effect during the nine months ended September 30, 2017 for either nuclear or regulated hydroelectric generation, pending the outcome of OPG's current application with the OEB for new regulated prices.

Cash Flow from Operations

Cash flow provided by operating activities was $485 million for the three months ended September 30, 2017 and $698 million for the nine months ended September 30, 2017, compared to $530 million and $1,211 million for the same periods in 2016, respectively. The decrease in cash flow provided by operating activities was expected and primarily due to lower generation revenue receipts reflecting lower generation from the Regulated – Nuclear Generation segment as a result of the ongoing refurbishment of Unit 2 at the Darlington GS and the expiry, on December 31, 2016, of the OEB-authorized rate riders for nuclear and regulated hydroelectric generation. The decrease in cash flow during the nine months ended September 30, 2017 was also due to higher income tax instalments.

The decrease in cash flow provided by operating activities for the three and nine month periods ended September 30, 2017 was partly offset by lower OM&A expenditures and lower contributions to the Used Fuel Segregated Fund in 2017. Both the Used Fuel Segregated Fund and the Decommissioning Segregated Fund were determined to be fully funded based on an updated estimate of OPG's nuclear waste management and nuclear facilities decommissioning obligations pursuant to a reference plan approved by the Province ~~for years 2017 to 2021,~~ under the Ontario Nuclear Funds Agreement (ONFA), effective January 1, 2017. Pursuant to the ONFA, the reference plan is required to be updated at least once every five years. Contributions to either or both of the Nuclear Segregated Funds may be required in the future should the funds be in an underfunded position at the time of the next ONFA reference plan update. The year-over-year decrease in cash flow also was partially offset by the payment of a supplemental rent rebate to Bruce Power in the first quarter of 2016 in relation to a period in 2015. The lease agreement for the Bruce nuclear generating stations was amended in late 2015 to eliminate this rebate provision going forward.

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Return on Common Equity Excluding Accumulated Other Comprehensive Income

ROE Excluding AOCI is an indicator of OPG's performance consistent with the Company's strategy to provide value to the Shareholder. ROE Excluding AOCI is measured over a 12-month period.

ROE Excluding AOCI was 4.4 percent for the 12 months ended September 30, 2017, compared to 4.2 percent for the 12 months ended December 31, 2016. The increase was primarily due to higher net income attributable to the Shareholder for the 12 months ended September 30, 2017, which reflected the gain on sale of OPG's head office premises and associated parking facility recorded in the second quarter of 2017, partially offset by the lower earnings from the decrease in nuclear electricity generation reflecting the Unit 2 refurbishment outage at the Darlington GS without a corresponding increase in the nuclear base regulated price, as expected. The lower nuclear generation as a result of the refurbishment outage will continue to negatively affect OPG's ROE Excluding AOCI until such time as new regulated prices are approved by the OEB, anticipated in the fourth quarter of 2017. **[MONITOR]**

Funds from Operations Adjusted Interest Coverage

FFO Adjusted Interest Coverage is an indicator of OPG's ability to meet interest obligations from operating cash flows. The indicator is measured over a 12-month period. FFO Adjusted Interest Coverage for the 12 months ended September 30, 2017 was 4.2 times, compared to 5.1 times for the 12 months ended December 31, 2016. FFO Adjusted Interest Coverage in 2017 reflected a year-over-year decrease in FFO before interest due to lower cash flow provided by operating activities, partially offset by the impact of a lower adjusted interest expense due to a decrease in the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets.

The decrease in the excess of interest on pension and OPEB benefit obligations over expected return on pension plan assets in the nine months of 2017 was primarily due to the change in the method used to estimate the interest cost and service cost components of pension and OPEB costs. Effective January 1, 2017, OPG adopted a full yield curve approach to the estimation of these cost components, by applying the specific spot rates along the yield curve used in the determination of the projected benefit obligations to the relevant projected cash flows. Under the previous method, these components of pension and OPEB costs were calculated using the same single weighted-average discount rates as reflected in the calculation of the benefit obligations. This change in the method was accounted for prospectively, as a change in estimate. The resulting reduction in pension and OPEB costs for the three and nine month periods ended September 30, 2017 did not have a material impact on net income as it was largely offset by the impact of OEB-authorized variance and deferral accounts in the regulated business segments. Further details on the full yield curve approach can be found in the 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Pension and Other Post-Employment Benefits*.

Commented [A4]: Does this have any implications for the methodology used for the IFRS adjustments for the purposes of the Province's Public Accounts?

Enterprise Total Generating Cost per MWh

The Enterprise TGC per MWh decreased to $46.65 for the three months ended September 30, 2017, compared to $50.72 for the same quarter in 2016. The decrease was mainly due to lower OM&A expenses before the impact of regulatory accounts and higher SBG-adjusted hydroelectric generation reflecting higher water flows.

The Enterprise TGC per MWh was $47.77 for the nine months ended September 30, 2017, an increase compared to $46.74 for the same period in 2016. The increase was expected and mainly a result of lower electricity generation due to the Unit 2 refurbishment outage at the Darlington GS, largely offset by lower OM&A expenses before the impact of regulatory accounts and higher SBG-adjusted hydroelectric generation reflecting higher water flows.

If Unit 2 at the Darlington GS was not currently undergoing refurbishment and had continued to operate in a manner consistent with the performance of the remaining units at the Darlington GS, adjusting for generation constraints on these units related to the transition of the station toward refurbishment, the Enterprise TGC would have been approximately $4 per MWh lower for both the three and nine month periods ended September 30, 2017. This sensitivity was calculated using the estimated incremental electricity and associated fuel cost that are expected to have resulted in the absence of the refurbishment.

Nuclear Total Generating Cost per MWh

The Nuclear TGC per MWh was $58.75 for the three months ended September 30, 2017, which was comparable to $58.55 for the same quarter in 2016. For the three months ended September 30, 2017, the higher generation at the Pickering GS and the impact of lower OM&A expenses before the impact of regulatory accounts was mostly offset by the expected decrease in nuclear electricity generation reflecting the Unit 2 refurbishment outage at the Darlington GS and higher sustaining capital expenditures. The Nuclear TGC per MWh was $67.87 for the nine months ended September 30, 2017, compared to $61.07 for the same period in 2016. The increase in the Nuclear TGC per MWh for the nine months ended September 30, 2017 was expected and primarily due to the decrease in nuclear electricity generation, partially offset by lower OM&A expenses before the impact of regulatory accounts.

Hydroelectric Total Generating Cost per MWh

The Hydroelectric TGC per MWh was $26.20 for the three months ended September 30, 2017, compared to $31.01 for the same quarter in 2016. The decrease was primarily due to higher SBG-adjusted hydroelectric electricity generation reflecting higher water flows. The Hydroelectric TGC per MWh was $21.74 for the nine months ended September 30, 2017, compared to $23.99 for the same period in 2016. The decrease was primarily due to lower OM&A expenses before the impact of regulatory accounts and lower sustaining capital expenditures.

ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are not measurements in accordance with US GAAP and should not be considered alternative measures to net income, cash flow provided by operating activities, or any other performance measure under US GAAP. OPG believes that these non-GAAP financial measures are effective indicators of its performance and are consistent with the Company's strategic imperatives and related objectives. The definition and calculation of ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are found in the section, *Supplementary Non-GAAP Financial Measures*.

Recent Developments

Ontario's 2017 Long Term Energy Plan

On October 26, 2017, Ontario's Ministry of Energy issued the 2017 Long Term Energy Plan. The Plan is currently being analyzed by OPG but is not expected to significantly impact OPG's business. There are no fundamental changes from the principles in the 2013 Long Term Energy Plan, which include cost effectiveness, reliability, clean energy and community engagement. The 2017 Long Term Energy Plan fully supports nuclear refurbishment projects in Ontario and the extension of commercial operation of all Pickering units to 2024. **[MONITOR & UPDATE DETAILS FOLLOWING RELEASE]**

OEB's Decision on New Regulated Prices **[MONITOR]**

Ontario's Fair Hydro Plan

OPG continues to prepare for its involvement as the Financial Services Manager for Ontario's Fair Hydro Plan (the Fair Hydro Plan) on a commercial basis. Accordingly, the financing entity was established in XX 2017 as the Fair Hydro Trust (the Trust), following the execution of its constating documents. The majority unitholder and beneficiary of the Trust is a wholly-owned subsidiary of OPG. Through this ownership and OPG's control over the key activities of the Trust, the Company will consolidate the Trust for accounting purposes commencing in the fourth quarter of 2017. **[MONITOR]**

In order for the Trust to provide financing for the deferred Global Adjustment costs, the Trust will incur senior debt from capital markets and subordinated debt from OPG. The Trust is structured to be bankruptcy remote and ring fenced from OPG to protect the Company's assets and operations. In support of the Fair Hydro Plan, the following developments have transpired:

Commented [A5]: Why not rephrase as acquiring the investment asset related to the deferred GA costs (right to future recovery)?

- In October 2017, *Ontario Regulation 206/17 General* was amended to establish details of the recovery mechanism for the monthly carrying costs incurred by the Trust from June 1, 2017 to July 31, 2021 payable by the IESO to the Trust. Originally established in June 2017, this regulation provides more details on the funding obligations incurred by the Trust and the fair allocation amount, the determination and collection of clean energy adjustments, the determination of the finance amount, the true up amount, and the regulatory asset, as well as principles and assumptions relating to the financing plan.
- A plan to amend the Company's Articles of Amalgamation to allow for the creation and issuance of Class A shares to be issued to the Province for its equity investment through OPG in the Fair Hydro Plan is in progress. The Province is expected to provide 44 percent of the total funding requirement related to the deferred Global Adjustment costs, which OPG will invest as subordinated debt into the Trust. OPG's Board approval and a Shareholder Resolution are expected later in the year to authorize the amendment.
- OPG is expected to provide five percent of the total funding requirement of the Trust related to the deferred Global Adjustment costs of the Fair Hydro Plan. OPG issued senior notes payable in October 2017 under a short form base shelf prospectus for general corporate purposes and to fund OPG's subordinated debt investment in the Trust. Further details of the debt offering can be found in the section, *Liquidity and Capital Resources* under the heading, *Financing Activities*.

Commented [A6]: Are any other details available to be released at this time?

OPG – Not for Q3 2017 reporting.

The first set of transactions of the Trust are expected to take place in the fourth quarter of 2017.

Canadian Nuclear Safety Commission Safety Rating for the Darlington GS and the Pickering GS

The Canadian Nuclear Safety Commission (CNSC) publishes an annual report on the safety performance of Canada's nuclear power plants. The report assesses how well plant operators are meeting regulatory requirements and program expectations in the areas of operational performance, safety analysis, radiation protection, waste management and conventional health and safety. On September 8, 2017, the CNSC issued an executive summary of its 2016 annual report. The CNSC gave both the Darlington GS and the Pickering GS the highest possible safety rating of "Fully Satisfactory". The Darlington GS achieved this rating for the eighth consecutive year, while the Pickering GS achieved this rating for the second consecutive year.

CORE BUSINESS, STRATEGY, AND OUTLOOK

The discussion in this section is qualified in its entirety by the cautionary statements included in the section, *Forward-Looking Statements,* at the beginning of the MD&A.

OPG's mission is to provide low cost power in a safe, clean, reliable and sustainable manner for the benefit of customers and its Shareholder. OPG also seeks to pursue, on a commercial basis, generation development projects and other business growth opportunities.

The following sections provide an update to OPG's disclosures in the 2016 annual MD&A related to its four key strategic imperatives – operational excellence, project excellence, financial strength, and social licence. A detailed discussion of these strategic imperatives is included in the 2016 annual MD&A in the section, *Core Business, Strategy, and Outlook*.

Operational Excellence

Operational excellence at OPG is accomplished by the safe and environmentally responsible generation of reliable and cost-effective electricity from the Company's generating assets through a highly trained and engaged workforce.

Electricity Generation Production and Reliability

- As part of the plan to extend Pickering operations, OPG is continuing to undertake the required technical work to confirm that the station's pressure tubes, a key life-limiting component of the station, will remain fit for service for operation to 2024. OPG is also nearing completion of component condition assessments to identify the work required to support the continued operation of the station. The accounting end of life assumptions for the Pickering GS, currently set at the end of 2020, will be reassessed based on the fuel channel analysis and safety case consistent with submissions for the CNSC approval, discussed below. The activities completed to date have had positive results, which will go towards re-confirming Pickering operations past 2020 are technically feasible. The Periodic Safety Review (PSR) is in progress and will confirm that extending operations of the Pickering units will be safe to the public, workers and the environment. The PSR consists of Safety Factor Reports (SFRs), a Global Assessment Report (GAR), and the Integration Improvement Plan (IIP). SFRs have been submitted to the CNSC and the GAR and IIP are on track for CNSC submission in October and November 2017, respectively. Other technical feasibility activities continue to progress as planned. Completion of various technical feasibility assessments are required to reach a high confidence conclusion to allow the station end of life to change for depreciation purposes. OPG's current application with the OEB for new base regulated prices, currently pending the OEB's decision, reflects OPG's plans to extend Pickering operations to 2024 and requests inclusion of the corresponding cost and generation impacts in the determination of the nuclear regulated price.
- OPG's current five-year operating licence for the Pickering GS was approved by the CNSC in 2013 and expires on August 31, 2018. This licence was issued assuming that the station would shut down in 2020. On June 28, 2017, OPG confirmed to the CNSC that it intends to cease commercial operation of all Pickering units on December 31, 2024. On August 28, 2017, OPG submitted a ten-year licence renewal application to the CNSC. The licence term spans the planned extended operations period, through to the end of commercial operation, defueling, dewatering and the start of placing the station in a safe storage state.
- Work continues on the rehabilitation of Unit 2 of the DeCew Falls hydroelectric GS and the rehabilitation and overhaul of Unit 2 of the Lower Notch hydroelectric GS.
- During the third quarter, a new control centre was opened at Saunders GS to merge its operations with Chenaux GS. The new control centre will overlook power production at ten hydroelectric stations along the Madawaska, Ottawa and St. Lawrence rivers.
- As part of the process to decommission the Nanticoke and Lambton generating stations, OPG has begun executing demolition plans that will ensure that the stations are closed safely, securely and in an environmentally responsible manner. The demolition of the Nanticoke coal yard equipment and structures is in progress, with a contract issued in July 2017 for the demolition of the Nanticoke powerhouse and associated structures. Project milestones for the Nanticoke site during the remainder of 2017 include completing the removal of coal yard equipment and structures, demolition of the ash silos, and mobilization of the contractor to prepare for removal of the stacks, powerhouse and associated structures. A competitive bidding process for the demolition of the Lambton GS has been completed, with a contract for the removal of the powerhouse and associated buildings expected to be awarded in 2018. An update of the associated asset retirement obligations related to the Nanticoke and Lambton sites is expected to be finalized in the fourth quarter of 2017.

Environmental Performance

There were no significant changes to environmental legislation affecting the Company during the third quarter of 2017. Disclosures related to the Company's environmental policy and environmental risks can be found in OPG's 2016 annual MD&A.

OPG communicates its environmental performance internally to employees and to external stakeholders, including the Ontario Ministry of the Environment and Climate Change, Environment and Climate Change Canada, the CNSC, and local communities. Details of OPG's environmental performance and initiatives to fulfill the Company's Environmental Policy can be found in OPG's 2016 Sustainability Report, available on the Company's website at www.opg.com. **[MONITOR]**

Project Excellence

OPG is pursuing a number of generation development and other major projects in support of Ontario's electricity planning initiatives. OPG remains focused on delivering projects safely, on time, on budget and with high quality. The status updates for OPG's major projects as at September 30, 2017 are outlined in the following table, with further details below.

Project	Capital expenditures		Approved budget	Expected in-service date	Current status
(millions of dollars)	**Year-to-date**	**Life-to-date**			
Darlington Refurbishment	924	4,109	12,800 [1]	First unit - 2020 Last unit - 2026	The setup of specialized tooling and equipment needed for the removal of reactor components was completed in the third quarter of 2017. All feeder tubes have been removed safely, and the pressure tubes have been severed in preparation for their removal. The Re-tube Waste Processing Building will be available for use in the fourth quarter of 2017. The project is tracking on schedule and on budget.
Peter Sutherland Sr. Hydroelectric GS	38	274	300	2017	The station was placed in-service on March 31, 2017, ahead of the originally planned schedule, and is expected to close below the approved budget. Project close-out activities are in progress.
Ranney Falls Hydroelectric GS	17	20	77	2019	Work is progressing on the expanded forebay, forebay wall concrete replacement, powerhouse and spillway areas. The project is tracking on schedule and on budget.
Nanticoke Solar Facility	1	2	107 **[MONITOR]**	2019	Project definition work is continuing, with construction planned to commence in the first quarter of 2018.
Deep Geologic Repository for low and intermediate level radioactive waste (L&ILW)	7 [2]	202 [2]			On August 21, 2017, the federal Minister of Environment and Climate Change requested further information on the project's environmental assessment (EA). OPG is reviewing the new request and will notify the Canadian Environmental Assessment Agency (CEAA) when it has a timeline for submission of that information.

[1] The total project budget of $12.8 billion is for the refurbishment of all four units at the Darlington GS.
[2] Expenditures are charged against the nuclear fixed asset removal and nuclear waste management liabilities (Nuclear Liabilities).

Commented [A7]: Does this imply that only 700M further is anticipated to be spent by the time Unit 2 gets completed? (Eg. 4.8B in Capital Expenditure)

Eg. from above:
"Once refurbished, Unit 2 is scheduled to be returned to service in the first quarter of 2020, at which time capital expenditures of approximately $4.8 billion are planned to be placed in service."

OPG – No, the LTD in the table includes prerequisite projects already declared in-service. The $4.8B was the OEB submitted estimate of a future in-service amount for Unit 2 refurbishment.

Please see updated wording below:

OPG's current application with the OEB for new regulated prices seeks an increase in the nuclear rate base, effective in the first quarter of 2020, to reflect the planned placement in service of the $4.8 billion in capital expenditures upon return to service of Unit 2, which includes expenditures incurred during the definition and planning phase of the project. Based on OPG's proposal in the application, the revenue requirement impact of the differences between the Unit 2 in-service amount included in the regulated prices and the actual amounts placed in service would be subject to true up via the Capacity Refurbishment Variance Account established by the OEB pursuant to *Ontario Regulation 53/05*. OPG's application proposes that the recovery of the HWSF's costs through regulated prices be subject to a separate prudence review by the OEB, to be conducted as part of a future OEB application.

Darlington Refurbishment

The Darlington generating units are approaching their originally designed end-of-life. Refurbishment of the four generating units is expected to extend the operating life of the station by approximately 30 years. OPG commenced the planning of the refurbishment in 2010.

In 2016, the Darlington Refurbishment project transitioned from the planning phase to the execution phase, as OPG commenced the refurbishment of the first unit, Unit 2, in October 2016, as planned. The unit was taken offline on October 15, 2016. De-fuelling of the reactor, the first critical refurbishment activity undertaken once the unit is removed from service, was completed safely in January 2017, with a total of 480 fuel channels de-fuelled. Islanding of Unit 2, the physical separation of the unit under refurbishment from the three operating units, was completed in April 2017, signifying the completion of the first major segment of the project.

The second major segment includes preparatory work to support the removal of feeder tubes and fuel channel assemblies and the removal of reactor components. The preparatory work was completed in the second quarter of 2017. The Re-tube Tooling Platform for hosting the tooling for the removal, inspection, and installation activities and the setup of specialized tooling and equipment needed for the removal and replacement of the reactor components were completed in the third quarter of 2017. The disassembly of reactor components commenced in August 2017, with the removal of all 960 feeder tubes completed safely in September 2017. This was followed by the severing of pressure tubes, with the severing of bellows and the removal of end fittings expected to commence thereafter and through the end of 2017. Other key project activities executed during the second segment include the completion of the primary side steam generator layup, installation of steam generator access ports to support future inspections, continuation of the major turbine generator overhaul and continued execution of the major electrical scope. OPG is also continuing to execute work to support the requirements set out in the CNSC approved IIP for the station.

Once refurbished, Unit 2 is scheduled to be returned to service in the first quarter of 2020, at which time capital expenditures of approximately $4.8 billion are planned to be placed in service. This includes expenditures incurred during the definition and planning phase of the overall project. The project is tracking on schedule and on budget.

With the substantial completion of the Re-tube Waste Processing Building in November 2017, 17 out of 18 pre-requisite projects in support of the execution phase of the project, including construction of facilities, infrastructure upgrades and installation of safety enhancements, have been completed and placed in service. Completion of the Heavy Water Storage and Drum Handling Facility (HWSF) has been delayed due to challenges with construction. OPG suspended the project in the second quarter of 2017 to evaluate the best approach to optimize cost and schedule and complete the project. Construction activities for the HWSF recommenced in the fourth quarter of 2017 following substantial completion of the Re-tube Waste Processing Building. This plan ensures that the necessary resources are available for both projects and, through resource levelling, improves their execution and cost efficiency. The delay in the completion of the HWSF will not impact the overall Darlington Refurbishment project schedule, as the HWSF is not on the project's critical path. This also will not impact the overall project budget of $12.8 billion, as the costs of the HWSF are included in this total figure. The recovery of HWSF costs through regulated prices will be subject to a prudence review by the OEB, which OPG has proposed be conducted as part of a future OEB application.

In addition to the execution of refurbishment activities on Unit 2, OPG is continuing planning activities for the refurbishment of the second unit, Unit 3, and is entering into associated commitments to procure major components that require long lead times. As of September 30, 2017, $70 million has been invested in planning activities related to the refurbishment of the second unit, Unit 3. These planning activities are being undertaken in accordance with the refurbishment project schedule.

The Financial Accountability Office of Ontario has issued a report titled "*An Assessment of the Financial Risks of the Nuclear Refurbishment Plan*". The report assesses both OPG and Bruce Power's refurbishment activities and the method in which those refurbishments and subsequent nuclear generation is provided to the marketplace. The report

concludes that the base case of refurbishing the six units at the Bruce nuclear GS and the four units at the Darlington nuclear GS provide the most cost effective, low emission generation source available to meet Ontario's baseload electricity requirements. This report re-affirms the positive economic and societal benefits associated with a strong nuclear program in the Province. **[MONITOR]**

Commented [A8]: Not yet released.

OPG – We put MONITOR to ensure status next Thursday before we release.

Ranney Falls Hydroelectric GS

During the third quarter of 2017, OPG continued construction work for a 10 MW single-unit powerhouse on the existing Ranney Falls GS site, as part of the Regulated – Hydroelectric segment. The new unit will replace an existing unit that reached its end of life in 2014. The existing forebay structure demolition has been completed and the upstream cofferdam has been constructed ahead of schedule. Construction continues on the expanded forebay, powerhouse and spillway. Excavation work is substantially complete and forebay wall concrete replacement is in progress. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget.

Nanticoke Solar Facility

The construction of a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands under a Large Renewable Procurement contract with the IESO, through Nanticoke Solar LP, a partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation, is planned to commence in the first quarter of 2018. During the third quarter of 2017, the partnership continued work to obtain approvals and permits required to enable the commencement of construction, and progressed procurement activities for equipment and for engineering and construction services. The facility is expected to be completed in the first quarter of 2019.

Deep Geologic Repository for Low and Intermediate Level Waste

OPG has proposed a deep geologic repository as the preferred solution for the safe long-term management of the L&ILW produced from the continued operation of OPG-owned nuclear generating stations. Agreement has been reached with local municipalities for OPG to develop the L&ILW Deep Geologic Repository (DGR) on lands adjacent to the Western Waste Management Facility (WWMF) in Kincardine, Ontario. The environmental effects of the proposed L&ILW DGR were examined by the CNSC and CEAA-appointed Joint Review Panel (JRP) to meet the requirements of the Canadian Environmental Assessment Act. The JRP submitted its report on the EA to the federal Minister of Environment in May 2015, concluding that, given mitigation, there is unlikely to be significant environmental impact from the project and recommending that the Minister approve the EA. In December 2016, at the request of the federal Minister of Environment and Climate Change, OPG submitted additional information on certain aspects of the EA, including information related to alternate locations for the project. Following its review of OPG's submission and a period of public comment, the CEAA requested further information that OPG subsequently provided in May 2017. In June 2017, the CEAA notified OPG that it had sufficient and adequate information to proceed with the next step of the environmental assessment process and advised that a draft report and updated terms and conditions will be prepared for public review.

On August 21, 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of potential cumulative effects of the project on the Saugeen Ojibway Nations' (SON) physical and cultural heritage, including a description of the potential effects of the project on the Nation's spiritual and cultural connection to the land. OPG is assessing the request and will notify the CEAA when it has determined the timeline for developing a response. The CEAA's draft report for public review will not be issued until this update is provided. The L&ILW DGR at the WWMF site remains OPG's preferred solution for the safe long-term management of the L&ILW.

OPG continues its engagement with the SON toward securing community support for the L&ILW DGR. The in-service date of the L&ILW DGR is expected to be approximately six to seven years from the start of construction.

Financial Strength

As a commercial enterprise, OPG's financial priority is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future growth.

Increase Revenue, Reduce Costs and Achieve Appropriate Return

In May 2016, OPG filed a 5-year application with the OEB for new regulated prices for production from its regulated hydroelectric and nuclear facilities, with a proposed effective date of January 1, 2017. Consistent with the requirements of *Ontario Regulation 53/05*, the application incorporates a rate smoothing proposal that would defer, for future collection, a portion of the approved annual nuclear revenue requirement for the period from January 1, 2017 to the end of the Darlington Refurbishment project, with a view to making changes in OPG's regulated prices more stable year-over-year. The application seeks to ensure that nuclear regulated prices under the rate smoothing approach allow for sufficient cash flow to meet the Company's liquidity needs, support cost effective funding for the Darlington Refurbishment project and other expenditures, and maintain the Company's investment grade credit rating, while taking into account both near-term and future impacts on customers. OPG expects to recognize amounts deferred under rate smoothing as income in the periods to which the underlying approved revenue requirements relate.

The application will further challenge and incentivize OPG to find additional cost reductions and efficiencies within its operations, as a result of greater de-coupling of nuclear and hydroelectric regulated prices from costs and a longer rate-setting period under the OEB's incentive ratemaking framework, which forms the basis for the ratemaking methodologies reflected in the application.

The application seeks an increase in the nuclear rate base, effective in early 2020, to reflect the planned placement in service of approximately $4.8 billion of capital expenditures upon the scheduled return to service of Unit 2 at the Darlington GS as part of the Darlington Refurbishment project and, effective in 2017, an increase in the deemed capital structure applied to the total regulated rate base to 49 percent equity and 51 percent debt, from 45 percent equity and 55 percent debt reflected in the existing regulated prices. The application also requests new rate riders, effective January 1, 2017, to recover or repay the December 31, 2015 balances in all of the Company's OEB-authorized variance and deferral accounts, with the exception of the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the portion of these balances previously approved for recovery or repayment through rate riders that were in effect during 2016.

The OEB's decision on the application, including the effective date of approved new regulated prices, is expected later in 2017. **[MONITOR]**

For generation assets that do not form part of the assets regulated by the OEB, OPG's strategy has been to secure appropriate long-term revenue arrangements. In line with this strategy, virtually all of OPG's non-regulated operating facilities and assets under construction are subject to long-term Energy Supply Agreements (ESAs) or other long-term contracts with the IESO.

Ensure Availability of Cost Effective Funding

In April 2017, DBRS Limited (DBRS) re-affirmed the long-term credit rating on OPG's debt at 'A (low)' and OPG's commercial paper rating at 'R-1 (low)'. All ratings from DBRS have a stable outlook. In July 2017, S&P Global Ratings (S&P) re-affirmed OPG's long-term credit rating at 'BBB+' with a stable outlook. S&P's commercial paper rating for OPG is 'A-1 (low)'.

Social Licence

As the largest electricity generator in Ontario with diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust. OPG is committed to maintaining high standards of public safety and corporate citizenship, including environmental stewardship, transparency, community engagement, and Indigenous relations.

OPG is focused on building long-term, mutually beneficial working relationships with Indigenous communities, businesses and organizations across Ontario, and continues to support procurement, employment and educational opportunities with its Indigenous community partners. The Company seeks to establish these relationships based on a foundation of respect for the languages, customs, and political, social and cultural organizations of the Indigenous communities.

In June 2017, OPG launched an Indigenous Business Engagement (IBE) Initiative. The purpose of this initiative is to increase access to procurement opportunities for Indigenous businesses interested in supplying materials and services to OPG. The IBE Initiative is based on a strategy that will identify opportunities in contracts, scopes of work and business plans for potential Indigenous business engagement; include criteria related to suppliers' ability to engage or partner with Indigenous people or businesses in assessing procurement proposals; and invest in relationships with Indigenous communities by increasing outreach efforts to enhance understanding of how to do business with OPG. OPG has continued to engage with various Indigenous business and communities as well as its suppliers to promote the IBE Initiative. In September 2017, OPG presented the IBE to the Mohawk Council of Akwesanse (Akwesanse). As a result, Akwesanse plans to create a database of businesses in the community that will participate in contracting and supply opportunities with OPG. In September 2017, OPG also hosted a similar presentation to the Williams Treaties First Nations, located proximate to the Pickering and Darlington Nuclear Generating Stations, at the quarterly meeting for these communities.

OPG is developing recruitment plans targeting Indigenous people. In October 2017, OPG participated in five Indigenous-specific career fairs to attract such talent. **[MONITOR]**

OPG has a transportation electrification strategy that will help position OPG as a leader in transportation electrification in Ontario. This strategy is intended to leverage OPG's clean electricity to support action on climate change, create growth opportunities for OPG, and enhance OPG's brand and social licence.

Outlook

The financial performance of OPG's regulated operations is driven, in large part, by the outcome of applications for regulated prices to the OEB. The existing base regulated prices were established by the OEB effective November 1, 2014 based on a forecast of costs and production for the regulated facilities for the 2014 to 2015 period. The future outcome of OPG's current application for new regulated prices, currently pending the OEB's decision, is expected to provide substantial price certainty for the regulated business for the 2017 to 2021 period.

In its application, OPG has requested January 1, 2017 as the effective date for the new regulated prices. In December 2016, the OEB issued an order declaring the existing base regulated prices interim, which preserves the OEB's ability to make the new regulated prices effective as early as January 1, 2017. Considering the timing of OPG's application and OPG's procedural adherence throughout the proceeding, the Company believes that the OEB could make the new regulated prices effective January 1, 2017. This would allow OPG to recover the difference between the approved new regulated prices and the existing regulated prices for the period between January 1, 2017 and the implementation date of the new prices based on the OEB's order. The OEB's decision on the application, including the effective date of the new regulated prices, is expected in the fourth quarter of 2017. **[MONITOR]** The continuation of existing regulated prices until the issuance of the OEB's decision is expected to continue to contribute to lower income, particularly from the Regulated – Nuclear Generation segment, and, excluding the gain on sale of the Company's head office premises and associated parking facility recorded in the second quarter of 2017, lower

Commented [A9]: Sp. "Akwesasne" ?

OPG – fixed spelling to as follows:

In September 2017, OPG presented the IBE to the Mohawk Council of Akwesasne (Akwesasne). As a result, the Akwesasne plan to create a database of businesses in the community that will participate in contracting and supply opportunities with OPG.

Commented [A10]: Does this deal with OPG owned fleet and other vehicles, or in line with the infrastructure for EV vehicles.

Can further details be provided in particular on the point of 'creating growth opportunities for OPG'.

OPG – revised wording for this paragraph as follows:

OPG has a strategy to help position the Company as a leader in transportation electrification in the province. The strategy aims to leverage the Company's clean, reliable and cost-effective electricity to power transportation, capitalize on future commercial growth opportunities, and enhance the Company's social licence. OPG is pursuing initiatives to increase the use of electric vehicles within its operations, and is assessing vehicle grid integration and hydrogen applications for the transportation sector.

ROE Excluding AOCI during 2017, compared to 2016. In large part, this is due to the year-over-year reduction in nuclear electricity generation resulting from the Unit 2 refurbishment outage at the Darlington GS, given that the existing nuclear regulated prices were determined in 2014 based on a higher production forecast that reflected the operation of all four units at the station. As such, the OEB's decision on the effective date of the new regulated prices, as well as the timing of the decision issuance, could have a significant impact on OPG's financial results during 2017.

Nuclear base regulated prices resulting from OPG's current application will be subject to a rate smoothing mechanism that defers collection of a portion of OEB-approved revenues to future periods. As expected, combined with the expiry of rate riders in effect to the end of 2016, a year-over-year reduction in nuclear generation due to the Unit 2 refurbishment outage at the Darlington GS and the continuation of existing regulated prices until such time as new prices are implemented by the OEB, this will result in lower cash flow from operating activities in 2017, compared to 2016. OPG expects to continue to have the necessary financial capacity and sufficient access to cost effective financing sources to continue to fund its capital requirements and other disbursements.

Lower nuclear generation due to the Darlington Refurbishment outages will continue, as planned, to negatively impact the Enterprise TGC metric for the duration of the refurbishment project. Variability in sustaining capital investment expenditures, including major sustaining projects for the hydroelectric operations, also will impact the Enterprise TGC in future periods.

Several OEB-authorized regulatory variance and deferral accounts currently in place contribute to reducing the relative variability of the Company's income and ROE Excluding AOCI. Among others, the regulatory accounts include those related to the revenue impact of variability in water flows and forgone production due to SBG conditions at the regulated hydroelectric stations. As there are no variance or deferral accounts in place related to the impact of generation performance of the nuclear stations on revenue from base regulated prices, the Regulated – Hydroelectric segment generally is expected to produce overall more predictable earnings. OPG continues to operate and maintain its nuclear facilities with a view to optimize their performance and availability, while focusing on improving the overall reliability and predictability of the fleet.

Electricity generated from most of OPG's non-regulated assets is subject to ESAs with the IESO. Based on these agreements, OPG expects the Contracted Generation Portfolio segment to continue to contribute a generally stable level of earnings and cash flow from operations going forward.

OPG's total forecast capital expenditures for the 2017 year are approximately $2.0 billion. This includes amounts for the Darlington Refurbishment project, hydroelectric and other development projects including the completion of the Peter Sutherland Sr. GS and the expansion of the Ranney Falls GS, and sustaining capital investments across the generating fleet. OPG's major projects are discussed in the section, *Project Excellence*.

In addition to the operating and financial performance of the electricity generation business, OPG's results are affected by the earnings on the Nuclear Segregated Funds, which are reported in the Regulated – Nuclear Waste Management segment. While the Nuclear Segregated Funds are managed to achieve, in the long term, the target rate of return based on the discount rate specified in the ONFA, the rates of return earned in a given period can be subject to various external factors including financial market conditions and, for the portion of the Used Fuel Segregated Fund guaranteed by the Province under the ONFA, changes in the Ontario consumer price index (CPI). In the near term, these factors can be volatile and cause fluctuations in the Company's income. This volatility is partially mitigated by the impact of the OEB-authorized Bruce Lease Net Revenues Variance Account and, as discussed below, the funded status of the two segregated funds.

As OPG does not have the right to withdraw surplus amounts from the Nuclear Segregated Funds, OPG limits the amount of Nuclear Segregated Funds assets reported on the balance sheet to the present value of such life cycle funding liability. This reduces the volatility of earnings on the Nuclear Segregated Funds reflected in net income when the funds are in a fully funded or overfunded position. As at September 30, 2017, the Decommissioning

Segregated Fund was overfunded by approximately 23 percent, and the Used Fuel Segregated Fund was marginally overfunded, by less than one percent, based on the 2017 ONFA Reference Plan. Variability in asset performance due to volatility inherent in financial markets and changes in Ontario CPI, or changes in funding liability estimates, may result in either or both funds becoming underfunded in the future.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

Regulated – Nuclear Generation Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue	**739**	885	**2,000**	2,631
Fuel expense	**81**	79	**217**	239
Gross margin	**658**	806	**1,783**	2,392
Operations, maintenance and administration	**511**	521	**1,693**	1,665
Depreciation and amortization	**116**	230	**333**	691
Property taxes	**7**	6	**20**	19
Income (loss) before other losses, interest, and income taxes	**24**	49	**(263)**	17
Other losses	**4**	2	**4**	-
Income (loss) before interest and income taxes	**20**	47	**(267)**	17

For the three and nine month periods ended September 30, 2017, the segment earnings decreased by $27 million and $284 million, respectively, compared to the same periods in 2016. The decrease in earnings was expected and primarily due to reduced revenue from the nuclear base regulated price of approximately $24 million and $230 million, respectively. The decrease was partially offset by an associated year-over-year decrease in fuel expense. The decrease in revenue during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, reflected lower electricity generation of 0.4 TWh and 4.0 TWh, respectively, primarily due to the ongoing Unit 2 refurbishment outage at the Darlington GS that began in October 2016, without a corresponding increase in the base regulated price. The existing nuclear base regulated price set by the OEB in 2014 continues to be in effect pending the OEB's decision on OPG's application for new regulated prices, proposed to be effective on January 1, 2017. The existing price does not reflect the lower generation as a result of the Darlington Refurbishment project, as it was set to allow the Company to recover its approved nuclear costs over a higher nuclear production volume, based on the 2014 and 2015 outage profile that did not include a refurbishment outage. The reduction in nuclear electricity generation for the three months ended September 30, 2017 was largely offset by the higher electricity generation from the Pickering GS.

OM&A expenses decreased by $10 million during the third quarter of 2017, compared to the same period in 2016, as a result of a higher materials and supplies obsolescence charge recognized in 2016. OM&A expenses increased by $28 million during the nine months ended September 30, 2017, compared to the same period in 2016, due to planned maintenance activities in 2017.

Depreciation and amortization expense, excluding amortization expense related to regulatory account balances, increased by $16 million and $30 million during the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016, primarily due to new assets in service.

The expiry of an OEB-authorized nuclear rate rider on December 31, 2016 contributed to the decrease in segment revenue for the three and nine month periods ended September 30, 2017, compared to the same periods in 2016. As rate riders allow for recovery of approved balances in OEB-authorized regulatory accounts, this decrease in revenue was largely offset by a decrease in amortization expense related to these balances. There was no rate rider

in effect during the nine months ended September 30, 2017, pending the outcome of OPG's current application to the OEB for new regulated prices.

The Unit Capability Factors for the Darlington and Pickering generating stations were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Unit Capability Factor *(%)* [1]				
Darlington GS	**96.2**	89.6	**82.1**	87.6
Pickering GS	**88.7**	77.3	**83.8**	73.8

[1] The nuclear Unit Capability Factor excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS was excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

The Unit Capability Factor at the Darlington GS increased in the third quarter of 2017, compared to the same quarter in 2016, primarily due to the lower number of planned outage days during the third quarter of 2017. The lower Unit Capability Factor at the Darlington GS for the nine months ended September 30, 2017, compared to the same period in 2016, reflected the higher number of planned outage days, largely driven by constraints related to the transition of the station toward refurbishment.

The increase in Unit Capability Factor at the Pickering GS for the three and nine month periods ended September 30, 2017 was primarily due to outage optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station compared to 2016.

Regulated – Nuclear Waste Management Segment

(millions of dollars) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Revenue	**33**	36	**90**	102
Operations, maintenance and administration	**35**	38	**96**	108
Accretion on nuclear fixed asset removal and nuclear waste management liabilities	**230**	228	**696**	684
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(196)**	(248)	**(579)**	(620)
(Loss) Income before interest and income taxes	**(36)**	18	**(123)**	(70)

The segment loss before interest and income taxes was $36 million and $123 million during the three and nine months ended September 30, 2017, respectively, a decrease in earnings of $54 million and $53 million compared to the same periods in 2016. The decline in earnings was primarily due to lower earnings from the Nuclear Segregated Funds, net of the impact of the impact of the Bruce Lease Net Revenues Variance Account, reflecting higher earnings from market returns on fund assets and the CPI-adjusted rate of return guaranteed by the Province for the portion of the Used Fuel Segregated Fund related to the initial 2.23 million used fuel bundles (committed return) in the third quarter of 2016.

As both the Decommissioning Segregated Fund and the Used Fuel Fund were in an overfunded position during the three and nine months period ended September 30, 2017, compared to the underlying funding liabilities per the approved ONFA Reference Plan, the earnings on the funds during these periods reflected the growth rate in the present value of the funding liabilities and were not impacted by market returns and committed return. The higher earnings on both funds during the three and nine months periods ended September 30, 2016 reflected market returns and committed return, as the Decommissioning Segregated Fund became over 120 percent funded during the third quarter of 2016 while the Used Fuel Fund was underfunded, compared to the corresponding funding liabilities.

Higher market returns and committed return in the third quarter of 2016 in relation to the funding liabilities' growth rate reflected in fund earnings during 2017 resulted in a year-over-year decrease in the amount of earnings on the Nuclear Segregated Funds.

As of December 31, 2016, OPG recorded a decrease of approximately $1,570 million to the Nuclear Liabilities and associated asset retirement costs capitalized as part of the carrying value of the nuclear generating stations. The resulting year-over-year decreases in accretion on fixed asset removal and nuclear waste management liabilities recorded in the Regulated – Nuclear Waste Management segment and depreciation and fuel expenses recorded in the Regulated – Nuclear Generation segment during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, were offset by the impact of the Bruce Lease Net Revenues Variance Account and the Nuclear Liability Deferral Account authorized by the OEB.

Under the current OEB-approved cost recovery methodology, these changes in expenses also are not expected to materially affect OPG's income during the rest of 2017, as they are expected to continue to be largely offset by the impact of the regulatory accounts until such time as the OEB implements corresponding changes to OPG's nuclear regulated prices, and subsequently by the impact of such new regulated prices. Further details on the change in the estimate of the Nuclear Liabilities as of December 31, 2016 are described in OPG's 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Asset Retirement Obligation*. **[MONITOR]**

Regulated – Hydroelectric Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue [1]	**327**	350	**1,069**	1,148
Fuel expense	**88**	88	**258**	259
Gross margin	**239**	262	**811**	889
Operations, maintenance and administration	**81**	87	**232**	238
Depreciation and amortization	**34**	56	**103**	169
Property tax	**1**	1	**1**	1
Income before other losses (gains), interest and income taxes	**123**	118	**475**	481
Other losses (gains)	**1**	1	**1**	(19)
Income before interest and income taxes	**122**	117	**474**	500

[1] During the three and nine month periods ended September 30, 2017, the Regulated – Hydroelectric segment revenue included incentive payments of $4 million and $9 million, respectively, related to the OEB-approved hydroelectric incentive mechanism (three and nine month periods ended September 30, 2016 – incentive payments of $6 million and $8 million, respectively). The mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers. The incentive payments are reduced to remove incentive revenues arising in connection with SBG conditions.

The increase in segment income before interest and income taxes of $5 million during the third quarter of 2017, compared to the same quarter in 2016, was primarily the result of a decrease in OM&A expenses, mainly due to the timing of repairs and maintenance work in 2017 and a deferral of outages during the high water period.

The decrease in segment income before interest and income taxes of $26 million during the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to a gain of $22 million recognized during the first quarter of 2016 to reflect the OEB's January 2016 decision to reverse a portion of an earlier capital cost disallowance related to the Niagara Tunnel project expenditures, in response to a motion by OPG. The income impact of OEB-approved variance accounts also contributed to the year-over-year decrease in income for the period. These factors were partially offset by the decrease in OM&A expenses related to the timing of repairs and maintenance work in 2017 and a deferral of outages during the high water period.

The decrease in revenue from the segment for the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was largely due to the expiry of an OEB-authorized rate rider on

December 31, 2016. As the rider allowed for the recovery of approved balances in OEB-authorized regulatory accounts, the resulting reduction in revenue was largely offset by lower amortization expense related to these balances. There was no rate rider in effect during the first nine months of 2017 pending the outcome of OPG's current application to the OEB for new regulated prices.

The Hydroelectric Availability for the stations included in the Regulated – Hydroelectric segment was as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Hydroelectric Availability *(%)*	**87.6**	84.1	**89.0**	89.8

The Hydroelectric Availability in the third quarter of 2017 was higher compared to the same period in 2016, primarily due to a higher number of planned outages in 2016 as a result of the refurbishment of the Sir Adam Beck Pump GS reservoir between April 2016 and February 2017. The marginal decrease in Hydroelectric Availability during the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to a higher number of unplanned outage days at the Northwestern Ontario and Niagara region hydroelectric stations, partially offset by higher availability from the Sir Adam Beck Pump GS.

Contracted Generation Portfolio Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue	**141**	149	**431**	431
Fuel expense	**15**	19	**42**	42
Gross margin	**126**	130	**389**	389
Operations, maintenance and administration	**39**	44	**118**	129
Depreciation and amortization	**20**	19	**59**	56
Accretion on fixed asset removal liabilities	**3**	2	**7**	6
Property taxes	**-**	1	**5**	6
Income from investments subject to significant influence	**(11)**	(11)	**(29)**	(28)
Income before other loss, interest and income taxes	**75**	75	**229**	220
Other loss	**-**	1	**-**	1
Income before interest and income taxes	**75**	74	**229**	219

Income before interest and income taxes from the segment increased by $1 million and $10 million during the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016. The increase in earnings for the three months ended September 30, 2017 mainly resulted from revenues from the Peter Sutherland Sr. GS that was placed in-service at the end of the first quarter of 2017 and lower OM&A expenses, partially offset by lower revenue from the Atikokan GS. The decrease in revenue from the Atikokan GS was primarily due to higher revenues in 2016, when the station was called upon to provide the needed support to the electricity system in Northwestern Ontario as a result of an outage at a local transformer station. For the nine months ended September 30, 2017, the increase in earnings was primarily due to lower OM&A expenses. The lower OM&A expenses for the three and nine month periods ended September 30, 2017 were mainly due to the prospective adoption of the full yield curve approach to the estimation of the service and interest cost components of pension and OPEB costs starting in 2017.

The Hydroelectric Availability and the Thermal Equivalent Forced Outage Rate (EFOR) for the Contracted Generation Portfolio segment were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Hydroelectric Availability *(%)*	**66.1**	68.2	**76.9**	79.6
Thermal EFOR *(%)*	**2.6**	2.1	**6.0**	1.3

Lower Hydroelectric Availability during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was primarily due to an increase in the number of planned outage days at the Lower Mattagami River hydroelectric generating stations.

The higher Thermal EFOR during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was primarily due to a higher number of unplanned outage days at a Lennox GS unit as a result of a transmission outage and a generator cooling water system outage in 2017.

Services, Trading, and Other Non-Generation Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue	**9**	15	**36**	52
Fuel expense	**1**	1	**1**	1
Gross margin	**8**	14	**35**	51
Operations, maintenance and administration	**1**	11	**2**	20
Depreciation and amortization	**8**	8	**22**	25
Accretion on fixed asset removal liabilities	**2**	2	**6**	6
Property taxes	**-**	4	**4**	9
(Loss) income before other gains, interest, and income taxes	**(3)**	(11)	**1**	(9)
Other gains	**(2)**	(3)	**(385)**	(5)
Income (loss) before interest and income taxes	**(1)**	(8)	**386**	(4)

Segment earnings improved by $7 million during the third quarter of 2017, compared to the same quarter in 2016. The improvement in earnings was primarily due to lower OM&A expenses reflecting project expenditures incurred in the third quarter of 2016, and OPG's decision, in the fourth quarter of 2016, to proceed with the decommissioning of Lambton GS.

Segment income before interest and income taxes increased by $390 million for the nine months ended September 30, 2017, compared to the same period in 2016. The increase in earnings mainly reflected the gain on the sale of OPG's head office premises and associated parking facility recorded during the second quarter of 2017.

LIQUIDITY AND CAPITAL RESOURCES

OPG's primary sources of liquidity and capital are funds generated from operations, bank financing, credit facilities provided by the Ontario Electricity Financial Corporation (OEFC), long-term corporate debt, and capital market financing. These sources are used for multiple purposes including: to invest in plants and technologies, to undertake major projects, to fund long-term obligations such as contributions to the pension fund and the Nuclear Segregated Funds, to make payments under the OPEB plans, to fund expenditures on Nuclear Liabilities not reimbursable from the Nuclear Segregated Funds, to service and repay long-term debt, to provide general working capital, and to fund OPG's investment in the Fair Hydro Plan.

Changes in cash and cash equivalents for the three and nine month periods ended September 30 are as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Cash and cash equivalents, beginning of period	**242**	295	**186**	464
Cash flow provided by operating activities	**485**	530	**698**	1,211
Cash flow used in investing activities	**(463)**	(390)	**(720)**	(1,253)
Cash flow provided by (used in) financing activities	**16**	(9)	**116**	4
Net increase (decrease)	**38**	131	**94**	(38)
Cash and cash equivalents, end of period	**280**	426	**280**	426

For a discussion of cash flow provided by operating activities and the FFO Adjusted Interest Coverage ratio, refer to the details in the section, *Highlights* under the heading, *Overview of Results*.

Investing Activities

Electricity generation is a capital-intensive business. It requires continued investment in plants and technologies to maintain and improve operating performance including asset reliability, safety and environmental performance, to increase the generating capacity of existing stations, and to invest in the development of new generating stations, emerging technologies and other business growth opportunities.

Cash flow used in investing activities during the third quarter of 2017 was $463 million, compared to $390 million for the same period in 2016. The increase in cash flow used for investing activities mainly resulted from higher expenditures on the Darlington Refurbishment project in the third quarter of 2017.

Cash flow used in investing activities decreased by $533 million for the nine months ended September 30, 2017, compared to the same period in 2016. The decrease in net cash flow used in investing activities was primarily due to the receipt of proceeds from the sale of OPG's head office premises and associated parking facility in the second quarter of 2017 pursuant to a Shareholder Declaration and Shareholder Resolution, and the acquisition of nine million common shares of Hydro One Limited (Hydro One) in the second quarter of 2016, partially offset by higher expenditures on the Darlington Refurbishment project in 2017. OPG acquired the Hydro One shares for investment purposes, to mitigate the risk of future price volatility related to the Company's future share delivery obligations under the collective agreements with the Power Workers' Union and The Society of Energy Professionals.

Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from the sale of head office premises and associated parking facility, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. OPG expects that the amount of designated proceeds to be transferred into the Consolidated Revenue Fund will be largely consistent with the after-tax gain on sale. The transfer is expected to take place later in 2017.

Financing Activities

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. In the second quarter of 2017, OPG renewed and extended the expiry date of both tranches from May 2021 to May 2022. There were no amounts outstanding under the bank credit facility as at September 30, 2017.

There was $160 million of commercial paper outstanding under OPG's commercial paper program as at September 30, 2017.

As at September 30, 2017, OPG also maintained $25 million of short-term, uncommitted overdraft facilities, and a further $463 million of short-term, uncommitted credit facilities, which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other general corporate purposes. As at September 30, 2017, a total of $388 million of Letters of Credit had been issued under these facilities. This included $349 million for the supplementary pension plans, $38 million for general corporate purposes, and $1 million related to the operation of the PEC.

The Company has an agreement to sell an undivided co-ownership interest in its current and future accounts receivable to an independent trust, expiring on November 30, 2018. The maximum amount of co-ownership interest that can be sold under this agreement is $150 million. As at September 30, 2017, no borrowings were issued under this agreement and there were Letters of Credit outstanding under this agreement of $150 million, which were issued in support of OPG's supplementary pension plans.

As at September 30, 2017, Lower Mattagami Energy Limited Partnership (LME) maintained a $400 million bank credit facility to support the funding requirements for the Lower Mattagami River project including support for LME's commercial paper program and the issuance of the Letters of Credit. The facility consists of a $300 million tranche which, in the third quarter of 2017, was extended to mature in August 2022 and a $100 million tranche which, in the third quarter of 2017, was reduced from $200 million and extended to mature in August 2018. As at September 30, 2017, there was no external commercial paper outstanding under LME's commercial paper program. A letter of credit of $55 million was issued in July 2017 and remains outstanding as at September 30, 2017 under the $300 million tranche of the credit facility.

In June 2016, OPG entered into a $700 million general corporate credit facility agreement with the OEFC, which expires on December 31, 2017. In the third quarter of 2017, the agreement was amended to increase the credit facility to $2,350 million and to extend its expiry date to December 31, 2018.

In February 2017, OPG issued senior notes payable to the OEFC totalling $200 million and maturing in February 2047. The effective interest rate and coupon interest rate of these notes was 4.12 percent. In June 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in June 2047. The effective interest rate and coupon interest rate of these notes was 3.65 percent. In August 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in August 2047. The effective interest rate and coupon interest rate of these notes was 3.86 percent. In September 2017, OPG issued senior notes payable to the OEFC totalling $400 million and maturing in September 2047. The effective interest rate and coupon interest rate of these notes was 4.07 percent. As at September 30, 2017, there were outstanding long-term borrowings of $800 million under this credit facility.

In October 2017, OPG issued $500 million of senior notes payable under a Medium Term Note Program. The notes bear a coupon interest rate of 3.32 percent and an effective rate of 3.43 percent, payable semi-annually until maturity on October 4, 2027. The offering was made under OPG's $2 billion short form base shelf prospectus dated September 12, 2017. The net proceeds will be used for general corporate purposes, including the financing of OPG's subordinated debt investment in the Fair Hydro Plan.

As at September 30, 2017, OPG's long-term debt outstanding was $5,482 million, including $628 million due within one year.

OPG continues to evaluate arrangements that would appropriately support the Company's financing needs and capital expenditure programs.

Contractual and Commercial Commitments

Pension Plan Actuarial Valuation

A new actuarial valuation of the OPG registered pension plan was filed with the Financial Services Commission of Ontario in September 2017 with an effective date of January 1, 2017. The annual funding requirements in accordance with the new actuarial valuation are $212 million for 2017, $215 million for 2018, and $219 million for 2019. The next actuarial valuation must have an effective date no later than January 1, 2020.

BALANCE SHEET HIGHLIGHTS

The following section provides highlights of OPG's unaudited interim consolidated financial position using selected balance sheet data:

(millions of dollars) (unaudited)	As At September 30 2017	As At December 31 2016
Property, plant and equipment - net	**20,801**	19,998
The increase was primarily due to capital expenditures on the Darlington Refurbishment project, partially offset by depreciation expense.		
Nuclear fixed asset removal and nuclear waste management funds *(current and non-current portions)*	**16,534**	15,984
The increase was primarily due to earnings on the Nuclear Segregated Funds, partially offset by reimbursements of eligible expenditures on nuclear fixed asset removal and nuclear waste management activities.		
Short-term debt	**160**	2
The increase was due to commercial paper issued under OPG's commercial paper program during the third quarter of 2017.		
Fixed asset removal and nuclear waste management liabilities	**20,075**	19,484
The increase was primarily a result of accretion expense representing the increase in the liabilities due to the passage of time, partially offset by expenditures on nuclear fixed asset removal and waste management activities.		

Off-Balance Sheet Arrangements

In the normal course of operations, OPG engages in a variety of transactions that, under US GAAP, are either not recorded in the Company's interim consolidated financial statements or are recorded in the Company's interim consolidated financial statements using amounts that differ from the full contract amounts. Principal off-balance sheet activities for OPG include guarantees and long-term contracts.

CHANGES IN ACCOUNTING POLICIES AND ESTIMATES

OPG's significant accounting policies are outlined in Note 3 to the audited consolidated financial statements as at and for the year ended December 31, 2016. A discussion of recent accounting pronouncements and change in accounting estimate are included in Note 2 to OPG's unaudited interim consolidated financial statements as at and for the three and nine month periods ended September 30, 2017 under the heading, *Significant Accounting Policies and Estimates*. Disclosure regarding OPG's critical accounting policies is included in OPG's 2016 annual MD&A.

RISK MANAGEMENT

The following provides an update to the discussion of the Company's risks and risk management activities included in OPG's 2016 annual MD&A. As such, the disclosure in this section should be read in conjunction with the *Risk Management* section included in the annual MD&A.

Risks to Achieving Project Excellence

Deep Geologic Repository for Low and Intermediate Level Waste

In August 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of the potential cumulative effects of the DGR project on the physical and cultural heritage of the SON, taking into account the results of the SON Community Process. OPG continues to work with the SON, however the timing and outcome of the SON Community Process and the EA decision by the Minister are uncertain.

Risks to Maintaining Financial Strength

Commodity Markets

Changes in the market price of fuels used to produce electricity can adversely impact OPG's earnings and cash flow from operations.

To manage the risk of unpredictable increases in the price of fuels, the Company has fuel hedging programs, which include fixed price and indexed contracts.

The percentages hedged of OPG's fuel requirements are shown in the following table. These amounts are based on yearly forecasts of generation and supply mix, and as such, are subject to change as these forecasts are updated.

	2017 [1]	2018	2019
Estimated fuel requirements hedged [2]	73%	73%	69%

[1] Based on actual fuel requirements hedged for the nine months ended September 30, 2017 and forecast for the remainder of the year.

[2] Represents the approximate portion of megawatt-hours of expected generation production (and year-end inventory targets) from each type of OPG-operated facility (nuclear, hydroelectric and thermal) for which the Company has entered into contractual arrangements or obligations in order to secure the price of fuel, or which is subject to regulation. In the case of hydroelectric generation, this represents the gross revenue charge and water rental charges. Excess fuel inventories (nuclear and thermal) in a given year are attributed to the next year for the purpose of measuring hedge ratios.

Foreign Exchange

OPG's earnings and cash flow can be affected by movements in the United States dollar (USD) relative to the Canadian dollar.

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are denominated in, or tied to, USD. To manage this risk, OPG periodically employs various financial instruments such as forwards and other

derivative contracts, in accordance with approved risk management policies. As at September 30, 2017, OPG had no foreign exchange contracts outstanding.

Trading

OPG's financial performance can be affected by its trading activities.

OPG's electricity trading operations are closely monitored, with total exposures measured and reported to senior management on a daily basis. The main metric used to measure the financial risk of trading activity is Value at Risk (VaR). VaR is defined as a probabilistic maximum potential future loss expressed in monetary terms for a portfolio based on normal market conditions over a set period of time. For the third quarter of 2017, the VaR utilization ranged between $0.2 million and $0.3 million.

Credit

Deterioration in energy markets counterparty credit and non-performance by suppliers and contractors can adversely impact OPG's earnings and cash flow from operations.

OPG manages its exposure to suppliers or counterparties by evaluating their financial condition and negotiating appropriate collateral or other forms of security. OPG's credit exposure relating to energy markets transactions as at September 30, 2017 was $356 million, including $346 million with the IESO. Management considers the Company's risk exposure relating to electricity sales through the IESO-administered spot market to be low as the IESO oversees the credit worthiness of all market participants. In accordance with the IESO's prudential support requirements, market participants are required to provide collateral to cover funds that they might owe to the market. Of the $10 million remaining exposure as at September 30, 2017, over 95 percent was related to investment grade counterparties.

Fair Hydro Plan

OPG's role in connection with the Fair Hydro Plan could have reputational impacts on the Company.

The *Ontario Fair Hydro Plan Act, 2017* received Royal Assent on June 1, 2017 and its attendant regulations came into force in June, July, and October 2017. **[UPDATE]** The regulations clarify aspects of the structure and program logistics required for ~~OPG, as~~ the Financial Services Manager of the Fair Hydro Plan, which OPG is planning to undertake, to refinance a portion of the Global Adjustment through the Trust. OPG's reputation could potentially be adversely impacted through its involvement with the Fair Hydro Plan and through stakeholder opinions related to this involvement.

Commented [A11]: Not sure this is the right wording. OPG's role as FSM is required under the Act, but not the refinancing through the Trust – the OPG Financing Entity's (or entities) role is discretionary.

Recovery of Pension and OPEB Costs

On September 14, 2017, the OEB issued its final report on the guiding principles and the policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the electricity and natural gas sectors. The report reaffirmed the conclusions of the initial report issued in May 2017, including the establishment of the accrual basis of accounting as the default rate-setting method and the establishment of a variance account to record asymmetric carrying charges in favour of ratepayers on the differences between the accrual costs recovered and cash payments made by a utility for pension and OPEB plans. The report requires OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the Pension & OPEB Cash Versus Accrual Differential Deferral Account that has been in effect since November 1, 2014, until such time as the OEB approves the resumption of the accrual basis of recovery. The future recovery of amounts recorded in the account will be subject to this approval. The report confirmed that OPG would become subject to the carrying charges on the differences between accrual costs and cash payments going back to November 1, 2014, with the charges calculated on the portion of such differences that have been recovered through regulated prices. The carrying charges will be determined at prescribed interest rate set quarterly by the OEB based on the quarterly return of a mid-term corporate bond index yield. This outcome has reduced OPG's risk related to the recovery of actual pension and OPEB accrual

costs and the recovery of the balance in the Pension & OPEB Cash Versus Accrual Differential Deferral Account. The account had a balance of $552 million as at September 30, 2017 and is recognized on the Company's consolidated balance sheet as a regulatory asset. OPG's financial results for the three and nine month periods ended September 30, 2017 were not impacted by the issuance of the OEB's report.

RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One, the IESO and the OEFC. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions are summarized below:

	Three Months Ended September 30			
	2017		2016	
(millions of dollars) (unaudited)	**Revenue**	**Expense**	**Revenue**	**Expense**
Hydro One				
Electricity sales	**2**	**-**	1	-
Services	**-**	**3**	-	3
Dividends	**2**	**-**	-	2
Province of Ontario				
Decommissioning Fund excess funding [1]	**-**	**(44)**	-	201
Used Fuel Fund rate of return guarantee and excess funding [1]	**-**	**(39)**	-	295
Gross revenue charges	**-**	**27**	-	28
ONFA guarantee fee	**-**	**2**	-	2
Other	**-**	**2**	-	-
OEFC				
Gross revenue charges	**-**	**62**	-	57
Interest expense on long-term notes	**-**	**40**	-	42
Income taxes, net of investment tax credits	**-**	**23**	-	28
IESO				
Electricity related revenue	**1,126**	**4**	1,293	7
	1,130	**80**	1,294	665

(millions of dollars) (unaudited)	Nine Months Ended September 30 2017 Revenue	2017 Expense	2016 Revenue	2016 Expense
Hydro One				
Electricity sales	**7**	**-**	4	-
Services	**1**	**8**	1	12
Dividends	**6**	**-**	-	4
Province of Ontario				
Decommissioning Fund excess funding [1]	**-**	**164**	-	137
Used Fuel Fund rate of return guarantee and excess funding [1]	**-**	**217**	-	190
Gross revenue charges	**-**	**84**	-	91
ONFA guarantee fee	**-**	**6**	-	6
Other	**-**	**3**	-	-
OEFC				
Gross revenue charges	**-**	**156**	-	147
Interest expense on long-term notes	**-**	**122**	-	127
Income taxes, net of investment tax credits	**-**	**132**	-	112
IESO				
Electricity related revenue	**3,228**	**11**	3,894	22
	3,242	**903**	3,899	848

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at September 30, 2017 and December 31, 2016, the Nuclear Segregated Funds were reported net of amounts due to the Province of $3,796 million and $3,415 million, respectively. The details of accounting for the Nuclear Segregated Funds are described in OPG's 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

The receivable, available-for-sale securities, payable and long-term debt balances between OPG and its related parties are summarized below:

(millions of dollars) (unaudited)	September 30 2017	December 31 2016
Receivables from related parties		
Hydro One	**1**	1
IESO	**346**	421
OEFC	**3**	1
PEC	**2**	4
Province of Ontario	**5**	2
Available-for-sale securities		
Hydro One shares	**190**	212
Accounts payable and accrued charges		
OEFC	**37**	61
Province of Ontario	**6**	2
IESO	**2**	2
Long-term debt (including current portion)		
Notes payable to OEFC	**3,245**	3,295

OPG holds interest-bearing Province of Ontario bonds in the Nuclear Segregated Funds and the OPG registered pension fund. As at September 30, 2017, the Nuclear Segregated Funds held $1,498 million of interest-bearing Province of Ontario bonds, while the registered pension fund had no such holdings. As at December 31, 2016, the Nuclear Segregated Funds and the registered pension fund held $1,652 million and $284 million of interest-bearing Province of Ontario bonds, respectively. These bonds are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

There have been no related party transactions related to the Fair Hydro Plan and associated financing activities. The first transaction between the Trust and the IESO is expected later in 2017.

INTERNAL CONTROLS OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

The Company maintains a comprehensive system of policies, procedures, and processes that represents its framework for internal controls over financial reporting and for its disclosure controls and procedures (together, ICOFR). There were no changes in the Company's internal control system during the current interim period that has or is reasonably likely to have a material impact to the ICOFR.

QUARTERLY FINANCIAL HIGHLIGHTS

The following tables set out selected financial information from OPG's unaudited interim consolidated financial statements for each of the eight most recently completed quarters.

(millions of dollars - except where noted) (unaudited)	**September 30 2017**	**June 30 2017**	**March 31 2017**	**December 31 2016**
Revenue	**1,217**	1,146	1,176	1,388
Net income (loss)	**140**	307	68	(8)
Less: Net income attributable to non-controlling interest	**9**	4	4	5
Net income (loss) attributable to the Shareholder	**131**	303	64	(13)
Per common share, attributable to the Shareholder *(dollars)*	**$0.51**	$1.18	$0.25	($0.05)

(millions of dollars - except where noted) (unaudited)	**September 30 2016**	**June 30 2016**	**March 31 2016**	**December 31 2015**
Revenue	1,400	1,387	1,478	1,312
Net income (loss)	198	135	128	(100)
Less: Net income attribute to the non-controlling interest	4	3	5	1
Net income (loss) attributable to the Shareholder	194	132	123	(101)
Per common share, attributable to the Shareholder *(dollars)*	$0.76	$0.51	$0.48	($0.39)

Trends

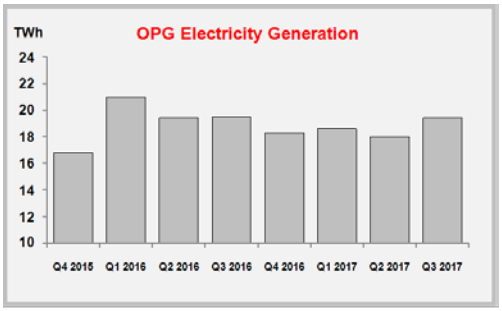
OPG's quarterly results are affected by changes in grid-supplied electricity demand, primarily resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. Weather conditions affect water flows, electricity demand, and prevalence of SBG conditions. Historically, OPG's revenues have been higher in the first

quarter of a fiscal year as a result of winter heating demands and in the third quarter due to air conditioning and cooling demands. The financial impact of forgone production due to SBG conditions at the regulated hydroelectric stations and the financial impact of differences between forecast water flows reflected in OEB-approved regulated prices and the actual water flows are mitigated by regulatory variance accounts authorized by the OEB.

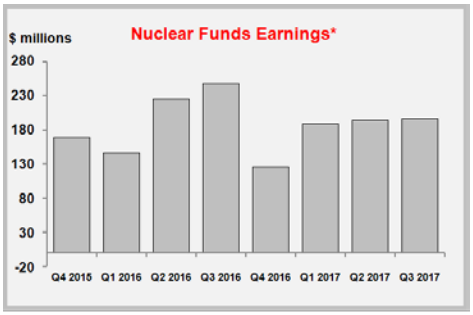
The timing of planned outages at a nuclear generating station during the year can cause variability in year-over-year operating results for partial periods of a fiscal year, including the impact on revenue and OM&A expenses, but is not a significant driver of variability for full fiscal year results.

OPG's electricity generation was reduced as a result of the Unit 2 refurbishment outage at the Darlington GS, which began in October 2016 and is expected to continue until early 2020.

OPG's financial results are also affected by the earnings on the Nuclear Segregated Funds, net of the impact of the Bruce Lease Net Revenues Variance Account.



Additional items that affected net income in certain quarters above are described in OPG's 2016 annual MD&A under



*net of regulatory variance account

the section, *Quarterly Financial Highlights*.

SUPPLEMENTARY NON-GAAP FINANCIAL MEASURES

In addition to providing net income and other financial information in accordance with US GAAP, certain non-GAAP financial measures are also presented in OPG's MD&A. These non-GAAP measures do not have any standardized meaning prescribed by US GAAP and, therefore, may not be comparable to similar measures presented by other issuers. OPG utilizes these measures to make operating decisions and assess performance. Readers of the MD&A would utilize these measures in assessing the Company's financial performance from ongoing operations. The Company believes that these indicators are important since they provide additional information about OPG's performance, facilitate comparison of results over different periods, and present measures consistent with the Company's strategies to provide value to the Shareholder, improve cost performance, and ensure availability of cost effective funding. These non-GAAP financial measures have not been presented as an alternative to net income, cash flow provided by operating activities, or any other measure in accordance with US GAAP, but as indicators of operating performance.

The definitions of the non-GAAP financial measures are as follows:

(1) **ROE Excluding AOCI** is defined as net income attributable to the Shareholder divided by average equity attributable to the Shareholder excluding AOCI, for the period. ROE Excluding AOCI is measured over a 12-month period and is calculated as follows:

	Twelve Months Ended	
(millions of dollars – except where noted) (unaudited)	**September 30 2017**	**December 31 2016**
ROE Excluding AOCI		
Net income attributable to the Shareholder	**485**	436
Divided by: Average equity attributable to the Shareholder, excluding AOCI	**11,055**	10,442
ROE Excluding AOCI *(percent)*	**4.4**	4.2

(2) **FFO Adjusted Interest Coverage** is defined as FFO before interest divided by adjusted interest expense. FFO before interest is defined as cash flow provided by operating activities adjusted for interest paid, interest capitalized to fixed and intangible assets, and changes to non-cash working capital balances for the period. Adjusted interest expense is calculated as net interest expense plus interest income, interest capitalized to fixed and intangible assets, interest related to regulatory assets and liabilities, and the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets, for the period.

FFO Adjusted Interest Coverage is measured over a 12-month period and is calculated as follows:

	Twelve Months Ended	
(millions of dollars – except where noted) (unaudited)	**September 30 2017**	**December 31 2016**
FFO before interest		
Cash flow provided by operating activities	**1,082**	1,595
Add: Interest paid	**270**	269
Less: Interest capitalized to fixed and intangible assets	**(161)**	(141)
Less: Changes to non-cash working capital balances	**38**	42
FFO before interest	**1,229**	1,765
Adjusted interest expense		
Net interest expense	**84**	120
Add: Interest income	**8**	7
Add: Interest capitalized to fixed and intangible assets	**161**	141
Add: Interest related to regulatory assets and liabilities	**43**	30
Add: Excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets [1]	**-**	45
Adjusted interest expense	**296**	343
FFO Adjusted Interest Coverage *(times)*	**4.2**	5.1

[1] A value of nil is used in the calculation when interest on pension and OPEB projected benefit obligations is equal to, or lower than, expected return on pension plan assets.

(3) **Enterprise Total Generating Cost per MWh** is used to measure OPG's overall organizational cost performance. Enterprise TGC per MWh is defined as OM&A expenses (excluding the Darlington Refurbishment project and other generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to OPG's electricity generation business), fuel expense for OPG-operated stations including hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures (excluding the Darlington Refurbishment project and other generation development projects) incurred during the period, divided by total electricity generation from OPG-operated generating stations plus electricity generation forgone due to SBG conditions during the period.

(millions of dollars – except where noted) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Enterprise TGC				
Total OM&A expenses	**635**	666	**2,054**	2,061
Total fuel expense	**185**	187	**518**	541
Total capital expenditures	**476**	444	**1,335**	1,162
Less: Darlington Refurbishment capital and OM&A costs	**(328)**	(269)	**(943)**	(717)
Less: Other generation development project capital and OM&A costs	**(17)**	(42)	**(53)**	(121)
Add (Less): OM&A and fuel expenses (refundable through) deferred in regulatory variance and deferral accounts	**4**	35	**(19)**	76
Less: Nuclear fuel expense for non OPG-operated stations	**(13)**	(18)	**(42)**	(50)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**13**	5	**47**	38
Less: OM&A expenses ancillary to electricity generation business	**(4)**	(5)	**(13)**	(17)
Other adjustments	**(3)**	(12)	**(7)**	(15)
	948	991	**2,877**	2,958
Adjusted electricity generation *(TWh)*				
Total OPG electricity generation	**19.4**	19.5	**56.0**	59.9
Adjust for electricity generation forgone due to SBG conditions and OPG's share of electricity generation from co-owned facilities	**0.9**	0.1	**4.2**	3.4
	20.3	19.6	**60.2**	63.3
Enterprise TGC per MWh *($/MWh)* [1]	**46.65**	50.72	**47.77**	46.74

[1] Amounts may not calculate due to rounding.

(4) **Nuclear Total Generating Cost per MWh** is used to measure the cost performance of OPG's nuclear generating assets. Nuclear TGC per MWh is defined as OM&A expenses of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the nuclear electricity generation business), nuclear fuel expense for OPG-operated stations (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs) incurred during the period, divided by nuclear electricity generation for the period.

(millions of dollars – except where noted) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Nuclear TGC				
Regulated – Nuclear Generation OM&A expenses	**511**	521	**1,693**	1,665
Regulated – Nuclear Generation fuel expense	**81**	79	**217**	239
Regulated – Nuclear Generation capital expenditures	**409**	339	**1,150**	896
Less: Darlington Refurbishment capital and OM&A costs	**(328)**	(269)	**(943)**	(717)
Add: Regulated – Nuclear Generation OM&A and fuel expenses deferred in regulatory variance and deferral accounts	**5**	31	**6**	84
Less: Nuclear fuel expense for non OPG-operated stations	**(13)**	(18)	**(42)**	(50)
Less: Regulated - Nuclear Generation OM&A expenses ancillary to nuclear electricity generation business	**(1)**	(1)	**(3)**	(4)
Other adjustments	**1**	3	**(1)**	(1)
	665	685	**2,077**	2,112
Nuclear electricity generation (TWh)	**11.3**	11.7	**30.6**	34.6
Nuclear TGC per MWh (*$/MWh*) [1]	**58.75**	58.55	**67.87**	61.07

[1] Amounts may not calculate due to rounding.

(5) **Hydroelectric Total Generating Cost per MWh** is used to measure the cost performance of OPG's hydroelectric generating assets. Hydroelectric TGC per MWh is defined as OM&A expenses of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the hydroelectric electricity generation business), hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding expenditures related to the Peter Sutherland Sr. GS, Ranney Falls GS, and other hydroelectric generation development projects) incurred during the period, divided by total hydroelectric electricity generation plus hydroelectric electricity generation forgone due to SBG conditions during the period. OPG reports hydroelectric gross revenue charge and water rental payments as fuel expense.

(millions of dollars – except where noted) (unaudited)	**Three Months Ended September 30**		**Nine Months Ended September 30**	
	2017	**2016**	**2017**	**2016**
Hydroelectric TGC				
Regulated – Hydroelectric OM&A expenses	**81**	87	**232**	238
Regulated – Hydroelectric fuel expense	**88**	88	**258**	259
Contracted Generation Portfolio OM&A expenses	**39**	44	**118**	129
Contracted Generation Portfolio fuel expense	**15**	19	**42**	42
Regulated – Hydroelectric and Contracted Generation Portfolio capital expenditures	**56**	92	**141**	231
Less: Regulated – Hydroelectric and Contracted Generation Portfolio generation development project capital and OM&A costs	**(17)**	(41)	**(52)**	(117)
Less: Thermal OM&A and fuel expenses and capital expenditures in the Contracted Generation Portfolio	**(39)**	(51)	**(119)**	(126)
(Less) Add: Regulated – Hydroelectric OM&A and fuel expenses refundable through regulatory variance and deferral accounts	**(1)**	4	**(25)**	(8)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**13**	5	**47**	38
Other adjustments	**(1)**	(1)	**-**	(1)
	234	246	**642**	685
Adjusted hydroelectric electricity generation *(TWh)*				
Regulated – Hydroelectric electricity generation	**7.3**	6.9	**23.5**	22.8
Contracted Generation Portfolio electricity generation	**0.8**	0.9	**1.9**	2.5
Adjust for hydroelectric electricity generation forgone due to SBG conditions and non-hydroelectric electricity generation of the Contracted Generation Portfolio, including OPG's share of electricity generation from co-owned facilities	**0.8**	0.1	**4.1**	3.4
	8.9	7.9	**29.5**	28.7
Hydroelectric TGC per MWh *($/MWh)* [1]	**26.20**	31.01	**21.74**	23.99

[1] Amounts may not calculate due to rounding.

(6) **Gross margin** is defined as revenue less fuel expense.

For further information, please contact: Investor Relations 416-592-6700

webmaster@opg.com

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www.sedar.com

From: Ronald Kwan
To: John Kim
Subject: RE: EXTERNAL – RE: OPG Q3 2017 Submission to Province
Date: Monday, November 06, 2017 7:14:31 PM
Attachments: Q3 2017 OPG MDA - DRAFT - PROVINCE MAILING_EFB_CommentsV4_addressed by OPG_Markup.docx

---

Hi John,

I had a couple suggested edits, some comments and a question, as attached.

Ron

From: HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
Sent: November-06-17 18:19
To: John Kim <John.Kim@ofina.on.ca>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Subject: RE: EXTERNAL – RE: OPG Q3 2017 Submission to Province

Hi John,

Please see our responses to your comments. Let us know if you have any others. Thank you.

Regards,

Philip

Philip Ho, CPA, CA | Senior Manager, External Reporting & Accounting Policy | Ontario Power Generation
700 University Avenue, Toronto ON M5G 1X6 | Phone: (416) 592-3320| E-mail: philip.ho@opg.com

---

From: John Kim [mailto:John.Kim@ofina.on.ca]
Sent: Monday, October 30, 2017 6:16 PM
To: HO Philip -FIN & C CTRL <philip.ho@opg.com>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Subject: EXTERNAL – RE: OPG Q3 2017 Submission to Province

*** Exercise caution. This is an EXTERNAL email. DO NOT open attachments or click links from unknown senders or unexpected email. ***

Hi Philip,

See attached with our comments on the MD&A.

These are staff level comments as Ron has not had a chance to review.

Thanks,

John

From: HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
Sent: Wednesday, October 25, 2017 12:22 PM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>; 'Montgomery, Kaitlin (MOF)' <Kaitlin.Montgomery@ontario.ca>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>
Subject: OPG Q3 2017 Submission to Province

Hi All,

Please find attached OPG's draft Q3 2017 Financial Results Press Release, Management's Discussion and Analysis (MD&A), and Financial Statements for the Province's review.

We would greatly appreciate comments on the above **no later than Monday, Oct 30th**.

These documents will be filed with the Ontario Securities Commission on **Thursday, November 9th** following OPG's Board of Directors meeting.

Kindly forward all comments directly to Philip Ho – philip.ho@opg.com.

To assist the review process, the following are the key items in the Q3 2017 MD&A:

Highlights	
Recent Developments	MD&A p.10-11
Darlington Refurbishment	MD&A p.13-15
Ontario's Fair Hydro Plan	MD&A p.10-11

Philip Ho, CPA, CA | Senior Manager, External Reporting & Accounting Policy | Ontario Power Generation
700 University Avenue, Toronto ON M5G 1X6 | Phone: (416) 592-3320| E-mail: philip.ho@opg.com

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ONTARIO POWER GENERATION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

2017 THIRD QUARTER REPORT

[DRAFT]

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ONTARIO POWER GENERATION

ONTARIO POWER GENERATION INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) should be read in conjunction with the unaudited interim consolidated financial statements and accompanying notes of Ontario Power Generation Inc. (OPG or Company) as at and for the three and nine months ended September 30, 2017. OPG's unaudited interim consolidated financial statements are prepared in accordance with United States generally accepted accounting principles (US GAAP) and are presented in Canadian dollars.

For a complete description of OPG's corporate strategies, risk management, corporate governance, and the effect of critical accounting policies and estimates on OPG's results of operations and financial condition, this MD&A should also be read in conjunction with OPG's audited consolidated financial statements, accompanying notes, the Annual Information Form, and the MD&A as at and for the year ended December 31, 2016.

As required by *Ontario Regulation 395/11*, as amended, a regulation under the *Financial Administration Act* (Ontario), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. In 2014, the Ontario Securities Commission approved an exemption which allows OPG to apply US GAAP up to January 1, 2019. The term of the exemption is subject to certain conditions, which may result in the expiry of the exemption prior to January 1, 2019. For details, refer to the section, *Critical Accounting Policies and Estimates* under the heading, *Exemptive Relief for Reporting under US GAAP,* in OPG's 2016 annual MD&A. This MD&A is dated November 9, 2017.

FORWARD-LOOKING STATEMENTS

The MD&A contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could", and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

All forward-looking statements involve inherent assumptions, risks, and uncertainties, including those set out in the section, *Risk Management,* and forecasts discussed in the section, *Core Business, Strategy, and Outlook.* All forward-looking statements could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's generating station performance and availability, fuel costs, surplus baseload generation (SBG), cost of fixed asset removal and nuclear waste management, performance and earnings of investment funds, refurbishment of existing facilities, development and construction of new facilities, pension and other post-employment benefit (OPEB) obligations and funds, income taxes, proposed new legislation, the ongoing evolution of Ontario's electricity industry, environmental and other regulatory requirements, health, safety and environmental developments, business continuity events, the weather, financing and liquidity, applications to the Ontario Energy Board (OEB) for regulatory prices, the impact of regulatory decisions by the OEB, and forecasts of earnings, cash flows, Funds from Operations (FFO) Adjusted Interest Coverage, Return on Common Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI), Total Generating Cost (TGC) and capital expenditures. Accordingly, undue reliance should not be placed on any forward-looking statement. The forward-looking statements included in this MD&A are made only as of the date of this MD&A. Except as required by applicable securities laws, OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events, or otherwise.

THE COMPANY

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG was established under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (Province or Shareholder).

As at September 30, 2017, OPG's electricity generation portfolio had an in-service capacity of 16,210 megawatts (MW). OPG operates two nuclear generating stations, 66 hydroelectric generating stations, three thermal generating stations, and one wind power turbine. In addition, OPG and TransCanada Energy Ltd. co-own the 550 MW Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS). OPG and ATCO Power Canada Ltd. co-own the 560 MW Brighton Beach gas-fired combined cycle GS (Brighton Beach). OPG's 50 percent share of the in-service capacity and generation volume of these co-owned facilities is included in the generation portfolio statistics set out in this report. The income from the co-owned facilities is accounted for using the equity method of accounting, and OPG's share of income is presented as income from investments subject to significant influence in the Contracted Generation Portfolio segment.

OPG also owns two other nuclear generating stations, the Bruce A GS and the Bruce B GS, which are leased on a long-term basis to Bruce Power LP (Bruce Power). Income from these leased stations is included in revenue under the Regulated – Nuclear Generation segment. The leased stations are not included in the generation portfolio statistics set out in this report.

All of OPG's owned and co-owned generating facilities are located in Ontario. OPG does not operate PEC, Brighton Beach, the Bruce A GS and the Bruce B GS.

A description of OPG's segments is provided in OPG's 2016 annual MD&A in the section, *Business Segments*.

In-Service Generating Capacity

OPG's in-service generating capacity by business segment as at September 30, 2017 and December 31, 2016 was as follows:

	As at	
(MW)	**September 30 2017**	**December 31 2016**
Regulated – Nuclear Generation [1]	**5,728**	5,728
Regulated – Hydroelectric	**6,426**	6,421
Contracted Generation Portfolio [2]	**4,056**	4,028
Total	**16,210**	16,177

[1] The in-service generating capacity as of September 30, 2017 and December 31, 2016 excludes Unit 2 of the Darlington GS. The unit, which has a generating capacity of 878 MW, was taken offline in mid-October 2016 and is currently undergoing refurbishment.

[2] Includes OPG's share of in-service generating capacity of 275 MW for PEC and 280 MW for Brighton Beach.

During the nine months ended September 30, 2017, the total in-service capacity increased by 33 MW. The increase was primarily due to the completion of the Peter Sutherland Sr. hydroelectric GS, which was placed in-service at the end of the first quarter of 2017, and the upgrade of Unit 10 of the Sir Adam Beck 1 hydroelectric GS, which was completed in June 2017.

HIGHLIGHTS

Overview of Results

This section provides an overview of OPG's unaudited interim consolidated operating results. Significant factors which contributed to OPG's results during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, are discussed below.

(millions of dollars – except where noted) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Revenue	**1,217**	1,400	**3,539**	4,265
Fuel expense	**185**	187	**518**	541
Gross margin	**1,032**	1,213	**3,021**	3,724
Operations, maintenance and administration	**635**	666	**2,054**	2,061
Depreciation and amortization	**178**	313	**517**	941
Accretion on fixed asset removal and nuclear waste management liabilities	**235**	232	**709**	696
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(196)**	(248)	**(579)**	(620)
Income from investments subject to significant influence	**(11)**	(11)	**(29)**	(28)
Property taxes	**8**	12	**30**	35
	849	964	**2,702**	3,085
Income before other losses (gains), interest and income taxes	**183**	249	**319**	639
Other losses (gains)	**3**	1	**(380)**	(23)
Income before interest and income taxes	**180**	248	**699**	662
Net interest expense	**21**	28	**56**	92
Income before income taxes	**159**	220	**643**	570
Income tax expense	**19**	22	**128**	109
Net income	**140**	198	**515**	461
Net income attributable to the Shareholder	**131**	194	**498**	449
Net income attributable to non-controlling interest [1]	**9**	4	**17**	12
Electricity production (TWh) [2]	**19.4**	19.5	**56.0**	59.9
Cash flow provided by operating activities	**485**	530	**698**	1,211

[1] Relates to the 25 percent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in the Lower Mattagami Limited Partnership, the 33 percent interest of Coral Rapids Power Corporation, a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership, and the 10 percent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP.

[2] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

Third Quarter

Net income attributable to the Shareholder was $131 million for the third quarter of 2017, a decrease of $63 million compared to the same quarter in 2016. Income before interest and income taxes for the third quarter of 2017 was $180 million, a decrease of $68 million compared to the same quarter in 2016.

Commented [A1]:
Wondering if this should be 437?
Since:
Q3 9-mos ended – Q2 6-mos ended = 698-261 = 437

Was Q2 "6-month ended June 30" number for Cash flow provided by operating activities revised?

OPG: In Q3 2017, adjustments for non-cash balances related to Darlington Refurbishment capital expenditures have been reclassified from the "Net changes in non-cash working capital balances" line to the "Investment in property, plant and equipment and intangible assets" line. Comparative amounts have been reclassified accordingly.

Significant factors that reduced income before interest and income taxes:

- Lower earnings from the nuclear base regulated price of approximately $24 million reflecting lower electricity generation of 0.4 terawatt hours (TWh) from the Regulated – Nuclear Generation segment and the continuation of existing base regulated prices set by the OEB in 2014. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS since October 2016, largely offset by an increase in generation from Pickering GS. The increase in generation from the Pickering GS was primarily due to outage optimization, favourable unit conditions and execution of planned outage work. The base regulated prices set in 2014 continue to be in effect pending the OEB's decision on OPG's current application for new regulated prices, expected later in 2017. **[MONITOR]** The existing nuclear base regulated price was set to allow the Company to recover its approved nuclear costs over a higher nuclear production volume, based on the 2014 and 2015 outage profile that did not include a refurbishment outage. OPG has requested January 1, 2017 as the effective date of the new regulated prices.
- Lower earnings on the nuclear fixed asset removal and nuclear waste management funds (Nuclear Segregated Funds) of $52 million.
- Higher depreciation and amortization expense of $16 million in the Regulated – Nuclear Generation segment, excluding amortization expense related to balances in OEB-authorized regulatory variance and deferral accounts (regulatory accounts), primarily due to new assets in service.

The expiry of rate riders for the recovery of approved balances in OEB-authorized regulatory accounts on December 31, 2016 contributed to the decrease in revenue for the three months ended September 30, 2017, compared to the same period in 2016, but was largely offset by a decrease in the amortization expense related to these balances. OPG has requested new rate riders in its current application to the OEB for new regulated prices, with a proposed effective date of January 1, 2017.

Significant factor that increased income before interest and income taxes:

- Lower operations, maintenance and administration (OM&A) expenses of $31 million, mainly in the Regulated – Nuclear Generation segment, as a result of a higher materials and supplies obsolescence charge recognized in the third quarter of 2016, Services, Trading and Other Non-Generation segment due to project expenditures incurred in the third quarter of 2016, and Regulated – Hydroelectric segment due to the timing of repairs and maintenance work in 2017 and a deferral of outages during the high water period.

Net interest expense decreased by $7 million during the third quarter of 2017, compared to the same quarter in 2016, primarily due to a higher amount of interest costs capitalized for the Darlington Refurbishment project expenditures and a higher amount of interest costs deferred in OEB-authorized regulatory accounts.

Income tax expense for the three months ended September 30, 2017 was $19 million, compared to $22 million for the same period in 2016. The decrease in income tax expense was primarily due to lower income before taxes and a higher change in reserves from the resolution of uncertainties, partially offset by a lower amount of tax expense deferred in regulatory assets.

Year-To-Date

Net income attributable to the Shareholder was $498 million for the first nine months of 2017, an increase of $49 million compared to the same period in 2016. Income before interest and income taxes for the first nine months of 2017 was $699 million, an increase of $37 million compared to the same period in 2016.

Significant factor that increased income before interest and income taxes:

- Higher earnings of $390 million from the Services, Trading, and Other Non-Generation segment, primarily reflecting the gain on sale of OPG's head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street that was recognized in the second quarter of 2017. The sale of the

Commented [A2]: If approved by OEB (during Q4), would this result in a higher regulated price and a revenue/net income pick up for 2017 reported in OPG's Q4?

OPG – It depends on the effective date of the decision on the base regulated prices. If the OEB decision on the new base regulated prices are retrospectively effective as of Jan 1, 2017 for example, then it should result in a higher revenue/net income pick up for 2017 assuming the new regulated prices are higher.

assets was required by a Shareholder Declaration and a Shareholder Resolution. The gain on sale was $283 million, which is net of tax effects of $95 million.

Significant factors that reduced income before interest and income taxes:

- Lower earnings from the nuclear base regulated price of approximately $230 million, partially offset by a decrease in nuclear fuel expense of $22 million, reflecting lower electricity generation of 4.0 TWh from the Regulated – Nuclear Generation segment and the continuation of existing base regulated prices set by the OEB in 2014. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS, partially offset by an increase in generation from Pickering GS.
- Lower earnings on the Nuclear Segregated Funds of $41 million.
- Higher depreciation and amortization expense of $30 million in the Regulated – Nuclear Generation segment, excluding amortization expense related to regulatory account balances, primarily due to new assets in service.
- A gain of $22 million recorded in the first quarter of 2016 to reflect the OEB's decision on OPG's motion asking the OEB to review and vary parts of its November 2014 decision on OPG's regulated prices.

The expiry of rate riders for the recovery of approved balances in OEB-authorized regulatory accounts on December 31, 2016 contributed to the decrease in revenue for the nine months ended September 30, 2017, compared to the same period in 2016, but was primarily offset by a decrease in the amortization expense related to these balances.

Net interest expense decreased by $36 million for the nine months ended September 30, 2017, compared to the same period in 2016, primarily due to a higher amount of interest costs capitalized for the Darlington Refurbishment project expenditures and a higher amount of interest costs deferred in OEB-authorized regulatory accounts.

Commented [A3]: Does this imply there were interest costs related to Darlington Refurb previously (same quarter previous year), that were not capitalized, but were able to be capitalized this year?

OPG – There were higher Darlington Refurb project expenditures in 2017, compared to 2016.

Income tax expense for the nine months ended September 30, 2017 was $128 million, compared to $109 million for the same period in 2016. The increase in income tax expense was primarily due to higher income before income taxes.

Segment Results

The following table summarizes OPG's income before interest and income taxes by business segment. A detailed discussion of OPG's performance by reportable segment is included in the section, *Discussion of Operating Results by Business Segment*.

(millions of dollars)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Income (loss) before interest and income taxes				
Regulated – Nuclear Generation	**20**	47	**(267)**	17
Regulated – Hydroelectric	**122**	117	**474**	500
Contracted Generation Portfolio	**75**	74	**229**	219
Total electricity generation business segments	**217**	238	**436**	736
Regulated – Nuclear Waste Management	**(36)**	18	**(123)**	(70)
Services, Trading, and Other Non-Generation	**(1)**	(8)	**386**	(4)
	180	248	**699**	662

Electricity Generation

Electricity generation for the three and nine month periods ended September 30, 2017 and 2016 was as follows:

(TWh)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Regulated – Nuclear Generation	**11.3**	11.7	**30.6**	34.6
Regulated – Hydroelectric	**7.3**	6.9	**23.5**	22.8
Contracted Generation Portfolio [1]	**0.8**	0.9	**1.9**	2.5
Total OPG electricity generation	**19.4**	19.5	**56.0**	59.9
Total electricity generation by all other generators in Ontario [2]	**16.6**	19.5	**51.7**	53.8

[1] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.
[2] Non-OPG generation is calculated as the Ontario electricity demand plus net exports, as published by the Independent Electricity System Operator (IESO), minus OPG electricity generation.

Total OPG electricity generation decreased by 0.1 TWh during the third quarter of 2017, compared to the same quarter in 2016, and by 3.9 TWh during the nine months ended September 30, 2017, compared to the same period in 2016. As expected, the lower electricity generation from the Regulated – Nuclear Generation segment was primarily the result of the removal from service of Unit 2 at the Darlington GS for the duration of the unit's refurbishment, which began in October 2016. This decrease in electricity generation was largely offset by an increase in generation from the Pickering GS, primarily due to outage optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station, and higher hydroelectric generation from the Regulated – Hydroelectric segment.

The higher electricity generation of 0.4 TWh and 0.7 TWh from the Regulated – Hydroelectric segment for the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016, was due to higher water flows primarily on the eastern Ontario river systems, net of water spilled as a result of SBG conditions, discussed below.

The lower electricity generation of 0.6 TWh from the Contracted Generation Portfolio segment for the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to higher SBG conditions. The electricity generation from the Contracted Generation Portfolio segment for the three months ended September 30, 2017 was comparable to the same period in 2016.

OPG's operating results are impacted by changes in grid-supplied electricity demand resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. For the three and nine month periods ended September 30, 2017, Ontario's electricity demand as reported by the IESO was 33.6 TWh and 98.5 TWh, respectively, compared to 36.7 TWh and 103.8 TWh for the same periods in 2016, respectively, excluding electricity exports out of the province.

Power that is surplus to the Ontario market is managed by the IESO, mainly through generation reductions at hydroelectric, other grid-connected renewable resources and nuclear stations. Reducing hydroelectric production is the first measure used by the IESO to manage SBG conditions. Low demand conditions in Ontario continued to be prevalent in 2017, resulting in forgone hydroelectric generation for OPG of 1.1 TWh and 4.5 TWh due to SBG conditions in the three and nine month periods ended September 30, 2017, respectively, compared to 0.5 TWh and 3.9 TWh during the same periods in 2016, respectively. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions during these periods was offset by the impact of a regulatory variance account authorized by the OEB. OPG did not forgo any electricity production at its nuclear stations due to SBG conditions.

Average Sales Prices

The majority of OPG's generation is from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments. The same base regulated prices for electricity generated by these segments, authorized by the OEB effective November 1, 2014, were in effect during the first nine months of 2017 as in 2016. These prices will remain in effect until such time as the OEB approves new regulated prices based on OPG's current application. **[MONITOR]** The base regulated prices established in 2014 are discussed in OPG's 2016 annual MD&A in the section, *Revenue Mechanisms for Regulated and Non-Regulated Generation*.

The average sales price for the Regulated – Nuclear Generation segment was 5.8 cents per kilowatt hour (¢/kWh) during the three and nine month periods ended September 30, 2017, respectively, compared to 6.9 ¢/kWh during the same periods in 2016. The decrease in the average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized nuclear rate rider of $10.84 per megawatt hour (MWh) for the recovery of variance and deferral account balances. The average sales price for the Regulated – Hydroelectric segment was 4.1 ¢/kWh during the three and nine month periods ended September 30, 2017, respectively, compared to 4.4 ¢/kWh during the same periods in 2016. The decrease in the average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized regulated hydroelectric rate rider of $3.19/MWh for the recovery of variance and deferral account balances. The rate riders were established to recover approved balances recorded in the variance and deferral accounts in prior years. As such, the year-over-year changes in revenue from the rate riders were largely offset by changes in amortization expense related to these balances. There were no rate riders in effect during the nine months ended September 30, 2017 for either nuclear or regulated hydroelectric generation, pending the outcome of OPG's current application with the OEB for new regulated prices.

Cash Flow from Operations

Cash flow provided by operating activities was $485 million for the three months ended September 30, 2017 and $698 million for the nine months ended September 30, 2017, compared to $530 million and $1,211 million for the same periods in 2016, respectively. The decrease in cash flow provided by operating activities was expected and primarily due to lower generation revenue receipts reflecting lower generation from the Regulated – Nuclear Generation segment as a result of the ongoing refurbishment of Unit 2 at the Darlington GS and the expiry, on December 31, 2016, of the OEB-authorized rate riders for nuclear and regulated hydroelectric generation. The decrease in cash flow during the nine months ended September 30, 2017 was also due to higher income tax instalments.

The decrease in cash flow provided by operating activities for the three and nine month periods ended September 30, 2017 was partly offset by lower OM&A expenditures and lower contributions to the Used Fuel Segregated Fund in 2017. Both the Used Fuel Segregated Fund and the Decommissioning Segregated Fund were determined to be fully funded based on an updated estimate of OPG's nuclear waste management and nuclear facilities decommissioning obligations pursuant to a reference plan approved by the Province ~~for years 2017 to 2021,~~ under the Ontario Nuclear Funds Agreement (ONFA), effective January 1, 2017. Pursuant to the ONFA, the reference plan is required to be updated at least once every five years. Contributions to either or both of the Nuclear Segregated Funds may be required in the future should the funds be in an underfunded position at the time of the next ONFA reference plan update. The year-over-year decrease in cash flow also was partially offset by the payment of a supplemental rent rebate to Bruce Power in the first quarter of 2016 in relation to a period in 2015. The lease agreement for the Bruce nuclear generating stations was amended in late 2015 to eliminate this rebate provision going forward.

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Return on Common Equity Excluding Accumulated Other Comprehensive Income

ROE Excluding AOCI is an indicator of OPG's performance consistent with the Company's strategy to provide value to the Shareholder. ROE Excluding AOCI is measured over a 12-month period.

ROE Excluding AOCI was 4.4 percent for the 12 months ended September 30, 2017, compared to 4.2 percent for the 12 months ended December 31, 2016. The increase was primarily due to higher net income attributable to the Shareholder for the 12 months ended September 30, 2017, which reflected the gain on sale of OPG's head office premises and associated parking facility recorded in the second quarter of 2017, partially offset by the lower earnings from the decrease in nuclear electricity generation reflecting the Unit 2 refurbishment outage at the Darlington GS without a corresponding increase in the nuclear base regulated price, as expected. The lower nuclear generation as a result of the refurbishment outage will continue to negatively affect OPG's ROE Excluding AOCI until such time as new regulated prices are approved by the OEB, anticipated in the fourth quarter of 2017. **[MONITOR]**

Funds from Operations Adjusted Interest Coverage

FFO Adjusted Interest Coverage is an indicator of OPG's ability to meet interest obligations from operating cash flows. The indicator is measured over a 12-month period. FFO Adjusted Interest Coverage for the 12 months ended September 30, 2017 was 4.2 times, compared to 5.1 times for the 12 months ended December 31, 2016. FFO Adjusted Interest Coverage in 2017 reflected a year-over-year decrease in FFO before interest due to lower cash flow provided by operating activities, partially offset by the impact of a lower adjusted interest expense due to a decrease in the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets.

The decrease in the excess of interest on pension and OPEB benefit obligations over expected return on pension plan assets in the nine months of 2017 was primarily due to the change in the method used to estimate the interest cost and service cost components of pension and OPEB costs. Effective January 1, 2017, OPG adopted a full yield curve approach to the estimation of these cost components, by applying the specific spot rates along the yield curve used in the determination of the projected benefit obligations to the relevant projected cash flows. Under the previous method, these components of pension and OPEB costs were calculated using the same single weighted-average discount rates as reflected in the calculation of the benefit obligations. This change in the method was accounted for prospectively, as a change in estimate. The resulting reduction in pension and OPEB costs for the three and nine month periods ended September 30, 2017 did not have a material impact on net income as it was largely offset by the impact of OEB-authorized variance and deferral accounts in the regulated business segments. Further details on the full yield curve approach can be found in the 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Pension and Other Post-Employment Benefits*.

Commented [A4]: Does this have any implications for the methodology used for the IFRS adjustments for the purposes of the Province's Public Accounts?

Enterprise Total Generating Cost per MWh

The Enterprise TGC per MWh decreased to $46.65 for the three months ended September 30, 2017, compared to $50.72 for the same quarter in 2016. The decrease was mainly due to lower OM&A expenses before the impact of regulatory accounts and higher SBG-adjusted hydroelectric generation reflecting higher water flows.

The Enterprise TGC per MWh was $47.77 for the nine months ended September 30, 2017, an increase compared to $46.74 for the same period in 2016. The increase was expected and mainly a result of lower electricity generation due to the Unit 2 refurbishment outage at the Darlington GS, largely offset by lower OM&A expenses before the impact of regulatory accounts and higher SBG-adjusted hydroelectric generation reflecting higher water flows.

If Unit 2 at the Darlington GS was not currently undergoing refurbishment and had continued to operate in a manner consistent with the performance of the remaining units at the Darlington GS, adjusting for generation constraints on these units related to the transition of the station toward refurbishment, the Enterprise TGC would have been approximately $4 per MWh lower for both the three and nine month periods ended September 30, 2017. This sensitivity was calculated using the estimated incremental electricity and associated fuel cost that are expected to have resulted in the absence of the refurbishment.

Nuclear Total Generating Cost per MWh

The Nuclear TGC per MWh was $58.75 for the three months ended September 30, 2017, which was comparable to $58.55 for the same quarter in 2016. For the three months ended September 30, 2017, the higher generation at the Pickering GS and the impact of lower OM&A expenses before the impact of regulatory accounts was mostly offset by the expected decrease in nuclear electricity generation reflecting the Unit 2 refurbishment outage at the Darlington GS and higher sustaining capital expenditures. The Nuclear TGC per MWh was $67.87 for the nine months ended September 30, 2017, compared to $61.07 for the same period in 2016. The increase in the Nuclear TGC per MWh for the nine months ended September 30, 2017 was expected and primarily due to the decrease in nuclear electricity generation, partially offset by lower OM&A expenses before the impact of regulatory accounts.

Hydroelectric Total Generating Cost per MWh

The Hydroelectric TGC per MWh was $26.20 for the three months ended September 30, 2017, compared to $31.01 for the same quarter in 2016. The decrease was primarily due to higher SBG-adjusted hydroelectric electricity generation reflecting higher water flows. The Hydroelectric TGC per MWh was $21.74 for the nine months ended September 30, 2017, compared to $23.99 for the same period in 2016. The decrease was primarily due to lower OM&A expenses before the impact of regulatory accounts and lower sustaining capital expenditures.

ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are not measurements in accordance with US GAAP and should not be considered alternative measures to net income, cash flow provided by operating activities, or any other performance measure under US GAAP. OPG believes that these non-GAAP financial measures are effective indicators of its performance and are consistent with the Company's strategic imperatives and related objectives. The definition and calculation of ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are found in the section, *Supplementary Non-GAAP Financial Measures*.

Recent Developments

Ontario's 2017 Long Term Energy Plan

On October 26, 2017, Ontario's Ministry of Energy issued the 2017 Long Term Energy Plan. The Plan is currently being analyzed by OPG but is not expected to significantly impact OPG's business. There are no fundamental changes from the principles in the 2013 Long Term Energy Plan, which include cost effectiveness, reliability, clean energy and community engagement. The 2017 Long Term Energy Plan fully supports nuclear refurbishment projects in Ontario and the extension of commercial operation of all Pickering units to 2024. **[MONITOR & UPDATE DETAILS FOLLOWING RELEASE]**

OEB's Decision on New Regulated Prices **[MONITOR]**

Ontario's Fair Hydro Plan

OPG continues to prepare for its involvement as the Financial Services Manager for Ontario's Fair Hydro Plan (the Fair Hydro Plan) on a commercial basis. Accordingly, the financing entity was established in XX 2017 as the Fair Hydro Trust (the Trust), following the execution of its constating documents. The majority unitholder and beneficiary of the Trust is a wholly-owned subsidiary of OPG. Through this ownership and OPG's control over the key activities of the Trust, the Company will consolidate the Trust for accounting purposes commencing in the fourth quarter of 2017. **[MONITOR]**

In order for the Trust to provide financing for the deferred Global Adjustment costs, the Trust will incur senior debt from capital markets and subordinated debt from OPG. The Trust is structured to be bankruptcy remote and ring fenced from OPG to protect the Company's assets and operations. In support of the Fair Hydro Plan, the following developments have transpired:

Commented [A5]: Why not rephrase as acquiring the investment asset related to the deferred GA costs (right to future recovery)?

- In October 2017, *Ontario Regulation 206/17 General* was amended to establish details of the recovery mechanism for the monthly carrying costs incurred by the Trust from June 1, 2017 to July 31, 2021 payable by the IESO to the Trust. Originally established in June 2017, this regulation provides more details on the funding obligations incurred by the Trust and the fair allocation amount, the determination and collection of clean energy adjustments, the determination of the finance amount, the true up amount, and the regulatory asset, as well as principles and assumptions relating to the financing plan.
- A plan to amend the Company's Articles of Amalgamation to allow for the creation and issuance of Class A shares to be issued to the Province for its equity investment through OPG in the Fair Hydro Plan is in progress. The Province is expected to provide 44 percent of the total funding requirement related to the deferred Global Adjustment costs, which OPG will invest as subordinated debt into the Trust. OPG's Board approval and a Shareholder Resolution are expected later in the year to authorize the amendment.
- OPG is expected to provide five percent of the total funding requirement of the Trust related to the deferred Global Adjustment costs of the Fair Hydro Plan. OPG issued senior notes payable in October 2017 under a short form base shelf prospectus for general corporate purposes and to fund OPG's subordinated debt investment in the Trust. Further details of the debt offering can be found in the section, *Liquidity and Capital Resources* under the heading, *Financing Activities*.

Commented [A6]: Are any other details available to be released at this time?

OPG – Not for Q3 2017 reporting.

The first set of transactions of the Trust are expected to take place in the fourth quarter of 2017.

Canadian Nuclear Safety Commission Safety Rating for the Darlington GS and the Pickering GS

The Canadian Nuclear Safety Commission (CNSC) publishes an annual report on the safety performance of Canada's nuclear power plants. The report assesses how well plant operators are meeting regulatory requirements and program expectations in the areas of operational performance, safety analysis, radiation protection, waste management and conventional health and safety. On September 8, 2017, the CNSC issued an executive summary of its 2016 annual report. The CNSC gave both the Darlington GS and the Pickering GS the highest possible safety rating of "Fully Satisfactory". The Darlington GS achieved this rating for the eighth consecutive year, while the Pickering GS achieved this rating for the second consecutive year.

CORE BUSINESS, STRATEGY, AND OUTLOOK

The discussion in this section is qualified in its entirety by the cautionary statements included in the section, *Forward-Looking Statements,* at the beginning of the MD&A.

OPG's mission is to provide low cost power in a safe, clean, reliable and sustainable manner for the benefit of customers and its Shareholder. OPG also seeks to pursue, on a commercial basis, generation development projects and other business growth opportunities.

The following sections provide an update to OPG's disclosures in the 2016 annual MD&A related to its four key strategic imperatives – operational excellence, project excellence, financial strength, and social licence. A detailed discussion of these strategic imperatives is included in the 2016 annual MD&A in the section, *Core Business, Strategy, and Outlook*.

Operational Excellence

Operational excellence at OPG is accomplished by the safe and environmentally responsible generation of reliable and cost-effective electricity from the Company's generating assets through a highly trained and engaged workforce.

Electricity Generation Production and Reliability

- As part of the plan to extend Pickering operations, OPG is continuing to undertake the required technical work to confirm that the station's pressure tubes, a key life-limiting component of the station, will remain fit for service for operation to 2024. OPG is also nearing completion of component condition assessments to identify the work required to support the continued operation of the station. The accounting end of life assumptions for the Pickering GS, currently set at the end of 2020, will be reassessed based on the fuel channel analysis and safety case consistent with submissions for the CNSC approval, discussed below. The activities completed to date have had positive results, which will go towards re-confirming Pickering operations past 2020 are technically feasible. The Periodic Safety Review (PSR) is in progress and will confirm that extending operations of the Pickering units will be safe to the public, workers and the environment. The PSR consists of Safety Factor Reports (SFRs), a Global Assessment Report (GAR), and the Integration Improvement Plan (IIP). SFRs have been submitted to the CNSC and the GAR and IIP are on track for CNSC submission in October and November 2017, respectively. Other technical feasibility activities continue to progress as planned. Completion of various technical feasibility assessments are required to reach a high confidence conclusion to allow the station end of life to change for depreciation purposes. OPG's current application with the OEB for new base regulated prices, currently pending the OEB's decision, reflects OPG's plans to extend Pickering operations to 2024 and requests inclusion of the corresponding cost and generation impacts in the determination of the nuclear regulated price.
- OPG's current five-year operating licence for the Pickering GS was approved by the CNSC in 2013 and expires on August 31, 2018. This licence was issued assuming that the station would shut down in 2020. On June 28, 2017, OPG confirmed to the CNSC that it intends to cease commercial operation of all Pickering units on December 31, 2024. On August 28, 2017, OPG submitted a ten-year licence renewal application to the CNSC. The licence term spans the planned extended operations period, through to the end of commercial operation, defueling, dewatering and the start of placing the station in a safe storage state.
- Work continues on the rehabilitation of Unit 2 of the DeCew Falls hydroelectric GS and the rehabilitation and overhaul of Unit 2 of the Lower Notch hydroelectric GS.
- During the third quarter, a new control centre was opened at Saunders GS to merge its operations with Chenaux GS. The new control centre will overlook power production at ten hydroelectric stations along the Madawaska, Ottawa and St. Lawrence rivers.
- As part of the process to decommission the Nanticoke and Lambton generating stations, OPG has begun executing demolition plans that will ensure that the stations are closed safely, securely and in an environmentally responsible manner. The demolition of the Nanticoke coal yard equipment and structures is in progress, with a contract issued in July 2017 for the demolition of the Nanticoke powerhouse and associated structures. Project milestones for the Nanticoke site during the remainder of 2017 include completing the removal of coal yard equipment and structures, demolition of the ash silos, and mobilization of the contractor to prepare for removal of the stacks, powerhouse and associated structures. A competitive bidding process for the demolition of the Lambton GS has been completed, with a contract for the removal of the powerhouse and associated buildings expected to be awarded in 2018. An update of the associated asset retirement obligations related to the Nanticoke and Lambton sites is expected to be finalized in the fourth quarter of 2017.

Environmental Performance

There were no significant changes to environmental legislation affecting the Company during the third quarter of 2017. Disclosures related to the Company's environmental policy and environmental risks can be found in OPG's 2016 annual MD&A.

OPG communicates its environmental performance internally to employees and to external stakeholders, including the Ontario Ministry of the Environment and Climate Change, Environment and Climate Change Canada, the CNSC, and local communities. Details of OPG's environmental performance and initiatives to fulfill the Company's Environmental Policy can be found in OPG's 2016 Sustainability Report, available on the Company's website at www.opg.com. **[MONITOR]**

Project Excellence

OPG is pursuing a number of generation development and other major projects in support of Ontario's electricity planning initiatives. OPG remains focused on delivering projects safely, on time, on budget and with high quality. The status updates for OPG's major projects as at September 30, 2017 are outlined in the following table, with further details below.

Project	Capital expenditures		Approved budget	Expected in-service date	Current status
(millions of dollars)	**Year-to-date**	**Life-to-date**			
Darlington Refurbishment	924	4,109	12,800 [1]	First unit - 2020 Last unit - 2026	The setup of specialized tooling and equipment needed for the removal of reactor components was completed in the third quarter of 2017. All feeder tubes have been removed safely, and the pressure tubes have been severed in preparation for their removal. The Re-tube Waste Processing Building will be available for use in the fourth quarter of 2017. The project is tracking on schedule and on budget.
Peter Sutherland Sr. Hydroelectric GS	38	274	300	2017	The station was placed in-service on March 31, 2017, ahead of the originally planned schedule, and is expected to close below the approved budget. Project close-out activities are in progress.
Ranney Falls Hydroelectric GS	17	20	77	2019	Work is progressing on the expanded forebay, forebay wall concrete replacement, powerhouse and spillway areas. The project is tracking on schedule and on budget.
Nanticoke Solar Facility	1	2	107 **[MONITOR]**	2019	Project definition work is continuing, with construction planned to commence in the first quarter of 2018.
Deep Geologic Repository for low and intermediate level radioactive waste (L&ILW)	7 [2]	202 [2]			On August 21, 2017, the federal Minister of Environment and Climate Change requested further information on the project's environmental assessment (EA). OPG is reviewing the new request and will notify the Canadian Environmental Assessment Agency (CEAA) when it has a timeline for submission of that information.

[1] The total project budget of $12.8 billion is for the refurbishment of all four units at the Darlington GS.
[2] Expenditures are charged against the nuclear fixed asset removal and nuclear waste management liabilities (Nuclear Liabilities).

Commented [A7]: Does this imply that only 700M further is anticipated to be spent by the time Unit 2 gets completed? (Eg. 4.8B in Capital Expenditure)

Eg. from above:
"Once refurbished, Unit 2 is scheduled to be returned to service in the first quarter of 2020, at which time capital expenditures of approximately $4.8 billion are planned to be placed in service."

OPG – No, the LTD in the table includes prerequisite projects already declared in-service. The $4.8B was the OEB submitted estimate of a future in-service amount for Unit 2 refurbishment.

Please see updated wording below:

OPG's current application with the OEB for new regulated prices seeks an increase in the nuclear rate base, effective in the first quarter of 2020, to reflect the planned placement in service of the $4.8 billion in capital expenditures upon return to service of Unit 2, which includes expenditures incurred during the definition and planning phase of the project. Based on OPG's proposal in the application, the revenue requirement impact of the differences between the Unit 2 in-service amount included in the regulated prices and the actual amounts placed in service would be subject to true up via the Capacity Refurbishment Variance Account established by the OEB pursuant to *Ontario Regulation 53/05*. OPG's application proposes that the recovery of the HWSF's costs through regulated prices be subject to a separate prudence review by the OEB, to be conducted as part of a future OEB application.

Darlington Refurbishment

The Darlington generating units are approaching their originally designed end-of-life. Refurbishment of the four generating units is expected to extend the operating life of the station by approximately 30 years. OPG commenced the planning of the refurbishment in 2010.

In 2016, the Darlington Refurbishment project transitioned from the planning phase to the execution phase, as OPG commenced the refurbishment of the first unit, Unit 2, in October 2016, as planned. The unit was taken offline on October 15, 2016. De-fuelling of the reactor, the first critical refurbishment activity undertaken once the unit is removed from service, was completed safely in January 2017, with a total of 480 fuel channels de-fuelled. Islanding of Unit 2, the physical separation of the unit under refurbishment from the three operating units, was completed in April 2017, signifying the completion of the first major segment of the project.

The second major segment includes preparatory work to support the removal of feeder tubes and fuel channel assemblies and the removal of reactor components. The preparatory work was completed in the second quarter of 2017. The Re-tube Tooling Platform for hosting the tooling for the removal, inspection, and installation activities and the setup of specialized tooling and equipment needed for the removal and replacement of the reactor components were completed in the third quarter of 2017. The disassembly of reactor components commenced in August 2017, with the removal of all 960 feeder tubes completed safely in September 2017. This was followed by the severing of pressure tubes, with the severing of bellows and the removal of end fittings expected to commence thereafter and through the end of 2017. Other key project activities executed during the second segment include the completion of the primary side steam generator layup, installation of steam generator access ports to support future inspections, continuation of the major turbine generator overhaul and continued execution of the major electrical scope. OPG is also continuing to execute work to support the requirements set out in the CNSC approved IIP for the station.

Once refurbished, Unit 2 is scheduled to be returned to service in the first quarter of 2020, at which time capital expenditures of approximately $4.8 billion are planned to be placed in service. This includes expenditures incurred during the definition and planning phase of the overall project. The project is tracking on schedule and on budget.

With the substantial completion of the Re-tube Waste Processing Building in November 2017, 17 out of 18 pre-requisite projects in support of the execution phase of the project, including construction of facilities, infrastructure upgrades and installation of safety enhancements, have been completed and placed in service. Completion of the Heavy Water Storage and Drum Handling Facility (HWSF) has been delayed due to challenges with construction. OPG suspended the project in the second quarter of 2017 to evaluate the best approach to optimize cost and schedule and complete the project. Construction activities for the HWSF recommenced in the fourth quarter of 2017 following substantial completion of the Re-tube Waste Processing Building. This plan ensures that the necessary resources are available for both projects and, through resource levelling, improves their execution and cost efficiency. The delay in the completion of the HWSF will not impact the overall Darlington Refurbishment project schedule, as the HWSF is not on the project's critical path. This also will not impact the overall project budget of $12.8 billion, as the costs of the HWSF are included in this total figure. The recovery of HWSF costs through regulated prices will be subject to a prudence review by the OEB, which OPG has proposed be conducted as part of a future OEB application.

In addition to the execution of refurbishment activities on Unit 2, OPG is continuing planning activities for the refurbishment of the second unit, Unit 3, and is entering into associated commitments to procure major components that require long lead times. As of September 30, 2017, $70 million has been invested in planning activities related to the refurbishment of the second unit, Unit 3. These planning activities are being undertaken in accordance with the refurbishment project schedule.

The Financial Accountability Office of Ontario has issued a report titled "*An Assessment of the Financial Risks of the Nuclear Refurbishment Plan*". The report assesses both OPG and Bruce Power's refurbishment activities and the method in which those refurbishments and subsequent nuclear generation is provided to the marketplace. The report

concludes that the base case of refurbishing the six units at the Bruce nuclear GS and the four units at the Darlington nuclear GS provide the most cost effective, low emission generation source available to meet Ontario's baseload electricity requirements. This report re-affirms the positive economic and societal benefits associated with a strong nuclear program in the Province. **[MONITOR]**

Commented [A8]: Not yet released.

OPG – We put MONITOR to ensure status next Thursday before we release.

Ranney Falls Hydroelectric GS

During the third quarter of 2017, OPG continued construction work for a 10 MW single-unit powerhouse on the existing Ranney Falls GS site, as part of the Regulated – Hydroelectric segment. The new unit will replace an existing unit that reached its end of life in 2014. The existing forebay structure demolition has been completed and the upstream cofferdam has been constructed ahead of schedule. Construction continues on the expanded forebay, powerhouse and spillway. Excavation work is substantially complete and forebay wall concrete replacement is in progress. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget.

Nanticoke Solar Facility

The construction of a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands under a Large Renewable Procurement contract with the IESO, through Nanticoke Solar LP, a partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation, is planned to commence in the first quarter of 2018. During the third quarter of 2017, the partnership continued work to obtain approvals and permits required to enable the commencement of construction, and progressed procurement activities for equipment and for engineering and construction services. The facility is expected to be completed in the first quarter of 2019.

Deep Geologic Repository for Low and Intermediate Level Waste

OPG has proposed a deep geologic repository as the preferred solution for the safe long-term management of the L&ILW produced from the continued operation of OPG-owned nuclear generating stations. Agreement has been reached with local municipalities for OPG to develop the L&ILW Deep Geologic Repository (DGR) on lands adjacent to the Western Waste Management Facility (WWMF) in Kincardine, Ontario. The environmental effects of the proposed L&ILW DGR were examined by the CNSC and CEAA-appointed Joint Review Panel (JRP) to meet the requirements of the Canadian Environmental Assessment Act. The JRP submitted its report on the EA to the federal Minister of Environment in May 2015, concluding that, given mitigation, there is unlikely to be significant environmental impact from the project and recommending that the Minister approve the EA. In December 2016, at the request of the federal Minister of Environment and Climate Change, OPG submitted additional information on certain aspects of the EA, including information related to alternate locations for the project. Following its review of OPG's submission and a period of public comment, the CEAA requested further information that OPG subsequently provided in May 2017. In June 2017, the CEAA notified OPG that it had sufficient and adequate information to proceed with the next step of the environmental assessment process and advised that a draft report and updated terms and conditions will be prepared for public review.

On August 21, 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of potential cumulative effects of the project on the Saugeen Ojibway Nations' (SON) physical and cultural heritage, including a description of the potential effects of the project on the Nation's spiritual and cultural connection to the land. OPG is assessing the request and will notify the CEAA when it has determined the timeline for developing a response. The CEAA's draft report for public review will not be issued until this update is provided. The L&ILW DGR at the WWMF site remains OPG's preferred solution for the safe long-term management of the L&ILW.

OPG continues its engagement with the SON toward securing community support for the L&ILW DGR. The in-service date of the L&ILW DGR is expected to be approximately six to seven years from the start of construction.

Financial Strength

As a commercial enterprise, OPG's financial priority is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future growth.

Increase Revenue, Reduce Costs and Achieve Appropriate Return

In May 2016, OPG filed a 5-year application with the OEB for new regulated prices for production from its regulated hydroelectric and nuclear facilities, with a proposed effective date of January 1, 2017. Consistent with the requirements of *Ontario Regulation 53/05*, the application incorporates a rate smoothing proposal that would defer, for future collection, a portion of the approved annual nuclear revenue requirement for the period from January 1, 2017 to the end of the Darlington Refurbishment project, with a view to making changes in OPG's regulated prices more stable year-over-year. The application seeks to ensure that nuclear regulated prices under the rate smoothing approach allow for sufficient cash flow to meet the Company's liquidity needs, support cost effective funding for the Darlington Refurbishment project and other expenditures, and maintain the Company's investment grade credit rating, while taking into account both near-term and future impacts on customers. OPG expects to recognize amounts deferred under rate smoothing as income in the periods to which the underlying approved revenue requirements relate.

The application will further challenge and incentivize OPG to find additional cost reductions and efficiencies within its operations, as a result of greater de-coupling of nuclear and hydroelectric regulated prices from costs and a longer rate-setting period under the OEB's incentive ratemaking framework, which forms the basis for the ratemaking methodologies reflected in the application.

The application seeks an increase in the nuclear rate base, effective in early 2020, to reflect the planned placement in service of approximately $4.8 billion of capital expenditures upon the scheduled return to service of Unit 2 at the Darlington GS as part of the Darlington Refurbishment project and, effective in 2017, an increase in the deemed capital structure applied to the total regulated rate base to 49 percent equity and 51 percent debt, from 45 percent equity and 55 percent debt reflected in the existing regulated prices. The application also requests new rate riders, effective January 1, 2017, to recover or repay the December 31, 2015 balances in all of the Company's OEB-authorized variance and deferral accounts, with the exception of the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the portion of these balances previously approved for recovery or repayment through rate riders that were in effect during 2016.

The OEB's decision on the application, including the effective date of approved new regulated prices, is expected later in 2017. **[MONITOR]**

For generation assets that do not form part of the assets regulated by the OEB, OPG's strategy has been to secure appropriate long-term revenue arrangements. In line with this strategy, virtually all of OPG's non-regulated operating facilities and assets under construction are subject to long-term Energy Supply Agreements (ESAs) or other long-term contracts with the IESO.

Ensure Availability of Cost Effective Funding

In April 2017, DBRS Limited (DBRS) re-affirmed the long-term credit rating on OPG's debt at 'A (low)' and OPG's commercial paper rating at 'R-1 (low)'. All ratings from DBRS have a stable outlook. In July 2017, S&P Global Ratings (S&P) re-affirmed OPG's long-term credit rating at 'BBB+' with a stable outlook. S&P's commercial paper rating for OPG is 'A-1 (low)'.

Social Licence

As the largest electricity generator in Ontario with diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust. OPG is committed to maintaining high standards of public safety and corporate citizenship, including environmental stewardship, transparency, community engagement, and Indigenous relations.

OPG is focused on building long-term, mutually beneficial working relationships with Indigenous communities, businesses and organizations across Ontario, and continues to support procurement, employment and educational opportunities with its Indigenous community partners. The Company seeks to establish these relationships based on a foundation of respect for the languages, customs, and political, social and cultural organizations of the Indigenous communities.

In June 2017, OPG launched an Indigenous Business Engagement (IBE) Initiative. The purpose of this initiative is to increase access to procurement opportunities for Indigenous businesses interested in supplying materials and services to OPG. The IBE Initiative is based on a strategy that will identify opportunities in contracts, scopes of work and business plans for potential Indigenous business engagement; include criteria related to suppliers' ability to engage or partner with Indigenous people or businesses in assessing procurement proposals; and invest in relationships with Indigenous communities by increasing outreach efforts to enhance understanding of how to do business with OPG. OPG has continued to engage with various Indigenous business and communities as well as its suppliers to promote the IBE Initiative. In September 2017, OPG presented the IBE to the Mohawk Council of Akwesanse (Akwesanse). As a result, Akwesanse plans to create a database of businesses in the community that will participate in contracting and supply opportunities with OPG. In September 2017, OPG also hosted a similar presentation to the Williams Treaties First Nations, located proximate to the Pickering and Darlington Nuclear Generating Stations, at the quarterly meeting for these communities.

OPG is developing recruitment plans targeting Indigenous people. In October 2017, OPG participated in five Indigenous-specific career fairs to attract such talent. **[MONITOR]**

OPG has a transportation electrification strategy that will help position OPG as a leader in transportation electrification in Ontario. This strategy is intended to leverage OPG's clean electricity to support action on climate change, create growth opportunities for OPG, and enhance OPG's brand and social licence.

Outlook

The financial performance of OPG's regulated operations is driven, in large part, by the outcome of applications for regulated prices to the OEB. The existing base regulated prices were established by the OEB effective November 1, 2014 based on a forecast of costs and production for the regulated facilities for the 2014 to 2015 period. The future outcome of OPG's current application for new regulated prices, currently pending the OEB's decision, is expected to provide substantial price certainty for the regulated business for the 2017 to 2021 period.

In its application, OPG has requested January 1, 2017 as the effective date for the new regulated prices. In December 2016, the OEB issued an order declaring the existing base regulated prices interim, which preserves the OEB's ability to make the new regulated prices effective as early as January 1, 2017. Considering the timing of OPG's application and OPG's procedural adherence throughout the proceeding, the Company believes that the OEB could make the new regulated prices effective January 1, 2017. This would allow OPG to recover the difference between the approved new regulated prices and the existing regulated prices for the period between January 1, 2017 and the implementation date of the new prices based on the OEB's order. The OEB's decision on the application, including the effective date of the new regulated prices, is expected in the fourth quarter of 2017. **[MONITOR]** The continuation of existing regulated prices until the issuance of the OEB's decision is expected to continue to contribute to lower income, particularly from the Regulated – Nuclear Generation segment, and, excluding the gain on sale of the Company's head office premises and associated parking facility recorded in the second quarter of 2017, lower

Commented [A9]: Sp. "Akwesasne" ?

OPG – fixed spelling to as follows:

In September 2017, OPG presented the IBE to the Mohawk Council of Akwesasne (Akwesasne). As a result, the Akwesasne plan to create a database of businesses in the community that will participate in contracting and supply opportunities with OPG.

Commented [A10]: Does this deal with OPG owned fleet and other vehicles, or in line with the infrastructure for EV vehicles.

Can further details be provided in particular on the point of 'creating growth opportunities for OPG'.

OPG – revised wording for this paragraph as follows:

OPG has a strategy to help position the Company as a leader in transportation electrification in the province. The strategy aims to leverage the Company's clean, reliable and cost-effective electricity to power transportation, capitalize on future commercial growth opportunities, and enhance the Company's social licence. OPG is pursuing initiatives to increase the use of electric vehicles within its operations, and is assessing vehicle grid integration and hydrogen applications for the transportation sector.

ROE Excluding AOCI during 2017, compared to 2016. In large part, this is due to the year-over-year reduction in nuclear electricity generation resulting from the Unit 2 refurbishment outage at the Darlington GS, given that the existing nuclear regulated prices were determined in 2014 based on a higher production forecast that reflected the operation of all four units at the station. As such, the OEB's decision on the effective date of the new regulated prices, as well as the timing of the decision issuance, could have a significant impact on OPG's financial results during 2017.

Nuclear base regulated prices resulting from OPG's current application will be subject to a rate smoothing mechanism that defers collection of a portion of OEB-approved revenues to future periods. As expected, combined with the expiry of rate riders in effect to the end of 2016, a year-over-year reduction in nuclear generation due to the Unit 2 refurbishment outage at the Darlington GS and the continuation of existing regulated prices until such time as new prices are implemented by the OEB, this will result in lower cash flow from operating activities in 2017, compared to 2016. OPG expects to continue to have the necessary financial capacity and sufficient access to cost effective financing sources to continue to fund its capital requirements and other disbursements.

Lower nuclear generation due to the Darlington Refurbishment outages will continue, as planned, to negatively impact the Enterprise TGC metric for the duration of the refurbishment project. Variability in sustaining capital investment expenditures, including major sustaining projects for the hydroelectric operations, also will impact the Enterprise TGC in future periods.

Several OEB-authorized regulatory variance and deferral accounts currently in place contribute to reducing the relative variability of the Company's income and ROE Excluding AOCI. Among others, the regulatory accounts include those related to the revenue impact of variability in water flows and forgone production due to SBG conditions at the regulated hydroelectric stations. As there are no variance or deferral accounts in place related to the impact of generation performance of the nuclear stations on revenue from base regulated prices, the Regulated – Hydroelectric segment generally is expected to produce overall more predictable earnings. OPG continues to operate and maintain its nuclear facilities with a view to optimize their performance and availability, while focusing on improving the overall reliability and predictability of the fleet.

Electricity generated from most of OPG's non-regulated assets is subject to ESAs with the IESO. Based on these agreements, OPG expects the Contracted Generation Portfolio segment to continue to contribute a generally stable level of earnings and cash flow from operations going forward.

OPG's total forecast capital expenditures for the 2017 year are approximately $2.0 billion. This includes amounts for the Darlington Refurbishment project, hydroelectric and other development projects including the completion of the Peter Sutherland Sr. GS and the expansion of the Ranney Falls GS, and sustaining capital investments across the generating fleet. OPG's major projects are discussed in the section, *Project Excellence*.

In addition to the operating and financial performance of the electricity generation business, OPG's results are affected by the earnings on the Nuclear Segregated Funds, which are reported in the Regulated – Nuclear Waste Management segment. While the Nuclear Segregated Funds are managed to achieve, in the long term, the target rate of return based on the discount rate specified in the ONFA, the rates of return earned in a given period can be subject to various external factors including financial market conditions and, for the portion of the Used Fuel Segregated Fund guaranteed by the Province under the ONFA, changes in the Ontario consumer price index (CPI). In the near term, these factors can be volatile and cause fluctuations in the Company's income. This volatility is partially mitigated by the impact of the OEB-authorized Bruce Lease Net Revenues Variance Account and, as discussed below, the funded status of the two segregated funds.

As OPG does not have the right to withdraw surplus amounts from the Nuclear Segregated Funds, OPG limits the amount of Nuclear Segregated Funds assets reported on the balance sheet to the present value of such life cycle funding liability. This reduces the volatility of earnings on the Nuclear Segregated Funds reflected in net income when the funds are in a fully funded or overfunded position. As at September 30, 2017, the Decommissioning

Segregated Fund was overfunded by approximately 23 percent, and the Used Fuel Segregated Fund was marginally overfunded, by less than one percent, based on the 2017 ONFA Reference Plan. Variability in asset performance due to volatility inherent in financial markets and changes in Ontario CPI, or changes in funding liability estimates, may result in either or both funds becoming underfunded in the future.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

Regulated – Nuclear Generation Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue	**739**	885	**2,000**	2,631
Fuel expense	**81**	79	**217**	239
Gross margin	**658**	806	**1,783**	2,392
Operations, maintenance and administration	**511**	521	**1,693**	1,665
Depreciation and amortization	**116**	230	**333**	691
Property taxes	**7**	6	**20**	19
Income (loss) before other losses, interest, and income taxes	**24**	49	**(263)**	17
Other losses	**4**	2	**4**	-
Income (loss) before interest and income taxes	**20**	47	**(267)**	17

For the three and nine month periods ended September 30, 2017, the segment earnings decreased by $27 million and $284 million, respectively, compared to the same periods in 2016. The decrease in earnings was expected and primarily due to reduced revenue from the nuclear base regulated price of approximately $24 million and $230 million, respectively. The decrease was partially offset by an associated year-over-year decrease in fuel expense. The decrease in revenue during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, reflected lower electricity generation of 0.4 TWh and 4.0 TWh, respectively, primarily due to the ongoing Unit 2 refurbishment outage at the Darlington GS that began in October 2016, without a corresponding increase in the base regulated price. The existing nuclear base regulated price set by the OEB in 2014 continues to be in effect pending the OEB's decision on OPG's application for new regulated prices, proposed to be effective on January 1, 2017. The existing price does not reflect the lower generation as a result of the Darlington Refurbishment project, as it was set to allow the Company to recover its approved nuclear costs over a higher nuclear production volume, based on the 2014 and 2015 outage profile that did not include a refurbishment outage. The reduction in nuclear electricity generation for the three months ended September 30, 2017 was largely offset by the higher electricity generation from the Pickering GS.

OM&A expenses decreased by $10 million during the third quarter of 2017, compared to the same period in 2016, as a result of a higher materials and supplies obsolescence charge recognized in 2016. OM&A expenses increased by $28 million during the nine months ended September 30, 2017, compared to the same period in 2016, due to planned maintenance activities in 2017.

Depreciation and amortization expense, excluding amortization expense related to regulatory account balances, increased by $16 million and $30 million during the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016, primarily due to new assets in service.

The expiry of an OEB-authorized nuclear rate rider on December 31, 2016 contributed to the decrease in segment revenue for the three and nine month periods ended September 30, 2017, compared to the same periods in 2016. As rate riders allow for recovery of approved balances in OEB-authorized regulatory accounts, this decrease in revenue was largely offset by a decrease in amortization expense related to these balances. There was no rate rider

in effect during the nine months ended September 30, 2017, pending the outcome of OPG's current application to the OEB for new regulated prices.

The Unit Capability Factors for the Darlington and Pickering generating stations were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Unit Capability Factor *(%)* [1]				
Darlington GS	**96.2**	89.6	**82.1**	87.6
Pickering GS	**88.7**	77.3	**83.8**	73.8

[1] The nuclear Unit Capability Factor excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS was excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

The Unit Capability Factor at the Darlington GS increased in the third quarter of 2017, compared to the same quarter in 2016, primarily due to the lower number of planned outage days during the third quarter of 2017. The lower Unit Capability Factor at the Darlington GS for the nine months ended September 30, 2017, compared to the same period in 2016, reflected the higher number of planned outage days, largely driven by constraints related to the transition of the station toward refurbishment.

The increase in Unit Capability Factor at the Pickering GS for the three and nine month periods ended September 30, 2017 was primarily due to outage optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station compared to 2016.

Regulated – Nuclear Waste Management Segment

(millions of dollars) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Revenue	**33**	36	**90**	102
Operations, maintenance and administration	**35**	38	**96**	108
Accretion on nuclear fixed asset removal and nuclear waste management liabilities	**230**	228	**696**	684
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(196)**	(248)	**(579)**	(620)
(Loss) Income before interest and income taxes	**(36)**	18	**(123)**	(70)

The segment loss before interest and income taxes was $36 million and $123 million during the three and nine months ended September 30, 2017, respectively, a decrease in earnings of $54 million and $53 million compared to the same periods in 2016. The decline in earnings was primarily due to lower earnings from the Nuclear Segregated Funds, net of the impact of the impact of the Bruce Lease Net Revenues Variance Account, reflecting higher earnings from market returns on fund assets and the CPI-adjusted rate of return guaranteed by the Province for the portion of the Used Fuel Segregated Fund related to the initial 2.23 million used fuel bundles (committed return) in the third quarter of 2016.

As both the Decommissioning Segregated Fund and the Used Fuel Fund were in an overfunded position during the three and nine months period ended September 30, 2017, compared to the underlying funding liabilities per the approved ONFA Reference Plan, the earnings on the funds during these periods reflected the growth rate in the present value of the funding liabilities and were not impacted by market returns and committed return. The higher earnings on both funds during the three and nine months periods ended September 30, 2016 reflected market returns and committed return, as the Decommissioning Segregated Fund became over 120 percent funded during the third quarter of 2016 while the Used Fuel Fund was underfunded, compared to the corresponding funding liabilities.

Higher market returns and committed return in the third quarter of 2016 in relation to the funding liabilities' growth rate reflected in fund earnings during 2017 resulted in a year-over-year decrease in the amount of earnings on the Nuclear Segregated Funds.

As of December 31, 2016, OPG recorded a decrease of approximately $1,570 million to the Nuclear Liabilities and associated asset retirement costs capitalized as part of the carrying value of the nuclear generating stations. The resulting year-over-year decreases in accretion on fixed asset removal and nuclear waste management liabilities recorded in the Regulated – Nuclear Waste Management segment and depreciation and fuel expenses recorded in the Regulated – Nuclear Generation segment during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, were offset by the impact of the Bruce Lease Net Revenues Variance Account and the Nuclear Liability Deferral Account authorized by the OEB.

Under the current OEB-approved cost recovery methodology, these changes in expenses also are not expected to materially affect OPG's income during the rest of 2017, as they are expected to continue to be largely offset by the impact of the regulatory accounts until such time as the OEB implements corresponding changes to OPG's nuclear regulated prices, and subsequently by the impact of such new regulated prices. Further details on the change in the estimate of the Nuclear Liabilities as of December 31, 2016 are described in OPG's 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Asset Retirement Obligation*. **[MONITOR]**

Regulated – Hydroelectric Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue [1]	**327**	350	**1,069**	1,148
Fuel expense	**88**	88	**258**	259
Gross margin	**239**	262	**811**	889
Operations, maintenance and administration	**81**	87	**232**	238
Depreciation and amortization	**34**	56	**103**	169
Property tax	**1**	1	**1**	1
Income before other losses (gains), interest and income taxes	**123**	118	**475**	481
Other losses (gains)	**1**	1	**1**	(19)
Income before interest and income taxes	**122**	117	**474**	500

[1] During the three and nine month periods ended September 30, 2017, the Regulated – Hydroelectric segment revenue included incentive payments of $4 million and $9 million, respectively, related to the OEB-approved hydroelectric incentive mechanism (three and nine month periods ended September 30, 2016 – incentive payments of $6 million and $8 million, respectively). The mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers. The incentive payments are reduced to remove incentive revenues arising in connection with SBG conditions.

The increase in segment income before interest and income taxes of $5 million during the third quarter of 2017, compared to the same quarter in 2016, was primarily the result of a decrease in OM&A expenses, mainly due to the timing of repairs and maintenance work in 2017 and a deferral of outages during the high water period.

The decrease in segment income before interest and income taxes of $26 million during the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to a gain of $22 million recognized during the first quarter of 2016 to reflect the OEB's January 2016 decision to reverse a portion of an earlier capital cost disallowance related to the Niagara Tunnel project expenditures, in response to a motion by OPG. The income impact of OEB-approved variance accounts also contributed to the year-over-year decrease in income for the period. These factors were partially offset by the decrease in OM&A expenses related to the timing of repairs and maintenance work in 2017 and a deferral of outages during the high water period.

The decrease in revenue from the segment for the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was largely due to the expiry of an OEB-authorized rate rider on

December 31, 2016. As the rider allowed for the recovery of approved balances in OEB-authorized regulatory accounts, the resulting reduction in revenue was largely offset by lower amortization expense related to these balances. There was no rate rider in effect during the first nine months of 2017 pending the outcome of OPG's current application to the OEB for new regulated prices.

The Hydroelectric Availability for the stations included in the Regulated – Hydroelectric segment was as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Hydroelectric Availability *(%)*	**87.6**	84.1	**89.0**	89.8

The Hydroelectric Availability in the third quarter of 2017 was higher compared to the same period in 2016, primarily due to a higher number of planned outages in 2016 as a result of the refurbishment of the Sir Adam Beck Pump GS reservoir between April 2016 and February 2017. The marginal decrease in Hydroelectric Availability during the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to a higher number of unplanned outage days at the Northwestern Ontario and Niagara region hydroelectric stations, partially offset by higher availability from the Sir Adam Beck Pump GS.

Contracted Generation Portfolio Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue	**141**	149	**431**	431
Fuel expense	**15**	19	**42**	42
Gross margin	**126**	130	**389**	389
Operations, maintenance and administration	**39**	44	**118**	129
Depreciation and amortization	**20**	19	**59**	56
Accretion on fixed asset removal liabilities	**3**	2	**7**	6
Property taxes	**-**	1	**5**	6
Income from investments subject to significant influence	**(11)**	(11)	**(29)**	(28)
Income before other loss, interest and income taxes	**75**	75	**229**	220
Other loss	**-**	1	**-**	1
Income before interest and income taxes	**75**	74	**229**	219

Income before interest and income taxes from the segment increased by $1 million and $10 million during the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016. The increase in earnings for the three months ended September 30, 2017 mainly resulted from revenues from the Peter Sutherland Sr. GS that was placed in-service at the end of the first quarter of 2017 and lower OM&A expenses, partially offset by lower revenue from the Atikokan GS. The decrease in revenue from the Atikokan GS was primarily due to higher revenues in 2016, when the station was called upon to provide the needed support to the electricity system in Northwestern Ontario as a result of an outage at a local transformer station. For the nine months ended September 30, 2017, the increase in earnings was primarily due to lower OM&A expenses. The lower OM&A expenses for the three and nine month periods ended September 30, 2017 were mainly due to the prospective adoption of the full yield curve approach to the estimation of the service and interest cost components of pension and OPEB costs starting in 2017.

The Hydroelectric Availability and the Thermal Equivalent Forced Outage Rate (EFOR) for the Contracted Generation Portfolio segment were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Hydroelectric Availability *(%)*	**66.1**	68.2	**76.9**	79.6
Thermal EFOR *(%)*	**2.6**	2.1	**6.0**	1.3

Lower Hydroelectric Availability during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was primarily due to an increase in the number of planned outage days at the Lower Mattagami River hydroelectric generating stations.

The higher Thermal EFOR during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was primarily due to a higher number of unplanned outage days at a Lennox GS unit as a result of a transmission outage and a generator cooling water system outage in 2017.

Services, Trading, and Other Non-Generation Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue	**9**	15	**36**	52
Fuel expense	**1**	1	**1**	1
Gross margin	**8**	14	**35**	51
Operations, maintenance and administration	**1**	11	**2**	20
Depreciation and amortization	**8**	8	**22**	25
Accretion on fixed asset removal liabilities	**2**	2	**6**	6
Property taxes	**-**	4	**4**	9
(Loss) income before other gains, interest, and income taxes	**(3)**	(11)	**1**	(9)
Other gains	**(2)**	(3)	**(385)**	(5)
Income (loss) before interest and income taxes	**(1)**	(8)	**386**	(4)

Segment earnings improved by $7 million during the third quarter of 2017, compared to the same quarter in 2016. The improvement in earnings was primarily due to lower OM&A expenses reflecting project expenditures incurred in the third quarter of 2016, and OPG's decision, in the fourth quarter of 2016, to proceed with the decommissioning of Lambton GS.

Segment income before interest and income taxes increased by $390 million for the nine months ended September 30, 2017, compared to the same period in 2016. The increase in earnings mainly reflected the gain on the sale of OPG's head office premises and associated parking facility recorded during the second quarter of 2017.

LIQUIDITY AND CAPITAL RESOURCES

OPG's primary sources of liquidity and capital are funds generated from operations, bank financing, credit facilities provided by the Ontario Electricity Financial Corporation (OEFC), long-term corporate debt, and capital market financing. These sources are used for multiple purposes including: to invest in plants and technologies, to undertake major projects, to fund long-term obligations such as contributions to the pension fund and the Nuclear Segregated Funds, to make payments under the OPEB plans, to fund expenditures on Nuclear Liabilities not reimbursable from the Nuclear Segregated Funds, to service and repay long-term debt, to provide general working capital, and to fund OPG's investment in the Fair Hydro Plan.

Changes in cash and cash equivalents for the three and nine month periods ended September 30 are as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Cash and cash equivalents, beginning of period	**242**	295	**186**	464
Cash flow provided by operating activities	**485**	530	**698**	1,211
Cash flow used in investing activities	**(463)**	(390)	**(720)**	(1,253)
Cash flow provided by (used in) financing activities	**16**	(9)	**116**	4
Net increase (decrease)	**38**	131	**94**	(38)
Cash and cash equivalents, end of period	**280**	426	**280**	426

For a discussion of cash flow provided by operating activities and the FFO Adjusted Interest Coverage ratio, refer to the details in the section, *Highlights* under the heading, *Overview of Results*.

Investing Activities

Electricity generation is a capital-intensive business. It requires continued investment in plants and technologies to maintain and improve operating performance including asset reliability, safety and environmental performance, to increase the generating capacity of existing stations, and to invest in the development of new generating stations, emerging technologies and other business growth opportunities.

Cash flow used in investing activities during the third quarter of 2017 was $463 million, compared to $390 million for the same period in 2016. The increase in cash flow used for investing activities mainly resulted from higher expenditures on the Darlington Refurbishment project in the third quarter of 2017.

Cash flow used in investing activities decreased by $533 million for the nine months ended September 30, 2017, compared to the same period in 2016. The decrease in net cash flow used in investing activities was primarily due to the receipt of proceeds from the sale of OPG's head office premises and associated parking facility in the second quarter of 2017 pursuant to a Shareholder Declaration and Shareholder Resolution, and the acquisition of nine million common shares of Hydro One Limited (Hydro One) in the second quarter of 2016, partially offset by higher expenditures on the Darlington Refurbishment project in 2017. OPG acquired the Hydro One shares for investment purposes, to mitigate the risk of future price volatility related to the Company's future share delivery obligations under the collective agreements with the Power Workers' Union and The Society of Energy Professionals.

Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from the sale of head office premises and associated parking facility, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. OPG expects that the amount of designated proceeds to be transferred into the Consolidated Revenue Fund will be largely consistent with the after-tax gain on sale. The transfer is expected to take place later in 2017.

Financing Activities

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. In the second quarter of 2017, OPG renewed and extended the expiry date of both tranches from May 2021 to May 2022. There were no amounts outstanding under the bank credit facility as at September 30, 2017.

There was $160 million of commercial paper outstanding under OPG's commercial paper program as at September 30, 2017.

As at September 30, 2017, OPG also maintained $25 million of short-term, uncommitted overdraft facilities, and a further $463 million of short-term, uncommitted credit facilities, which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other general corporate purposes. As at September 30, 2017, a total of $388 million of Letters of Credit had been issued under these facilities. This included $349 million for the supplementary pension plans, $38 million for general corporate purposes, and $1 million related to the operation of the PEC.

The Company has an agreement to sell an undivided co-ownership interest in its current and future accounts receivable to an independent trust, expiring on November 30, 2018. The maximum amount of co-ownership interest that can be sold under this agreement is $150 million. As at September 30, 2017, no borrowings were issued under this agreement and there were Letters of Credit outstanding under this agreement of $150 million, which were issued in support of OPG's supplementary pension plans.

As at September 30, 2017, Lower Mattagami Energy Limited Partnership (LME) maintained a $400 million bank credit facility to support the funding requirements for the Lower Mattagami River project including support for LME's commercial paper program and the issuance of the Letters of Credit. The facility consists of a $300 million tranche which, in the third quarter of 2017, was extended to mature in August 2022 and a $100 million tranche which, in the third quarter of 2017, was reduced from $200 million and extended to mature in August 2018. As at September 30, 2017, there was no external commercial paper outstanding under LME's commercial paper program. A letter of credit of $55 million was issued in July 2017 and remains outstanding as at September 30, 2017 under the $300 million tranche of the credit facility.

In June 2016, OPG entered into a $700 million general corporate credit facility agreement with the OEFC, which expires on December 31, 2017. In the third quarter of 2017, the agreement was amended to increase the credit facility to $2,350 million and to extend its expiry date to December 31, 2018.

In February 2017, OPG issued senior notes payable to the OEFC totalling $200 million and maturing in February 2047. The effective interest rate and coupon interest rate of these notes was 4.12 percent. In June 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in June 2047. The effective interest rate and coupon interest rate of these notes was 3.65 percent. In August 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in August 2047. The effective interest rate and coupon interest rate of these notes was 3.86 percent. In September 2017, OPG issued senior notes payable to the OEFC totalling $400 million and maturing in September 2047. The effective interest rate and coupon interest rate of these notes was 4.07 percent. As at September 30, 2017, there were outstanding long-term borrowings of $800 million under this credit facility.

In October 2017, OPG issued $500 million of senior notes payable under a Medium Term Note Program. The notes bear a coupon interest rate of 3.32 percent and an effective rate of 3.43 percent, payable semi-annually until maturity on October 4, 2027. The offering was made under OPG's $2 billion short form base shelf prospectus dated September 12, 2017. The net proceeds will be used for general corporate purposes, including the financing of OPG's subordinated debt investment in the Fair Hydro Plan.

As at September 30, 2017, OPG's long-term debt outstanding was $5,482 million, including $628 million due within one year.

OPG continues to evaluate arrangements that would appropriately support the Company's financing needs and capital expenditure programs.

Contractual and Commercial Commitments

Pension Plan Actuarial Valuation

A new actuarial valuation of the OPG registered pension plan was filed with the Financial Services Commission of Ontario in September 2017 with an effective date of January 1, 2017. The annual funding requirements in accordance with the new actuarial valuation are $212 million for 2017, $215 million for 2018, and $219 million for 2019. The next actuarial valuation must have an effective date no later than January 1, 2020.

BALANCE SHEET HIGHLIGHTS

The following section provides highlights of OPG's unaudited interim consolidated financial position using selected balance sheet data:

(millions of dollars) (unaudited)	As At September 30 2017	As At December 31 2016
Property, plant and equipment - net	**20,801**	19,998
The increase was primarily due to capital expenditures on the Darlington Refurbishment project, partially offset by depreciation expense.		
Nuclear fixed asset removal and nuclear waste management funds *(current and non-current portions)*	**16,534**	15,984
The increase was primarily due to earnings on the Nuclear Segregated Funds, partially offset by reimbursements of eligible expenditures on nuclear fixed asset removal and nuclear waste management activities.		
Short-term debt	**160**	2
The increase was due to commercial paper issued under OPG's commercial paper program during the third quarter of 2017.		
Fixed asset removal and nuclear waste management liabilities	**20,075**	19,484
The increase was primarily a result of accretion expense representing the increase in the liabilities due to the passage of time, partially offset by expenditures on nuclear fixed asset removal and waste management activities.		

Off-Balance Sheet Arrangements

In the normal course of operations, OPG engages in a variety of transactions that, under US GAAP, are either not recorded in the Company's interim consolidated financial statements or are recorded in the Company's interim consolidated financial statements using amounts that differ from the full contract amounts. Principal off-balance sheet activities for OPG include guarantees and long-term contracts.

CHANGES IN ACCOUNTING POLICIES AND ESTIMATES

OPG's significant accounting policies are outlined in Note 3 to the audited consolidated financial statements as at and for the year ended December 31, 2016. A discussion of recent accounting pronouncements and change in accounting estimate are included in Note 2 to OPG's unaudited interim consolidated financial statements as at and for the three and nine month periods ended September 30, 2017 under the heading, *Significant Accounting Policies and Estimates*. Disclosure regarding OPG's critical accounting policies is included in OPG's 2016 annual MD&A.

RISK MANAGEMENT

The following provides an update to the discussion of the Company's risks and risk management activities included in OPG's 2016 annual MD&A. As such, the disclosure in this section should be read in conjunction with the *Risk Management* section included in the annual MD&A.

Risks to Achieving Project Excellence

Deep Geologic Repository for Low and Intermediate Level Waste

In August 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of the potential cumulative effects of the DGR project on the physical and cultural heritage of the SON, taking into account the results of the SON Community Process. OPG continues to work with the SON, however the timing and outcome of the SON Community Process and the EA decision by the Minister are uncertain.

Risks to Maintaining Financial Strength

Commodity Markets

Changes in the market price of fuels used to produce electricity can adversely impact OPG's earnings and cash flow from operations.

To manage the risk of unpredictable increases in the price of fuels, the Company has fuel hedging programs, which include fixed price and indexed contracts.

The percentages hedged of OPG's fuel requirements are shown in the following table. These amounts are based on yearly forecasts of generation and supply mix, and as such, are subject to change as these forecasts are updated.

	2017 [1]	2018	2019
Estimated fuel requirements hedged [2]	73%	73%	69%

[1] Based on actual fuel requirements hedged for the nine months ended September 30, 2017 and forecast for the remainder of the year.

[2] Represents the approximate portion of megawatt-hours of expected generation production (and year-end inventory targets) from each type of OPG-operated facility (nuclear, hydroelectric and thermal) for which the Company has entered into contractual arrangements or obligations in order to secure the price of fuel, or which is subject to regulation. In the case of hydroelectric generation, this represents the gross revenue charge and water rental charges. Excess fuel inventories (nuclear and thermal) in a given year are attributed to the next year for the purpose of measuring hedge ratios.

Foreign Exchange

OPG's earnings and cash flow can be affected by movements in the United States dollar (USD) relative to the Canadian dollar.

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are denominated in, or tied to, USD. To manage this risk, OPG periodically employs various financial instruments such as forwards and other

derivative contracts, in accordance with approved risk management policies. As at September 30, 2017, OPG had no foreign exchange contracts outstanding.

Trading

OPG's financial performance can be affected by its trading activities.

OPG's electricity trading operations are closely monitored, with total exposures measured and reported to senior management on a daily basis. The main metric used to measure the financial risk of trading activity is Value at Risk (VaR). VaR is defined as a probabilistic maximum potential future loss expressed in monetary terms for a portfolio based on normal market conditions over a set period of time. For the third quarter of 2017, the VaR utilization ranged between $0.2 million and $0.3 million.

Credit

Deterioration in energy markets counterparty credit and non-performance by suppliers and contractors can adversely impact OPG's earnings and cash flow from operations.

OPG manages its exposure to suppliers or counterparties by evaluating their financial condition and negotiating appropriate collateral or other forms of security. OPG's credit exposure relating to energy markets transactions as at September 30, 2017 was $356 million, including $346 million with the IESO. Management considers the Company's risk exposure relating to electricity sales through the IESO-administered spot market to be low as the IESO oversees the credit worthiness of all market participants. In accordance with the IESO's prudential support requirements, market participants are required to provide collateral to cover funds that they might owe to the market. Of the $10 million remaining exposure as at September 30, 2017, over 95 percent was related to investment grade counterparties.

Fair Hydro Plan

OPG's role in connection with the Fair Hydro Plan could have reputational impacts on the Company.

The *Ontario Fair Hydro Plan Act, 2017* received Royal Assent on June 1, 2017 and its attendant regulations came into force in June, July, and October 2017. **[UPDATE]** The regulations clarify aspects of the structure and program logistics required for ~~OPG, as~~ the Financial Services Manager of the Fair Hydro Plan, which OPG is planning to undertake, to refinance a portion of the Global Adjustment through the Trust. OPG's reputation could potentially be adversely impacted through its involvement with the Fair Hydro Plan and through stakeholder opinions related to this involvement.

Commented [A11]: Not sure this is the right wording. OPG's role as FSM is required under the Act, but not the refinancing through the Trust – the OPG Financing Entity's (or entities) role is discretionary.

Recovery of Pension and OPEB Costs

On September 14, 2017, the OEB issued its final report on the guiding principles and the policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the electricity and natural gas sectors. The report reaffirmed the conclusions of the initial report issued in May 2017, including the establishment of the accrual basis of accounting as the default rate-setting method and the establishment of a variance account to record asymmetric carrying charges in favour of ratepayers on the differences between the accrual costs recovered and cash payments made by a utility for pension and OPEB plans. The report requires OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the Pension & OPEB Cash Versus Accrual Differential Deferral Account that has been in effect since November 1, 2014, until such time as the OEB approves the resumption of the accrual basis of recovery. The future recovery of amounts recorded in the account will be subject to this approval. The report confirmed that OPG would become subject to the carrying charges on the differences between accrual costs and cash payments going back to November 1, 2014, with the charges calculated on the portion of such differences that have been recovered through regulated prices. The carrying charges will be determined at prescribed interest rate set quarterly by the OEB based on the quarterly return of a mid-term corporate bond index yield. This outcome has reduced OPG's risk related to the recovery of actual pension and OPEB accrual

costs and the recovery of the balance in the Pension & OPEB Cash Versus Accrual Differential Deferral Account. The account had a balance of $552 million as at September 30, 2017 and is recognized on the Company's consolidated balance sheet as a regulatory asset. OPG's financial results for the three and nine month periods ended September 30, 2017 were not impacted by the issuance of the OEB's report.

RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One, the IESO and the OEFC. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions are summarized below:

	Three Months Ended September 30			
	2017		2016	
(millions of dollars) (unaudited)	**Revenue**	**Expense**	**Revenue**	**Expense**
Hydro One				
Electricity sales	**2**	**-**	1	-
Services	**-**	**3**	-	3
Dividends	**2**	**-**	-	2
Province of Ontario				
Decommissioning Fund excess funding [1]	**-**	**(44)**	-	201
Used Fuel Fund rate of return guarantee and excess funding [1]	**-**	**(39)**	-	295
Gross revenue charges	**-**	**27**	-	28
ONFA guarantee fee	**-**	**2**	-	2
Other	**-**	**2**	-	-
OEFC				
Gross revenue charges	**-**	**62**	-	57
Interest expense on long-term notes	**-**	**40**	-	42
Income taxes, net of investment tax credits	**-**	**23**	-	28
IESO				
Electricity related revenue	**1,126**	**4**	1,293	7
	1,130	**80**	1,294	665

(millions of dollars) (unaudited)	Nine Months Ended September 30 2017 Revenue	2017 Expense	2016 Revenue	2016 Expense
Hydro One				
Electricity sales	**7**	**-**	4	-
Services	**1**	**8**	1	12
Dividends	**6**	**-**	-	4
Province of Ontario				
Decommissioning Fund excess funding [1]	**-**	**164**	-	137
Used Fuel Fund rate of return guarantee and excess funding [1]	**-**	**217**	-	190
Gross revenue charges	**-**	**84**	-	91
ONFA guarantee fee	**-**	**6**	-	6
Other	**-**	**3**	-	-
OEFC				
Gross revenue charges	**-**	**156**	-	147
Interest expense on long-term notes	**-**	**122**	-	127
Income taxes, net of investment tax credits	**-**	**132**	-	112
IESO				
Electricity related revenue	**3,228**	**11**	3,894	22
	3,242	**903**	3,899	848

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at September 30, 2017 and December 31, 2016, the Nuclear Segregated Funds were reported net of amounts due to the Province of $3,796 million and $3,415 million, respectively. The details of accounting for the Nuclear Segregated Funds are described in OPG's 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

The receivable, available-for-sale securities, payable and long-term debt balances between OPG and its related parties are summarized below:

(millions of dollars) (unaudited)	September 30 2017	December 31 2016
Receivables from related parties		
Hydro One	**1**	1
IESO	**346**	421
OEFC	**3**	1
PEC	**2**	4
Province of Ontario	**5**	2
Available-for-sale securities		
Hydro One shares	**190**	212
Accounts payable and accrued charges		
OEFC	**37**	61
Province of Ontario	**6**	2
IESO	**2**	2
Long-term debt (including current portion)		
Notes payable to OEFC	**3,245**	3,295

OPG holds interest-bearing Province of Ontario bonds in the Nuclear Segregated Funds and the OPG registered pension fund. As at September 30, 2017, the Nuclear Segregated Funds held $1,498 million of interest-bearing Province of Ontario bonds, while the registered pension fund had no such holdings. As at December 31, 2016, the Nuclear Segregated Funds and the registered pension fund held $1,652 million and $284 million of interest-bearing Province of Ontario bonds, respectively. These bonds are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

There have been no related party transactions related to the Fair Hydro Plan and associated financing activities. The first transaction between the Trust and the IESO is expected later in 2017.

INTERNAL CONTROLS OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

The Company maintains a comprehensive system of policies, procedures, and processes that represents its framework for internal controls over financial reporting and for its disclosure controls and procedures (together, ICOFR). There were no changes in the Company's internal control system during the current interim period that has or is reasonably likely to have a material impact to the ICOFR.

QUARTERLY FINANCIAL HIGHLIGHTS

The following tables set out selected financial information from OPG's unaudited interim consolidated financial statements for each of the eight most recently completed quarters.

(millions of dollars - except where noted) (unaudited)	**September 30 2017**	**June 30 2017**	**March 31 2017**	**December 31 2016**
Revenue	**1,217**	1,146	1,176	1,388
Net income (loss)	**140**	307	68	(8)
Less: Net income attributable to non-controlling interest	**9**	4	4	5
Net income (loss) attributable to the Shareholder	**131**	303	64	(13)
Per common share, attributable to the Shareholder *(dollars)*	**$0.51**	$1.18	$0.25	($0.05)

(millions of dollars - except where noted) (unaudited)	**September 30 2016**	**June 30 2016**	**March 31 2016**	**December 31 2015**
Revenue	1,400	1,387	1,478	1,312
Net income (loss)	198	135	128	(100)
Less: Net income attribute to the non-controlling interest	4	3	5	1
Net income (loss) attributable to the Shareholder	194	132	123	(101)
Per common share, attributable to the Shareholder *(dollars)*	$0.76	$0.51	$0.48	($0.39)

Trends

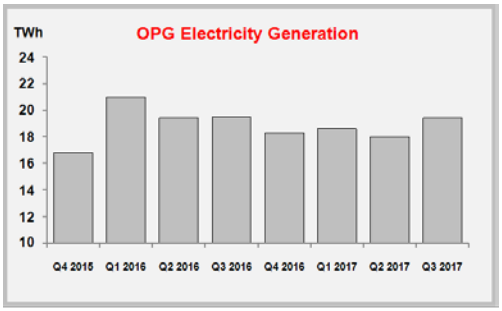
OPG's quarterly results are affected by changes in grid-supplied electricity demand, primarily resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. Weather conditions affect water flows, electricity demand, and prevalence of SBG conditions. Historically, OPG's revenues have been higher in the first

quarter of a fiscal year as a result of winter heating demands and in the third quarter due to air conditioning and cooling demands. The financial impact of forgone production due to SBG conditions at the regulated hydroelectric stations and the financial impact of differences between forecast water flows reflected in OEB-approved regulated prices and the actual water flows are mitigated by regulatory variance accounts authorized by the OEB.

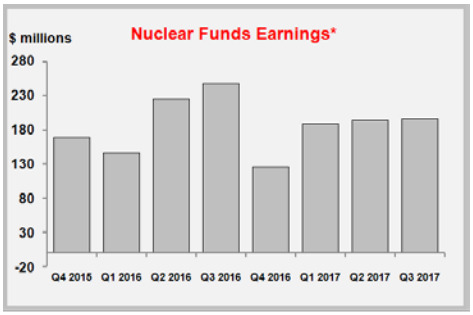
The timing of planned outages at a nuclear generating station during the year can cause variability in year-over-year operating results for partial periods of a fiscal year, including the impact on revenue and OM&A expenses, but is not a significant driver of variability for full fiscal year results.

OPG's electricity generation was reduced as a result of the Unit 2 refurbishment outage at the Darlington GS, which began in October 2016 and is expected to continue until early 2020.

OPG's financial results are also affected by the earnings on the Nuclear Segregated Funds, net of the impact of the Bruce Lease Net Revenues Variance Account.



Additional items that affected net income in certain quarters above are described in OPG's 2016 annual MD&A under



*net of regulatory variance account

the section, *Quarterly Financial Highlights*.

SUPPLEMENTARY NON-GAAP FINANCIAL MEASURES

In addition to providing net income and other financial information in accordance with US GAAP, certain non-GAAP financial measures are also presented in OPG's MD&A. These non-GAAP measures do not have any standardized meaning prescribed by US GAAP and, therefore, may not be comparable to similar measures presented by other issuers. OPG utilizes these measures to make operating decisions and assess performance. Readers of the MD&A would utilize these measures in assessing the Company's financial performance from ongoing operations. The Company believes that these indicators are important since they provide additional information about OPG's performance, facilitate comparison of results over different periods, and present measures consistent with the Company's strategies to provide value to the Shareholder, improve cost performance, and ensure availability of cost effective funding. These non-GAAP financial measures have not been presented as an alternative to net income, cash flow provided by operating activities, or any other measure in accordance with US GAAP, but as indicators of operating performance.

The definitions of the non-GAAP financial measures are as follows:

(1) **ROE Excluding AOCI** is defined as net income attributable to the Shareholder divided by average equity attributable to the Shareholder excluding AOCI, for the period. ROE Excluding AOCI is measured over a 12-month period and is calculated as follows:

	Twelve Months Ended	
(millions of dollars – except where noted) (unaudited)	**September 30 2017**	**December 31 2016**
ROE Excluding AOCI		
Net income attributable to the Shareholder	**485**	436
Divided by: Average equity attributable to the Shareholder, excluding AOCI	**11,055**	10,442
ROE Excluding AOCI *(percent)*	**4.4**	4.2

(2) **FFO Adjusted Interest Coverage** is defined as FFO before interest divided by adjusted interest expense. FFO before interest is defined as cash flow provided by operating activities adjusted for interest paid, interest capitalized to fixed and intangible assets, and changes to non-cash working capital balances for the period. Adjusted interest expense is calculated as net interest expense plus interest income, interest capitalized to fixed and intangible assets, interest related to regulatory assets and liabilities, and the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets, for the period.

FFO Adjusted Interest Coverage is measured over a 12-month period and is calculated as follows:

	Twelve Months Ended	
(millions of dollars – except where noted) (unaudited)	**September 30 2017**	**December 31 2016**
FFO before interest		
Cash flow provided by operating activities	**1,082**	1,595
Add: Interest paid	**270**	269
Less: Interest capitalized to fixed and intangible assets	**(161)**	(141)
Less: Changes to non-cash working capital balances	**38**	42
FFO before interest	**1,229**	1,765
Adjusted interest expense		
Net interest expense	**84**	120
Add: Interest income	**8**	7
Add: Interest capitalized to fixed and intangible assets	**161**	141
Add: Interest related to regulatory assets and liabilities	**43**	30
Add: Excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets [1]	**-**	45
Adjusted interest expense	**296**	343
FFO Adjusted Interest Coverage *(times)*	**4.2**	5.1

[1] A value of nil is used in the calculation when interest on pension and OPEB projected benefit obligations is equal to, or lower than, expected return on pension plan assets.

(3) **Enterprise Total Generating Cost per MWh** is used to measure OPG's overall organizational cost performance. Enterprise TGC per MWh is defined as OM&A expenses (excluding the Darlington Refurbishment project and other generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to OPG's electricity generation business), fuel expense for OPG-operated stations including hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures (excluding the Darlington Refurbishment project and other generation development projects) incurred during the period, divided by total electricity generation from OPG-operated generating stations plus electricity generation forgone due to SBG conditions during the period.

(millions of dollars – except where noted) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Enterprise TGC				
Total OM&A expenses	**635**	666	**2,054**	2,061
Total fuel expense	**185**	187	**518**	541
Total capital expenditures	**476**	444	**1,335**	1,162
Less: Darlington Refurbishment capital and OM&A costs	**(328)**	(269)	**(943)**	(717)
Less: Other generation development project capital and OM&A costs	**(17)**	(42)	**(53)**	(121)
Add (Less): OM&A and fuel expenses (refundable through) deferred in regulatory variance and deferral accounts	**4**	35	**(19)**	76
Less: Nuclear fuel expense for non OPG-operated stations	**(13)**	(18)	**(42)**	(50)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**13**	5	**47**	38
Less: OM&A expenses ancillary to electricity generation business	**(4)**	(5)	**(13)**	(17)
Other adjustments	**(3)**	(12)	**(7)**	(15)
	948	991	**2,877**	2,958
Adjusted electricity generation *(TWh)*				
Total OPG electricity generation	**19.4**	19.5	**56.0**	59.9
Adjust for electricity generation forgone due to SBG conditions and OPG's share of electricity generation from co-owned facilities	**0.9**	0.1	**4.2**	3.4
	20.3	19.6	**60.2**	63.3
Enterprise TGC per MWh *($/MWh)* [1]	**46.65**	50.72	**47.77**	46.74

[1] Amounts may not calculate due to rounding.

(4) **Nuclear Total Generating Cost per MWh** is used to measure the cost performance of OPG's nuclear generating assets. Nuclear TGC per MWh is defined as OM&A expenses of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the nuclear electricity generation business), nuclear fuel expense for OPG-operated stations (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs) incurred during the period, divided by nuclear electricity generation for the period.

(millions of dollars – except where noted) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Nuclear TGC				
Regulated – Nuclear Generation OM&A expenses	**511**	521	**1,693**	1,665
Regulated – Nuclear Generation fuel expense	**81**	79	**217**	239
Regulated – Nuclear Generation capital expenditures	**409**	339	**1,150**	896
Less: Darlington Refurbishment capital and OM&A costs	**(328)**	(269)	**(943)**	(717)
Add: Regulated – Nuclear Generation OM&A and fuel expenses deferred in regulatory variance and deferral accounts	**5**	31	**6**	84
Less: Nuclear fuel expense for non OPG-operated stations	**(13)**	(18)	**(42)**	(50)
Less: Regulated - Nuclear Generation OM&A expenses ancillary to nuclear electricity generation business	**(1)**	(1)	**(3)**	(4)
Other adjustments	**1**	3	**(1)**	(1)
	665	685	**2,077**	2,112
Nuclear electricity generation (TWh)	**11.3**	11.7	**30.6**	34.6
Nuclear TGC per MWh (*$/MWh*) [1]	**58.75**	58.55	**67.87**	61.07

[1] Amounts may not calculate due to rounding.

(5) **Hydroelectric Total Generating Cost per MWh** is used to measure the cost performance of OPG's hydroelectric generating assets. Hydroelectric TGC per MWh is defined as OM&A expenses of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the hydroelectric electricity generation business), hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding expenditures related to the Peter Sutherland Sr. GS, Ranney Falls GS, and other hydroelectric generation development projects) incurred during the period, divided by total hydroelectric electricity generation plus hydroelectric electricity generation forgone due to SBG conditions during the period. OPG reports hydroelectric gross revenue charge and water rental payments as fuel expense.

(millions of dollars – except where noted) (unaudited)	**Three Months Ended September 30**		**Nine Months Ended September 30**	
	2017	**2016**	**2017**	**2016**
Hydroelectric TGC				
Regulated – Hydroelectric OM&A expenses	**81**	87	**232**	238
Regulated – Hydroelectric fuel expense	**88**	88	**258**	259
Contracted Generation Portfolio OM&A expenses	**39**	44	**118**	129
Contracted Generation Portfolio fuel expense	**15**	19	**42**	42
Regulated – Hydroelectric and Contracted Generation Portfolio capital expenditures	**56**	92	**141**	231
Less: Regulated – Hydroelectric and Contracted Generation Portfolio generation development project capital and OM&A costs	**(17)**	(41)	**(52)**	(117)
Less: Thermal OM&A and fuel expenses and capital expenditures in the Contracted Generation Portfolio	**(39)**	(51)	**(119)**	(126)
(Less) Add: Regulated – Hydroelectric OM&A and fuel expenses refundable through regulatory variance and deferral accounts	**(1)**	4	**(25)**	(8)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**13**	5	**47**	38
Other adjustments	**(1)**	(1)	**-**	(1)
	234	246	**642**	685
Adjusted hydroelectric electricity generation *(TWh)*				
Regulated – Hydroelectric electricity generation	**7.3**	6.9	**23.5**	22.8
Contracted Generation Portfolio electricity generation	**0.8**	0.9	**1.9**	2.5
Adjust for hydroelectric electricity generation forgone due to SBG conditions and non-hydroelectric electricity generation of the Contracted Generation Portfolio, including OPG's share of electricity generation from co-owned facilities	**0.8**	0.1	**4.1**	3.4
	8.9	7.9	**29.5**	28.7
Hydroelectric TGC per MWh *($/MWh)* [1]	**26.20**	31.01	**21.74**	23.99

[1] Amounts may not calculate due to rounding.

(6) **Gross margin** is defined as revenue less fuel expense.

For further information, please contact: Investor Relations 416-592-6700

webmaster@opg.com

Media Relations 416-592-4008

1-877-592-4008

www.opg.com
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From: Ronald Kwan
To: John Kim
Subject: RE: EXTERNAL – RE: OPG Q3 2017 Submission to Province
Date: Wednesday, November 08, 2017 5:53:39 PM

Thanks John – though I was thinking you could just check with OPG that they had made any required conforming edits.

Ron

From: John Kim
Sent: November-08-17 17:46
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: HO Philip -FIN & C CTRL <philip.ho@opg.com>; MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>
Subject: Re: EXTERNAL – RE: OPG Q3 2017 Submission to Province

Thanks from me too. Will check to see if any conforming changes are needed in f/s

Sent from my iPad

On Nov 8, 2017, at 5:28 PM, Ronald Kwan <Ronald.Kwan@ofina.on.ca> wrote:

> Thanks Philip, John.
>
> Ron
>
> ---
>
> **From:** HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
> **Sent:** November-08-17 17:27
> **To:** John Kim <John.Kim@ofina.on.ca>
> **Cc:** MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
> **Subject:** RE: EXTERNAL – RE: OPG Q3 2017 Submission to Province
>
> Hi John,
>
> Regarding comment on pg 8, we have removed 'for years 2017 to 2021' as suggested.
> Regarding comment on pg 10, we have edited the wording to read 'In order for the Trust to finance the deferred Global Adjustment costs …' as suggested.
>
> Thank you.
>
> Philip
>
> ---
>
> **From:** John Kim [mailto:John.Kim@ofina.on.ca]
> **Sent:** Wednesday, November 08, 2017 2:04 PM
> **To:** HO Philip -FIN & C CTRL <philip.ho@opg.com>
> **Cc:** MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; Ronald

Kwan <Ronald.Kwan@ofina.on.ca>
Subject: RE: EXTERNAL – RE: OPG Q3 2017 Submission to Province

Hi Philip,

On a couple of items, we have follow up. Pls. refer to p. 8 and p. 10.

Thanks,

John

From: HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
Sent: Wednesday, November 08, 2017 1:30 PM
To: John Kim <John.Kim@ofina.on.ca>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Subject: RE: EXTERNAL – RE: OPG Q3 2017 Submission to Province

Hi John,

Please see our responses to your three additional comments. Thank you.

Philip

From: John Kim [mailto:John.Kim@ofina.on.ca]
Sent: Monday, November 06, 2017 7:35 PM
To: HO Philip -FIN & C CTRL <philip.ho@opg.com>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Subject: RE: EXTERNAL – RE: OPG Q3 2017 Submission to Province

Hi Philip,

We have gone through again and some additional comment boxes and edits.

Thanks,

John

From: HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
Sent: Monday, November 06, 2017 6:19 PM
To: John Kim <John.Kim@ofina.on.ca>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
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Hi John,

Please see our responses to your comments. Let us know if you have any others. Thank you.

Regards,

Philip

Philip Ho, CPA, CA | Senior Manager, External Reporting & Accounting Policy | Ontario Power Generation
700 University Avenue, Toronto ON M5G 1X6 | Phone: (416) 592-3320| E-mail: philip.ho@opg.com

---

From: John Kim [mailto:John.Kim@ofina.on.ca]
Sent: Monday, October 30, 2017 6:16 PM
To: HO Philip -FIN & C CTRL <philip.ho@opg.com>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
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Hi Philip,

See attached with our comments on the MD&A.

These are staff level comments as Ron has not had a chance to review.

Thanks,

John

From: HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
Sent: Wednesday, October 25, 2017 12:22 PM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>; 'Montgomery, Kaitlin (MOF)' <Kaitlin.Montgomery@ontario.ca>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>
Subject: OPG Q3 2017 Submission to Province

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Discussion and Analysis (MD&A), and Financial Statements for the Province's review.

We would greatly appreciate comments on the above **no later than Monday, Oct 30th**.

These documents will be filed with the Ontario Securities Commission on **Thursday, November 9th** following OPG's Board of Directors meeting.

Kindly forward all comments directly to Philip Ho – philip.ho@opg.com.

To assist the review process, the following are the key items in the Q3 2017 MD&A:

Highlights	
Recent Developments	MD&A p.10-11
Darlington Refurbishment	MD&A p.13-15
Ontario's Fair Hydro Plan	MD&A p.10-11

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From: HO Philip -FIN & C CTRL
To: Ronald Kwan; John Kim
Cc: GORE Michael -FIN & C CTRL; DYKXHOORN Sandra -STAKEREL
Subject: RE: EXTERNAL – RE: OPG Q4 2017 Submission to Province
Date: Thursday, March 08, 2018 2:36:14 PM

Hi Ron,

Point taken. I did a bit of research. It seems both is widely used. 'Were' is past subjunctive whereas 'Was' is the simple past. Using the simple past in lieu of the past subjunctive is acceptable in spoken English. In formal English, using the past subjunctive may be better. That being said, we've used 'was' in the previous quarters so we will stick with the current wording and take it into consideration for first quarter of 2018. Thank you for the clarification.

Philip

From: Ronald Kwan [mailto:Ronald.Kwan@ofina.on.ca]
Sent: Thursday, March 08, 2018 2:18 PM
To: HO Philip -FIN & C CTRL <philip.ho@opg.com>; John Kim <John.Kim@ofina.on.ca>
Cc: GORE Michael -FIN & C CTRL <michael.gore@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>
Subject: RE: EXTERNAL – RE: OPG Q4 2017 Submission to Province

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Ron

From: HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
Sent: March-08-18 14:07
To: John Kim <John.Kim@ofina.on.ca>
Cc: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>
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This is broadly consistent with the wording used in the Financing Plan. Please let us know if you have comments.

Our external reporting timeline remains the same as previously communicated. Please let us know if you

have any other comments.

Thank you.

Regards,

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Cc: GORE Michael -FIN & C CTRL <michael.gore@opg.com>; PAN Rebecca -FIN & C CTRL <rebecca.pan@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>
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From: Ronald Kwan
To: "HO Philip -FIN & C CTRL"; John Kim
Cc: GORE Michael -FIN & C CTRL; DYKXHOORN Sandra -STAKEREL
Subject: RE: EXTERNAL – RE: OPG Q4 2017 Submission to Province
Date: Thursday, March 08, 2018 2:17:54 PM

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Cc: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; PAN Rebecca -FIN & C CTRL <rebecca.pan@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; LAURETA LAPIRA May -TREASURY <may.lapira@opg.com>; LADAK Lubna -TREASURY <lubna.ladak@opg.com>; MAK Ricky -TREASURY <ricky.mak@opg.com>
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Sent: Friday, February 16, 2018 5:11 PM
To: 'Shruti.Talwar@ontario.ca' <Shruti.Talwar@ontario.ca>; 'Manu.Sud@ontario.ca' <Manu.Sud@ontario.ca>; 'John.Kim@ofina.on.ca' <John.Kim@ofina.on.ca>; 'Ronald.Kwan@ofina.on.ca' <Ronald.Kwan@ofina.on.ca>
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Kindly forward all comments directly to Philip Ho – philip.ho@opg.com.

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Subject:	RE: EXTERNAL – RE: OPG Q4 2017 Submission to Province
Date:	Thursday, March 08, 2018 2:07:27 PM
Attachments:	Q4 2017 Press Release - PROVINCE MAILING_Markup v Sent.docx 2017 AIF - DRAFT - Feb 16 - PROVINCE MAILING_EFB_v4 Sent.docx Q4 2017 MD&A - DRAFT - Feb 16 - PROVINCE MAILING_EFB_v4 Sent.docx Q4 2017 OPG FS Feb 25_230PM_RPT excerpt for Prov(TPW Comments).docx Q4 2017 OPG FS PROVINCE MAILING Feb 16_EFB_v4 Sent.docx Q4 2017 OPG MDA - DRAFT - Feb 25_230PM_RPT excerpt for Prov (TPW Comments).docx

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ONTARIO POWER GENERATION

News
from Ontario Power Generation

700 University Avenue Toronto, ON M5G 1X6

Tel: 416-592-4008 or 1-800-592-4008 Fax: 416-592-2178
www.opg.com

[DRAFT]

Mar. 8, 2018

OPG REPORTS 2017 FINANCIAL RESULTS

OPG records increase in net income for third consecutive year

[Toronto]: – Ontario Power Generation Inc. (OPG or Company) today reported net income attributable to the Shareholder of $860 million for 2017, compared to $436 million in 2016.

"As stewards of Ontario's publicly-owned generating assets, I am pleased with our strong 2017 financial results, which marks the third year-over-year increase in net income. OPG's major focus remains on the largest clean energy project in Canada, the refurbishment of the Darlington Generating Station. This ten-year project will extend the life of this asset and ensure a safe, reliable, and clean source of electricity for another 30 years," said Jeff Lyash, OPG President and CEO. "Darlington's Unit 2 recently passed the halfway point, based on work performed, while remaining on time and on budget due to the hard work and dedication of our employees and partners. This success was recognized by our shareholder, the Province of Ontario, which has confirmed its commitment to proceed with Darlington's Unit 3 refurbishment in 2020."

Commented [HP-&CC1]: No change required.

Commented [RK2]: Comment for Energy: Has MENE signed off on this wording?

Lyash continued, "The Peter Sutherland Sr. Generating Station was completed in 2017, on budget and ahead of schedule, and is the latest example of OPG's commitment to working closely in partnership with Indigenous communities."

"Pickering Generating Station significantly improved its operating performance over last year by increasing its capability factor to 80 per cent in 2017. By continuing to operate this important asset to 2024, we will ensure a safe and clean source of reliable power during the refurbishment of Darlington. OPG has applied to its regulator, the Canadian Nuclear Safety Commission, for a licence to keep Pickering online until 2024 and expects a decision on this application in 2018," added Lyash.

Commented [HP-&CC3]: Changed

The Ontario Energy Board's (OEB) decision on OPG's new regulated rates was issued in December 2017, establishing new rates to be applied with an effective date of June 1, 2017. OPG recognized the impact of the newly established base regulated rates for OPG's nuclear and most of its hydroelectric generation for the year resulting in additional net revenues of approximately $480 million **[MONITOR]**. Net income was negatively impacted by the planned reduction in nuclear electricity generation, primarily due to the Darlington Refurbishment, in conjunction with the continued application of previously established interim rates for the period in 2017 prior to the effective date of the new base regulated rates.

The OEB's approval of the final payment amounts order, including determinations on the new regulated prices and rate smoothing, are not expected to have a material impact on the total revenue recorded for the June 1, 2017 to December 31, 2017 period. The OEB is expected to issue the final payment amounts order in the first half of 2018 **[MONITOR]**. OPG continues to provide electricity at a price that is 40 per cent less than other generators and is the only electricity generator in Ontario that has its prices set through a public hearing process by the OEB.

The gain of $283 million on the sale of OPG's head office building and parking facility recorded in the second quarter of 2017 and higher earnings on the nuclear fixed asset removal and nuclear waste management segregated funds of $24 million during 2017 compared to 2016 offset the year-to-date reduction in generation revenue.

The Fair Hydro Trust (the Trust) was established in December 2017 in accordance with the *Ontario Fair Hydro Act*, 2017, (the Fair Hydro Act), which appointed OPG as the Financial Services Manager of the Trust. The Fair Hydro Act established a framework under which the costs of clean energy investments and benefits associated with the ~~Government~~Province of Ontario's clean energy initiatives are to be allocated more fairly between present and future consumers of electricity under the Fair Hydro Plan. In December 2017, the Trust purchased its first tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $1.2 billion. In February 2018, the Trust issued $500 million of senior notes payable maturing on May 15, 2033.

Commented [RK4]: The average of?

OPG – changed. Edited wording as follows:

Taking into account the impact of the OEB's decision, OPG continues to provide electricity at a price that is 40 per cent less than the average of other generators.

Commented [RK5]: Is Energy okay with this wording?

OPG – MoE's comments sent on March 7 did not have comments on this.

Commented [HP-&CC6]: No changes.

Generating and Operating Performance

Electricity generated in 2017 decreased to 74.1 terawatt hours (TWh) from 78.2 TWh in 2016. The decrease in electricity generation reflected the expected lower generation from the Darlington GS and lower generation from the contracted plants. The decrease was partially offset by higher generation from the Pickering GS, primarily due to fewer outage days, and higher generation from the regulated hydroelectric stations.

Regulated – Nuclear Generation Segment

Lower nuclear generation of 4.9 TWh during 2017 was primarily due to the removal from service of Unit 2 at the Darlington GS for the duration of the unit's refurbishment that began in October 2016 and is expected to continue until early 2020. Offsetting the reduction in generation from the Darlington GS was an increase in generation of 1.5 TWh from the strong performance of the Pickering GS during 2017.

For 2017, the unit capability factor for the operating units at the Darlington GS was 85.2 per cent, compared to 89.5 per cent for 2016. The decrease was primarily a result of a higher number of planned outage days at the station in 2017, largely driven by the planned transition of the station towards refurbishment.

At the Pickering GS, the unit capability factor increased to 80.0 per cent for 2017, compared to 75.2 per cent for 2016, primarily due to outage cycle optimization and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station in 2017.

Regulated – Hydroelectric Segment

Higher generation from the regulated hydroelectric stations of 1.2 TWh during 2017 compared to 2016, was due to higher water flows, primarily on the eastern Ontario river systems.

The availability of 88.0 per cent at these stations in 2017 was slightly lower than 89.0 per cent for 2016. The marginal decrease in the availability was primarily due to a higher number of unplanned outage days at the Northwestern Ontario, Niagara and Eastern Ontario region hydroelectric stations, partially offset by higher availability from the Sir Adam Beck Pump GS due to a higher number of planned outages days in 2016 as a result of the refurbishment of the station's reservoir.

Contracted Generation Portfolio Segment

Lower generation from the Contracted Generation Portfolio of 0.4 TWh during 2017 compared to 2016, was mainly due to higher surplus baseload generation conditions.

The availability of these hydroelectric stations for 2017 was 74.6 per cent, compared to 77.3 per cent for 2016. The decrease in the availability was primarily due to an increase in the number of planned outage days at the Lower Mattagami River hydroelectric generating stations.

Total Generating Cost

The Enterprise Total Generating Cost per megawatt hour (MWh) for 2017 was $50.66, compared to $48.45 for 2016. The increase was expected and mainly a result of lower electricity generation due to the Unit 2 refurbishment outage at the Darlington GS and higher sustaining capital expenditures, which was partially offset by higher hydroelectric electricity generation adjusted for surplus baseload generation.

If Unit 2 at the Darlington GS wereas not currently undergoing refurbishment and had continued to operate in a manner consistent with the performance of the remaining units at the station, adjusted for generation constraints on these units related to the transition of the station toward refurbishment, the Enterprise Total Generating Cost would have been approximately $4 to $5 per MWh lower for 2017. This sensitivity was calculated using the estimated incremental electricity generation and associated fuel cost that are expected to have resulted in the absence of the refurbishment.

Commented [HP-&CC7]: No change. Unit 2 is singular.

Generation Development

OPG is undertaking a number of generation development and life extension projects in support of Ontario's electricity planning initiatives. Significant developments during 2017 were as follows:

Darlington Refurbishment

The Darlington Refurbishment project is expected to extend the operating life of the four-unit Darlington GS by approximately 30 years. The approved budget for the four-unit refurbishment is $12.8 billion, which includes the costs of the pre-requisite projects in support of the execution phase of the refurbishment. In October 2016, OPG commenced the refurbishment of the first unit, Unit 2. The de-fuelling of the reactor and islanding of Unit 2 were completed in the first half of 2017. The Re-tube Tooling

Platform for hosting the tooling for the removal, inspection and installation activities, and the setup of specialized tooling and equipment needed for the removal and replacement of the reactor components were completed in the third quarter of 2017. The disassembly of reactor components began in August 2017, with the removal of all 960 feeder tubes completed in September 2017. The removal of fuel channel assemblies commenced in October 2017. As part of the fuel channel assemblies, the removal of pressure tubes is in progress and will be followed by the removal of calandria tubes. The second major segment and the removal of all reactor components is expected to be completed in mid-2018.

Most of the pre-requisite projects, including construction of facilities, infrastructure upgrades and installation of safety enhancements, have been completed and placed in service. The Re-tube Waste Processing Building was completed in November 2017. Construction activities for the Heavy Water Storage and Drum Handling Facility (HWSF) have recommenced following the substantial completion of the Re-tube Waste Processing Building. This sequencing ensured that the necessary resources were available to support the execution of both projects. The HWSF is expected to be completed by the second quarter of 2019 and is not on the critical path for the Darlington Refurbishment project, which continues to track on schedule. The increase in the cost estimate for the HWSF will be accommodated within the overall Darlington Refurbishment budget of $12.8 billion. Taking into account the execution performance of the Unit 2 refurbishment, the overall Darlington Refurbishment project continues to track on budget.

In addition to the execution of refurbishment activities on Unit 2, OPG is continuing planning activities for the refurbishment of the second unit, Unit 3, and is entering into associated commitments to procure major components that require long lead times. As of December 31, 2017, $93 million has been invested in planning activities related to the refurbishment of the second unit.

Total life-to-date capital expenditures on the project were approximately $4.4 billion as at December 31, 2017.

Ranney Falls Hydroelectric GS

In 2017, OPG began construction work on a 10 MW single-unit powerhouse on the existing Ranney Falls GS site, as part of the Regulated – Hydroelectric segment. The new unit will replace an existing unit that reached its end of life in 2014. The existing forebay structure has been demolished and the new concrete structure has been completed. Excavation has been completed and construction continues in the expanded forebay, powerhouse and spillway area. The new forebay concrete wall has been completed, and concrete placement of the new powerhouse and the spillway integrated structure is in progress. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget.

Nanticoke Solar Facility

The construction of a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands, through Nanticoke Solar LP, a partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation, is planned to commence in the first quarter of 2018. During 2017, the partnership continued work to obtain approvals and permits required to enable the commencement of construction. Significant

contracts for equipment and engineering construction services were executed in the first quarter of 2018. The facility, to operate under a contract with the IESO, is expected to be completed in the first quarter of 2019, with a budget of $107 million. **[MONITOR]**

FINANCIAL AND OPERATIONAL HIGHLIGHTS

(millions of dollars – except where noted)	**2017**	**2016**
Revenue	**5,158**	5,653
Fuel expense	**689**	727
Gross margin	**4,469**	4,926
Operations, maintenance and administration	**2,824**	2,747
Depreciation and amortization	**679**	1,257
Accretion on fixed asset removal and nuclear waste management liabilities	**960**	929
Earnings on Nuclear Segregated Funds - (a reduction to expenses)	**(801)**	(746)
Earnings from Fair Hydro Trust - (a reduction to expenses)	**(1)**	-
Income from investments subject to significant influence	**(38)**	(37)
Other net (gains) expenses	**(339)**	35
Income before interest and income taxes	**1,185**	741
Net interest expense	**95**	120
Income tax expense	**209**	168
Net income	**881**	453
Net income attributable to the Shareholder	**860**	436
Net income attributable to non-controlling interest [1]	**21**	17
Income before interest and income taxes		
Electricity generation business segments	**971**	928
Regulated – Nuclear Waste Management	**(150)**	(174)
Services, Trading, and Other Non-Generation	**364**	(13)
Fair Hydro Trust	**-**	-
Total income before interest and income taxes	**1,185**	741
Cash flow		
Cash flow provided by operating activities	**944**	1,817
Electricity generation (TWh)		
Regulated – Nuclear Generation	**40.7**	45.6
Regulated – Hydroelectric	**30.7**	29.5
Contracted Generation Portfolio [2]	**2.7**	3.1
Total electricity generation	**74.1**	78.2
Nuclear unit capability factor (per cent) [3]		
Darlington Nuclear GS	**85.2**	89.5
Pickering Nuclear GS	**80.0**	75.2
Availability (per cent)		
Regulated – Hydroelectric	**88.0**	89.0
Contracted Generation Portfolio – hydroelectric stations	**74.6**	77.3
Equivalent forced outage rate		
Contracted Generation Portfolio – thermal stations	**2.4**	1.6
Enterprise Total Generating Cost (TGC) per MWh for the twelve months ended December 31, 2017 and 2016 ($/MWh) [4]	**50.66**	48.45
Return on Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI) for the twelve months ended December 31, 2017 and 2016 (%) [4]	**7.5**	4.2
Funds from Operations (FFO) Adjusted Interest Coverage for the twelve months ended December 31, 2017 and 2016 (times) [4]	**3.3**	5.1

[1] Relates to the 25 per cent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation in the Lower Mattagami Limited Partnership, the 33 per cent interest of Coral Rapids Power Corporation (CRP), a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership, and the 10 per cent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP. CRP increased its partnership interest to 33 percent in April 2017.

[2] Includes OPG's share of generation volume from its 50 per cent ownership interests in the Portlands Energy Centre and Brighton Beach GS.

[3] Nuclear unit capability factor excludes unit(s) during the period in which they are undergoing refurbishment. Unit 2 of the Darlington GS is excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

[4] Enterprise TGC per MWh, ROE Excluding AOCI, and FFO Adjusted Interest Coverage are non-GAAP financial measures and do not have any standardized meaning prescribed by US GAAP. Additional information about the non-GAAP measures is provided in OPG's Management's Discussion and Analysis for the year ended December 31, 2017, in the sections *Highlights – FFO Adjusted Interest Coverage*, *Highlights – Return on Common Equity Excluding Accumulated Other Comprehensive Income*, and *Highlights – Enterprise Total Generating Cost per MWh*, as well as *Supplementary Non-GAAP Financial Measures.*

Ontario Power Generation Inc. is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. Our mission is providing low cost power in a safe, clean, reliable and sustainable manner for the benefit of our customers and shareholder.

Ontario Power Generation Inc.'s audited consolidated financial statements and Management's Discussion and Analysis as at and for the year ended December 31, 2017 can be accessed on OPG's web site (www.opg.com), the Canadian Securities Administrators' web site (www.sedar.com), or can be requested from the Company.

For further information, please contact: Investor Relations 416-592-6700
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1-877-592-4008

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ONTARIO POWER GENERATION INC.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2017

[DRAFT]

March 8, 2018

ANNUAL INFORMATION FORM
FOR THE YEAR ENDED DECEMBER 31, 2017

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PRESENTATION OF INFORMATION

References in this Annual Information Form (AIF) to the "Company", the "Corporation" or "OPG" are made to Ontario Power Generation Inc. Unless otherwise noted, the information contained in this AIF is as at or for the year ended December 31, 2017. Amounts are expressed in Canadian dollars unless otherwise indicated. Financial information is presented in accordance with United States generally accepted accounting principles (US GAAP). This AIF is dated March 8, 2018.

ADDITIONAL INFORMATION

Additional information relating to the Company may be found on SEDAR at www.sedar.com. Additional financial information relating to the Company is provided in the Company's annual Management's Discussion and Analysis (MD&A) and audited consolidated financial statements as at and for the year ended December 31, 2017, which is available on SEDAR at www.sedar.com or on the Company's website at www.opg.com. ***The above information is made available in accordance with legal requirements of an AIF and is not, unless otherwise specifically stated, incorporated by reference into this AIF.***

Details regarding compensation paid to directors and executive officers of the Company during the financial year ended December 31, 2017 is included in OPG's Statement of Executive Compensation (Form 51-102F6), which is available on SEDAR at www.sedar.com and is incorporated by reference herein.

FORWARD-LOOKING INFORMATION

This AIF contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could", and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

All forward-looking statements involve inherent assumptions, risks, and uncertainties. All forward-looking statements could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's generating station performance and availability, fuel costs, surplus baseload generation (SBG), cost of fixed asset removal and nuclear waste management, performance and earnings of investment funds, refurbishment of existing facilities, development and construction of new facilities, pension and other post-employment benefit (OPEB) obligations and funds, income taxes, proposed new legislation, the ongoing evolution of Ontario's electricity industry, environmental and other regulatory requirements, health, safety and environmental developments, business continuity events, the weather, financing and liquidity, applications to the Ontario Energy Board (OEB) for regulatory prices, the impact of regulatory decisions by the OEB, Ontario's Fair Hydro Plan (Fair Hydro Plan or the Plan), OM&A expenditures, retention of critical talent, supplier and third party performance, and project expenditures. Accordingly, undue reliance should not be placed on any forward-looking statement. The forward-looking statements included in this AIF are made only as of the date of this AIF. Except as required by applicable securities laws, OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events, or otherwise.

OPG faces various risks that could have a material adverse effect on its business, strategy, generating stations, reputation, financial condition, operating results, generation development and other projects. There may be further risks and uncertainties that are not presently known, or that are not currently believed to be material, that may in the future adversely affect the Company's performance or financial condition. OPG may be exposed to a significant event that it is not fully insured or indemnified against, or to a party that fails to meet its indemnification obligations. For details on risks faced by OPG, refer to the section, *Risk Management*, in the Company's 2017 year-end MD&A.

CORPORATE STRUCTURE

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG was formed in April 1999 through the restructuring of Ontario Hydro's integrated electricity business. OPG was established under the *Business Corporations Act* (Ontario) (OBCA) and is wholly owned by the Province of Ontario (Province or Shareholder). OPG and the Province are parties to a Memorandum of Agreement (MOA) that sets out OPG's role and responsibilities. The current MOA was executed in July 2015 and reaffirmed for continuance by both the Ontario Minster of Energy and the OPG Board of Directors' Chair in the fourth quarter of 2016, as required by the MOA following a change in the Minister of Energy. Further details on the MOA are discussed in the section, *Interest of Management and Others in Material Transactions* under the heading, *Relationship with the Province and the OEFC*.

OPG's registered head office is located at 700 University Avenue, Toronto, Ontario, M5G 1X6, Canada.

OVERVIEW OF OPG

OPG is Ontario's largest clean energy generator. As at December 31, 2017, OPG operated two nuclear generating stations, three thermal generating stations, 66 hydroelectric generating stations, and one wind power turbine. The majority of OPG's generation is from its rate-regulated nuclear and rate-regulated hydroelectric stations. In addition, OPG and TransCanada Energy Ltd. co-own the 550 megawatt (MW) Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS). OPG and ATCO Power Canada Ltd. co-own the 560 MW Brighton Beach gas-fired combined cycle GS (Brighton Beach). Including its share of the co-owned facilities, OPG's total in-service generating capacity was 16,210 MW as at December 31, 2017, which represented approximately 45 percent of installed generation capacity in Ontario's electricity grid as reported by the Independent Electricity System Operator (IESO). OPG's in-service generating capacity as of December 31, 2017 excludes Unit 2 of the Darlington Nuclear GS. The unit, which has a generating capacity of 878 MW, was taken offline in mid-October 2016 and is currently undergoing refurbishment. OPG operates under an electricity generation licence issued by the OEB, which is valid until October 30, 2023. OPG expects the licence to be renewed in the future.

OPG also owns two other nuclear generating stations, the Bruce A GS and the Bruce B GS, which are leased on a long-term basis to Bruce Power L.P. (Bruce Power) and are not included in the generation and other operating statistics set out in this AIF.

All of OPG's owned and co-owned generating facilities are located in Ontario.

Effective in the fourth quarter of 2017, following the establishment of the Fair Hydro Trust (the Trust) as the financing entity to implement the Fair Hydro Plan under the *Ontario Fair Hydro Plan Act, 2017* (the Fair Hydro Act or the Act), OPG has modified its reportable business segments to include the Fair Hydro Trust segment. Through its control over the key activities of the Trust and its obligation to absorb losses through ownership of the Trust's subordinated debt, the Company consolidates the financial results of the Trust in accordance with US GAAP. The Fair Hydro Trust segment reports the income related to OPG's role as Financial Services Manager under the Act and holder of subordinated debt issued by the Trust, including the financial results of the Trust. The Fair Hydro Plan and the Fair Hydro Trust are discussed in the section, *General Development of the Business* under the heading, *General Development* and in the section, *Description of the Business* under the heading, *Fair Hydro Trust Segment*.

OPG's business operations are divided into six business segments and are discussed under the heading, *General Development* and in their respective sections. The six business segments are as follows:

- Regulated – Nuclear Generation
- Regulated – Nuclear Waste Management
- Regulated – Hydroelectric
- Contracted Generation Portfolio
- Services, Trading, and Other Non-Generation
- Fair Hydro Trust

Pursuant to the *Ontario Energy Board Act, 1998* and *Ontario Regulation 53/05,* OPG receives OEB-authorized regulated prices for electricity generated from the Pickering and Darlington nuclear generating stations and the 54 hydroelectric facilities prescribed for rate regulation (collectively, prescribed facilities or regulated facilities). The OEB is an independent, quasi-judicial tribunal that regulates market participants in Ontario's natural gas and electricity industries, and reports to the Legislature of the Province through the Ontario Ministry of Energy. OPG is Ontario's only electricity generator subject to rate regulation by the OEB.

Of OPG's 54 regulated hydroelectric facilities, 48 facilities were prescribed for rate regulation effective July 1, 2014 pursuant to a November 2013 amendment to *Ontario Regulation 53/05*. The remaining six regulated hydroelectric facilities and the Pickering and Darlington nuclear generating stations have been subject to rate regulation by the OEB since 2008.

Electricity generated from most of OPG's non-regulated assets is subject to Energy Supply Agreements (ESAs) with the IESO. The IESO is a non-profit corporate entity governed by an independent Board of Directors appointed by the Province and is responsible for operating the electricity market and directing the operation of the bulk electrical system in Ontario. Effective January 1, 2015, the Ontario Power Authority (OPA), an organization previously established by the Province with a mandate to contribute to the development of a reliable and sustainable electricity system in Ontario, merged with the IESO. The new entity continued under the name IESO. The IESO is the counterparty to the ESAs and other agreements that were previously executed with the OPA.

ESAs are in effect for the capacity and production from OPG's three operating thermal generating stations – the oil/gas dual-fuelled Lennox GS, the biomass powered Atikokan GS and the advanced biomass fuelled unit at the Thunder Bay GS. The results of these stations are reported under the Contracted Generation Portfolio segment. The expiry dates of these ESAs range from January 2020 to July 2024. In addition, 50-year ESAs are in place for the hydroelectric facilities reported under the Contracted Generation Portfolio segment. The hydroelectric ESAs for the operating stations have expiry dates ranging from February 2059 to March 2067. The ESAs for the contracted generating stations result in a relatively stable stream of revenues from the Contracted Generation Segment.

OPG's revenue and electricity generation by business segment for the years ended December 31, 2017, 2016 and 2015 and OPG's in-service generating capacity as at December 31, 2017, 2016 and 2015 are summarized in the table below.

		Regulated – Nuclear Generation	Regulated – Nuclear Waste Management	Regulated – Hydroelectric	Contracted Generation Portfolio [1]	Services, Trading, and Other Non-Generation	Fair Hydro Trust
2017	Revenue *(millions of dollars)* [2]	**3,095**	**121**	**1,436**	**579**	**43**	**1** [4]
	Electricity Generation *(terawatt hours)*	**40.7**	**N/A**	**30.7**	**2.7**	**N/A**	**N/A**
	In-service Generating Capacity *(MW)* [3]	**5,728**	**N/A**	**6,426**	**4,056**	**N/A**	**N/A**
2016	Revenue *(millions of dollars)* [2]	3,481	138	1,527	573	68	N/A
	Electricity Generation *(terawatt hours)*	45.6	N/A	29.5	3.1	N/A	N/A
	In-service Generating Capacity *(MW)* [3]	5,728	N/A	6,421	4,028	N/A	N/A
2015	Revenue *(millions of dollars)* [2]	3,245	122	1,619	535	73	N/A
	Electricity Generation *(terawatt hours)*	44.5	N/A	30.4	3.1	N/A	N/A
	In-service Generating Capacity *(MW)*	6,606	N/A	6,428	4,021	N/A	N/A

[1] The in-service generating capacity includes OPG's share of 275 MW for PEC and 280 MW for Brighton Beach, and the electricity generation includes OPG's share of its 50 percent ownership in these stations.
[2] Revenue for each segment is shown before inter-segment elimination.
[3] Regulated – Nuclear Generation segment excludes the generating capacity of 878 MW from Unit 2 of the Darlington GS, which has been undergoing refurbishment since mid-October 2016.
[4] This represents OPG's earnings from the Fair Hydro Trust, which consist of income related to OPG's role as Financial Services Manager under the Act and holder of subordinated debt issued by the Trust, including the financial results of the Trust.

For the year ended December 31, 2017, OPG's electricity generation accounted for over 50 percent of the total energy generated on Ontario's electricity grid, as reported by the IESO.

OPG is subject to a number of provincial and federal legislation and regulations, including the decisions of administrative tribunals or other regulatory bodies, and to Canada's international obligations under certain international treaties. Collectively, these sources dictate many of the constraints within which OPG is permitted to operate its facilities and manage its business.

Strategic Imperatives

OPG's mission is to provide low cost power in a safe, clean, reliable and sustainable manner for the benefit of its customers and its Shareholder. OPG also seeks to pursue, on a commercial basis, generation development projects and other business growth opportunities to the benefit of the Shareholder. The four strategic imperatives of OPG are briefly described below.

Operational Excellence

Operational excellence at OPG is accomplished by the safe and environmentally responsible generation of reliable and cost-effective electricity from the Company's generating assets through a highly trained and engaged workforce. Workplace safety and public safety are overriding priorities in all activities performed at OPG.

Project Excellence

OPG is pursuing a number of generation development and other projects in support of Ontario's electricity planning initiatives. OPG's major generation projects include the refurbishment of the Darlington GS, the expansion of the Ranney Falls hydroelectric GS, and the construction of a solar facility at the Nanticoke GS site. OPG aims to be an industry leader in project management capability and performance.

Financial Strength

As a commercial enterprise, OPG's financial priority is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future growth. Inherent in this priority are the following objectives:

- Increasing revenue, reducing costs and achieving appropriate return;
- Ensuring availability of cost effective funding for operational needs, generation development projects and other business opportunities, and long-term obligations;
- Pursuing opportunities to expand the existing core business and capitalize on new growth paths including emerging renewable energy opportunities; and
- Managing risks. Refer to the section, *Risk Management*, in the Company's 2017 year-end MD&A for more details.

Social Licence

As the largest, publicly-owned electricity generator in Ontario with geographically diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust. OPG is committed to maintaining high standards of public safety and corporate citizenship, including environmental stewardship, transparency, community engagement, and Indigenous relations.

OPG has in place a Code of Business Conduct that establishes the standards, expectations, and accountabilities for ethical behaviour. All employees and all parties with whom the Company does business are expected to abide by OPG's Code of Business Conduct. A copy of the Code of Business Conduct can be found on SEDAR at www.sedar.com and also is available on the Company's website at www.opg.com.

Further details on OPG's strategic imperatives can be found in the corresponding sections of the Company's 2017 year-end MD&A in the section, *Core Business, Strategy, and Outlook.*

GENERAL DEVELOPMENT OF THE BUSINESS

The following is a summary of key developments in OPG's business since January 2015.

General Development

OPG's Regulated Prices and Other OEB-Related Developments

Energy revenue generated from the Company's regulated nuclear and regulated hydroelectric facilities is based on regulated prices determined by the OEB through public proceedings. To date, the regulated prices have included a volumetric base regulated price, and volumetric rate riders for the recovery or repayment of approved variance and deferral account balances. As the regulated operations account for the majority of the Company's electricity generation, the outcomes of OPG's applications for regulated prices to the OEB determine a large portion of the Company's revenues and can have a significant impact on the Company's financial performance.

The following are the OEB-authorized regulated prices for electricity generated from the Company's regulated facilities in effect during the years ended December 31:

	2017		2016	2015	
($/megawatt hour)	**January 1 to May 31**	**June 1 to December 31** [1]		**January 1 to June 30**	**July 1 to December 31**
Regulated – Nuclear Generation					
Base regulated price	**59.29**	**80.65**	59.29	59.29	59.29
Variance and deferral account rate riders	**-**	**-**	10.84 [2]	1.33	12.17 [2]
	59.29	**80.65**	70.13	60.62	71.46
Regulated – Hydroelectric					
Hydroelectric generating stations prescribed for rate regulation prior to 2014					
Base regulated price	**40.20**	**41.67**	40.20	40.20	40.20
Variance and deferral account rate riders	**-**	**-**	3.19 [2]	6.04	9.23 [2]
	40.20	**41.65**	43.39	46.24	49.43
Hydroelectric generating stations prescribed for rate regulation effective in 2014					
Base regulated price	**41.93**	**41.67**	41.93	41.93	41.93
Variance and deferral account rate riders	**-**	**-**	3.19 [2]	-	3.19 [2]
	41.93	**41.67**	45.12	41.93	45.12

[1] Regulated prices for the June 1, 2017 to December 31, 2017 period were calculated and submitted to the OEB by OPG in January 2018 based on the OEB's December 28, 2017 decision on OPG's 2017-2021 application for new regulated prices. The final regulated prices will be determined by the OEB as part of the final payment amounts order process, which is expected to be completed in the first half of 2018. As part of the process, the OEB is expected to authorize separate rate riders to allow for the recovery of the shortfall between the new regulated prices and the previous regulated prices that OPG continues to receive during the period between June 1, 2017 and the implementation date of the new regulated prices pending the issuance of the final payment amounts order. The incremental revenue for the period between June 1, 2017 and December 31, 2017 arising from this retrospective application of new regulated prices was accrued in 2017. **[MONITOR]**

[2] The OEB authorized interim period rate riders for the period from October 1, 2015 to December 31, 2016 to allow for the recovery of the riders effective July 1, 2015 for the period from July 1, 2015 to September 30, 2015. The nuclear interim period rate rider was $2.17 per megawatt hour (MWh) and the regulated hydroelectric interim period rate rider was $0.64/MWh. These interim period rate riders have not been included in the above table. All rate riders in effect during 2016 expired on December 31, 2016.

Base Regulated Prices

The OEB's decision on OPG's May 2016 five-year application for new regulated prices for its nuclear and regulated hydroelectric generation was issued on December 28, 2017, following a public hearing process. Based on the OEB's December 2017 decision, the new base regulated prices are determined on an incentive ratemaking methodology for the hydroelectric operations and under a custom incentive regulation framework for the nuclear operations. For the hydroelectric facilities, the new base regulated price is determined using a formula that annually escalates the previous regulated prices, subject to some adjustments, based on inflation less a stretch factor to incent additional innovation and efficiency. For the nuclear facilities, the new regulated price is determined under a rate smoothing approach that defers a portion of the approved nuclear revenue requirement for future collection, with the aim of making more stable changes in OPG's production-weighted regulated prices year over year. The nuclear revenue requirement is based on the OEB-approved forecasts of operating costs as reduced by a stretch factor and a return on rate base. Rate base for OPG represents the average net level of investment in regulated fixed and intangible assets in service and an allowance for working capital.

For the first time since OPG's prescribed facilities became subject to rate regulation, the new prices have been determined on an incentive ratemaking methodology for the hydroelectric operations and a custom incentive regulation framework for the nuclear operations.

For the hydroelectric facilities, effective June 1, 2017, the base regulated prices in effect prior to June 1, 2017, with some adjustments, will be escalated for each of years 2017 to 2021 using a formula equal to an industry-specific weighted inflation factor based on indices published annually by the OEB for use in incentive regulation formulas, less a stretch factor adjustment. The OEB accepted OPG's proposal to set the annual stretch factor adjustment at 0.3 percent. Based on the approved formula, the 2017 increase in the base regulated price for the regulated hydroelectric facilities is 1.4 percent as of June 1, 2017 and the 2018 increase is 0.9 percent as of January 1, 2018. For the 2019-2021 period, the base regulated price for the regulated hydroelectric facilities will be determined annually before the beginning of each year using the approved formula and inflation indices published by the OEB.

For the nuclear operations, a revenue requirement is determined for each of the years 2017 to 2021 based on the OEB-allowed level of OPG's forecast operating costs, reduced by a stretch factor amount, as well as a return on rate base determined using OEB's generic prescribed rate of return and an OPG-specific deemed capital structure. OPG has calculated that the findings of the OEB's December 2017 decision with respect to the forecast operating costs, rate base and deemed capital structure for the nuclear generating facilities will result in nuclear revenue requirements totalling $15.9 billion over the five years.

The OEB's findings with respect to the nuclear revenue requirement include approval for inclusion in rate base of in-service amounts related to the Darlington Refurbishment of $5.5 billion by 2021, including $4.8 billion forecast in the first quarter of 2020 upon return to service of Unit 2, $0.4 billion forecast for pre-requisite projects excluding the construction of the Heavy Water Storage and Drum Handling Facility (HWSF) over the 2016-2021 period and $0.3 billion for pre-requisite projects placed in service prior to 2016. The OEB is expected to review the HWSF project as part of a future application. In the decision, the OEB concluded that it is appropriate to evaluate OPG's performance on the Darlington Refurbishment project at an overall level rather by individual cost component, with recovery of any increases over the approved in-service amounts subject to a future prudence review. The revenue requirement impact of differences between the approved in-service additions and the actual in-service additions will be recorded in the Capacity Refurbishment Variance Account authorized by the OEB pursuant to *Ontario Regulation 53/05*. The $4.8 billion forecast in-service amount upon return to service of Unit 2 includes expenditures incurred during the definition and planning phase of the project.

The OEB also approved OPG's requested forecast costs of approximately $292 million for activities to enable Pickering commercial operations beyond 2020 and agreed to inclusion of operating cost and generation impacts associated with continued operation of Pickering in 2021 in nuclear regulated prices. The differences between approved forecast enabling costs for continued Pickering operations and the actual amounts will be recorded in the Capacity Refurbishment Variance Account for future review and disposition by the OEB.

Excluding amounts that otherwise would have been recorded in OEB-authorized regulatory accounts for repayment to, or recovery from, customers in the future, the OEB's decision reduced OPG's proposed five-year nuclear revenue requirement by $0.6 billion. The main adjustments made by the OEB included a reduction of $100 million per year to requested OM&A costs , a reduction of 10 percent per year to forecast non-Darlington refurbishment capital in-service additions entering rate base over the 2017-2021 period, an increase and expansion of the scope of the stretch factor for nuclear costs that further reduced the revenue requirement, and a rejection of OPG's request to increase the equity component of the existing deemed capital structure of 45 percent equity and 55 percent debt. The OEB increased and expanded the annual stretch factor to 0.6 percent to most of OPG's OM&A expenses incurred directly for, or allocated to, the nuclear facilities, as well as to non-Darlington refurbishment capital in-service additions. The stretch factor is applied starting in 2018 and compounds in each year to 2021.

In accordance with *Ontario Regulation 53/05*, the nuclear revenue requirement continues to be adjusted by the amount of OPG's revenues, net of costs, from leasing the Bruce nuclear generating stations to Bruce Power. As directed by the OEB, OPG's revenues and costs related to the Bruce nuclear generating stations continue to be determined in accordance with US GAAP for the purposes of establishing the nuclear revenue requirement and are subject to the Bruce Lease Net Revenues Variance Account in accordance with *Ontario Regulation 53/05*. This includes costs related to the portion of the Nuclear Liabilities associated with the Bruce nuclear generating stations. The OEB's decision maintained the previously approved cost recovery methodology for the costs of the Nuclear Liabilities for the prescribed facilities and for the Bruce facilities, directing OPG to file a future study examining such methodologies jurisdictionally and for OPG's assets specifically. The decision fully incorporated the impacts of the updated estimate of OPG's obligations for nuclear waste management and nuclear facilities decommissioning as at December 31, 2016, including through a new ONFA reference plan effective January 1, 2017 and the change in the Nuclear Liabilities recorded on December 31, 2016.

As proposed by OPG, the OEB set recovery of pension and OPEB costs in the nuclear revenue requirement on the basis of OPG's cash payments for pension and OPEB plans, with differences between pension and OPEB accrual costs and cash payments continuing to be recorded in the Pension & OPEB Cash to Accrual Differential Deferral Account. The regulatory treatment of pension and OPEB costs is discussed further under the heading, *Pension and OPEB Cost Recovery Methodology*.

To reflect the OEB's decision, in the fourth quarter of 2017, OPG recorded incremental revenue of approximately $480 million for the period June 1, 2017 to December 31, 2017 based on the draft payment amounts order. The revenue was recorded as an increase in regulatory assets for the June 1, 2017 to December 31, 2017 revenue shortfall based on proposed new regulated prices for nuclear facilities and regulated hydroelectric facilities, net of a regulatory liability recognized in relation to OPG's rate smoothing proposal. The OEB's approval of the final payment amounts order, including the allocation of the approved revenue requirement between nuclear regulated prices and rate smoothing deferrals, is not expected to have a material impact on the net revenue increase recorded in the fourth quarter of 2017. The OEB is expected to issue the final payment amounts order and implement new regulated prices in the first half of 2018. **[MONITOR]**

The base regulated prices in effect from January 2015 through May 2017 were established by the OEB's November 2014 decision and December 2014 order on OPG's September 2013 rate application. This included regulated prices effective November 1, 2014 for the 48 hydroelectric facilities that were prescribed for rate regulation effective July 1, 2014. Prior to November 1, 2014, the generation revenue for these hydroelectric facilities was based on the Ontario electricity spot market price, including for the period from

July 1, 2014 to November 1, 2014 as determined by the OEB. The base regulated prices effective November 1, 2014 remained in effect until May 31, 2017.

The regulated prices in effect from January 2015 through May 2017 for the nuclear facilities and the hydroelectric facilities prescribed for rate regulation prior to 2014 were determined by the OEB based on approved 24-month revenue requirements for the 2014 to 2015 period totaling approximately $7.3 billion. This reflected a reduction of $833 million from the revenue requirements submitted by OPG. The regulated price for the 48 hydroelectric facilities prescribed for rate regulation beginning in 2014 was established based on an approved 18-month revenue requirement for the period from July 1, 2014 to December 31, 2015 of approximately $750 million, a reduction of $101 million from OPG's submission. The most significant adjustments made by the OEB to OPG's September 2013 rate request included the following:

- Allowed pension and OPEB costs were limited to the forecast 2014 and 2015 cash expenditures for these plans, which were approximately $600 million lower, including related tax impacts, than the forecast accrual costs submitted by OPG. The difference between accrual costs and cash expenditures is being recorded in a deferral account authorized by the OEB. For further details, see *Pension and OPEB Cost Recovery Methodology* in this section. **[CONFIRM]**
- A reduction in overall forecast compensation costs of $100 million in each of 2014 and 2015 across all of OPG's regulated facilities.
- An increase in the forecast nuclear production of 0.5 terawatt hours (TWh) annually used to set the nuclear regulated prices, which had the effect of reducing the approved nuclear regulated price.
- The rate base addition for the Niagara Tunnel project to construct a third tunnel to divert additional water to OPG's generating stations on the Niagara River was limited to $1,365 million, which resulted in a write-off of $77 million being charged to operations in 2014.
- A reduction in the 2014 income tax expense included in the regulated prices by the amount of the regulatory tax loss calculated for 2013, which reduced the 2014/2015 revenue requirement by approximately $70 million.

In December 2014, OPG filed a motion with the OEB asking it to review and vary the parts of its November 2014 decision related to the disallowance of the Niagara Tunnel project expenditures and the application of the 2013 regulatory tax loss against the 2014/2015 revenue requirement. In its January 2016 decision on the motion, the OEB reversed a portion of the Niagara Tunnel project disallowance and upheld the original tax loss decision. In the first quarter of 2016, OPG recorded a gain of $22 million to recognize the expected future recovery from customers of the reversed portion of the Niagara Tunnel project disallowance.

In its November 2014 decision, the OEB adjusted the deemed capital structure applied to OPG's total regulated rate base to 45 percent equity and 55 percent debt, from 47 percent equity and 53 percent debt used previously. In making this adjustment, the OEB found that there had been an overall improvement in the risk profile of OPG's regulated operations, based on the increased proportionate share of rate base related to hydroelectric facilities. This reduced the 2014/2015 revenue requirements. In general, OPG's actual capital structure contains a significantly higher proportion of equity than has been reflected in the OEB-approved deemed capital structure, which has had the effect of reducing OPG's return on shareholder's equity.

Variance and Deferral Accounts and Rate Riders

Consistent with the requirements of *Ontario Regulation 53/05*, OPG's overall production-weighted regulated prices will be smoothed, with a resulting portion of the approved annual nuclear revenue requirements for the 2017-2021 period deferred in the Rate Smoothing Deferral Account for future collection. The non-deferred portion of each year's nuclear revenue requirement is divided by the OEB-approved forecast of OPG's nuclear electricity generation for the corresponding year to determine the base nuclear regulated price. The OEB approved the nuclear electricity generation forecast as requested by OPG.
As amended in March 2017, *Ontario Regulation 53/05* requires rate smoothing to be applied in a manner that makes changes in OPG's weighted-average nuclear and hydroelectric regulated prices more stable year over year. Previously, the regulation required that rate smoothing be applied with a view of making

more stable year-over-year changes in OPG's nuclear regulated prices only. Per the regulation, the deferral account records interest at a long-term debt rate reflecting OPG's cost of long-term borrowing approved by the OEB, compounded annually. The regulation requires the OEB to authorize recovery of the balance in the account on a straight line basis over a period not to exceed 10 years following the end of the Darlington Refurbishment project. OPG recognizes positive amounts deferred under rate smoothing as an increase in net regulatory assets and an increase in revenue in the period to which the underlying approved revenue requirement relates. Negative amounts determined under rate smoothing are correspondingly recorded as a decrease in net regulatory assets and a decrease to revenue.

On January 17, 2018, OPG submitted a draft payment amounts order to the OEB that proposed nuclear base regulated prices for each year of the 2017-2021 period, including a rate smoothing proposal, based on the December 2017 decision's findings. The rate smoothing proposal takes into account the near-term and future impacts on customers, while seeking to ensure that resulting nuclear regulated prices allow for sufficient cash flow to maintain the Company's investment grade credit rating and support availability of cost effective funding, while taking into account both near-term and future impacts on customers. Based on the OEB's direction, the draft payment amounts order also included proposed periods for recovery, through interim period shortfall rate riders, of the retrospective revenue shortfall for the period between June 1, 2017 and the implementation date of the new regulated prices based on proposed new regulated prices that would have been in effect during that period. The draft payment amounts also included proposed recovery periods, through variance and deferral account rate riders, for regulatory account balances approved for recovery in this application. **[MONITOR]**

Variance and deferral accounts are typically established by the OEB to capture, for subsequent review and approval, differences between actual costs and revenues and the corresponding forecast amounts approved by the OEB in setting regulated prices, or to record the impact of items not reflected in the approved regulated prices. Such accounts generally help to mitigate risks and uncertainties to the regulated entity and its customers.

The OEB has authorized several variance and deferral accounts for OPG, including those required by *Ontario Regulation 53/05*. The authorized accounts include, among others, those related to the gross margin impact of variability in regulated hydroelectric electricity production due to differences between the forecast and actual water conditions and due to the effect of SBG conditions, changes in liabilities for nuclear waste management and nuclear facilities decommissioning, changes in revenues and costs related to the lease and related agreements with Bruce Power for the Bruce nuclear generating stations, and variances in the revenue requirement impact of capital and non-capital costs incurred to increase the output of, refurbish, or add operating capacity to the regulated facilities, including the Darlington Refurbishment project. A number of these accounts are subject to an OEB prudence review. There is currently no regulatory variance or deferral account related to the impact of generation performance of OPG's nuclear stations on revenue from the base regulated prices. The Darlington Refurbishment project is discussed in the section, *General Development of the Business* under the heading, *Nuclear Business Development – Darlington Refurbishment*.

Approved balances in the regulatory variance and deferral accounts authorized by OPG are recovered or refunded through volumetric rate riders. The additional revenue from the riders is largely offset by a corresponding increase in amortization expense related to the variance and deferral account balances, which are typically recognized as assets (amounts recoverable from customers) or liabilities (amounts payable to customers) on the Company's balance sheet. Differences in amounts recovered or repaid through rate riders due to differences between actual and forecast production volumes are recorded in separate variance accounts for future disposition. **[MONITOR]**

The OEB accepted all variance and deferral account balances proposed for recovery that were not already accepted as part of the Settlement Agreement, resulting in approval of recovery of $305 million recorded in variance and deferral variance accounts as at December 31, 2015, without adjustments. The Settlement Agreement provided for the continuation of all applicable existing variance and deferral accounts. In addition to the Rate Smoothing Deferral Account, the OEB established, as of the effective date of the new regulated prices, new variance and deferral accounts to record costs related to implementing the Canadian

Nuclear Safety Commission's (CNSC) Fitness for Duty program and to record differences between forecast and actual amount of Scientific Research & Experimental Development investment tax credits attributable to the nuclear facilities. In January 2018, OPG filed a motion asking the OEB to review and vary the effective date of the new regulated prices to January 1, 2017. The motion did not impact OPG's financial results for the year ended December 31, 2017.

Consistent with the effective date of the OEB's December 2017 decision, for the period from January 1, 2017 to May 31, 2017, OPG continued to record additions to the existing variance and deferral accounts for the nuclear and regulated hydroelectric facilities pursuant to the OEB's previous decisions and orders. These additions reflected differences between actual and forecast amounts embedded in the regulated prices in effect prior to the June 1, 2017 effective date.

The rate riders in effect in 2015 and 2016 included those authorized by the OEB's October 2015 order on OPG's application in 2014 to recover or repay most of the December 31, 2014 variance and deferral account balances, discussed below. The 2015 rate riders also included those established by the OEB's December 2014 order on OPG's September 2013 rate application for the period January 1, 2015 to December 31, 2015. The December 2014 order allowed for recovery of $189 million recorded in certain variance and deferral accounts as at December 31, 2013, without adjustments.

The total balances approved for recovery by the OEB's October 2015 order were approximately $1.8 billion, of which approximately $1.5 billion was the subject of an OEB-approved partial settlement agreement reached by OPG and intervenors. The remaining balances of $263 million were approved by the OEB's September 2015 decision, without adjustments. The rate riders authorized by the October 2015 order were in effect from July 1, 2015 to December 31, 2016 and allowed for recovery of $933 million of the total approved balances.

Amendments to Ontario Regulation 53/05

In November 2015, the Province amended *Ontario Regulation 53/05* to establish a deferral account, effective January 1, 2017, that will record, for future recovery, a portion of the annual OEB-approved revenue requirements for OPG's regulated nuclear facilities during the period from January 1, 2017 to the end of the Darlington Refurbishment project. The amended regulation requires the OEB to determine the revenue requirements for OPG's nuclear facilities on a five-year basis for the ten-year period beginning on January 1, 2017. The portion of the approved revenue requirement deferred in the new account each year also will be determined by the OEB on a five-year basis during this ten-year period. The regulation stipulates that the deferral account will record interest at a long-term debt rate reflecting OPG's cost of long-term borrowing approved by the OEB, compounded annually, and that the OEB shall authorize recovery of the balance in the account on a straight line basis over a period not to exceed 10 years following the end of the Darlington Refurbishment project. OPG expects to recognize the deferred amounts as income in the period to which the underlying approved revenue requirements relate.

The November 2015 amendment required the portion of the approved annual nuclear revenue requirements deferred for future recovery to be determined with a view of making more stable year-over-year changes in OPG's nuclear regulated prices only. In March 2017, the Province amended *Ontario Regulation 53/05* to require that the deferred portion of the approved annual nuclear revenue requirements be determined with a view of making more stable year-over-year changes in OPG's weighted-average nuclear and hydroelectric regulated prices, including rate riders. The amendment is intended to make more predictable the impact on customer bills resulting from changes in OPG's overall regulated prices, reducing the average year-over-year change in customer bills over the term of OPG's May 2016 application for new regulated prices.

The regulation was also amended in November 2015 to require the OEB to accept the need for the Darlington Refurbishment project in light of Ontario's 2013 Long-Term Energy Plan (LTEP) and the related policy of the Province endorsing the need for nuclear refurbishment. Furthermore, the 2017 LTEP reaffirms the Province's support for nuclear refurbishment. The 2017 LTEP is discussed in the section, *General*

Development of the Business under the heading, *General Development – Ontario's Long-Term Energy Plan*.

Pension and OPEB Cost Recovery Methodology

Using the methodology previously applied by the OEB in setting OPG's regulated prices, the revenue requirements submitted by OPG in its September 2013 rate application included a forecast of 2014 and 2015 pension and OPEB costs determined on an accrual basis in accordance with US GAAP. In its November 2014 decision and December 2014 order on the application, the OEB approved revenue requirements based on OPG's estimated minimum required contributions to its registered pension plan, and a forecast of OPG's expenditures on the OPEB and supplementary pension plans. In directing this reduction in the revenue requirement, the OEB agreed with OPG and certain other parties that a generic proceeding on the regulatory treatment and recovery of pension and OPEB costs would be beneficial. The OEB also indicated that a change in the recovery methodology for OPG's pension and OPEB amounts from the accrual basis, if required, would be addressed in a future OPG rate proceeding, informed by the outcome of the generic proceeding.

Pending the generic proceeding, the OEB established the Pension & OPEB Cash Versus Accrual Differential Deferral Account. Effective November 1, 2014, this deferral account records the difference between OPG's actual pension and OPEB costs for the regulated business determined on an accrual basis and the corresponding actual cash expenditures for these plans. The OEB's November 2014 decision indicated that the future recovery, if any, of amounts recorded in the deferral account would be subject to the outcome of a future generic OEB proceeding on the regulatory treatment and recovery of pension and OPEB costs. The balance in the account is recognized as a regulatory asset on OPG's balance sheet.

On September 14, 2017, the OEB issued its final report on the guiding principles and policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the Ontario electricity and natural gas sectors. The report establishes the accrual basis of accounting as the method of determining pension and OPEB amounts for rate-setting purposes, unless the OEB finds that this method does not result in just and reasonable rates in the circumstances of a particular utility. The report also provides for the establishment of a generic variance account to record asymmetric carrying charges in favour of ratepayers on the differences between the accrual costs recovered and cash payments made by a utility in respect of pension and OPEB plans. Carrying charges on this differential are to be assessed at the OEB's prescribed interest rate, on a prospective basis from the effective date of the new variance account. For OPG, this differential will include amounts going back to November 1, 2014, with the charges calculated on the portion of the differential that has been recovered through regulated prices. None of this differential has been recovered to date. The prescribed interest rate is set quarterly by the OEB based on the quarterly return of a mid-term corporate bond index yield.

The OEB's September 2017 report and the OEB's December 2017 decision on OPG's application for new regulated prices require OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the Pension & OPEB Cash to Accrual Differential Deferral Account in effect since November 1, 2014, until such time as the OEB approves resumption of the accrual basis of recovery for OPG. The future recovery of amounts recorded in the account will be subject to this approval. The OEB's report did not impact OPG's financial results for the year ended December 31, 2017.

The Company recognizes the amount set aside in the Pension & OPEB Cash Versus Accrual Differential Deferral Account as a regulatory asset. As at December 31, 2017, the regulatory asset had a balance of $614 million. Consistent with the expectations set out in the OEB's December 2017 decision, in 2018, OPG plans to file an application with the OEB requesting disposition of the Pension & OPEB Cash Versus Accrual Differential Deferral Account balance as well as balances accumulated since December 31, 2015 in other regulatory accounts.

Supreme Court of Canada's Decision on 2011 OEB Ruling

In September 2015, the Supreme Court of Canada (Supreme Court) issued its decision upholding the OEB's disallowance of $145 million of OPG's forecast nuclear compensation costs for the 2011 to 2012 period. The majority of these costs were based on previously negotiated collective bargaining agreements. This disallowance was part of the OEB's March 2011 decision on OPG's application for regulated prices effective March 1, 2011. The Supreme Court decision underscores that OPG must continue to establish the reasonableness of both committed and future costs as part of the rate-setting process.

Ontario's Fair Hydro Plan

On March 2, 2017, the Province announced the Fair Hydro Plan aimed at reducing electricity bills for eligible residential, farm, small businesses ~~and other eligible~~ consumers (Specified Consumers) in the province by refinancing a portion of the Global Adjustment costs over a longer period of time. The Global Adjustment includes the difference between Ontario's electricity market clearing price used to dispatch generation and the prices paid to contracted and regulated generators in the province, and the cost of conservation and demand management programs. On June 1, 2017, the Fair Hydro Act received Royal Assent and the associated general regulation came into force in June 2017. The Act established a framework under which the costs and benefits associated with the Government of Ontario's clean energy initiatives are to be allocated between present and future consumers of electricity under the Fair Hydro Plan. The general regulation provides details on the structural, operational and financial elements required to implement the Fair Hydro Plan.

Commented [MR-1]: Did not update as this wording is similar to our prior quarter(s) disclosure.

Pursuant to the Act, effective May 1, 2017, the IESO began to defer a portion of the Global Adjustment costs. The Act allows the IESO to transfer a portion of the deferred balance to a financing entity that would fund the deferral in exchange for an irrevocable right to recover the balance and associated financing and other costs from Specified Consumers in the future (Investment Interest). The legislation appointed OPG as the Financial Services Manager under the Act and conveyed upon the Financial Services Manager statutory obligations, including the creation of one or more financing entities that may acquire Investment Interests from the IESO.

In November 2017, OPG's Board of Directors provided its final approval regarding OPG's involvement with the Trust on commercial terms following the fulfilment of all conditions it established in May 2017. Accordingly, the Fair Hydro Trust was established as the financing entity contemplated by the Act in December 2017. The majority unitholder and beneficiary of the Trust is a wholly-owned subsidiary of OPG. The Trust is structured to be bankruptcy remote and ring fenced from OPG in order to protect the Company's assets and operations.

In order for the Trust to finance the Investment Interest acquired from the IESO, it will incur senior debt from capital markets and subordinated debt from OPG. The Trust's investment will attract financing amounts and other related fees, which, under the general regulation, will be payable by the IESO as carrying costs until July 2021 and by Specified Consumers through the Clean Energy Adjustment to be invoiced by local distribution companies commencing in May 2021, with the three-month lag in 2021 intended to cover the billing and collection lag from the introduction of the Clean Energy Adjustment. The carrying costs include all financing and third-party costs other than payment of principal on debt.

Concurrent with every issuance of the Trust's senior notes, it is expected that OPG will purchase subordinated debt of the Trust in an aggregate amount not to exceed 49 percent of the Trust's total outstanding debt, with 44 percent of the funding to be provided by the Province through equity injections and five percent to be provided by OPG. The subordination level may vary over time, but must at least equal to, or be greater than 35 percent of all outstanding debt. Through OPG's control over the key activities of the Trust and its obligation to absorb losses through ownership of the Trust's subordinated debt, the Company consolidates the financial results of the Trust in accordance with US GAAP.

On December 21, 2017, the Trust purchased its first tranche of Investment Interest from the IESO in the amount of approximately $1.18 billion. Fifty-one percent of the funding requirement or $601 million was financed by the Trust through a revolving warehouse facility ranked as senior notes, and the remaining 49

percent was funded through the issuance of short-term subordinated debt to OPG. The Investment Interest has been classified as a financing receivable on OPG's consolidated balance sheet.

OPG's subordinated debt investment in the Trust was funded through the following sources:

- The Province provided 44 percent of the total funding requirement or $519 million, through an equity injection in OPG in exchange for approximately 12.2 million non-voting Class A common shares at a price of $42.46 per share. The Company's Articles of Amalgamation were amended effective December 1, 2017 to allow for the creation and issuance of Class A shares. Refer to Note 14 to the Company's audited annual financial statements as at and for the year ended December 31, 2017 for further details; and
- OPG provided five percent of the total funding requirement or approximately $60 million.

In February 2018, the Trust issued $500 million of senior notes payable with a coupon interest rate of 3.36 percent and an effective interest rate of 3.42 percent, payable semi-annually until maturity on May 15, 2033. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility issued in December 2017. By the end of the first quarter of 2018, the Trust is expected to acquire another tranche of Investment Interest from the IESO, which is expects to fund using its revolving warehouse facility.

Refer to the section, *Liquidity and Capital Resources* under the heading, *Financing Activities* for further details on the Trust's financing arrangements and OPG's public debt offering in the Company's 2017 year-end MD&A.

Ontario's Long-Term Energy Plan

On October 26, 2017, Ontario's Ministry of Energy issued the 2017 LTEP that outlines the Province's plans for the future development of Ontario's electricity system. The 2017 LTEP focuses on the affordability, reliability and flexibility of a clean energy supply in the province. The 2017 LTEP replaces the previous LTEP issued in 2013.

As it relates to the supply of electricity, the 2017 LTEP recognizes the refurbishment of Ontario's nuclear generating stations as the most cost-effective option for producing emission-free baseload generation to meet Ontario's needs and reaffirms the Province's support for the refurbishment of the four units at the Darlington GS and the six units at the Bruce generating stations, subject to the principles established in the 2013 Long-Term Energy Plan. The 2017 LTEP also recognizes the value to customers of continuing to operate the Pickering GS until 2024, as planned. With respect to hydroelectric electricity generation, the 2017 LTEP highlights the opportunity to continue to invest in optimizing existing hydroelectric facilities, noting that pumped hydroelectric storage could play an important role in the reliability of the electricity system.

Additionally, the 2017 LTEP discusses the potential impact of a number of innovative technologies on the future of the electricity system. Among others, these include the increased electrification of the transportation sector, the emergence of energy storage, and the opportunity for Ontario to foster nuclear innovation technologies. OPG continues to assess how best to capitalize on potential business opportunities in these and other areas. The 2017 LTEP also recognizes the importance of Indigenous peoples' continuing role in shaping Ontario's energy planning, projects and policies.

Renewal of Collective Agreements and Acquisition of Hydro One Limited Shares

Most of OPG's regular employees are represented by one of two unions: the Power Workers' Union (PWU) and The Society of Energy Professionals (The Society). As at December 31, 2017, the PWU represented approximately 53 percent of OPG's regular workforce, while The Society represented approximately 35 percent of the regular workforce.

The previous collective agreement between OPG and the PWU expired on March 31, 2015. In May 2015, the parties agreed to renew the collective agreement for a three-year term, expiring on March 31, 2018.

The changes to the collective agreement included increases to employee pension plan contributions in each year of the agreement. Negotiations for a new labour agreement with the PWU are underway. **[MONITOR]** The previous collective agreement between OPG and The Society expired on December 31, 2015. In November 2015, the parties agreed to renew the collective agreement for a three-year term, expiring on December 31, 2018. Changes to the collective agreement included increases to employee pension plan contributions in each of the first two years of the agreement. The changes in pension plan contributions apply to current employees and future employees of both unions, and do not have an end date.

The changes to both collective agreements provided existing employees with lump sum payments for each of the first two years of the respective contract and eligibility to annually receive shares in Hydro One Limited (Hydro One) for up to 15 years starting in the third year of the contract, as long as these employees continue to make contributions to the OPG pension plan and have less than 35 years of pensionable service. The lump sum payments and future share awards are intended to compensate current eligible employees, over a defined period, for their increased pension plan contributions.

In April 2016, OPG acquired nine million common shares of Hydro One at $23.65 per share as part of a secondary share offering by the Province through a syndicate of underwriters. The acquisition, totaling $213 million, was made for investment purposes to mitigate the risk of future price volatility related to OPG's future share delivery obligations under the collective agreements. The shares acquired in this transaction represent the substantial majority of OPG's currently anticipated purchases of Hydro One shares.

In addition to the regular workforce, construction work is performed through 19 craft unions with established bargaining rights at OPG facilities. These bargaining rights are established either through the Electrical Power Systems Construction Association (EPSCA) or directly with OPG. Collective agreements between the Company and its construction unions are negotiated either directly or through EPSCA. All of these collective agreements currently have multi-year terms, expiring on April 30, 2020.

Shareholder Declarations and Shareholder Resolutions to Sell Certain Non-Core Real Estate Properties

In December 2015, OPG received a Shareholder Declaration and a Shareholder Resolution requiring the Company to sell its head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street in Toronto, Ontario. The sale was completed in April 2017, with a gain on sale of $283 million, which is net of tax effects of $95 million, recognized in net income in the second quarter of 2017. The pre-tax gain on sale was recorded as an item of Other gains in the consolidated statement of income in the Services, Trading and Other Non-Generation segment. Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. The amount of designated proceeds transferred into the Consolidated Revenue Fund are expected to approximate ~~will be equal to~~ the after-tax gain on sale. **[MONITOR]** The transfer is expected to take place in the first quarter of 2018, through a special dividend authorized by OPG's Board of Directors in March 2018. **[MONITOR]**

Commented [DS2]: The amount of designated proceeds will be determined by regulation and therefore uncertain until the regulation is filed and made public.

Commented [MR-3]: We have made the change.

In June 2016, OPG received a Shareholder Declaration and a Shareholder Resolution that requires the Company to sell its former Lakeview GS site located in Mississauga, Ontario. OPG has entered into a purchase and sale agreement with a purchaser with the sale scheduled to close in March 2018. An estimated after-tax gain on sale of approximately $200 million is expected to be recognized in net income upon completion of the transaction in the first quarter of 2018. **[MONITOR]** Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. OPG anticipates the amount of designated proceeds transferred into the Consolidated Revenue Fund to approximate the after-tax gain on the sale. In accordance with the Shareholder Resolution, approximately one-third of the site is to be transferred to the City of Mississauga, by the purchaser, for parkland, institutional, and cultural uses.

Neither the former Lakeview GS site nor the Company's head office premises and associated parking facility are considered core assets to OPG's business.

For a complete list of Shareholder directives, refer to the section, *Interest of Management and Others in Material Transactions* under the heading, *Relationship with the Province and the OEFC – Shareholder Directives*.

Business Transformation **[UPDATE]**

OPG has completed a multi-year initiative with the objective of transforming itself into a more streamlined, agile and efficient organization. The business transformation initiative was intended to drive sustainable change across the Company, while ensuring that there is no adverse impact on the safety, reliability and environmental sustainability of OPG's operations. OPG's cumulative savings from reductions in regular headcount from ongoing operations, through the business transformation and other initiatives, since the beginning of 2011, reached $1 billion in 2016.

The business transformation initiative involved aggressively pursuing cost control and efficiency improvements at the enterprise and business unit level, including realignment of work, streamlining of processes and leveraging workforce attrition. As part of the initiative, OPG implemented a centre-led organizational model intended to more efficiently utilize resources. In 2015, OPG successfully completed a large-scale initiative, the Enterprise System Consolidation Project, to streamline the company's software systems and improve business processes by implementing a common enterprise software platform.

Although business transformation has concluded as a discrete initiative, improving organizational performance and building on efficiency gains achieved to date remains a key priority for the Company. OPG continues to review its cost structure, identify cost improvement strategies and embed an outcomes-driven culture that reinforces low cost, efficiency, and organizational agility as part of business decision-making.

Nuclear Business Development

Darlington Refurbishment

Government's Endorsement and Execution Phase

The Darlington generating units are approaching their originally designed end-of-life. Refurbishment of the four generating units to extend the operating life of the station by approximately 30 years, into the 2050s. In January 2016, the Government of Ontario's support for the Darlington Refurbishment project was affirmed through the Ontario Minister of Energy's announcement endorsing OPG's plan to refurbish the four Darlington units at a total project budget of $12.8 billion, including capitalized interest and escalation. The Province's announcement followed the approval of the project budget and schedule by OPG's Board of Directors in November 2015. The refurbishment of the last unit is scheduled to be completed by 2026. *Ontario Regulation 53/05* requires the OEB to ensure that OPG recovers capital and non-capital costs and firm financial commitments in respect of the Darlington Refurbishment project, if the OEB is satisfied that the costs were prudently incurred and that the firm financial commitments were prudently made.

The refurbishment project is a multi-phase program comprising several sub-projects. The major work streams include: de-fuelling of reactors and refurbishment of the fuel handling equipment; removal and replacement of feeder tubes and fuel channel assemblies in each reactor (Retube and Feeder Replacement or RFR); inspections and repairs of turbine generator sets and replacement of associated control systems; mechanical cleaning, water lancing, and inspection and maintenance work on steam generators; and replacement or repairs of certain other station components referred to as balance of plant. The RFR is the largest sub-project and represents a majority of the critical path schedule.

In 2016, the Darlington Refurbishment project transitioned from the planning phase to the execution phase, as OPG commenced the refurbishment of the first unit, Unit 2, in October 2016 as planned. The unit was

taken offline on October 15, 2016. De-fuelling of the reactor was completed in January 2017, with a total of 480 fuel channels de-fuelled. Islanding of Unit 2, the physical separation of the unit under refurbishment from the three operating units, was completed in April 2017, signifying the completion of the first major segment of the project.

The second major segment includes preparatory work to support the removal of feeder tubes and fuel channel assemblies, followed by the removal of reactor components. The preparatory work was completed in the second quarter of 2017. The Re-tube Tooling Platform for hosting the tooling for the removal, inspection and installation activities, and the setup of specialized tooling and equipment needed for the removal and replacement of the reactor components were completed in the third quarter of 2017. The disassembly of reactor components commenced in August 2017, with the removal of all 960 feeder tubes completed safely in September 2017. The removal of fuel channel assemblies commenced in October 2017. As part of the fuel channel assemblies, the removal of pressure tubes is in progress and will be followed by the removal of calandria tubes. The second major segment and the removal of all reactor components is expected to be completed by mid-2018. Key projects in the second major segment finished in 2018 include the completion of the primary side steam generator layup and installation of steam generator access ports to support future inspections. Other key project activities being executed during the second segment include the continuation of the major turbine generator overhaul, which will be completed in the second quarter of 2018, and continued execution of the major electrical scope. OPG is also continuing to execute work to support the requirements set out in the CNSC-approved Integrated Implementation Plan (IIP) for the station.

Most of the pre-requisite projects, including construction of facilities, infrastructure upgrades and installation of safety enhancements, have been completed and placed in-service. The Re-tube Waste Processing Building was completed in November 2017. Completion of the HWSF has been delayed due to challenges with construction. OPG suspended the project in the second quarter of 2017 to evaluate the best approach to optimize cost and schedule and complete the project. Construction to complete the facility recommenced in the fourth quarter of 2017. The HWSF is expected to be completed by the second quarter of 2019 and is not on the critical path for the Darlington Refurbishment project, which continues to track on schedule. The increase in the cost estimate for the HWSF will be accommodated within the overall Darlington Refurbishment budget of $12.8 billion. Taking into account the execution performance of the Unit 2 refurbishment, the overall Darlington Refurbishment project continues to track on budget.

The OEB accepted OPG's rate application with respect to the refurbishment of the Darlington units including an increase in the nuclear rate base, effective in the first quarter of 2020, to reflect the planned in service of $4.8 billion in capital expenditures upon the return to service of Unit 2, which includes expenditures incurred during the definition and planning phase of the project. Based on OPG's proposal in the application, the revenue requirement impact of the differences between the forecast Unit 2 in-service amount included in the regulated prices and the actual amounts placed in service would be subject to true up via the Capacity Refurbishment Variance Account established by the OEB pursuant to *Ontario Regulation 53/05*.

In addition to the execution of refurbishment activities on Unit 2, OPG is continuing planning activities for the refurbishment of the second unit, Unit 3, and is entering into associated commitments to procure major components that require long lead times. These planning activities are being undertaken in accordance with the refurbishment project schedule. In February 2018, the Province confirmed its commitment to proceed with Darlington's Unit 3 refurbishment in 2020. **[MONITOR]**

On November 21, 2017, the Financial Accountability Office of Ontario issued a report, "*An Assessment of the Financial Risks of the Nuclear Refurbishment Plan*". The report assesses the impact of OPG and Bruce Power's nuclear refurbishments on customers and the Province based on mechanisms in place for the recovery of the costs to refurbish and subsequently operate the nuclear stations. The report concludes that refurbishment of the four units at the Darlington GS and the six units at the Bruce nuclear generating stations provides the most cost effective, low emission generation source available to meet Ontario's baseload electricity requirements.

CNSC Regulatory Approvals

In December 2013, OPG submitted an application to the CNSC for the operating licence renewal for the Darlington GS. The CNSC granted the Darlington GS a ten-year operating licence in December 2015, which is the longest licence ever granted by the CNSC to a Canadian nuclear power plant. The new licence, which is effective from January 1, 2016 to November 30, 2025, spans most of the planned duration of the Darlington Refurbishment project.

In line with the CNSC's regulatory requirements related to life extensions of nuclear power plants in effect at the time that OPG began to undertake the Darlington Refurbishment project, OPG completed a series of assessments, including an environmental assessment (EA), an Integrated Safety Review, and a Global Assessment Report (GAR). The EA decision, issued by the CNSC and Fisheries and Oceans Canada in March 2013 following public hearings, confirmed that, taking into account identified mitigation measures, the project was not likely to cause significant adverse environmental effects. In April 2014, the CNSC accepted the GAR as meeting all regulatory requirements related to life extensions of nuclear power plants. In November 2014 and April 2016, respectively, certain intervenors' request for a judicial review and subsequent appeal to the Federal Court of Appeal related to the EA decision were dismissed by the courts.

Actions identified as part of the above assessments to meet updated codes, standards and practices, and to ensure that the operation of the station continues to pose minimal risk to health, safety, security and the environment, were integrated into the IIP. As part of the Darlington operating licence renewal in December 2015, the CNSC approved the regulatory scope defined in the IIP. OPG has been undertaking activities in support of the IIP requirements, including the commissioning of two safety enhancements at the station, the Third Emergency Power Generator and the Containment Filtered Venting System, which were placed in-service in April 2017. There were 17 IIP commitments scheduled and completed for 2017.

Extension of Commercial Operations at Pickering to 2024

In 2015, OPG completed the necessary work to demonstrate with sufficient confidence that the Pickering fuel channel life, a key life-limiting component of the station, will allow all six operating units of the station to operate to the end of 2020. OPG's early technical work at that time also showed that the Pickering GS can be operated safely beyond 2020. OPG's objective is to maximize the safe and reliable operating life of the Pickering units. As announced in 2016 and approved by the Province, OPG is continuing to execute on a plan to extend safe and reliable operation of the Pickering GS to 2024. Extending operations at the Pickering GS will provide Ontario with a clean, reliable source of baseload electricity during the Darlington GS and initial Bruce nuclear unit refurbishments, providing continued employment for up to 4,000 full-time employees at OPG.

OPG's current five-year operating licence for the Pickering GS was approved by the CNSC in 2013 and expires on August 31, 2018. This current licence was issued assuming that the station would shut down in 2020. On June 28, 2017, OPG confirmed to the CNSC that it intends to cease commercial operation of all Pickering units on December 31, 2024. On August 28, 2017, OPG submitted a ten-year licence renewal application to the CNSC. The requested licence term spans the planned extended commercial operations period, through to the planned period of de-fuelling, de-watering and beginning to place the station in a safe storage state in 2028. In support of the licence renewal, OPG undertook a Periodic Safety Review (PSR), a comprehensive assessment of the station's design and operation to confirm that there is a high level of safety throughout the operating life and to determine what reasonable and practical enhancements can be made to further improve safety. The PSR also includes a component condition assessment of the station to identify the work required to support the station's continued operation. The PSR has confirmed that extending operations of the Pickering units will continue to pose minimal risk to the health, safety and security of workers, the public and the environment. The final major component of the PSR was submitted to the CNSC in November 2017. The CNSC's review of the PSR submission and licence application is in progress. Based on the evidence and documentation submitted to the CNSC, OPG is confident in obtaining a licence renewal that would support our extended operations plan for Pickering GS.

As part of the plan to extend Pickering operations, OPG has been continuing to undertake the required technical work to confirm that the station's pressure tubes, a key life-limiting component of the station, will remain fit for service for operation to 2024. In the fourth quarter of 2017, OPG has confirmed that technical assessments completed to date provide sufficient confidence in the programs and provisions in place to assure fitness-for-service of fuel channel components in line with the planned extended operations period. This evaluation is consistent with the safety case reflected in OPG's operating licence renewal application for the Pickering GS submitted to the CNSC in 2017, discussed above. Taking these factors into account, OPG revised the accounting end-of-life assumptions for the Pickering GS from December 31, 2020 for all units to December 31, 2022 for Units 1 and 4 and December 31, 2024 for Units 5 to 8, effective December 31, 2017.

The change in the Pickering GS accounting end-of-life assumptions did not impact OPG's net income in 2017. The change is expected to decrease depreciation expense by $77 million in 2018, including the associated impact on the nuclear asset retirement obligation recorded as of December 31, 2017 but before the impact of regulatory accounts. Regulatory accounts, including a new deferral account proposed by OPG in a December 2017 application to the OEB, are expected to largely offset the decrease in depreciation expense. As of December 31, 2017, OPG recorded an increase of $188 million in the Nuclear Liabilities and associated asset retirement costs capitalized as part of carrying value of property, plant and equipment reflecting the change in the Pickering GS accounting end-of-life assumptions from December 31, 2020 for all operating units to December 31, 2022 for Units 1 and 4 and December 31, 2024 for Units 5 to 8. The increase in the liabilities is primarily due to higher fixed costs associated with the Used Fuel Disposal and L&ILW Storage programs, discounted using the current credit-adjusted risk-free rate of 2.94 percent. The adjustment did not impact net income for 2017. The adjustment is not expected to have a material impact on net income in 2018 as the associated impact on expenses is expected to be largely offset by OEB-authorized regulatory accounts. On December 29, 2017, OPG applied for an accounting order to establish a variance account to record, from January 1, 2018 until the effective date of the OEB's next payment amounts order, the revenue requirement impact of changes to nuclear liabilities and depreciation and amortization expense resulting from changes to station end-of-life dates for OPG's Pickering prescribed nuclear facilities that will be effective December 31, 2017. Pending the OEB's review of the application, an interim order was issued January 31, 2018 establishing the proposed variance account effective January 1, 2018. The OEB's final decision in the account is expected later in 2018.

The income statement impacts associated with the changes to the Nuclear Liabilities are offset by the Bruce Lease Net Revenues Variance Account and the Nuclear Liability Deferral Account authorized by the OEB or new variance account to be authorized by OEB for the prescribed facilities.

Bruce Power Refurbishment and Bruce Lease Agreement

OPG leases the four-unit Bruce A (Units 1 to 4) and the four-unit Bruce B (Units 5 to 8) nuclear generating stations and associated lands and facilities to Bruce Power on a long-term basis. Bruce Units 1 and 2 were refurbished by Bruce Power under a refurbishment agreement with the IESO and returned to service in 2012. While Bruce Power is responsible for operating all of the leased units, OPG is primarily responsible for the management of the nuclear used fuel and other nuclear waste associated with the Bruce nuclear generating facilities, as well as the decommissioning of the facilities at the Bruce site. Under the lease agreement between Bruce Power and OPG (Bruce Lease) and related agreements, OPG receives base rent and supplemental rent payments from Bruce Power, fees for nuclear waste management other than used fuel, and fees for certain other services. The output from the Bruce nuclear generating stations is not subject to rate regulation by the OEB.

In December 2015, the Province announced that the refurbishment agreement between the IESO and Bruce Power had been updated and that Bruce Power will proceed with the refurbishment of the six un-refurbished units of the Bruce nuclear generating stations. In order to facilitate Bruce Power's refurbishment plans, the Bruce Lease and related agreements were amended in December 2015 to extend Bruce Power's future options to renew the lease up to the end of 2064. To achieve better alignment with OPG's costs, the agreements were also amended to revise, starting in 2016, the approach for calculating supplemental rent payments and fees for nuclear waste management other than used fuel, and to modify the fee structure for

OPG's heavy water detritiation services starting in 2017. Beginning in 2016, supplemental rent payments wholly represent fees for nuclear used fuel management. Amendments were also made to enable certain adjustments to future base rent, supplemental rent and other fees for potential future changes in OPG's decommissioning and nuclear waste management cost estimates related to the Bruce facilities, and to remove a conditional supplemental rent rebate provision effective December 4, 2015. Certain of the above amendments were executed by OPG pursuant to a Shareholder Declaration and Shareholder Resolutions issued in November 2015. For a complete list of Shareholder directives, refer to the section, *Interest of Management and Others in Material Transactions* under the heading, *Relationship with the Province and the OEFC – Shareholder Directives*.

The refurbishment of Bruce Power's Unit 6 is scheduled to commence on January 1, 2020. As part of the preparation activities, OPG is working with Bruce Power to develop a fixed price cost estimate for the non-routine nuclear waste that will be generated from the Unit 6 refurbishment. The parties will execute a separate agreement that sets out the terms and conditions that will apply to this refurbishment waste. Pursuant to a Memorandum of Understanding dated November 12, 2015, OPG and Bruce Power have committed to ongoing collaboration to improve their respective refurbishment programs.

Ontario Nuclear Funds Agreement Reference Plan Update

OPG is responsible for the management of radioactive used nuclear fuel and low and intermediate level radioactive waste material (L&ILW) and the decommissioning of its nuclear stations and waste management facilities. Pursuant to the Ontario Nuclear Funds Agreement (ONFA), OPG is required to set aside monies into two segregated funds, the Used Fuel Segregated Fund and the Decommissioning Segregated Fund, to fund the future life cycle costs of long-term nuclear used fuel and L&ILW management and nuclear facilities decommissioning. OPG's required contributions to the Nuclear Segregated Funds are determined based on periodically updated reference plans approved by the Province under the ONFA, at least once every five years. As part of the reference plan update process, OPG estimates the total funding liabilities for future nuclear waste management and nuclear decommissioning based on life cycle cost estimates and a set of underpinning assumptions, including remaining useful lives of the nuclear stations, proposed methods and timing of nuclear waste disposal, and economic indicators. In accordance with US GAAP, OPG carries a present value asset retirement obligation on the balance sheet related to its nuclear waste management and nuclear decommissioning liabilities. In accordance with *Ontario Regulation 53/05*, the OEB is required to ensure that OPG recovers the revenue requirement impact of its nuclear waste management and nuclear decommissioning liabilities arising from the current approved ONFA reference plan. The current methodology applied by the OEB for including OPG's costs associated with these liabilities in the regulated prices was established by the OEB in its 2008 decision on OPG's first application for new regulated prices.

In 2016, OPG completed a comprehensive update of the estimate for its obligations for nuclear waste management and nuclear facilities decommissioning, in line with the required ONFA reference plan update process. The results of the update were reflected in a new ONFA reference plan as well as a downward adjustment in the asset retirement obligation carried on OPG's balance sheet as at December 31, 2017. The new ONFA reference plan was approved by the Province in December 2016, with an effective date of January 1, 2017 (the 2017 ONFA Reference Plan). Reflecting the funded status of the Used Fuel Segregated Fund and the Decommissioning Segregated Fund based on the revised lower life cycle liability estimates per the 2017 ONFA Reference Plan, no overall contributions to either the Used Fuel Segregated Fund or the Decommissioning Segregated Fund are currently required starting in 2017. Contributions may be required in the future should either or both of the funds be in an underfunded position when a new reference plan is approved. Such may be the case as a result of future variability in asset performance due to volatility inherent in financial markets and economic conditions. Future contribution levels also are dependent on changes in baseline cost estimates and underpinning planning assumptions used to establish the funding obligations in subsequent ONFA reference plans.

The overall reduction in OPG's nuclear waste management and nuclear decommissioning liabilities resulting from the comprehensive update was mainly due to a decrease in cost estimates to reflect a proposed new, more cost effective container design and engineered barrier concept to house used nuclear fuel for disposal, updated cost escalation rates, and a later expected in-service date for Nuclear Waste Management Organization's (NWMO) planned deep geologic repository for the long-term permanent disposal of Canada's used nuclear fuel. These decreases were partly offset by higher cost estimates related to station decommissioning, primarily due to a better definition of work required during the preparation for safe storage after station shutdown and a higher volume of waste expected to be generated during the decommissioning.

Further details on OPG's nuclear waste management and nuclear decommissioning obligations, the ONFA and proposed methods for long-term used fuel and L&ILW disposal are discussed in the section, *Description of the Business* under the heading, *Regulated – Nuclear Waste Management Segment.*

Hydroelectric Business Development

Peter Sutherland Sr. Hydroelectric Generating Station

In March 2015, OPG's Board of Directors approved a project to construct the Peter Sutherland Sr. GS, a new 28 MW hydroelectric station on the New Post Creek near its outlet to the Abitibi River, with a budget of $300 million. The station was constructed through PSS Generating Station LP, a partnership between OPG and Coral Rapids L.P., a wholly owned subsidiary of the Taykwa Tagamou Nation.

In March 2017, final testing and commissioning of the turbine and generator units were successfully completed and both units were declared substantially complete. On March 31, 2017, the project received a permit from the Ontario Ministry of the Environment and Climate Change (MOECC) to take water for operations to allow the station to operate commercially. The project is expected to close below the approved budget of $300 million. Project close-out activities are in progress. OPG began to receive contracted revenue for the project following the IESO's confirmation of the station's commercial operations as of March 31, 2017, under a 50-year hydroelectric ESA.

In April 2017, Coral Rapids Power Corporation (CRP) exercised its right under the partnership agreement to increase its interest in PSS to 33 percent.

Sir Adam Beck Pump Generating Station Reservoir Refurbishment

In August 2015, OPG's Board of Directors approved a project to refurbish the 300-hectare storage reservoir at the Sir Adam Beck Pump GS. The Sir Adam Beck Pump GS facility allows OPG to pump and store water diverted from the Sir Adam Beck generating complex during periods of low electricity demand to be used to generate up to 600 MW of electricity during subsequent periods of high electricity demand.

The refurbishment construction began in April 2016 and was completed in February 2017, ahead of the originally planned schedule date of April 2017 and below the approved budget of $58 million. The reservoir refurbishment work included the installation of a partial new reservoir liner and construction of a grout curtain in the bedrock foundation of the reservoir dyke. The refurbishment is expected to add approximately 50 more years to the reservoir's life. The Sir Adam Beck Pump GS is reported in the Regulated – Hydroelectric segment.

Ranney Falls Hydroelectric Generating Station

In 2017, OPG began construction work on a 10 MW single-unit powerhouse on the existing Ranney Falls GS site, as part of the Regulated – Hydroelectric segment. The new unit will replace an existing unit that reached its end of life in 2014. The existing forebay structure has been demolished and the new concrete structure has been completed. Excavation has been completed and construction continues in the expanded forebay, powerhouse and spillway area. The new forebay concrete wall has been completed, and concrete placement of the new powerhouse and the spillway integrated structure is in progress. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget.

Thermal and Solar Business Development

Nanticoke Solar Facility

In March 2016, Nanticoke Solar LP, then a partnership between OPG, SunEdison Canadian Construction LP (SECCLP) and a subsidiary of Six Nations of the Grand River Development Corporation, was selected through the first phase of IESO's Large Renewable Procurement (LRP) program to develop a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands in Haldimand County, Ontario. The LRP program was a competitive bidding process for procuring large renewable energy projects in Ontario. In March 2016, Nanticoke Solar LP and the IESO executed a 20-year LRP contract, which formalized the terms and conditions for the development and operation of the new solar facility. In the first quarter of 2017, OPG purchased SECCLP's interests in Nanticoke Solar LP and is working to obtain approvals and permits required to enable the commencement of construction planned for the first quarter of 2018. Significant contracts for equipment and engineering construction services were executed in the first quarter of 2018. The 20-year term of the LRP contract takes effect once the station achieves commercial operation, which is expected in the first quarter of 2019. The facility is expected to be completed in the first quarter of 2019, with a budget of $107 million. **[MONITOR]**

Decommissioning of Lambton and Nanticoke Coal-Fired Generating Stations

OPG ceased coal-fired generation at the Lambton and Nanticoke generating stations in September 2013 and December 2013, respectively. In November 2016 and July 2015, respectively, OPG announced that it would decommission the Lambton and Nanticoke generating stations as it could not commercially support continued preservation of these sites in light of the outlook for long-term electricity demand in the province that does not support the need for their future conversion. OPG has begun executing decommissioning plans for these two stations, which will ensure that they are closed safely, securely, and in an environmentally responsible manner. The decommissioning of the Nanticoke GS will accommodate the construction and operation of the Nanticoke solar facility.

During 2017, OPG substantially completed the demolition of the Nanticoke coal yard equipment and structures and issued a contract for the demolition of the Nanticoke powerhouse and associated structures. In the fourth quarter of 2017, the demolition contractor had been mobilized to prepare for the removal of the powerhouse and associated structures and initiated the preparatory work for the demolition of the stacks. The demolition of the stacks took place in February 2018. **[MONITOR]** A competitive bidding process for the demolition of the Lambton GS is in progress, with a contract for the removal of the powerhouse and associated structures expected to be issued during 2018. An update of the associated asset retirement obligations related to the Nanticoke and Lambton sites has been completed. For a discussion of the revaluation of this liability for non-nuclear fixed asset removal as at December 31, 2017, refer to the section, *Critical Accounting Policies and Estimates* under the heading, *Asset Retirement Obligations* in the Company's 2017 year-end MD&A.

DESCRIPTION OF THE BUSINESS

The Electricity Industry

The electricity industry is principally comprised of four components: generation, transmission, distribution, and marketing of energy and other services in wholesale and retail markets.

Generation is the production of electricity. Transmission is the transfer of electricity across high-voltage power lines from generating facilities to local areas. Distribution is the delivery of electricity within local areas to homes and businesses using relatively low-voltage power lines. Energy marketing relates to the purchase of large amounts of electricity or equivalent financial products, and the subsequent re-selling in smaller quantities to third parties in either the wholesale or retail markets.

Electricity has traditionally been generated in large, multi-unit, centralized facilities. These facilities are usually classified by: (i) the type of fuel used; (ii) capacity, typically expressed in MW; and (iii) dispatch mode (being whether or not the electricity generated by a particular facility is dispatched to meet peak, intermediate or baseload demand). The energy produced by a facility is generally expressed as its output over the time the facility operates, typically in terms of MWh. New supply from smaller scale, largely intermittent, renewable sources such as wind, solar, and bio-energy is being integrated into the power system, connected either directly to the transmission system or embedded in distribution networks. Distributed generation involves production of electricity closer to end users and away from large scale production facilities that require more transmission. Electricity systems typically require new capital expenditures and processes in order to accommodate intermittent generators.

Electricity is an essential commodity that cannot be stored without converting to other forms, a process that is more difficult in large volumes. Therefore, electricity supply must instantaneously match demand to maintain the stability and reliability of the electrical power system. This is accomplished by coordinating the supply of and demand for electricity, a responsibility typically assigned to regulated regional system operators. Electricity systems have evolved on a regional basis and are connected to neighbouring regional power grids. Such connections enhance system reliability and permit the economic purchase and sale of electricity between electricity markets.

Ontario's Electricity Industry

OPG's predecessor, Ontario Hydro, served as a vertically integrated electric utility in Ontario. Following the adoption of a restructuring plan for Ontario's electricity industry pursuant to the *Energy Competition Act, 1998,* five principal successors to Ontario Hydro's integrated electricity business began operating as separate entities on April 1, 1999:

- OPG, which purchased and assumed the electricity generation, wholesale energy, and ancillary services businesses of Ontario Hydro;
- Hydro One, which purchased and assumed the transmission, distribution, and retail energy services businesses of Ontario Hydro;
- the Independent Electricity Market Operator (later renamed the IESO), which was formed to act as both the independent electricity system operator and the market operator. The IESO is responsible for the dispatch of generation to meet demand, the control of the Ontario transmission grid, and the operation of energy and ancillary markets;
- the Electrical Safety Authority, which was established to carry out electrical equipment and electrical wiring safety and inspection functions; and
- the Ontario Electricity Financial Corporation (OEFC), which is the legal continuation of the former Ontario Hydro and is responsible for managing the debt and certain other obligations not transferred to other successor companies of Ontario Hydro.

OPG purchased and assumed all of the interest of Ontario Hydro in and to all officers, employees, assets, liabilities, rights and obligations of Ontario Hydro directly or indirectly relating in any manner to the applicable activities carried on by Ontario Hydro as of April 1, 1999, pursuant to the transfer orders made

by Order-in-Council under the *Electricity Act, 1998*. The transfer orders provide that if they fail for any reason to fully and effectively in law transfer any such asset, right, liability or obligation or that if such transfer would constitute a breach of the terms of the asset, right, liability or obligation or of any applicable law, such assets, rights, liabilities or obligations are not transferred, but are held by the OEFC for the benefit of OPG.

Ontario's competitive electricity market was opened by the IESO in 2002. The market is used to manage the purchase and sale of wholesale electricity in the province.

Since the opening of the competitive market, Ontario's power supply mix has experienced significant change. A significant amount of new capacity has been added, while coal-fired generation, which at its peak accounted for approximately 6,500 MW of capacity, has been eliminated. New natural gas powered capacity of approximately 5,000 MW as of the end of 2017 has largely replaced the peaking capacity previously provided by coal-fired generation, while the return to service of Units 1 and 2 at the Bruce A GS in 2012 added approximately 1,500 MW of baseload nuclear generation. New wind and solar capacity of over 7,000 MW has also been added as of the end of 2017, toward Ontario's longer-term target for total wind and solar capacity of about 10,000 MW.

While electricity supply in Ontario has increased, the province's electricity demand as reported by the IESO has fallen, by approximately 13 percent over the last decade, largely due to changes in economic conditions and conservation measures, and also in part due to the addition of small scale solar generation embedded in the distribution system. Embedded generation reduces the demand supplied by grid-connected generation. Reducing electricity demand by encouraging conservation and demand management has been a key part of the Government of Ontario's plan to reduce greenhouse gas (GHG) emissions from the province's electricity sector. Shorter-term fluctuations in electricity demand are impacted by variations in seasonal weather conditions. Ontario's electricity demand as reported by the IESO was 132 TWh in 2017, which excludes electricity exports out of the province.

In October 2017, Ontario's Ministry of Energy issued the 2017 LTEP that outlines the Province's plans for the future development of Ontario's electricity system. The 2017 LTEP focuses on the affordability, reliability and flexibility of a clean energy supply in the province. For further details on the LTEP, refer to the section, *General Development of the Business* under the heading, *General Development – Ontario's Long-Term Energy Plan.*

Ontario Electricity Market Activities

Real-time energy supply needs are met through the wholesale electricity market administered by the IESO, with the market clearing price, the Hourly Ontario Energy Price, set by offers or bids into the market. OPG offers its generation into this real-time energy market, or spot market, to be dispatched by the IESO. The IESO receives hourly offers from electricity generators and importers to provide energy, along with bids to withdraw energy from a few flexible loads and exporters, and then schedules the lowest-cost offers and bids needed to meet demand every five minutes.

Virtually all non-OPG generators in Ontario have bilateral contracts with the IESO that provide for payments that are different from the market price of electricity. In addition, the prices for all of OPG's nuclear and most of its hydroelectric stations are set by the OEB. The difference between the market price and the prices paid for regulated and contracted generation, as well the cost of conservation and demand management programs, are charged to Ontario electricity consumers through the Global Adjustment portion of the total price of electricity.

Maintaining power system reliability requires a continuous balance of supply and demand. Some generators are needed to produce a constant supply of energy to meet basic energy needs (baseload generation), while others are needed to adjust energy output to match changes in demand (peaking and intermediate generation). OPG's nuclear generating stations operate as baseload facilities, whereas its hydroelectric stations operate as baseload, intermediate or peaking stations, depending on their physical characteristics and hydrological conditions. OPG's thermal stations operate as peaking facilities.

SBG occurs when electricity production from the baseload facilities is greater than the market demand for electricity. Baseload generation supply surplus in Ontario is managed by the IESO, mainly through generation reductions at hydroelectric and certain nuclear stations and other grid-connected renewable resources. The prevalence of SBG conditions is impacted by weather conditions which affect electricity demand, wind and solar generation quantities, and through the impact on water flows, the availability of hydroelectric power. In 2017, OPG lost 5.9 TWh of hydroelectric generation due to SBG conditions. In each of 2016 and 2015, OPG lost 4.7 TWh and 3.2 TWh of hydroelectric generation due to SBG conditions. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions, which represents the majority of such production forgone by OPG to date, has been offset by a regulatory variance account authorized by the OEB. During 2017, 2016 and 2015, generation losses at OPG's regulated hydroelectric stations due to SBG conditions were 5.2 TWh, 4.3 TWh and 2.8 TWh, respectively.

The OEB has authorized an additional pricing mechanism for OPG's regulated hydroelectric generation that provides a financial incentive to OPG to shift hydroelectric generation from lower market price periods to higher market price periods. This is intended to benefit customers through the displacement of generation from the relatively higher cost sources such as natural gas. The time-shifting is made possible by the ability to store water in reservoirs located at a number of OPG's hydroelectric facilities, including the Sir Adam Beck Pump GS.

The IESO also administers the operating reserve market and a market for ancillary services. The objective of the operating reserve market is to ensure that additional supplies of energy are available to maintain power system reliability following an unforeseen event. Ancillary services include regulation service, reactive support, black start capacity, and other services required to maintain the reliability of the Ontario electricity system. OPG participates in these markets. Revenues earned by OPG's regulated facilities from providing services into these markets are applied by the OEB to reduce regulated prices for electricity generated from these facilities.

OPG and other Ontario electricity market participants are required to comply with market rules issued by the IESO. As an owner and operator of generating stations, OPG is also subject to reliability standards as set out by the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC) and the IESO. NERC, NPCC and IESO are standards authorities with the ability to create or modify reliability standards. Such standards are binding on OPG pursuant to the OEB-issued electricity generating license and the IESO market rules. The IESO monitors compliance with and enforces the market rules and coordinates with system operators and reliability agencies in other jurisdictions to ensure energy adequacy and security across the interconnected bulk electricity market in North America.

Interconnected Markets

The interconnected markets are electricity markets in neighbouring provinces and states whose transmission systems are connected to the Ontario power grid, either directly or through other contiguous interconnected markets. Ontario's market is interconnected with New York, Michigan, Minnesota, Manitoba, and Québec. Market intermediaries wishing to import or export electricity between Ontario and the interconnected markets are required to schedule these transactions through the Ontario spot market. OPG and its wholly owned subsidiary, OPG Energy Trading (OPGET), participate in the interconnected markets. Further details on OPGET are discussed under the heading, *Services, Trading, and Other Non-Generation Segment.*

Interconnection transmission capabilities between Ontario and the interconnected markets are subject to physical and weather dependent limitations. These limitations include planned or forced outages to transmission lines and other equipment that reduce transmission capacity. They also include wind and temperature conditions that affect the transfer capability of all transmission lines on the electrical system. For example, higher ambient air temperature lowers capacity, while higher wind speeds increase capacity. Overall power system parameters and conditions also can result in limitations on particular interties, being one or more transmission lines that connect Ontario to a neighbouring region. For example, high flow on one intertie may result in a reduction in the limit on another intertie.

Water Rights

OPG's management of available water resources directly affects the generation output, efficiency, and ultimately return on investment for the Company's hydroelectric assets. The watersheds on which OPG's hydroelectric generating facilities are located are shared by many users and are subject to various governance requirements, such as international, federal and provincial agreements, water power leases, and regulations. Accordingly, OPG must balance the economic, environmental, social and legal requirements associated with the watersheds when utilizing water to optimize electricity generation.

International Rivers

The six OPG hydroelectric generating stations subject to OEB rate regulation since 2008 are directly or indirectly supplied by two major international waterways, the Niagara River and the St. Lawrence River, and are subject to treaties with the U.S. relating to water use. These stations represent approximately 45 percent of OPG's total in-service hydroelectric capacity.

Through a series of agreements between the Government of Canada and the Province, and certain federal and provincial laws, OPG has been granted the right to exercise Canada's rights with respect to the construction, maintenance, and operation of generating facilities under the *Boundary Waters Treaty of 1909* and the *Niagara Diversion Treaty of 1950* between Canada and the U.S. Both of these treaties continue in perpetuity but are terminable by either party with 12 months prior written notice. Given the significance of these treaties, OPG does not expect either party to exercise their respective termination rights in the foreseeable future.

The *Boundary Waters Treaty of 1909* established the International Joint Commission with the mandate of regulating shared water uses and preventing and resolving disputes between U.S. and Canada. In December 2016, the International Joint Commission issued an order implementing a new plan to manage water levels and flows in Lake Ontario and the St. Lawrence River, effective January 7, 2017. The new plan, which replaced the existing plan in use since 1963, is intended to allow for more natural water levels, while minimizing impacts to other users, including hydroelectric power production. No significant changes in OPG's operations are expected as a result of the new plan.

The *Niagara Parks Act* (Ontario) gives the Niagara Parks Commission the authority to grant certain rights for the use of the waters of the Niagara River for purposes of power generation. By agreement with OPG, the Niagara Parks Commission has agreed not to grant any rights to third parties until after 2056.

Under an agreement between OPG and the St. Lawrence Seaway Management Corporation, a federal agency, the DeCew Falls generating stations use water that is transported along the Welland Canal from Lake Erie. The agreement has been renewed through June 30, 2038.

The Province has granted OPG the right to use water from the International Rapids section of the St. Lawrence River for power generation at the R.H. Saunders GS, subject to an agreement between the Government of Canada and the Province. The Government of Canada has the right, upon notice and after unsuccessful arbitration, to take over the operation of and title to the R.H. Saunders GS in the unlikely event of a breach of the agreement by the Province.

Interprovincial Rivers

Four of OPG's hydroelectric stations are located on the Ottawa River, which forms part of the Ontario-Québec border. These stations represent approximately 12 percent of OPG's total in-service hydroelectric capacity. Three of these stations are subject to 999-year leases with each of the Provinces of Ontario and Québec. The fourth station is subject to a water power lease with the Province of Ontario, which is renewable to 2031, subject to certain conditions. OPG's use of water from the Ottawa River basin is subject to guidelines established by the Ottawa River Regulation Planning Board, comprised of government and industry representatives.

Interior Rivers

Fifty-six of OPG's hydroelectric stations, representing approximately 43 percent of OPG's total in-service hydroelectric capacity, are located on 20 other Ontario river systems. OPG holds water power leases, Crown leases and licences with the Province on the river systems that supply 37 of these stations. A land use permit, issued for the Peter Sutherland Sr. GS, remains in effect while a water power lease for the site is prepared by the Ontario Ministry of Natural Resources and Forestry (MNRF). These leases and licences have expiry dates, including renewal periods, ranging between 2023 and 2075. Certain of these leases provide that the leased property and any fixed improvements, including generating stations and dams, will revert to the Province on the expiry of the lease. OPG intends to work towards new leases and licenses for these stations. OPG's use of Ontario's interior watersheds is constrained by restrictions contained in certain of the water power leases and licences. Eight of the 56 stations are located on the Trent and Rideau Waterways and are operated pursuant to licences from the federal government. These licences expire in February 2020. The process to renew the licences is currently underway with Parks Canada. Ten of the 56 stations are not subject to leases or licences.

The current provincial regulatory framework requires the development of Operational Plans for new storage dams and generating stations in Ontario, except for those on international rivers, interprovincial rivers, or rivers under federal jurisdiction. These plans include any limitations on water flows and elevations, and historically have been a component of formal Water Management Plans (WMPs). WMPs were established under the *Lakes and Rivers Improvement Act* (Ontario) and *Water Management Planning Guidelines for Waterpower (2002)*, on a watershed basis, in consultation with the Ontario Ministry of Natural Resources and Forestry, federal fisheries authorities, stakeholders, such as recreational and commercial users, local communities, environmental groups, and partners, such as Indigenous groups. In October 2016, the MNRF published a Technical Bulletin, *Maintaining Water Management Plans (2016),* eliminating the need for WMPs where they are not already in place, removing the expiry date from existing WMPs, and outlining the requirements for Operational Plans for new waterpower works going forward. Existing WMPs continue to be in effect. WMPs and Operational Plans may be amended as certain conditions change or new data becomes available. OPG operates in compliance with WMPs and Operational Plans.

The operations of certain OPG stations in northwestern Ontario can impact users in Manitoba and are subject to guidelines and directions provided by the Lake of the Woods Control Board, which is comprised of Ontario, Manitoba and federal government representatives.

Dams and Waterways

In Canada, dams fall under provincial jurisdiction, with the exception of dams situated in interprovincial and international boundary waters and canals, and those owned by the Government of Canada. The majority of OPG's dams fall within the jurisdiction of the Province, with approximately 20 dams falling within the jurisdiction of the Province of Québec and 13 dams associated with the Trent-Severn and Rideau Waterways falling under federal jurisdiction. The International Joint Commission has an oversight role for dams and associated works on international boundary waters, including the St. Lawrence River and the Niagara River.

The Province regulates dams under the *Lakes and Rivers Improvement Act* (Ontario) administered by the MNRF. The legislation requires MNRF approval for activities such as the construction, alteration, improvement, or repair of dams.

In August 2011, the MNRF published a revised set of Technical Guidelines for dams, following a period of public consultation. The Technical Guidelines represent the government standards for dam safety. OPG was an active participant in developing the Technical Guidelines through the MNRF's advisory panel. In general, OPG practices in the area of dam safety and public safety around dams exceed the minimum requirements outlined in the Technical Guidelines. In cooperation with the MNRF, OPG is developing a new risk-informed approach to prioritize the outcomes of dam safety assessments.

Currently, there is no federal or provincial regulation with respect to public safety around dams that addresses dam public safety issues relating to changes in operating water levels, discharges from the hydroelectric or dam facilities, and other waterways-based hazards posed by such facilities. The *Navigation Protection Act* (Canada) does, however, require OPG to obtain approvals for the installation of all in-water works, such as safety booms and buoys associated with the OPG Waterways Public Safety Program. Additional details on OPG's Dam Safety and Waterways Public Safety Programs are discussed under the heading, *Workplace Safety and Public Safety – Dam Safety and Waterways Public Safety*.

Generation Operations

Nuclear (Regulated – Nuclear Generation Segment)

Overview of Generating Facilities

OPG owns and operates two nuclear generating stations, the results of which are reported in the Regulated – Nuclear Generation business segment. The Pickering GS, comprised of six operating units and two units in a permanent safe shutdown state, is located on the shore of Lake Ontario in Pickering, Ontario. As at December 31, 2017, the station's total in-service capacity was 3,094 MW. Four of the eight Pickering units originally went into service in the 1970s. A decision was made by Ontario Hydro in the late 1990s to place these four units in voluntary lay-up. In 2003 and 2005, respectively, two of the four laid-up units were returned to commercial operation, with the two remaining units placed in a permanent safe shutdown state. The other four operating units have been in service since the mid 1980s.

The Darlington GS, comprised of three operating units and one unit, Unit 2, undergoing refurbishment as of mid-October 2016, is located on the shore of Lake Ontario in the Municipality of Clarington, Ontario. As at December 31, 2017, the total in-service capacity of the three operating units was 2,634 MW. Unit 2 has a capacity of 878 MW. All four Darlington units have been in service since the early 1990s. Both the Pickering GS and the Darlington GS have been designed to operate at full power as baseload facilities.

The performance of OPG-operated nuclear generating stations during 2017, 2016 and 2015 was as follows:

Regulated – Nuclear Generation Performance (2015 to 2017)

Station	No. of In-Service Units	Unit Capability Factor [1] (%)		
		2017	2016	2015
Darlington [2]	3	**85.2**	89.5	76.9
Pickering	6	**80.0**	75.2	79.4
Total	9			

[1] Unit capability factor is the amount of energy a generating unit is capable of producing as a percentage of its maximum output assuming no external constraints such as transmission limitations. The nuclear unit capability factor excludes unit(s) during the period in which they are undergoing refurbishment.

[2] Excluding Unit 2, which has been undergoing refurbishment since mid-October 2016.

The lower Unit Capability Factor at the Darlington GS in 2017, compared to 2016, reflected the higher number of planned outage days in 2017, largely driven by constraints related to the transition of the station's operating units toward refurbishment. The increase in the Unit Capability Factor at the Pickering GS in 2017, compared to 2016, was primarily due to outage cycle optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station compared to 2016.

OPG's Bruce A and Bruce B nuclear generating stations have been leased on a long-term basis to Bruce Power. The stations are located in the Municipality of Kincardine, Ontario on the shore of Lake Huron.

For additional information on OPG's nuclear operations, refer to the section, *Core Business, Strategy, and Outlook* under the heading, *Operational Excellence – Electricity Generation Production and Reliability* in the Company's 2017 year-end MD&A.

Nuclear Generation Technology

Nuclear generation harnesses the energy released during controlled nuclear fission reactions to produce steam that is used to drive turbines to generate electricity. Nuclear generation has two main advantages. It is a relatively low marginal-cost generation technology, and it produces virtually no GHG, sulphur dioxide, nitrogen oxide, or mercury emissions. The latter advantage has become more significant as governments implement climate change action plans and stricter air emission standards.

However, in contrast to other types of generating facilities, notwithstanding the lower fuel costs, nuclear generating stations incur nuclear waste management and decommissioning costs and greater operating and maintenance expenses. In addition, the construction of nuclear generating stations entails greater initial capital costs than other generation technologies. The higher initial costs reflect the complexity of the technical processes fundamental to nuclear electricity generation, and the additional design and safety precautions taken to protect the public from potential risks associated with nuclear operations.

All of OPG's nuclear generating stations use CANada Deuterium Uranium (CANDU) technology reactors. CANDU is a pressurized-heavy-water, natural-uranium power reactor, originally designed in the 1960s by a consortium of Canadian government agencies and private industry. CANDU reactors are unique in their use of natural-uranium fuel and deuterium oxide, or heavy water, as both a moderator to slow down the fission process and a coolant within the reactor. The refuelling system is also unique in that CANDU reactors can be refuelled at full power. This is due to the subdivision of the reactor core into hundreds of separate fuel channels, each holding a single string of natural uranium fuel bundles, allowing for greater fuel efficiency. In contrast, U.S. reactors, which use enriched uranium fuel, must be shut down during refuelling. All nuclear power reactors in Canada use CANDU technology. CANDU reactors are currently operating in Ontario, New Brunswick, Argentina, Romania, South Korea, India, Pakistan and China.

Nuclear Fuel Procurement

OPG's nuclear fuel supply chain engages in the purchase of uranium concentrate, the purchase of services for the conversion of uranium concentrate to uranium dioxide, and the purchase of services for the manufacture of fuel bundles containing uranium dioxide pellets. OPG currently establishes contractual arrangements with each of these components separately and as appropriate maintains ownership of the uranium throughout the supply chain. OPG maintains a portfolio of multi-year supply contracts for uranium concentrate with domestic and foreign suppliers and commodity traders. Occasionally, short-term spot market purchases are acquired to support a portion of its uranium concentrate needs. OPG's nuclear fuel bundles are supplied by a Canadian-based manufacturer.

Nuclear Regulation

The *Nuclear Safety and Control Act* (NSCA) establishes the mandate and authority of the CNSC to make regulations governing all aspects of the development and application of nuclear energy in Canada. The NSCA grants the CNSC the power to act as a court of record, the right to make regulations, the power to require financial guarantees for nuclear waste management and nuclear facilities decommissioning as a condition of granting a licence, order-making powers, and the power to impose monetary penalties for licence infractions. The NSCA also grants the CNSC the power to require periodic re-certification of nuclear operators and to set requirements for various nuclear facility security measures. It also provides for regulatory authority over environmental matters, including a requirement that licence applicants make adequate provision for the protection of the environment. The NSCA grants the CNSC licensing authority for all nuclear activities in Canada, including but not limited to the issuance of new licences to operators, the renewal of existing licences, protection of the environment arising from nuclear activities, and making regulations related to nuclear activities.

A fundamental principle in nuclear regulation is that the licensee bears the responsibility for safe operation, with the CNSC setting safety objectives in areas such as radiation protection and physical security for nuclear generating stations and the transport of radioactive materials. The CNSC verifies compliance with the licence and performs audits and inspections of the licensee's performance against these objectives. The CNSC also has issued guidance documents to assist licensees in complying with regulatory requirements. Requirements specified in these guidance documents have been incorporated into the design and operating documents for OPG's nuclear generating stations.

Since the operation and regulation of nuclear energy has transboundary impacts, Canada has become a signatory to various international conventions relating to nuclear energy and emergency responses and is bound by conventions that it has ratified. In addition, the CNSC has a bilateral information exchange and co-operation agreement with the U.S. Nuclear Regulatory Commission, which provides, among other things, for the prompt, reciprocal notification of reactor safety problems that could affect both U.S. and Canadian nuclear generation facilities.

The CNSC publishes an annual Regulatory Oversight Report on the safety performance of Canada's nuclear power plants. The report assesses how well plant operators are meeting regulatory requirements and program expectations in the areas of operational performance, safety analysis, radiation protection, waste management and conventional health and safety. On September 8, 2017, the CNSC issued an executive summary of its 2016 annual report, giving both the Darlington GS and the Pickering GS the highest possible safety rating of "Fully Satisfactory". The Darlington GS achieved this rating for the eighth consecutive year, while the Pickering GS achieved this rating for the second consecutive year.

In 2017, the CNSC approved regulatory document *REGDOC 2.2.4 – Fitness for Duty – Managing Alcohol and Drug Use* for use at Canadian nuclear power plants. This document sets out requirements for managing fitness for duty of workers in relation to alcohol and drug use at high-security sites, including for-cause alcohol and drug testing for workers in positions identified as safety-sensitive or safety-critical and random alcohol and drug testing for workers holding safety-critical positions. OPG intends to enhance its existing Fitness for Duty program to comply with these new requirements. OPG is working with its partners in the Canadian nuclear industry to develop a program suitable for Canada and its workers.

All of OPG's nuclear power reactor operating licences and waste facility licences are current and up to date. In 2016, OPG submitted applications with the CNSC seeking a ten-year licence renewal for the Western Waste Management Facility (WWMF), located at the Bruce generating stations' site, to May 31, 2027, and a ten-year licence renewal for the Pickering Waste Management Facility (PWMF) to August 31, 2028. The licence renewal applications were presented to the CNSC at public hearings in April 2017. On May 30, 2017, the CNSC announced that the WWMF licence was renewed for a ten-year period and will be valid until May 31, 2027. On February 7, 2018, the CNSC announced that the PWMF licence was renewed for a ten-year period and will be valid until August 31, 2028. Further details on the operating licence for the Darlington GS are found in the section, *General Development of the Business* under the heading, *Nuclear Business Development – Darlington Refurbishment* and for the Pickering GS in the section, *General Development of the Business* under the heading, *Nuclear Business Development – Extension of Commercial Operations at Pickering to 2024*.

Details on Canada's nuclear liability regime and related insurance coverage can be found under the heading, *Insurance*.

Fukushima Daiichi Response

In response to the 2011 Fukushima Daiichi incident in Japan, OPG has confirmed that its stations are safe and that systems and procedures are in place to withstand significant emergencies. In 2013, a systematic review and verification of defences against external hazards was completed at OPG-operated stations. The review showed that:

- the nuclear safety systems and multiple back-up power systems in place at the stations are effective; and
- the current design of the stations is strong and the stations are able to withstand extreme external events.

The review also provided recommendations for further opportunities to enhance the safety margin and to develop preparedness for unexpected events that go beyond the extreme events already considered in the design of the stations.

OPG's action plan in response to the Fukushima Daiichi event is well aligned with the CNSC's Fukushima Action Plan, issued in mid-2012. In 2013, OPG submitted its plans for the majority of the CNSC's Fukushima Action Plan items applicable to OPG-operated stations to the CNSC. In January 2015, the CNSC recognized OPG's efforts in this area and confirmed that all of the Fukushima action items were closed. OPG's Fukushima Implementation Plan included a number of key safety enhancements for providing additional back-up capability to increase OPG's flexibility to respond to unexpected and highly unlikely external events that can impact either a single unit or multiple units at the same time. CNSC staff concluded that OPG had strengthened reactor defence and enhanced its emergency response at both the Darlington GS and the Pickering GS in response to the lessons learned from the Fukushima Daiichi incident.

Nuclear Generating Station Life

Service life predictions for OPG-operated nuclear stations are developed by assessing the impacts of a number of operating, technical, and regulatory considerations on both unit and station economics. A decision by OPG to remove a unit from service would be primarily an economic decision that becomes more likely as the number of components requiring replacement and the frequency and duration of inspections required to ensure a unit's fitness for service increases. The key life-limiting components at OPG's nuclear stations include fuel channels, feeder tubes, steam generators, and other reactor components. End-of-service life predictions are reviewed as new information on possible degradation mechanisms becomes available and as future generation expectations are revised.

In December 2015, OPG revised the accounting assumptions for the estimated useful lives of the nuclear generating stations it operates. Effective December 31, 2015:

- the average service life of the Darlington GS was extended by one year to 2052 to reflect the approval of the refurbishment schedule in 2015; and
- the average service life of the Pickering GS was extended by less than one year to reflect the technical confidence that all six operating units of the station will operate to the end of 2020.

The accounting end of life assumptions for the Pickering GS have been reassessed in December 2017 based on the technical work performed to confirm that the longer fuel channel life necessary to extend Pickering operations can be achieved and that the units would be fit to operate beyond 2020, taking into account the requirement for the CNSC's approval. Further information can be found in the section, *General Development of the Business* under the heading, *Nuclear Business Development – Extension of Commercial Operations at Pickering to 2024*.

Nuclear Facility Planning

OPG uses a structured approach to identify and prioritize projects to optimize returns from nuclear station reinvestment within the constraints imposed by technical and financial requirements, while ensuring that safety, environmental, and other regulatory programs are of the highest priority. Input from predictive maintenance programs, life cycle management plans, and system health monitoring is used to determine the activities necessary to sustain and improve nuclear unit performance.

A structured framework modeled on the best practices identified by the Electric Power Research Institute, the Institute for Nuclear Power Operations and the World Association of Nuclear Operators (WANO) is used to optimize the maintenance of the nuclear generating stations and assess the health of the facilities. The structured framework includes predictive maintenance programs, which combine technologies and human expertise to analyze equipment performance, maintenance and design data in order to make timely decisions about the scope and timing of inspections and maintenance for major or critical equipment. The predictive maintenance program for each station is prioritized on the basis of the importance of the equipment for reactor safety. Life cycle management plans are maintained for critical station components and are updated annually to incorporate operating experience and new information. The life cycle plans define the inspection and maintenance programs required to ensure that these components perform in accordance with their design basis. In addition, system engineers conduct performance monitoring of station systems according to system performance monitoring plans that are based on a comparison of performance indicators against established targets to improve system performance. System performance is assessed by collecting, trending and analyzing station data. This information is reported in system health reports which are updated, at a minimum, annually.

OPG's practices impacting the performance of the nuclear stations are audited regularly by WANO, with identified areas for improvement acted upon with priority. In May 2016, OPG hosted a WANO peer evaluation that compared the Darlington GS against standards of excellence through an in-depth and objective review by an international panel of industry experts. The review maintained Darlington's excellent standing as one of the top performing nuclear plants in the world. In December 2017, OPG hosted a WANO peer evaluation for the Pickering GS, which focused on the safe and reliable operation of the station while evaluating the plant material condition, functional and cross-functional areas of the organization. Pickering showed significant improvement since its last review and has sustained its strong rating in 2018, resulting in its best ever WANO peer review.

In September 2016, OPG hosted a team of experts from the International Atomic Energy Agency (IAEA) at the Pickering GS to conduct a standard Operational Safety Review Team mission. The team conducted an in-depth review of performance and adherence to international safety standards. In the second quarter of 2017, the IAEA's Operational Safety Review Team released the final report and confirmed that the Pickering GS demonstrates strong commitment to safety.

Nuclear planned outages are necessary to execute inspection and maintenance work related to asset management and regulatory requirements for systems and equipment where access is not possible under normal operating conditions. Planned outages also give OPG an opportunity to perform system and equipment upgrades, project work, configuration changes, and other improvements and modifications. The nuclear generation plan, by reference to the station's life cycle management plans, establishes the number, frequency and duration of the outages for each year required to ensure the continued safe and reliable long-term operation of the plant and its compliance with CNSC regulatory requirements.

The outage cycle determines the number of planned outages at each station in a particular year. The Darlington GS is on a 36-month outage cycle, where each of the four units undergoes an outage every three years, resulting in one or two outages per year for the station. The Pickering GS was on a 24-month outage cycle. Supported by technical assessments undertaken for the extension of Pickering GS, the outage frequency has been optimized and extended from 24 to 30 months. In addition, on a periodic basis all units at each station are required to be shut down to allow for inspection and maintenance on the station vacuum building, containment systems and other safety systems. The CNSC currently requires these

outages every 12 years at the Darlington GS and every ten years at the Pickering GS. The most recent vacuum building outage took place at the Darlington GS in 2015 and at the Pickering GS in 2010.

Nuclear Ancillary Operations

OPG's nuclear generating units contain approximately 7,500 tonnes of deuterium oxide, or heavy water, not including heavy water contained at the leased Bruce stations. The heavy water is required to operate CANDU reactors. Ontario Hydro ceased the operation of its heavy water plants in 1997 and the plants were subsequently decommissioned. There are currently no heavy water plants in Canada. OPG believes that its existing inventory of heavy water will be sufficient to replenish supplies as a result of normal operating losses at its nuclear stations, including the refurbishment of the Darlington GS. OPG also believes that sufficient quantities of heavy water are available for possible changes in operating conditions or for new nuclear generating facilities. OPG seeks opportunities to sell available surplus quantities of heavy water from its inventory.

Tritium is a radioactive substance produced as a by-product of operating CANDU reactors, through the use of heavy water in the reactor moderator and heat transport systems. OPG operates a specialized facility at its Darlington site, the Darlington Tritium Removal Facility (TRF), which removes tritium from the tritiated heavy water (detritiation) used at the nuclear generating stations, in order to control the occupational dose exposure to employees and limit the amount of tritium released to the environment. The extracted tritium is chemically immobilized, placed in special containers, and safely stored in a vault. The Darlington TRF is also expected to be used to detritiate heavy water during the eventual decommissioning of OPG's nuclear generating stations. Some tritium is sold to government-approved organizations for authorized commercial and health industry uses. OPG also provides detritiation services to Bruce Power. Opportunities for providing detritiation services to other third parties are limited because of storage and capacity restrictions at the Darlington TRF.

Cobalt-60 produced and sold by OPG is used mainly in the health industry to sterilize surgical and medical supplies. Cobalt-60 is produced in Units 6, 7 and 8 at the Pickering GS. Cobalt-60 can be produced in reactors which, like the CANDU reactors, use adjuster rods to regulate power. The production process involves replacing the stainless steel rod by a rod containing Cobalt-59, which is isotopically converted into Cobalt-60 after lengthy exposure to the atomic reaction in the reactor core. During planned maintenance outages, the rods are removed, cut, and packaged for sale as Cobalt-60, and new rods are inserted in the reactor to continue the production cycle.

Hydroelectric (Regulated – Hydroelectric and Contracted Generation Portfolio Segments)

Overview of Generating Facilities

Hydroelectric generating stations use the energy of falling water to drive hydraulic turbines that generate electricity. OPG's hydroelectric stations provide one of the Company's competitive advantages – a reliable, relatively low-cost source of renewable energy free of air emissions. Electricity generation from OPG's hydroelectric facilities depends primarily upon the availability of water, which is affected largely by natural factors such as precipitation and evaporation. It is also impacted by the prevalence of SBG conditions.

OPG currently owns and operates 66 hydroelectric generating stations and 241 associated dams located on 24 river systems across Ontario. The results of 54 of these stations that are rate regulated by the OEB are reported in the Regulated – Hydroelectric segment. The results of the remaining 12 stations are subject to long-term ESAs with the IESO and are included in the Contracted Generation Portfolio segment. The 54 regulated hydroelectric stations include the 48 stations prescribed for rate regulation beginning in 2014 and the six stations that have been rate regulated by the OEB since 2008.

As at December 31, 2017, OPG's regulated hydroelectric facilities had a total in-service capacity of 6,426 MW and the non-regulated hydroelectric facilities had a total in-service capacity of 1,042 MW. OPG's hydroelectric generating stations range in age from the newly in-serviced Peter Sutherland Sr. GS to over 119 years and include the oldest assets in OPG's generation portfolio.

Hydroelectric ESAs with 50-year terms are in place for the following hydroelectric facilities:

- Lac Seul and Ear Falls generating stations, with an expiry date of February 2059;
- Healey Falls GS, with an expiry date of April 2060;
- Sandy Falls, Wawaitin, Lower Sturgeon, and Hound Chute generating stations, with an expiry date of December 2060;
- Little Long, Harmon, Smoky Falls, and Kipling generating stations, with an expiry date of January 2064; and
- Peter Sutherland Sr. GS placed in-service in March 2017, with an expiry date of March 2067.

In 2017, the number of regional groups was reduced from five to four, by integrating the central operations work centers into three of the other existing regional operations groups. The following are the four regional operations groups that operate and maintain OPG's hydroelectric facilities:

- Niagara Operations – includes the three Sir Adam Beck stations located on the Niagara River and the two DeCew Falls facilities located on the Welland River. These facilities have been rate regulated by the OEB since 2008. As part of the change in the regional groups, the Gravenhurst work centre joined with seven regulated stations on the Muskoka, Severn and Beaver Rivers. This operations group also includes OPG's wind turbine.
- Eastern Operations – includes the following ten regulated hydroelectric generating stations: the R.H. Saunders GS on the St. Lawrence River; the Otto Holden, Des Joachims, Chenaux, and Chats Falls generating stations on the Ottawa River; and the Mountain Chute, Barrett Chute, Calabogie, Stewartville, and Arnprior generating stations on the Madawaska River. The R.H. Saunders GS has been regulated by the OEB since 2008. As part of the change in the regional groups, the Campbellford work centre joined with eleven regulated stations and one non-regulated station on the Trent, Mississippi and Rideau Rivers.
- Northeast Operations – includes five regulated and eight non-regulated hydroelectric stations in northeastern Ontario. The regulated stations are the Chute and Lower Notch generating stations on the Montreal River; the Abitibi Canyon and Otter Rapids generating stations on the Abitibi River; and the Matabitchuan GS on the Matabitchuan River. The non-regulated stations are the Little Long, Harmon, Smoky Falls, and Kipling generating stations on the Lower Mattagami River; the Wawaitin, Sandy Falls, and Lower Sturgeon generating stations on the Upper Mattagami River; and the Hound Chute GS on the Montreal River. The North Bay and Coniston work centres joined this regional operations group with seven regulated stations on the Wanapitei and French Rivers.
- Northwest Operations – includes nine regulated and two non-regulated generating stations in northwestern Ontario. The regulated stations are the Pine Portage, Cameron Falls, and Alexander generating stations on the Nipigon River; the Silver Falls and Kakabeka Falls generating stations on the Kamanistikwia River; the Manitou Falls and Caribou Falls generating stations on the English River; the Aguasabon GS on the Aguasabon River; and the Whitedog Falls GS on the Winnipeg River. The non-regulated stations are the Lac Seul and Ear Falls generating stations on the English River.

These operations groups are also responsible for the operation and maintenance of OPG's thermal facilities discussed under the heading, *Generation Operations – Thermal (Contracted Generation Portfolio Segment)*.

The performance of OPG's hydroelectric generating stations during 2017, 2016 and 2015 was as follows:

Hydroelectric Generation Performance (2015 to 2017)

	Regulated – Hydroelectric			Contracted Generation Portfolio – Hydroelectric			Total Hydroelectric		
	2017	**2016**	**2015**	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Availability *(%)* [1]	**88.0**	89.0	91.2	**74.6**	77.3	88.6	**86.2**	87.5	90.9

[1] Availability is represented by the percentage of time the generating unit is capable of providing service, whether or not it is actually generating electricity, compared to the total time for the respective period.

Lower availability of the Regulated – Hydroelectric facilities during 2017 was primarily due to a higher number of unplanned outage days at the Northwestern Ontario, Niagara, and Eastern Ontario regions' hydroelectric stations, partially offset by higher availability from the Sir Adam Beck Pump GS due to a higher number of planned outages days in 2016 as a result of the refurbishment of the station's reservoir. Lower availability of the Contracted Generation Portfolio hydroelectric facilities in 2017 was primarily due to an increase in the number of planned outage days at the Lower Mattagami River hydroelectric generating stations.

Lower availability of the Regulated – Hydroelectric facilities during 2016 was primarily due to the planned reservoir refurbishment project at the Sir Adam Beck Pump GS. Lower availability of the Contracted Generation Portfolio hydroelectric facilities in 2016 was primarily due to a higher number of planned outage days at the Kipling and Harmon generating stations.

OPG's objectives for the hydroelectric operations include operating and maintaining the generating facilities in a safe, efficient and cost-effective manner, while increasing the output from the facilities and pursuing opportunities to increase capacity. OPG aims to increase the facilities' output by improving operational flexibility, enhancing reliability, optimizing outage planning and, subject to water conditions, increasing availability to meet electricity system demand. The Company continues to evaluate and implement plans to increase capacity, maintain and improve operational performance, and extend the operating life of its hydroelectric generating assets. These plans are accomplished through multi-year capital investment and other programs, including replacements and upgrades of turbine runners, and refurbishment or replacement of existing generators, transformers, and controls. Over the next four years, OPG plans to increase the total capacity of its renewable generating fleet by approximately 150 MW, which in addition to the runner replacement and upgrade program, includes the Ranney Falls GS and Sir Adam Beck frequency conversion projects. OPG is also planning to repair, rehabilitate, or replace a number of aging civil structures. Where economical and practical, OPG also pursues opportunities to refurbish, expand or redevelop its existing hydroelectric stations.

Additional information on OPG's hydroelectric operations are discussed in the section, *Core Business, Strategy, and Outlook* under the heading, *Operational Excellence – Electricity Generation Production and Reliability* in the Company's 2017 year-end MD&A.

Hydroelectric Facility Planning

Major components of hydroelectric facilities typically include: generating equipment such as turbines, generators and transformers; civil works such as powerhouses, dams, headworks, spillways and water conveyance canals and tunnels; and facilities required to operate and maintain the stations such as control rooms and work centres. Although there is a link between the age of a facility and the capital investment required to maintain that facility, age does not establish an upper limit on the expected useful life of hydroelectric facilities and dams. Regular maintenance and the replacement of specific components typically allow stations to operate for very long periods, especially for facilities built after 1925.

OPG operates six staffed control rooms across Ontario that provide remote control and monitoring for all of OPG's hydroelectric generating facilities. These control rooms are designed to minimize the number of staffed control rooms, reduce control system failures, and increase the amount of information available for production planning.

OPG uses a structured portfolio approach to identify and prioritize projects for its hydroelectric asset investment program. Engineering reviews and station condition assessments are performed to determine short-term and long-term expenditure requirements to sustain or improve the performance of each facility. These may be followed by the preparation of a facility life cycle plan, which is performed on an as-needed basis for marginal assets or assets potentially requiring significant expenditures relative to the value of the facility. This approach is designed to identify necessary capital, operating and maintenance expenditures for each facility and to direct resources towards those facilities that can best maintain or enhance their value.

OPG utilizes a preventive maintenance program that provides a consistent method of identifying, scheduling, and executing maintenance activities at the hydroelectric facilities. The maintenance program is based on the concept of streamlined reliability-centred maintenance, whereby the type and frequency of preventive maintenance applied to an individual component is determined based on the nature and consequences of failure, balancing cost and risk.

The cornerstone of OPG's project prioritization and preventive maintenance approaches for the hydroelectric assets is that safety, environmental, and other regulatory programs are of the highest priority.

Water Management

OPG's water management strategy for its hydroelectric facilities is to safely utilize available water for generation of electricity in conformance with legal, environmental, operational, and WMP and Operational Plan requirements. OPG uses hydrological and meteorological data to manage water levels, water flows and water storage, and strives to schedule water use for optimum utilization and to minimize controllable water spills due to SBG conditions.

Gross Revenue Charge and Water Rental Payments

Hydroelectric generating stations in Ontario are subject to taxes and charges as prescribed by *Ontario Regulation 124/02* under the *Electricity Act, 1998*. These taxes and charges, referred to as Gross Revenue Charge (GRC), are based on station gross revenue, which, for this purpose, is determined as the product of annual station energy generation and the prescribed revenue rate of $40/MWh (Gross Revenue). All OPG hydroelectric generating stations are subject to GRC Property Tax, which is determined by applying graduated tax rates, ranging from 2.5 percent to 26.5 percent through four tiers of production, to a station's annual Gross Revenue. GRC Property Tax payments are made to the OEFC. Hydroelectric generating stations that are subject to water power lease agreements with the MNRF are also subject to GRC Water Rental charges in addition to GRC Property Tax payments. The GRC Water Rental charge is determined as 9.5 percent of a station's annual Gross Revenue. GRC Water Rental payments are made to the Ontario Ministry of Finance.

Annual land rental fees are paid to the MNRF as prescribed by Crown leases and licences of occupation which authorize OPG's tenure (including flooding rights), typically at storage dam sites.

The eight OPG hydroelectric generating stations located on the Trent River and Rideau Canal are subject to rental charges prescribed by licences with Parks Canada. These licences authorize OPG to occupy the lands, maintain and operate the powerhouses and dams, and utilize water that is surplus to navigation needs for the generation of electricity.

Water conveyance charges are paid to the St. Lawrence Seaway Management Corporation as prescribed by a lease agreement providing for the withdrawal of water surplus to navigation needs from the Welland

Canal for utilization at the DeCew Falls generating stations. The water conveyance charges apply to the transport of water from Lake Erie through the Welland Canal to OPG's intakes at Allanburg.

Water rental payments are made to the Government of Québec, as prescribed by an agreement dated January 2, 1943 and a rate amending agreement effective January 2, 1993. These agreements pertain to the sharing of the water powers of the Ottawa River and were ratified by the Governments of Ontario and Québec. Water rental charges payable to the Province of Québec are based on one-half of the energy produced at the three regulated OPG hydroelectric generating stations located on the Ottawa River. The GRC payments made to the Province of Ontario with respect to these three sites are also based on one-half of the energy produced at the stations.

Under the aforementioned 1943 agreement, OPG also provides compensation to Hydro Québec for the generating value at OPG's stations on the Ottawa River attributed to the water diverted into the Ottawa River through the Dozois Reservoir in Québec. OPG shares in operation and maintenance costs pertaining to the dam enabling the Dozois diversion.

The GRC and water rental payments for the regulated hydroelectric stations are recoverable through OEB-approved regulated prices applicable to these stations.

Further details on water rights can be found in the section, *Description of the Business* under the heading, *Water Rights*.

Thermal (Contracted Generation Portfolio Segment)

Overview of Generating Facilities

Thermal generating stations use heat energy to drive steam turbines that generate electricity. OPG's wholly-owned operating thermal facilities are comprised of biomass-fuelled generating units at both Atikokan GS and Thunder Bay GS, and the dual-fuelled generating Lennox GS, which is capable of burning either oil or natural gas. The results of these facilities are reported in the Contracted – Generation Portfolio business segment.

The combined in-service capacity of the three operating thermal facilities was 2,458 MW as at December 31, 2017. The Lennox GS is located in Greater Napanee, Ontario and accounts for approximately 2,100 MW of this in-service capacity. The Atikokan GS is located in Atikokan, Ontario and has an in-service capacity of 205 MW. The Thunder Bay GS is located in Thunder Bay, Ontario and its advanced biomass fuelled unit has an in-service capacity of 153 MW.

Capacity and production from the Lennox GS are subject to an ESA with the IESO for the period from January 2013 to September 2022. Capacity and production from the Atikokan GS are subject to a ten-year ESA expiring in July 2024. For the Thunder Bay GS advanced biomass fuelled unit, capacity and production are subject to a five-year ESA expiring in January 2020.

OPG's three thermal generating stations operate as peaking facilities, depending on electricity demand. This provides Ontario's electricity system with the flexibility to meet changing daily system demand and capacity requirements and has enabled the system to accommodate the expansion of Ontario's renewable generation portfolio. The continued operation of these stations will continue to provide Ontario with capacity and peaking generation.

The three thermal generating stations are operated and maintained as part of regional operations groups used to operate and maintain the Company's hydroelectric facilities. The Lennox GS is operated under Eastern Operations, and the Atikokan and Thunder Bay generating stations are part of Northwest Operations.

Thermal stations that are no longer available to generate electricity are included in the Services, Trading, and Other Non-Generation business segment once they are removed from service. This includes the Lambton GS and Nanticoke GS sites, which ceased coal-fired generation in 2013.

Contracted Generation Portfolio – Thermal Performance (2015 to 2017)

	2017	2016	2015
Equivalent Forced Outage Rate (%) [1]	**2.4**	1.6	11.2

[1] Equivalent Forced Outage Rate is an index of the reliability of a generating unit at OPG's thermal stations. It is measured by the ratio of time a generating unit is forced out of service by unplanned events, including any forced deratings, compared to the amount of time the generating unit was available to operate.

The higher thermal EFOR in 2017, compared to 2016, was primarily due to a higher number of unplanned outage days at a Lennox GS unit as a result of a transmission outage and a generator-related outage in 2017. The change in thermal EFOR in 2016, compared to 2015, was primarily due to an outage in 2015 to perform repair work at the Lennox GS.

Additional information on OPG's thermal operations can be found in the section, *Core Business, Strategy, and Outlook* under the heading, *Operational Excellence – Electricity Generation Production and Reliability* in the Company's 2017 year-end MD&A.

Thermal Fuel Procurement

Due to the relatively low capacity factor of the Lennox GS, natural gas is purchased on the spot market, other than a small volume of fixed term natural gas required for non-generation operational services. Oil for the Lennox GS is contracted for and purchased on an as needed basis. Fuel switching at the station is based on market and fuel economics. Annual procurement of biomass fuel quantities for Atikokan GS and Thunder Bay GS is pre-determined by the corresponding ESAs. Agreements are in place with suppliers for the purchase of all biomass fuel pellets needed to provide fuel for the Atikokan GS for the duration of its ESA, and for most of the advanced biomass fuel pellets needed to provide fuel for the duration of the ESA for the Thunder Bay GS.

Thermal Facility Planning

OPG's facility planning approach is designed to identify necessary capital and operating and maintenance expenditures for each thermal facility. This planning approach aims to sustain facility availability for the remaining service life through station reinvestment within constraints imposed by technical, financial, safety, and system requirements, as well as regulatory and contractual limits. Periodic engineering reviews of major systems are conducted to identify performance issues, provide reinvestment recommendations where appropriate, and ensure that regulatory, safety and operating standards continue to meet expectations. OPG undertakes projects at thermal stations that are expected to achieve an appropriate return within the service life of the stations.

Thermal Station Decommissioning

OPG has recognized, and carries on its balance sheet, a liability to cover future expenditures to decommission and dismantle each of its thermal stations at the end of their estimated service lives. This provision is not funded and is estimated on the basis of station closure. Costs previously incurred by OPG to preserve Lambton and Nanticoke generating stations for potential conversion to natural gas in the future were not charged to the provision, as they were charged against net income as incurred.

Portlands Energy Centre Partnership

OPG has a 49.95 percent partnership interest in Portlands Energy Centre L.P., a limited partnership formed with TransCanada Energy Ltd. (49.95 percent) and the general partner of the partnership, Portlands Energy Centre Inc. (0.1 percent). The shareholders of Portlands Energy Centre Inc. are OPG (50 percent) and TransCanada Energy Ltd. (50 percent). PEC is a 550 MW combined cycle generation natural gas turbine electricity generating facility located on the former R. L. Hearn GS site in the port area of downtown Toronto, Ontario. The station was declared in-service in a combined cycle mode in April 2009. PEC operates under an Accelerated Clean Energy Supply contract with the IESO and trades electricity in the Ontario electricity market.

The Contracted Generation Portfolio segment includes OPG's share of equity income from its 50 percent ownership interest in the station. OPG's share of the in-service generating capacity and generation volume from its interest in the station are included in the operating statistics for the segment.

Brighton Beach Power Partnership

OPG has a 49.95 percent partnership interest in Brighton Beach Power L.P., a limited partnership formed with ATCO Power Canada Ltd. (49.95 percent) and the general partner of the partnership, Brighton Beach Power Ltd. (0.1 percent). The shareholders of Brighton Beach Power Ltd. are OPG (50 percent) and ATCO Power Canada Ltd. (50 percent). Brighton Beach is a 560 MW combined cycle gas turbine electricity generating facility located on the former J.C. Keith GS site in Windsor, Ontario. The station began commercial operation in July 2004. Brighton Beach operates under a tolling arrangement with Shell Energy North America (Canada) Inc. (Shell Energy), pursuant to which Shell Energy owns and trades the electricity produced by the facility in return for the supply of gas and the fees payable under the tolling agreement. Shell Energy's financial obligations are guaranteed by Shell Energy North America (US) L.P. (Shell L.P.), and Shell L.P.'s obligations are in turn guaranteed by Shell Oil Company.

The Contracted Generation Portfolio segment includes OPG's share of equity income from its 50 percent ownership interest in the station. OPG's share of the in-service generating capacity and generation volume from its interest in the station are included in the operating statistics for the segment.

Regulated – Nuclear Waste Management Segment

Overview

OPG is responsible for the ongoing management of radioactive wastes generated by its nuclear operations. In addition, OPG has the obligation for decommissioning its nuclear generating stations and nuclear waste facilities after the end of their useful lives and for managing radioactive wastes that arise in connection with the decommissioning. The handling and disposal of radioactive waste in Canada is subject to federal legislation.

The radioactive wastes generated by OPG's nuclear operations include the following:

- Used nuclear fuel bundles;
- Intermediate-level waste – material that has come in close contact with the reactors, but is less radioactive than used fuel, such as ion exchange resins and reactor equipment and components; and
- Low-level waste – material used in connection with station operation that is not highly radioactive, such as tools and protective clothing.

The Company's Regulated – Nuclear Waste Management segment reports the results of the Company's operations associated with the following:

- management of used nuclear fuel and L&ILW;

- decommissioning of OPG's nuclear generating stations including the stations on lease to Bruce Power and other nuclear facilities;
- management of the Nuclear Segregated Funds established under the ONFA to fund OPG's obligation for nuclear facilities decommissioning and the long-term management of nuclear waste; and
- Other related activities including the inspection and maintenance of the waste storage facilities.

The nuclear accretion expense, which is the increase in the carrying amount of the present value liabilities for nuclear fixed asset removal and nuclear waste management liabilities reported on the balance sheet due to the passage of time, and the earnings from the Nuclear Segregated Funds are reported under this segment. The Regulated – Nuclear Waste Management segment is considered rate regulated because OPG's costs associated with nuclear waste management and nuclear facilities decommissioning liabilities have been included by the OEB in the determination of regulated prices for production from the Pickering and Darlington nuclear generating stations.

Federal Government Policy

In accordance with the requirements of the *Nuclear Fuel Waste Act* (Canada) (NFWA), in 2002, OPG and the other owners of nuclear fuel waste in Canada established a separately incorporated NWMO, with a mandate to manage and coordinate the full range of activities relating to the long-term management of nuclear fuel waste in Canada. This includes the design and implementation of Canada's plan for the long-term management of used nuclear fuel. In 2007, the federal government approved NWMO's submitted option, the Adaptive Phased Management (APM) plan, as the long-term solution for nuclear fuel waste. The APM plan contemplates the eventual long-term permanent disposal of radioactive nuclear fuel waste in a deep geologic repository (DGR) after a collaborative process of communication and engagement with Canadians aimed at selecting a suitable geological site with an informed and willing host community. The NWMO is in the process of undertaking a multi-year site selection process for the used fuel DGR.

The NFWA also requires the nuclear fuel waste owners in Canada to establish and make payments into trust funds for the purpose of funding the implementation of the long-term management plan for used fuel. Accordingly, OPG has established the Ontario NFWA Trust (the NFWA Trust), which forms part of the Nuclear Segregated Funds under the ONFA. Additional details can be found in the section, *Description of the Business* under the heading, *Regulated – Nuclear Waste Management Segment – Funding Mechanisms.*

Current Practices

Used Nuclear Fuel

Used nuclear fuel bundles from OPG's reactors and leased reactors at the Bruce Nuclear site are temporarily stored at each nuclear generating station in water-filled pools, known as wet bays, for a cooling-off period of at least ten years, during which time their radioactivity is substantially reduced. Each nuclear generating station has sufficient capacity to store used nuclear fuel bundles in the wet bays for approximately 15 to 20 years of operation.

After the used nuclear fuel bundles have been stored for the cooling-off period, the bundles are transferred from the wet bays to above-ground dry storage containers at the corresponding nuclear station site. Currently, there is used nuclear fuel bundles in dry storage at the Pickering, Darlington and Bruce Nuclear sites.

OPG's planning assumption for the long-term management of used nuclear fuel bundles is consistent with the NWMO's APM concept of disposal in a deep geological repository. The NWMO has indicated that it currently expects an in-service date of 2043 at the earliest for the used fuel DGR.

Low and Intermediate Level Waste

The majority of OPG's L&ILW is stored at the radioactive waste management facility at WWMF located on the Bruce site. This facility, which continues to be owned and operated by OPG following the lease of the Bruce generating stations, operates under a separate licence issued by the CNSC. A smaller volume of ILW is stored at each of the radioactive waste management facilities at Pickering and Darlington sites. Respectively, these ILW storage facilities house the components from Pickering A's retube in the 1980's and from the recent Darlington Refurbishment of Unit 2. OPG's planning assumption for the long-term management of L&ILW is the placement of this nuclear waste in a separate L&ILW DGR.

Additional details can be found in the section, *Description of the Business* under the heading, *Regulated – Nuclear Waste Management Segment – Deep Geologic Repository for Low and Intermediate Level Waste.*

Station Decommissioning

OPG's planning assumption for the decommissioning of its nuclear generating stations is a deferred dismantlement strategy. Under this strategy, each station will be de-watered and de-fuelled immediately after it has ceased operations and prepared for safe storage and monitoring. Thereafter, OPG intends to monitor the station for approximately 30 years while in safe storage, after which time the station will be dismantled and the site restored over a period of approximately ten years. This strategy has been communicated to the CNSC through regular updates of OPG's preliminary decommissioning plans and liability estimates for the nuclear generating stations. Currently, OPG has received CNSC acceptance of the OPG Financial Guarantee for the five year period from 2018 to 2022 based on the fund performance and estimate for decommissioning the OPG nuclear assets. OPG's nuclear operating licences have been issued based on, amongst other things, CNSC's understanding of this strategy.

Deep Geologic Repository for Low and Intermediate Level Waste

OPG has proposed a deep geologic repository as the preferred solution for the safe long-term management of the L&ILW produced from the continued operation of OPG-owned nuclear generating stations and their eventual decommissioning. Agreement has been reached with local municipalities for OPG to develop the L&ILW DGR on lands adjacent to the WWMF in Kincardine, Ontario.

Under the NSCA, OPG requires licences from the CNSC for activities to be undertaken with respect to the L&ILW DGR project. Before the CNSC can make licensing decisions for the proposal, an EA must be conducted in compliance with the requirements of the *Canadian Environmental Assessment Act*. As part of the EA process for the L&ILW DGR, Environmental Impact Statement, Preliminary Safety Report, and Technical Support Documents were submitted to the CNSC in 2011. The purpose of these submissions was to obtain EA approval and a site preparation and construction licence from the Joint Review Panel (JRP) for the project. The responsibility of the JRP, which was appointed by the Canadian Environmental Assessment Agency (CEAA) and the CNSC in 2012, was to examine the environmental effects of the proposed DGR to meet the requirements of the *Canadian Environmental Assessment Act.* In May 2015, the JRP submitted its report and recommendations on the EA to the federal Minister of Environment. The report concluded that, given mitigation, there is unlikely to be significant environmental impact from the project and recommended that the Minister approve the EA. The report suggested that the project should be implemented expeditiously.

In August 2015, OPG responded to the CEAA's list of potential environmental conditions relating to the JRP report. In February 2016, the federal Minister of Environment and Climate Change requested additional information on certain aspects of the EA, including information related to alternate locations for the project and the impact on environmental effects if Canada's planned used fuel deep geologic repository being developed by the NWMO were to be located in close proximity to OPG's proposed L&ILW DGR. OPG has completed the requested studies and submitted the requested information in December 2016, as planned. Following its review of OPG's submission and a period of public comment, the CEAA requested further information that OPG subsequently provided in May 2017. In June 2017, the CEAA notified OPG that it had sufficient and adequate information to proceed with the next step of the environmental assessment

process and advised that a draft report and updated terms and conditions would be prepared for public review.

On August 21, 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of potential cumulative effects of the project on the Saugeen Ojibway Nation's (SON) physical and cultural heritage, including a description of the potential effects of the project on the Nation's spiritual and cultural connection to the land, taking into account the results of the SON Community Process. OPG is working closely with the SON to formulate a response to the information request.

The L&ILW DGR at the WWMF site remains OPG's preferred solution for the safe long-term management of the L&ILW. The in-service date of the L&ILW DGR is expected to be approximately six to seven years from the start of construction.

Funding Mechanisms

On April 1, 1999, Ontario Hydro's obligation for nuclear facilities decommissioning and nuclear waste management was transferred to OPG. The responsibility for funding the liabilities for nuclear facilities decommissioning and the long-term nuclear waste management between the Province and OPG is described in the ONFA. The key provisions of the ONFA are: (i) for OPG to establish two segregated funds, the Used Fuel Segregated Fund to fund the future costs of long-term nuclear used fuel waste management and certain costs of used fuel storage incurred after the stations are shut down, and the Decommissioning Segregated Fund to fund the future costs of nuclear decommissioning and long-term L&ILW management, and certain costs of used fuel storage incurred after the stations are shut down; (ii) for the OEFC to be responsible for funding approximately $2.4 billion present value as at April 1, 1999 that had been an accumulated liability of Ontario Hydro, which the OEFC has since then fully funded through an initial contribution to the Decommissioning Segregated Fund; (iii) for the Province to limit OPG's financial exposure in relation to the cost of used fuel management for the first 2.23 million bundles of used fuel; and (iv) for the Province to provide financial guarantees to the CNSC for OPG's nuclear decommissioning and nuclear waste management obligations, as required by the CNSC.

The Used Fuel Segregated Fund and the Decommissioning Segregated Fund are administered by a third party custodian and held in accounts segregated from OPG's other assets. OPG has granted a security interest in both funds to the Province. As a result, these funds are not available to satisfy the claims of OPG's creditors.

OPG's required contributions to the Used Fuel Segregated Fund and the Decommissioning Segregated Fund are determined based on reference plans and associated life cycle cost estimates periodically approved by the Province under the ONFA. These reference plans are prepared by OPG with the assistance of external consultants and based on external practices and international benchmarks. Under the ONFA reference plans, the total present value of OPG's future nuclear facilities decommissioning and nuclear waste management costs is determined based on baseline cost estimates and a set of underpinning major planning assumptions, including remaining useful lives of the nuclear stations, proposed methods and timing of nuclear waste disposal, and economic indicators. Given the long-term duration of these life cycle programs, the multiple assumptions involved and the evolving technology to handle nuclear waste, there is a significant degree of inherent uncertainty surrounding the measurement of the underlying costs, which may increase or decrease over time.

The limits to OPG's financial exposure under the ONFA with respect to the life cycle cost of long-term management of the first 2.23 million bundles of used fuel are as follows (all amounts are expressed in January 1, 1999 present value dollars): (i) OPG will bear all costs up to $4.6 billion; (ii) OPG and the Province will share, on an equal basis, costs incurred between $4.6 billion and $6.6 billion; (iii) OPG will be responsible for 10 percent of the costs incurred between $6.6 and $10 billion, and the Province will be responsible for the remaining 90 percent; (iv) the Province will be wholly responsible for any costs above $10 billion. As a result, OPG's funding liability for these used fuel costs under the ONFA is capped at $5.9 billion in January 1, 1999 present value dollars, which is equivalent to approximately $15.7 billion in December 31, 2017 present value dollars. OPG is responsible for all incremental costs

relating to the management of used fuel bundles in excess of the 2.23 million threshold. As at December 31, 2017, approximately 2.6 million bundles of used fuel waste had been produced. The 2.23 million fuel bundles threshold represents the estimated total life cycle bundles based on the initial estimated useful lives of the nuclear stations assumed in the ONFA.

Under the ONFA, the Province guarantees OPG's annual return earned in the Used Fuel Segregated Fund at 3.25 percent plus the rate of change in the Ontario Consumer Price Index, as defined in the ONFA, for funding related to the first 2.23 million used fuel bundles. Upon approval of a new or amended ONFA reference plan, the Province is obligated to make an additional contribution to the Used Fuel Segregated Fund in relation to the first 2.23 million bundles if the fund's assets earned a rate of return that is less than the guaranteed rate of return. If the return on the fund's assets exceeds the Province's guaranteed rate of return, the Province is entitled to withdraw any portion of the excess related to the first 2.23 million bundles, upon approval of a new or amended ONFA reference plan. OPG is responsible for cost increases and investment returns for the portion of the fund attributable to the used fuel bundles in excess of the 2.23 million threshold. OPG also is responsible for cost increases and investment returns for the Decommissioning Segregated Fund.

The investments in the Nuclear Segregated Funds include a diversified portfolio of equities and fixed income securities that are invested across geographic markets, as well as investments in real assets including infrastructure, real estate and agriculture. As the Nuclear Segregated Funds are invested to fund long-term liability requirements, the portfolio asset mix is structured to achieve the required return over a long-term horizon. While the Nuclear Segregated Funds are manage to achieve, in the long term, the target return rate based on the discount rate specified in the ONFA, the rates of return earned in a given period may be subject to various external factors including financial market conditions and changes in the Ontario Consumer Price Index, which, in the short-term, can be volatile and cause fluctuations in the Company's financial results. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

Under the current OEB-approved cost recovery methodology for OPG's nuclear waste management and nuclear facilities decommissioning liabilities, OPG's income is exposed to the rate of return risk for the portion of the Nuclear Segregated Funds related to the Pickering and Darlington nuclear generating stations.

Contributions to the Nuclear Segregated Funds

OPG's contribution requirements under the ONFA are recalculated each time there is an approved new or amended reference plan and under certain other events. Reference plans are required to be prepared at least every five years, or more frequently if there is an underlying change in the assumptions of the reference plan that both OPG and the Province agree are significant enough to trigger a recalculation of the contribution levels during the five-year period.

Prior to 2017, OPG made contributions to the Used Fuel Segregated Fund every quarter, including a one-time special payment in earlier years, as required by the ONFA. These contributions reflected ONFA requirements to fund the majority of the underlying used fuel liability by the end of the initial estimated useful lives of the nuclear stations assumed in the ONFA, resulting in significantly higher contributions to the Used Fuel Segregated Fund in the earlier years of OPG's existence. OPG has not been required to make contributions to the Decommissioning Segregated Fund, which was fully funded at its inception through the initial contribution made by the OEFC and, taking into account asset performance and changes in underlying funding obligations over time, at the time of every subsequent approved ONFA reference plan.

Based on the funded status of the Used Fuel Segregated Fund and the Decommissioning Segregated Fund reflecting the lower life cycle liability estimates per the 2017 ONFA Reference Plan, no overall contributions to either fund were required starting in 2017. Contributions to either or both funds may be required in the future should the funds be in an underfunded position when a new reference plan is approved. Such may be the case as a result of future variability in asset performance due to volatility inherent in financial markets and economic conditions. Future contribution levels also are dependent on changes in baseline cost

estimates and underpinning planning assumptions used to establish the funding obligations in subsequent ONFA reference plans, as well as any changes in the tax treatment of fund earnings. OPG's required contributions could increase, for example, if cost estimates increased, if the operating lives of the nuclear stations were revised, if fund assets earned less than the target rate of return, if the income earned in the funds became subject to tax, or if the NWMO were unable to receive the same sales tax treatment that OPG would be entitled to receive if the NWMO had not been established.

OPG is required to make annual contributions to the NFWA Trust based on a funding formula approved by the federal Minister of Natural Resources for OPG and the other nuclear fuel waste owners in Canada. The NFWA Trust forms part of the Used Fuel Segregated Fund. Any OPG contributions to the Used Fuel Segregated Fund as well as any portion of the Used Fuel Segregated Fund currently not in the NFWA Trust can be applied to satisfy the trust's annual contribution requirements. The funds in the Ontario NFWA Trust will be used for the purposes of long-term management of nuclear used fuel waste, in accordance with the NFWA. OPG and the Province are beneficiaries of the NFWA Trust.

If there is a surplus in the Decommissioning Segregated Fund such that the funding liabilities, as defined by the most recently approved ONFA Reference Plan, are at least 120 percent funded, OPG may direct, at the time a new or amended reference plan is approved, up to 50 percent of the surplus over 120 percent to the Used Fuel Segregated Fund, with the OEFC entitled to a distribution of an equal amount.

If there is a surplus in the Used Fuel Segregated Fund such that the funding liabilities, as defined by the most recently approved ONFA Reference Plan, are at least 110 percent funded, the Province has the right, at any time, to access the excess amount greater than 110 percent. Neither OPG nor the Province have a right to direct any amounts from the Used Fuel Segregated Fund to the Decommissioning Segregated Fund.

Upon termination of the ONFA, the Province has the sole right to any excess funds in the Decommissioning Segregated Fund and the Used Fuel Segregated Fund.

OPG has the responsibility for the management and disposal of the used nuclear fuel and L&ILW generated by the Bruce generating stations and for the eventual decommissioning of these stations. These obligations on the part of OPG are recovered from Bruce Power through annual rent payments and volume based fees per the Bruce Lease and related agreements. Pursuant to the lease agreement, Bruce Power must return the two Bruce stations to OPG together, in a de-fuelled and de-watered state. As such, these de-watering and de-fuelling costs will not be funded by OPG. Further details on the 2015 amendments to these agreements are found in the section, *General Development of the Business* under the heading, *Nuclear Business Development – Bruce Power Refurbishment and Bruce Lease Agreement*.

Provincial Guarantee

In accordance with the NSCA, the CNSC requires OPG to have sufficient funds available to discharge its existing nuclear waste management and nuclear decommissioning obligations. The CNSC process requires the CNSC financial guarantee requirement to be updated once every five years and for OPG to provide an annual report to the CNSC on the assumptions, asset values, and resulting financial guarantee requirements. The CNSC financial guarantee requirement calculation takes into account nuclear waste expected to be generated to the end of each year.

In November 2017, the CNSC accepted OPG's proposed 2018-2022 CNSC financial guarantee requirement to be satisfied by the forecast fair market value of the Nuclear Segregated Funds without the requirement of a Provincial Guarantee for the 2018-2022 period. As required by the terms of the ONFA, the Province is committed to provide a Provincial Guarantee to the CNSC, on behalf of OPG, should there be a shortfall between the CNSC financial guarantee requirement and the value of the Nuclear Segregated Funds in the 2018-2022 period, as it has been done in the past. OPG pays the Province an annual guarantee fee equal to 0.5 percent of the outstanding amount, if any, of the Provincial Guarantee.

Services, Trading, and Other Non-Generation Segment

The Services, Trading, and Other Non-Generation segment is a non-generation segment that is not subject to rate regulation. It includes the revenue and expenses related to OPG's trading and other non-hedging activities. As part of trading activities, OPG transacts with counterparties in Ontario and neighbouring energy markets in predominantly short-term trading activities of typically one year or less in duration. These activities relate to electricity that is purchased and sold at the Ontario border, financial energy trades, financial risk management energy product revenues, and sales of energy-related products.

In addition, the segment includes the results of OPGET, which engages in U.S.-based wholesale energy trading activities in the U.S. northeast. The activities of OPGET include trading electricity in the U.S. using over-the-counter energy-related derivatives. OPGET retains Federal Energy Regulatory Commission market-based rate authorization.

The segment also includes revenue from real estate rentals and non-regulated services, gains or losses on disposition of non-regulated real estate assets, costs associated with non-regulated business development activities, and costs related to the Lambton GS and Nanticoke GS sites.

Fair Hydro Trust Segment

The Fair Hydro Trust segment is a non-generation segment that is not subject to rate regulation. It includes OPG's earnings from the Fair Hydro Trust, which includes the financial results of the Trust, as well as income related to OPG's role as Financial Services Manager of the Fair Hydro Trust and holder of subordinated debt issued by the Trust. Earnings include interest income from OPG's investment in subordinated debt of the Trust of up to 49 percent of the Trust's total outstanding debt, recovery of related to third-party costs and fees for financial management and ongoing administration services, partially offset by interest costs on debt issued by OPG to fund five percent of the subordinated investment in the Trust, incurred third-party costs, and other incurred costs related to the management and administration of the Trust.

Indigenous Relations

The Aboriginal and treaty rights of Indigenous communities are recognized and affirmed in the *Constitution Act, 1982*. OPG's corporate governance includes an Indigenous Relations policy to help build and develop mutually beneficial working relationships with Indigenous communities proximate to the Company's present and future operations. The policy focuses on building respectful relationships with Indigenous communities, businesses and organizations through partnership, collaboration, and support for procurement, employment and educational opportunities. The Company seeks to establish and maintain these relationships based on a foundation of respect for the languages, customs, and political, social and cultural organizations of the indigenous communities.

OPG may be subject to claims by Indigenous communities or other Indigenous groups and individuals. These claims may stem from generation development activities, historic operations of Hydro Electric Power Commission of Ontario and Ontario Hydro that may have impacted Aboriginal and treaty rights, or the absence of legal permits, rights-of-way, or easements. Legal precedents created by court rulings may impact negotiations and resolution of past grievances. To date, OPG has resolved 23 past grievance claims with 21 communities, achieving final settlement agreements.

In line with the company's Indigenous Relations policy, OPG is pursuing prospective generation-related developments and other joint projects with Indigenous communities. OPG currently has four generation development partnerships with Indigenous communities. OPG's first such partnership became operational in early 2009 as part of the Obishikokaang Waasiganikewigamig/Lac Seul GS project. The signing of the "*Amisk-oo-Skow*" Agreement with the Moose Cree First Nation (MCFN) in early 2010 marked the second such partnership. In 2011, the Lower Mattagami Limited Partnership agreement was amended and restated to include the MCFN and their wholly owned Amisk-oo-Skow Finance Corporation as limited partners and to enable the MCFN to acquire up to 25 percent limited partnership interest in the Lower Mattagami River

project. During 2014, the MCFN acquired a 25 percent interest in the assets through its investment in the Lower Mattagami Limited Partnership as incremental units of the project were placed in-service.

OPG and CRP, a wholly owned corporation of the Taykwa Tagamou Nation, established Peter Sutherland Sr. GS Limited Partnership in January 2015. In March 2017, the Peter Sutherland Sr. GS was placed in-service and, in April 2017, the Taykwa Tagamou Nation, through CRP, increased their partnership interest in PSS to 33 percent under the partnership agreement.

Following selection by the IESO in March 2016, OPG and a subsidiary of the Six Nations of Grand River Development Corporation have partnered to develop a new 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands. The Nanticoke Solar Limited Partnership was formed in July 2015, and the Six Nations of Grand River Develop Coproration through its subsidiary acquired a 10 percent ownership interest in August 2015.

Other recent joint projects with Indigenous partners include two shoreline remediation projects completed in 2016. The Whitesand First Nation, working closely with OPG, completed a project to remediate nearly two kilometers of shoreline, while the Long Lake #58 First Nation undertook the management of a five-year shoreline remediation project. OPG also engaged the Mississaugas of New Credit regarding the sale of the Lakeview generating station site. OPG also has been engaging proactively with Indigenous communities regarding the Company's nuclear waste management operations, through regularly scheduled meetings and an ongoing dialogue in connection with OPG's proposed L&ILW DGR, the re-licensing of the PWMF and the WWMF, and the Pickering generating station's relicensing. Further engagement was conducted with First Nations in southwestern Ontario regarding the demolition of the Lambton and Nanticoke generating stations.

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OPG - correct

OPG is also committed to improving Indigenous access to procurement and employment opportunities, including increasing the profile of the nuclear generation industry in Indigenous communities. In 2017, OPG launched an Indigenous Business Engagement (IBE) Initiative. The purpose of this initiative is to increase access to procurement opportunities for Indigenous businesses interested in supplying materials and services to OPG. The IBE Initiative is based on a strategy that will identify opportunities in contracts, scopes of work and business plans for potential Indigenous business engagement; include criteria related to suppliers' ability to engage or partner with Indigenous people or businesses in assessing procurement proposals; and invest in relationships with Indigenous communities by increasing outreach efforts to enhance understanding of how to do business with OPG. OPG has been engaging with Indigenous businesses and communities as well as its suppliers to promote the IBE Initiative including the Mohawk Council of Akwesasne as well as the Williams Treaties First Nations, located proximate to the Pickering and Darlington nuclear generating stations.

OPG has been actively developing recruitment plans targeting Indigenous peoples. As part of this initiative, during the fourth quarter of 2017, OPG participated in several Indigenous-specific career fairs, hosted a Day in the Trades event for Indigenous students and job seekers as part of an open house at the Darlington Energy Centre, and approved additional plans aimed at increasing the number of Indigenous apprentices as part of the nuclear operations' recruitment program.

In November 2016, OPG was recognized for its ongoing commitment to engaging local Indigenous communities with the Canadian Electricity Association's (CEA) 2016 Sustainable Electricity award for Leadership in External Collaboration and Partnerships.

Workplace Safety and Public Safety

Workplace Health and Safety

In the area of workplace safety, OPG is committed to achieving excellent performance through continuous improvement and a strong safety culture, with the ultimate goal of zero injuries. OPG utilizes an integrated health and safety management system and a set of operational risk control procedures to ensure continued monitoring of health and safety performance and to support continuous learning and improvement in this area. Over the past five years, OPG has repeatedly stood in the top quartile of its comparator Canadian electrical utilities in various safety performance metrics.

Workplace safety performance is measured using two primary indicators at OPG, All Injury Rate (AIR) and Accident Severity Rate (ASR). OPG's AIR and ASR results for employee workplace safety were as follows for the year ended December 31:

	2017	2016	2015
AIR *(injuries per 200,000 hours worked)*	**0.48**	0.56	0.39
ASR *(days lost per 200,000 hours)*	**3.57**	2.59	0.50

In 2017, OPG's AIR improved from 2016 and was the third-best performance year in the history of the company. For those employee injuries that caused lost time from work, the total time lost from work in 2017 was greater than the previous year. OPG's analysis of the underlying safety events indicated that major contributors to the injuries and near misses included inadequate situational awareness and attention to detail, and suboptimal risk-based decisions, rather than missing or inadequate standards or programs. OPG continues to implement a number of initiatives to target the injury trends based on the analysis of the safety events, with a focus on the use of human performance tools including increased field supervisory oversight, situational awareness, communication, and procedural use and adherence.

In order to strengthen its safety performance, OPG continues to progress an organization-wide "iCare Enough to Act" initiative launched in 2016 and aimed at renewing employees' commitment to their own and each other's safety and well-being. Approaches to supervisory oversight, communication and safe work planning are being modified and updated to further strengthen safety as a foundational element of the Company's values-based culture.

Contractors are required to conduct work safely at OPG sites. In support of this requirement, OPG utilizes an independent contractor pre-qualification process, provides on-site safety support for many of its major projects, and works with contract partners to improve their health and safety programs to meet OPG's requirements. In the past nine years, OPG has consistently shown a better than average Construction Contractor AIR as compared to the Infrastructure Health and Safety Association Contractor AIR, a metric of construction contractor safety performance across Ontario. OPG has maintained this performance while engaging in the refurbishment of the Darlington GS, one of the largest infrastructure projects in Canada. The hours worked by contractors in 2017 were the largest in OPG's history, largely attributable to this project.

Since 2014, OPG has been operating under a single integrated health and safety management system and set of operational risk control procedures across the Company, providing consistent performance expectations for all employees. The control procedures are designed to ensure continued enterprise-wide monitoring of health and safety performance and to support continuous learning and improvement in these areas. Oversight and reporting by corporate and site safety functions is in place to provide senior management with regular information on the effectiveness of the safety management efforts, compliance with legal and corporate requirements, and safety performance trends. OPG's incident management system requires that all incidents, including near misses, be reported and investigated and that where beneficial, corrective action plans be developed and completed in order to prevent reoccurrences.

In 2014, OPG launched a Total Health initiative that aims to embed a health culture that supports employees and their families in their efforts to achieve an optimal level of health and functioning, through health education, health promotion, disease and injury prevention, and crisis intervention. In 2016, the Company launched the Mental Health First Aid training course for employees, an accredited training program facilitated by the Mental Health Commission of Canada. The training aims to increase awareness and empathy for mental illness, reduce stigma, support affected employees, and improve return to work outcomes. By the end of 2017, over 1600 "people leaders" had participated in this training.

Nuclear Radiation Safety

OPG manages a radiation protection program designed to minimize detrimental health effects to employees and members of the public. OPG follows developments in the field of radiation protection as documented by the International Commission on Radiological Protection (ICRP), the United Nations Scientific Committee on the Effects of Atomic Radiation, and the U.S. National Council on Radiation Protection and Measurements. Widely recognized as the main source of expert advice regarding protection from the harmful effects of ionizing radiation, the ICRP periodically issues recommendations concerning principles of radiation protection. These recommendations are usually adopted by most countries without significant modification and are incorporated into the applicable laws. The Canadian Radiation Protection Regulations are based on the recommendations of the ICRP, and OPG's nuclear facilities conform to these regulations. The CNSC is the federal agency that regulates radiation protection in Canada.

Radiation exposures to station personnel and the public are limited by station design and adherence to approved operating procedures. Over the years, OPG has been a leader in applying the principles of keeping radiation doses as low as reasonably achievable. OPG's internal operating limits for occupational exposure are set well below the regulatory limits to ensure that the regulatory limits are not exceeded. OPG's operating targets for radiological emissions are set at even more restrictive levels and typically represent small fractions of the regulatory limits.

To ensure continued public safety, radiation exposure to members of the public resulting from the operation of OPG's nuclear generating stations is estimated on an annual basis for individuals living or working near the stations. The annual dose to the public resulting from operations of each nuclear facility is expressed in microsieverts (μSv), an international unit of radiation dose measurement. For 2015, the annual public doses resulting from the Darlington GS operations and the Pickering GS operations were 0.5 μSv and 1.2 μSv, respectively, which is approximately 0.1 percent of the annual legal limit of 1,000 μSv. For 2016, the annual public doses resulting from the Darlington GS operations and the Pickering GS operations were 0.6 μSv and 1.5 μSv, respectively, which is less than 0.1 and 0.2 percent of the annual legal limit of 1,000 μSv, respectively. While the public doses from OPG's nuclear operations for the 2017 operating year will not be finalized until the second quarter of 2018, they are not expected to differ significantly from the 2016 levels.

As a condition of receiving operating licences for its nuclear facilities, OPG has developed comprehensive emergency plans that detail the Company's planned response to reactor accidents, as well as accidents involving the transportation of radioactive materials. These plans dictate how OPG will work with municipal, regional, provincial, and federal agencies to safeguard station personnel and members of the public in the unlikely event of a radiation emergency at one of OPG's facilities. Station staff are required to regularly participate in emergency exercises to maintain and continuously improve response capability for such events.

Dam Safety and Waterways Public Safety

OPG manages dam safety and other risks associated with the production of hydroelectric power through OPG's Safe Operations Policy and Dam Safety Program. The Safe Operations Policy directs that dams be designed, constructed, operated, and maintained in a manner that meets all regulatory requirements, or, in the absence of regulations, the safety guidelines published by the Canadian Dam Association or other industry best practices. OPG is one of the first dam owners in Canada to have developed and implemented a dam safety program and is considered an industry leader in many aspects of the program.

In addition to effectively managing the safety of dams against catastrophic failure, OPG has developed a number of technical standards and procedures concerning public safety around dams, and materials to educate the public and raise awareness of the hazards associated with the operation of the hydroelectric facilities. This includes the implementation of control measures in the form of signage, safety booms, buoys, fencing and audible alerts at the appropriate facilities. These measures are actively managed to maintain their effectiveness. OPG also strives to entrench a "Stay Clear – Stay Safe" message as part of its public education program, through strategically placed advertisements and engagement of other agencies, such as the MNRF, Ontario Provincial Police, Life Saving Society, Ontario Waterpower Association, and other stakeholders.

Since 2007, OPG has engaged an independent advisory panel consisting of internationally recognized experts to conduct an annual review of its Dam Safety Program. The Chair of the independent panel establishes areas of in-depth review and presents the observations to OPG's Board of Directors. The panel has consistently found that the risks associated with the dams owned and operated by OPG are being managed in alignment with industry best practices and guidelines. OPG remains committed to high standards of public safety on waterways around hydroelectric generating stations and dams, and continues to make investments in waterway and dam safety upgrades.

Additional details on the regulatory regime related to dams and waterways can be found in the section, *Description of the Business* under the heading, *Water Rights.*

Environment

Overview

OPG is committed to meeting compliance obligations, including any environmental commitments that it makes, with the objective of exceeding these compliance obligations where it makes business sense. OPG's Environmental Policy specifically commits the Company to:

- Establish an environmental management system (EMS) and maintain registration for this system to the ISO 14001 Environmental Management System standard;
- Work to prevent or mitigate adverse impacts on the environment with a long-term objective of continual improvement;
- Strive to be a leader in climate change mitigation; and
- Manage sites in a manner that strives to maintain, or enhance where it makes business sense, significant natural areas and associated species of concern.

The policy is implemented through OPG's EMS. Within the EMS, OPG sets environmental objectives and maintains planning, operational control, and monitoring programs to manage its negative and positive impacts on the environment. The most significant environmental aspects of OPG's operations include: chemical emissions to water, spills, fish impingement and entrainment, thermal effluent emissions, displacement of fossil fuels, enhancement and disruption of wildlife habitat, radiological emissions, radioactive waste generation, and water flow and level changes. The policy is reviewed annually as part of the EMS to ensure that it remains appropriate to the nature, scale and environmental impacts of OPG's activities.

OPG communicates its environmental performance to external and internal stakeholders through a range of engagement methods such as reports and correspondence to regulators, meetings, newsletters, open houses, consultations, news releases, advertising campaigns, social media, and participation in community events.

Details of OPG's environmental performance and initiatives to fulfill the Environmental Policy can be found in OPG's annual *Sustainability Report*, which is available on the Company's website at www.opg.com. ***Unless otherwise specifically stated, none of the information contained on, or connected to the Company's website nor any of the contents of the Sustainability Report are incorporated by reference herein.***

Environmental Compliance

OPG must comply with a large number of environmental requirements contained in statutes, regulations, by-laws, licences, permits and approvals. Failure to comply with applicable environmental laws may result in enforcement action, including the potential for orders or charges. OPG reports any incidents of non-compliance to the appropriate federal, provincial or municipal authorities as required, with corrective action plans developed and implemented accordingly.

Changes in environmental regulatory requirements may result in existing operations being in a state of non-compliance, a potential inability to comply, and potential costs and liabilities for OPG. To ensure compliance, such circumstances may require OPG to install control technologies, develop new processes, allowances or offsets, or place constraints on electricity production.

Protection of Fish

Electricity generating facilities located on waterways can impact fish in a number of ways. At nuclear and thermal stations, the intake of water for cooling purposes can result in fish being impinged on station equipment and fish larvae and eggs being entrained in the water as it passes through the station. The warmer water returned to the water body also has the potential to impact aquatic organisms and habitat near the station. At hydroelectric stations, the flow of water through the station turbines can result in fish entrainment and mortality, while physical barriers such as dams can prevent the migration of fish.

OPG utilizes measures such as fish ladders, trap and transport programs, stocking programs, barriers and deterring structures, water flow alterations, habitat protection and creation, and station effluent temperature limits to manage and mitigate impacts to fish. Potential regulatory changes being monitored and managed as risks by the Company include electricity production constraints and water flow management requirements to protect fish and fish habitat, and expanded fish passage requirements.

Biodiversity and Habitat Stewardship

The generation of electricity can have an impact on biodiversity, either directly through habitat loss and fragmentation or indirectly through emissions to the environment. OPG is committed to managing its sites in a manner that strives to maintain significant natural areas and associated species of concern. OPG also works with its community partners to support regional ecosystems and biodiversity through science-based habitat stewardship. OPG's regional biodiversity program strategically funds and promotes efforts to protect and restore biodiversity in areas of Ontario where genetic, species or ecosystem diversity have been most impacted, and substantive threats remain. In 2017, OPG continued efforts to protect and restore habitat, promote biodiversity education and awareness, and help the recovery of species at risk. In November 2017, OPG's biodiversity program was recognized by the CEA with the 2017 Sustainable Electricity award for Commitment to Continuous Performance Improvement.

Climate Change Mitigation and Air Quality

OPG's operational and growth strategies support reductions in GHG emissions and improved air quality. After safely ending coal-fired generation in the province, OPG has become Ontario's largest clean energy provider, producing and selling electricity that is 99 percent free of GHG and smog-causing emissions. The elimination of coal-fired electricity production at OPG's generating stations resulted in coal being reduced from one-quarter of Ontario's energy supply mix in 2003 to zero in 2014.

OPG monitors and reports GHG emissions from its facilities in accordance with the regulatory requirements set out by Environment and Climate Change Canada and the MOECC. In 2016, the Government of Ontario passed the *Climate Change Mitigation and Low-Carbon Economy Act, 2016* and the associated *Cap and Trade Program Regulation*. The legislation provides the foundation for regulating GHG emissions in Ontario and includes a cap and trade program, with the first compliance period being from January 1, 2017 to December 31, 2020. The cap and trade program is a market mechanism intended to give Ontarians an

incentive to reduce GHG emissions by putting a price on carbon. The program requirements are expected to result in increased fuel costs for some OPG-owned and co-owned generating facilities. Fuel costs for these stations are generally recovered from the electricity market. With OPG's low GHG emitting fleet, this is not expected to have a material adverse financial impact on the Company. OPG has established the necessary processes to comply with the cap and trade program requirements.

OPG is monitoring actions being taken by the Government of Ontario and the Government of Canada to reduce GHG emission levels and transition to a low-carbon economy. In support of efforts to mitigate climate change, the Company continues to evaluate and implement plans to increase the generation capacity of its hydroelectric generating fleet, where economical, and invest in other low-carbon technologies. OPG also has a strategy to help position the Company as a leader in transportation electrification in the province. The strategy aims to leverage the Company's clean, reliable and cost-effective electricity to power transportation, capitalize on future commercial growth opportunities, and enhance the Company's social licence. OPG is pursuing initiatives to increase the use of electric vehicles within its operations, and is assessing vehicle grid integration and hydrogen applications for the transportation sector. Ontario's climate change plan aims for electric and hydrogen passenger vehicles to represent five percent of new vehicle sales in the province by 2020.

As part of its commitment to help de-carbonize Ontario's transportation sector, OPG is a founding sponsor of Plug'n Drive, a non-profit organization working to accelerate the adoption of electric vehicles and to maximize their environmental and economic benefits. In May 2017, Plug'n Drive announced the opening of the world's first experiential learning facility dedicated to electric vehicle education and awareness, with OPG sponsoring the Centre's training facility.

Radiological Emissions

Very low levels of radioactivity are released to air and water as a result of operating the reactors at OPG's nuclear generating stations. OPG maintains an effluent monitoring and control program to ensure radiological emissions are kept well below the release limits specified in the station operating licences. OPG also has environmental monitoring programs in the vicinity of the nuclear stations to ensure operations have no adverse impacts on human health and the environment. These programs are designed to assess impacts, demonstrate compliance with regulatory limits, validate the effectiveness of containment and effluent controls, and verify predictions made by environmental risk assessments. Results from the monitoring programs have confirmed OPG's radiological emissions are a small fraction of the regulatory release limits.

In June 2016 and August 2016, the CNSC released sampling results from its independent environmental monitoring program, which confirmed that the public and the environment around OPG's nuclear generating stations continued to be safe.

Further details are discussed under the heading, *Workplace Safety and Public Safety – Nuclear Radiation Safety.*

People and Culture

Workforce Resourcing Strategies

Electricity generation involves complex technologies that require highly skilled and trained workers, and a well trained and engaged workforce is fundamental to the achievement of OPG's strategic imperatives. The Company is focused on improving the capability of its workforce through leadership development, knowledge management, diversity and inclusion programs, and hiring in key areas. Ability to secure the right talent mix in order to effectively meet the Company's immediate and longer term business needs on a timely basis is supported through workforce planning, resourcing and on-boarding strategies, both to acquire external talent into the organization and to develop existing employees. The goal of resourcing strategies and workforce planning is to ensure that the Company's workforce is diverse and has the right skill set and capability for the safe and effective operation of the generating facilities and successful delivery

of major projects, including the Darlington Refurbishment. These strategies are being designed to take into account anticipated staffing requirements to the end of planned commercial operations of the Pickering GS, through to the end of the planned period to de-fuel, de-water and place the station in a safe state condition.

As part of the strategy to develop and engage employees and to build leadership talent in support of the Company's long-term success, OPG has an active succession planning program with a focus on accelerating development. This includes a company-wide high potential leadership development program for qualified internal candidates. This 14-month cross-functional, competitive-entry program is designed to identify and develop candidates for future leadership positions while they are relatively early in their careers. OPG also has a talent management monitoring process to proactively assess staffing risks, challenges and opportunities.

Many positions at OPG have significant educational prerequisites and rigorous requirements for continuous training and periodic requalification. In addition to maintaining its internal training infrastructure, OPG relies on partnerships with government agencies, other electrical industry partners, and educational institutions to meet the required level of qualification.

Effective January 1, 2017, OPG implemented an Executive Compensation Program that is compliant with *Ontario Regulation 304/16: Executive Compensation Framework*, introduced in September 2016. While the Province released two subsequent amendments, *Ontario Regulation 187/17* and *Ontario Regulation 400/17* in June 2017 and November 2017, respectively, OPG's Executive Compensation Program continues to be subject to the original regulation's requirements. The regulation sets out how all employers designated under the *Broader Public Sector Executive Compensation Act, 2014*, including OPG, must establish and post compensation programs for executives. The program must include the compensation philosophy, salary and performance-related pay caps, comparative analysis details, and a description of other elements of compensation. OPG's Executive Compensation Program is designed to provide compensation that is at the 50th percentile of the market and focused on at-risk, performance based pay. The program will better enable OPG to attract, align and retain the executive talent critical to delivering Shareholder and customer value, while ensuring continued safe and reliable operations. For further information, refer to the section, *Corporate Governance* under the heading, *Compensation.*

Employees

OPG's average number of full-time employees and average number of seasonal, casual construction and non-regular staff (Other Staff) in 2017 were as follows:

Business Segment	**Full-time Employees**	**Other Staff**
Regulated – Nuclear Generation [1]	7,360	1,432
Regulated – Hydroelectric	1,125	54
Contracted Generation Portfolio	531	49
Services, Trading, and Other Non-Generation [2]	96	7
Total	**9,111**	**1,541**

[1] Including employees associated with the Regulated – Nuclear Waste Management segment.
[2] The Fair Hydro Trust, a non-generation segment that is not subject to rate regulation, was established in December 2017. As of December 31, 2017 there were 3 full-time employees in the Fair Hydro Trust segment.

The majority of OPG's employees are represented by the PWU and The Society. The PWU includes most workers below the level of first line manager – from clerical staff to technicians and trades staff and station operators. The Society includes supervisors, professional engineers, scientists, and other professionals. Bargaining rights with the 19 craft unions that perform construction work at OPG's generating facilities in addition to the regular workforce are established either through the EPSCA or directly with OPG. EPSCA is a voluntary association of owners and contractors who perform work in the electrical power systems sector. The primary purpose of EPSCA is negotiating and administering collective agreements on behalf of employers performing work on what is now OPG property. Collective agreements between the Company and its construction unions are negotiated either directly or through EPSCA. OPG currently has 17

agreements through EPSCA and two direct trade agreements. The two direct trade agreements are with the Canadian Union of Skilled Workers and the Brick and Allied Craft Union.

Insurance

The principal types of discretionary insurance carried by OPG include directors' and officers' liability, excess commercial general liability, all risks property, boiler and machinery breakdown, including statutory boiler and pressure vessel inspections, and business interruption. In addition to providing coverage for OPG's non-nuclear facilities, this insurance applies to the conventional operations at OPG's nuclear generating stations. OPG also maintains nuclear property insurance, including nuclear boiler and machinery breakdown, for damage to the nuclear portions of its generating stations and for perils propagating from the nuclear to the conventional side of its assets. This coverage complements the conventional property insurance program.

OPG also purchases or requires contractors to purchase discretionary insurance for construction projects. For the Darlington Refurbishment project, the insurance coverage for the pre-requisite construction works was placed in 2013 and for refurbishment execution in 2016. The owner-controlled insurance program for the refurbishment consists of wrap-up liability, course of construction and marine transit insurance.

OPG purchases certain insurance coverage as required by statute, namely owned and leased motor vehicle liability, aviation liability (for drone operations) and nuclear energy liability insurance. The federal *Nuclear Liability and Compensation Act* (NLCA) that came into effect on January 1, 2017, and its predecessor legislation, the *Nuclear Liability Act* (NLA), impose absolute liability on a licensed operator of a nuclear generating station for any damage to property of, or injury to, the public arising from a nuclear incident, other than damage resulting from sabotage or acts of war. As such, the legislation protects all other persons from liability, including suppliers of nuclear fuel and components used in nuclear reactors.

The NLCA requires all operators of nuclear generating stations in Canada to maintain specified amounts of nuclear liability insurance purchased from a federal government approved insurer or other equivalent forms of financial security approved by the federal government. Under the NLCA, OPG is required to maintain an initial $650 million per incident of nuclear energy liability insurance for each of its nuclear installations as defined by the NLCA effective in 2017, for which there is no deductible amount, with successive annual increases to $750 million, $850 million, and $1 billion over the 2018-2020 period. The Pickering GS site and the Darlington GS site are considered to be two separate nuclear installations under the NLCA. OPG is also required to maintain $13 million per incident of nuclear energy liability insurance for the WWMF. OPG is not responsible for purchasing nuclear liability insurance for the Bruce nuclear generating stations. Previously, the NLA required OPG to maintain $75 million per incident of nuclear energy liability insurance for each of the Pickering GS site and the Darlington GS site and $6 million for the WWMF, purchased from a federal government approved insurer. OPG continues to maintain nuclear liability insurance or other forms of financial security that have been approved by the federal government equal to the required liability limits.

Under Part I of the NLCA, an operator is liable for all damages resulting from a nuclear incident. If, in the opinion of the Governor in Council, OPG's liability could exceed the specified insured amount in respect of a nuclear incident, or it would be in the public interest to do so, the Governor in Council shall proclaim Part II of the NLCA as applicable in respect of a nuclear incident. Under Part II of the NLCA, OPG's liability would be effectively limited to the amount of required abovementioned insurance, and the Governor in Council may authorize additional funds to be paid by the federal government as may be specified in an order.

RISK FACTORS

For details on risks faced by OPG, see *Risk Management* in the Company's 2017 year-end MD&A.

DIVIDENDS

The declaration and payment of dividends remains at the sole discretion of OPG's Board of Directors and is dependent on the results of OPG's operations, the Company's financial condition and cash requirements, securities legislation requirements, and other factors considered relevant by the Board of Directors in exercising its discretion and judgment on an ongoing basis. OPG did not declare or pay any dividends for the years 2015 to 2017.

There are no restrictions in the articles of the Company that could prevent the Company from paying dividends. However, the declaration and payment of dividends are subject to financial tests set forth in the OBCA.

DESCRIPTION OF CAPITAL STRUCTURE

The authorized share capital of OPG consists of an unlimited number of common shares (the voting shares of the Company) and Class A shares. As at December 31, 2017, OPG had 256,300,010 common shares issued and outstanding, all of which are owned directly by the Province at a stated value of $5,126 million. As at December 31, 2017, OPG had 12,217,616 Class A shares issued and outstanding, all of which are owned directly by the Province at a stated value of approximately $519 million. OPG is authorized to issue an unlimited number of common shares and Class A shares without nominal or par value. Holders of common shares are entitled to one vote per share at meetings of the shareholders of the Company and, along with Class A shares, to receive dividends if, as, and when declared by the Board of Directors of the Company. Holders of common shares and Class A shares would participate, pro rata to their holding of common shares, and Class A share, in any distribution of the assets of the Company upon its liquidation, dissolution, or winding up. Any issuance of new shares is subject to the consent of all of OPG's shareholders.

All of the Company's voting securities are held by the Province. Accordingly, the Company is controlled by the Province.

CREDIT RATINGS

DBRS Limited (DBRS) and S&P Global Ratings (S&P) provide credit ratings for commercial entities. A credit rating generally provides investors with an independent measure of credit quality of an issue of securities. Credit rating categories for long-term debt instruments range from highest credit quality (generally 'AAA') to default in payment (generally 'D').

In April 2017, DBRS re-affirmed the long-term credit rating on OPG's debt at 'A (low)' and the commercial paper rating at 'R-1 (low)', each with a stable outlook. In July 2017, S&P re-affirmed OPG's long-term credit rating at BBB+ with a stable outlook. On July 7, 2015, S&P lowered OPG's long-term corporate credit rating from 'A-' to 'BBB+' with a stable outlook. S&P's rating action followed its July 6, 2015 downgrade to the Province's rating from 'AA-' to 'A+'. The link between the Province and OPG through ownership and financial support may impact OPG's credit rating. S&P's commercial paper rating for OPG is 'A-1 (low)'.

Long-term debt instruments that are rated in the 'A' category by DBRS are considered to be of good credit quality. The capacity for the payment of financial obligations by the obligor of such instruments is considered to be substantial, but of lesser credit quality than higher-rated entities. Entities in the 'A' category may be vulnerable to future events, but qualifying negative factors are considered manageable. The addition of a "high" or "low" modifier indicates relative standing within the rating category.

A 'BBB' rating category by S&P for long-term debt instruments means that the obligor has adequate capacity to meet its financial commitments, but is considered more subject to adverse economic conditions than higher-rated entities. The addition of a plus '+' or minus '-' designation after a rating indicates the relative standing within a particular rating category.

DBRS's commercial paper credit rating scale ranges from 'R-1(high)' to 'D', which represents the highest to lowest quality of such securities rated. The rating of 'R-1(low)' is the third highest and is considered to be of good credit quality. S&P's Canadian commercial paper rating scale ranges from 'A-1 (high)' to 'D', which represents the highest to lowest quality of such securities rated. The rating of 'A-1 (low)' is the third highest and is considered to be satisfactory.
There can be no assurance that a credit rating will remain in effect for any given period of time or that a credit rating will not be lowered, withdrawn or revised by either or both rating agencies if, in their judgment, circumstances so warrant. The rating of any securities is not a recommendation to buy, sell or hold such securities, and such ratings do not comment as to market price or suitability for a particular investor.

During the past two years, OPG has made payments to DBRS and S&P's credit rating agencies for their credit rating services and for other services. OPG reasonably expects such payments will continue in the future for the services acquired.

MARKET FOR SECURITIES

In October 2017, OPG issued Series 1 Notes with a coupon rate of 3.315 percent for a principal amount of $500 million are currently outstanding and are not listed on any exchange or similar market for securities. The Notes are due in 2027.

CORPORATE GOVERNANCE

National Instrument 58-101 *Disclosure of Corporate Governance Practices* (NI 58-101), has been implemented by Canadian securities regulatory authorities to provide greater transparency for the marketplace regarding issuers' corporate governance practices. OPG's corporate governance practices align with NI 58-101 and National Policy 58-201 *Corporate Governance Guidelines.* In addition, OPG has reviewed its governance practices against the principles discussed in the 2013 Report on Building High Performance Boards issued by the Canadian Coalition for Good Governance and concluded that OPG compares favourably to those principles that apply to OPG.

Information with respect to OPG's Board of Directors is as follows:

Board of Directors

OPG's Board of Directors (Board) is made up of 14 individuals with the following capabilities:

- managing large businesses;
- managing and operating nuclear stations;
- understanding of the Canadian nuclear environment;
- engineering and/or project management, including large infrastructure project management;
- managing capital intensive companies;
- knowledge and expertise in mergers and acquisitions;
- overseeing regulatory, government and public relations;
- human resources management;
- financial, investment, legal and corporate governance expertise;
- knowledge of information technology/cybersecurity;
- knowledge of Indigenous communities; and
- stakeholder management.

The Board exercises its independent supervision over management as follows: the majority of members of the Board are independent of the Company; meetings of the Board are held at least five times a year; a formal Charter for the Board and for each Board committee has been adopted and the charters are reviewed annually; the Board and each Board committee is chaired by an independent Director; and a portion of each Board and Board committee meeting is reserved for independent Directors to meet without management present.

OPG has a written position description for the Chief Executive Officer (CEO). This position is accountable to the Board for: ensuring a culture of integrity and ethical conduct; increasing Shareholder value; defining and executing a corporate strategy, including a sustainable business model that will service the long-term power generation needs of the province; and providing a standard of leadership that will achieve operational excellence with respect to matters of safety, stakeholder relationships, financial performance, asset reliability, and health, environmental and regulatory compliance. In addition, the Board delineates the President and CEO role and responsibilities through the By-laws, the Board Charter, the Board policies, and the corporate and CEO annual goals and objectives. The Board sets, and monitors performance against, annual corporate and CEO targets and objectives.

Director Independence

On an annual basis, the Compensation, Leadership and Governance Committee of the Board reviews the disclosures made by Directors in the annual Director Questionnaire and reviews each disclosed affiliation's relationship with OPG in order to determine whether the Director is (or remains) independent. The Compensation, Leadership and Governance Committee reports on its review to the Board.

Based on the meaning of Independence in Section 1.4 of National Instrument 52-110 *Audit Committees* (NI 52-110) and a review of the applicable factual circumstances against this standard, the Compensation, Leadership and Governance Committee has determined that all Directors listed are independent, except for Jeffrey Lyash, who is considered to have a material relationship with OPG by virtue of his position as President and CEO of OPG.

The Board has a Board of Directors Conflict of Interest Policy and Procedure that governs the disclosure and mitigation of Director conflicts or potential conflicts of interest and has adopted an annual process of written disclosure by Directors in order to:

(i) identify potential conflicts of interest for the purposes of complying with the Board of Directors Conflict of Interest Policy and the OBCA;
(ii) validate the Directors' independence and financial literacy for the purposes of complying with securities regulations related to boards of directors and audit committees; and
(iii) satisfy other disclosures and regulatory filings.

To further minimize potential conflicts of interest, the Board has a policy on interlocking directorships. This policy states that no more than two OPG Directors may sit on a board of directors of another reporting issuer at the same time. Directors must confirm that they are in compliance with OPG's policy on interlocking directorships when disclosing to the Board Chair appointments to other boards of directors.

Strategic Planning

OPG's Board holds an annual strategy session and devotes a significant portion of each regular Board meeting to discussion of strategic matters. Management is responsible for developing the strategy and presenting it to the Board for discussion.

In 2017, the Board received reports on key strategic issues, risks, competitive developments, and corporate opportunities facing the Company. Management ensures that the key strategic elements are incorporated into OPG's annual budget and business plan, which are reviewed and approved by the Board. The Board also periodically receives briefings from external advisors on broad energy industry developments and/or special strategic matters.

Overseeing the Management of Risk

The Board oversees OPG's approach of identifying, reporting and mitigating the risks that could significantly impact the Company's capacity to achieve its long-term strategic objectives, as well as specific business plan objectives. To fulfill its risk oversight responsibilities, the Board has established an Enterprise Risk Management Policy and an Audit and Risk Committee, comprised of independent Directors. The

committee's mandate includes oversight of the Enterprise Risk Management (ERM) framework that management uses to manage the Company's risk profile. The ERM framework assists the Board in understanding how risks may affect the Company and how they are being addressed by management. The Audit and Risk Committee receives quarterly reports from OPG's Chief Risk and Audit Executive (CRAE) on enterprise-wide risks.

Through the Compensation, Leadership and Governance Committee, the Board also monitors the risks associated with the executive compensation program, to preclude the Company's decision-makers from taking excessive risk in order to achieve incentives under the compensation plans. The CRAE and Senior Vice President, People & Culture and Chief Ethics Officer jointly review the executive compensation framework on an annual basis to identify any potential for unintended risk-taking. The CRAE and Senior Vice President, People & Culture and Chief Ethics Officer provide an annual joint report to the Compensation, Leadership and Governance Committee on the results of their review.

Directors

The following tables set forth the name, age, municipality of residence, position with the Company and principal occupation of each of the Directors of the Company as of March 8, 2018. Each Director holds office until he or she resigns or a successor is elected or appointed. For a discussion of the Board Committee structure, refer to the heading, *Committees of the Board of Directors*.

Bernard Lord
Age: 52
Moncton, New Brunswick, Canada

Bernard Lord was appointed Board Chair for Ontario Power Generation on April 1, 2014. Mr. Lord is the CEO of Médavie, a not-for-profit Canadian medical care insurance company headquartered in Moncton, New Brunswick.

Mr. Lord earned a bachelor's degree with a major in economics as well as a bachelor's degree in common law from l'Université de Moncton. He has also received honorary doctorate degrees from University of New Brunswick, l'Université de Moncton and Saint Thomas University. He was admitted to the New Brunswick Law Society in 1993 and was appointed as Queen's Counsel in 2011.

Mr. Lord was the CEO of the Canadian Wireless and Telecommunications Association from October 2008 until August 2016. He also served on several other boards of directors.

In 1999, Mr. Lord became one of Canada's youngest Premiers at the age of 33. His majority government was re-elected in 2003 and he served as Premier of New Brunswick until October 2006. He was elected four times as a Member of the New Brunswick Legislative Assembly.

Mr. Lord's government introduced several new initiatives to support the development of natural resources while also protecting the environment, including a new energy policy that lead to the restructuring of NB Power and the refurbishment of the Point Lepreau nuclear generating station.

During Mr. Lord's terms as Premier, New Brunswick saw the lowest unemployment rate in 30 years and tax cuts each year, combined with balanced budgets and debt reduction. His government made record investments in health care and education while strengthening local democracy and modernizing the Official Languages Act.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since November 2013) *****	8 of 8	100%
Special Committee (since March 2017)	14 of 15	93%
The Board Chair is not a member of any standing Committee. The Board Chair attends all Committee meetings.	18 of 18	100%

Principal Occupation: CEO of Médavie

Board Memberships for other Reporting Issuers: None

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

*Chair

Jeffrey Lyash
Age: 56
Toronto, Ontario, Canada

Jeff Lyash is the President and CEO of OPG. Mr. Lyash was formerly the president of CB&I Power, a position he held from 2013 to 2015, where he was responsible for a full range of engineering, procurement and construction of multi-billion dollar electrical generation projects in both domestic and international markets. He also provided operating plant services for nuclear, coal, gas, oil and renewable generation.

Prior to joining CB&I in 2013, Mr. Lyash served as Executive Vice President of Energy Supply for Duke/Progress Energy from 2008 to 2012. With Duke Energy, he led engineering, maintenance and operations of the company's 42,000-megawatt generation fleet, fuel procurement, power trading, major projects and construction, environmental programs, and health and safety programs.

Before the merger of Progress Energy and Duke Energy, Mr. Lyash served as Executive Vice President of Energy Supply for Progress Energy. In this role, he oversaw Progress Energy's diverse 22,000-megawatt fleet of generating resources including nuclear, coal, oil, natural gas and hydroelectric stations. In addition, he was responsible for generating fleet fuel procurement and power trading operations.

Mr. Lyash began his career in the utility industry in 1981, joining Progress Energy in 1993. Before assuming the role of Executive Vice President of Energy Supply, he served as Executive Vice President of Corporate Development, President and Chief Executive Officer of Progress Energy Florida, Senior Vice President of Energy Delivery Florida, and Vice President of Transmission. He also held a wide range of management and executive roles in Progress Energy's nuclear program, including Operations Manager, Engineering Manager, Plant Manager, and Director of Site Operations.

Before joining Progress Energy, Mr. Lyash worked for the U.S. Nuclear Regulatory Commission (NRC) in a number of senior technical and management positions throughout the northeast United States and in Washington, D.C, receiving the NRC Meritorious Service Award in 1987.

Mr. Lyash earned a Bachelor's Degree in Mechanical Engineering from Drexel University, and was honored with the Drexel University Distinguished Alumnus Award in 2009. He has held a Senior Reactor Operator License from the NRC, and is a graduate of the U.S. Office of Personnel Management Executive Training Program and the Duke Fuqua School of Business Advanced Management Program.

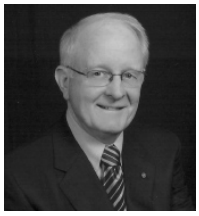
2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since August 2015)	8 of 8	100%
The President and CEO attends all Committee meetings, excluding independent Director in-camera meetings/sessions.	18 of 18	100%

Principal Occupation: President & Chief Executive Officer, Ontario Power Generation Inc.

Board Memberships for other Reporting Issuers: None

Independence from OPG: Not Independent

Interlocking Directorships on Boards of other Reporting Issuers: None



William Coley
Age: 74
Charlotte, North Carolina, U.S.A

Bill Coley served as Chief Executive of British Energy from 2005 to 2009 when he retired following the successful combination of British Energy and EDF Energy. He was President of Duke Power from 1997 until his retirement in February 2003, holding various officer level positions in engineering, operations and senior management during his 37-year career with the company.

Mr. Coley is a director of E.R. Jahna Industries. He also served on the WANO Fukushima Commission

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since January 2013)	8 of 8	100%
Compensation, Leadership and Governance Committee (since February 2016)	5 of 5	100%
Generation Oversight Committee (since February 2016)	4 of 4	100%
Darlington Refurbishment Committee (since May 2015)	4 of 4	100%
Special Committee (since March 2017)	15 of 15	100%

Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: None

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

Elisabeth (Lisa) DeMarco
Age: 50
Toronto, Ontario Canada

Lisa DeMarco is a senior partner at DeMarco Allan LLP with over two decades of experience in law, regulation, policy, and advocacy relating to energy and climate change. Ms. DeMarco was previously a partner at Macleod Dixon LLP from 2002 to 2012, partner at Norton Rose Canada LLP from 2012 to 2013 and partner at Norton Rose Fulbright LLP from 2013 to 2014. She represents several governments and leading energy companies in a wide variety of natural gas, electricity, pipeline and energy storage matters before various regulatory agencies, including the OEB and the National Energy Board. She has been an adjunct professor at Osgoode Hall Law School, is a guest lecturer at a number of law schools and presents regularly.

Ms. DeMarco also assists leading Canadian energy companies and Indigenous business organizations on domestic and overseas power project development, renewable power projects, alternative fuel projects, cleantech development and finance, energy storage, carbon capture and storage, corporate social responsibility, environmental disclosure, clean energy finance, and sustainable business strategy.

She is ranked by Chambers Global as one of the world's leading climate change lawyers and regularly attends and advises on related United Nations negotiations. She is ranked and repeatedly recommended by LEXpert, Expert Guide, International Who's Who, and Chambers Canada as a leading energy (oil, gas, and electricity) and environment lawyer. Ms. DeMarco has worked for multilateral development banks and energy companies on deals and projects in India, Brazil, Sri Lanka, Thailand, Argentina, Chile, Ireland, Africa, Mexico, China, Russia, California, Alberta, Ontario, Nova Scotia, British Columbia, Saskatchewan, Prince Edward Island and Québec. She plays an ongoing and active role in the development and drafting of energy and greenhouse gas emissions policy, regulation, and law throughout Canada, and in various countries around the world. She was also lead counsel on all aspects of the successful sale of an Ontario power distribution company to Hydro One. Lisa was an appointed member of Ontario Premier's Clean Energy Task Force and Climate Action Group.

Ms. DeMarco is a member of theBoard of Directors of the Advanced Energy Centre at MaRS, and Ontario Power Generation. She is a graduate of the University of Western Ontario (BSc Hon. – 1990), the University of Toronto (MSc. – 1992), Osgoode Hall Law School, York University (LLB – 1995) and the Vermont Law School (MSEL, summa cum laude – 1995) and is called to the bar in England and Ontario.

2017 Board/Committee Membership:	**2017 Attendance**	
Board (since April 2014)	8 of 8	100%
Audit and Risk Committee (since February 2016)	5 of 5	100%
Generation Oversight Committee (since February 2016)	4 of 4	100%
Special Committee (since March 2017)	15 of 15	100%

Principal Occupation: Senior Partner, DeMarco Allan LLP

Board Memberships for other Reporting Issuers: None

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

Jean Paul (JP) Gladu
Age: 44
Toronto, Ontario, Canada

JP Gladu is currently the President and CEO of the Canadian Council for Aboriginal Business (CCAB) based in Toronto. Anishinaabe from Thunder Bay, Mr. Gladu is a member of Bingwi Neyaashi Anishinaabek located on the eastern shores of Lake Nipigon. Mr. Gladu has over two decades of experience in the natural resource sector including work with Aboriginal communities and organizations, environmental non-government organizations, industry and governments from across Canada, including involvement in business development for the Bingwi Neyaashi Anishinaabek Nation from 2009 to 2012. He has produced a number of publications related to Aboriginal issues including: forest certification, Native values collection, biofuel opportunities, First Nation community land use plans, criteria and indicators for sustainable forestry, and cedar product development.

Mr. Gladu holds a Forest Technician Diploma from the Sault College of Applied Arts and Technology, a Bachelor of Science degree in forestry from Northern Arizona University, and an Executive Masters of Business Administration from Queens University in Kingston. In 2014, he was a recipient of the Community Service Award – Transformation Awards from Diversity Magazine. Mr. Gladu was nominated for the 2013 Premier's Award for Outstanding Ontario College Graduates, was recognized as one of five Northern Leaders in 2012 by Northern Ontario Business and was elected Class President of the 2012 Queens Executive Masters of Business Administration.

Mr. Gladu currently serves on the Canadian Electricity Associations' Public Advisory Panel, Noront Resources and Chancellor of St, Paul's University Board of Governors. He has also held previous board positions with Colleges and Institutes Canada (previously the Association of Canadian Community Colleges), Northern Policy Institute, Canadian Foundation for Economic Education boards of directors, Centre for Research and Innovation in the Bio-Economy, Papasay Management Corporation, and a board member of the Canadian Bioenergy Association. He also held advisory positions with the Canadian Association of Petroleum Producers Renewable Clean Energy Committee and the Ontario Provincial Forest Policy Committee.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since November 2015)	6 of 8	75%
Compensation, Leadership and Governance Committee (since February 2016)	5 of 5	100%
Generation Oversight Committee (since February 2016)	3 of 4	75%

Principal Occupation: President and CEO, Canadian Council for Aboriginal Business

Board Memberships for other Reporting Issuers: Noront Resources Ltd. *(TSX)*

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

John Herron
Age: 64
Punta Gorda, Florida, U.S.A.

John Herron retired from Entergy in April 2013 where he was the President, CEO and Chief Nuclear Officer of Entergy Nuclear, with responsibility for Entergy's nuclear plants located in New York, Massachusetts, Vermont, Michigan, Louisiana, Mississippi and Arkansas as well as the company's management service to the Cooper Nuclear Station for the state of Nebraska.

He previously served as Entergy's Senior Vice President for Nuclear Operations handling the operational side of fleet management. Mr. Herron joined Entergy in February 2001 as Vice President, Operations at the Waterford 3 Nuclear Station in Killona, Louisiana. He then moved to New York as the Senior Vice President of the Indian Point Energy Center in February 2002.

Mr. Herron began his career in nuclear operations in 1979 at Vermont Yankee Nuclear Power Corporation. His positions there included technical services superintendent, operations manager, technical programs manager, shift supervisor, and supervisory control room operator. In 1994, he moved to Brownville, Nebraska to become plant manager at Nebraska Public Power District's Cooper Nuclear Station.

Mr. Herron then joined the Tennessee Valley Authority as plant manager at Sequoyah Nuclear Plant in Soddy-Daisy, Tennessee, from October 1996 through July 1999. From July 1999 to February 2001, Mr. Herron served as site Vice President at TVA's Browns Ferry Nuclear Plant.

Prior to his career in utilities, Mr. Herron served in the U.S. Navy from 1972 to 1978. He was attached to the USS Tullibee and the S1C NPTU Windsor, where he was an instructor at the Nuclear Submarine Prototype School.

Mr. Herron holds a bachelor's degree in Business Management from Franklin Pierce College in Rindge, New Hampshire. He also attended the Advanced Management Program at the Harvard Business School in May 2005.

Mr. Herron currently serves on the board of directors for Duke Energy. He also served on the board of directors for the Institute of Nuclear Power Operations and on the Nuclear Strategic Issues Advisory Committee of the Nuclear Energy Institute. In the aftermath of Japan's 2011 earthquake, he was named to the WANO Post-Fukushima Commission and the U.S. nuclear industry's Fukushima response steering committee.

2017 Board/Committee Membership:	**2017 Attendance**	
Board (since November 2013)	8 of 8	100%
Generation Oversight Committee* (since February 2016)	4 of 4	100%
Darlington Refurbishment Committee (since May 2015)	4 of 4	100%

Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: Duke Energy (NYSE)

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

* Chair of Committee

Ani Hotoyan-Joly
Age: 56
Markham, Ontario, Canada

Ani Hotoyan-Joly is currently Chief Financial Officer and Corporate Secretary of Coventree Inc. Prior to Coventree, she was V.P. Finance and Chief Financial Officer at Swiss Reinsurance Company Canada (P&C) and prior to that held senior positions at Zurich Canada. Ms. Hotoyan-Joly is a member of the Board of Directors of Women's College Hospital and is a member of the Executive Committee and Chair of the Governance and Nominations Committee. She is currently a member of the Executive Board of Armenian Relief Society's Roubina (Toronto) Chapter and was the Past Chair of A.R.S. Armenian Private School's Board of Trustees.

Ms. Hotoyan-Joly is a Chartered Professional Accountant and Chartered Accountant and holds a Bachelor of Commerce degree from the University of Toronto and the ICD.D designation from the Institute of Corporate Directors. She was elected as a 2016 Diversity 50 Candidate by the Canadian Board Diversity Council.

2017 Board/Committee Membership:	**2017 Attendance**	
Board (since March 2017)	6 of 6	100%
Audit and Risk Committee (since March 2017)	4 of 4	100%
Compensation, Leadership and Governance Committee (since March 2017)	4 of 4	100%

Principal Occupation: Chief Financial Officer and Corporate Secretary, Coventree Inc.

Board Memberships for other Reporting Issuers: None

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

Wendy Kei
Age: 50
Toronto, Ontario, Canada

Ms. Wendy Kei currently serves on the Board of Guyana Goldfields, Inc., as the Chair of the Audit Committee, a member of the Human Resources & Compensation Committee and a member of the Corporate Governance & Nominating Committee. She is an accomplished Finance Executive with over 25 years of business experience in a variety of industries. For the past 14 years, Ms. Kei has been working within the mining industry and brings a strong focus on corporate governance, financial and risk management and a strong expertise in executing complex mergers and acquisitions.

Ms. Kei is a Chartered Professional Accountant and Chartered Accountant and previously served as Chief Financial Officer of Dominion Diamond Corporation (formerly Harry Winston Diamond Corporation and Aber Diamond Corporation).

Ms. Kei is a member of the Chartered Professional Accountants of Ontario, and holds a Bachelor of Mathematics from the University of Waterloo. Ms. Kei was selected as a Diversity 50 2016 Candidate by the Canadian Board Diversity Council.

2017 Board/Committee Membership:	**2017 Attendance**	
Board (since March 2017)	6 of 6	100%
Audit and Risk Committee (since March 2017)	4 of 4	100%
Generation Oversight Committee (since March 2017)	3 of 3	100%

Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: Guyana Goldfields Inc. *(TSX)*

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

M. George Lewis
Age: 57
Toronto, Ontario, Canada

From February 2007 until November 2015, George Lewis was a member of RBC's Group Executive, one of eight executives responsible for setting the overall strategic direction for Royal Bank of Canada, Canada's largest bank. In that capacity, he served as Group Head of RBC Wealth Management from 2007 and RBC Insurance from 2012. As Group Head, Wealth Management, Mr. Lewis led the RBC businesses that serve the wealth management needs of affluent clients globally, and units that provide asset management and trust products. He was also Chairman of RBC Global Asset Management Inc.

From July 2000 to May 2008, Mr. Lewis was Chief Executive Officer of RBC Global Asset Management, which under his leadership became Canada's largest single mutual-fund family (RBC Funds) and one of Canada's largest asset management firms. He previously served as Head of Wealth Management for the Canadian Personal and Business segment and, from 2003 to 2006, was Head of all banking and investment products for RBC's Canadian Business.

From 1998 to 2000, Mr. Lewis was Managing Director, Head of Institutional Equity with RBC Capital Markets, responsible for global institutional-equity sales, trading and research. He was previously a top-rated equity analyst and Director of Research. He began his career with RBC in 1986, in the investment banking division of RBC Capital Markets.

Mr. Lewis has extensive experience in the investment industry, has a Masters of Business Administration degree with distinction from Harvard University and a Bachelor of Commerce degree with high distinction from Trinity College at the University of Toronto. He is also a Chartered Financial Analyst and an FCA/FCPA and has been certified by the Institute of Corporate Directors.

Mr. Lewis serves on the board of directors of Enbridge Income Fund Holdings Inc., the Canadian Film Centre and the Anglican Diocese of Toronto Foundation. He is a current member and past chair of the Bishop's Company of the Anglican Diocese of Toronto, as well as a patron and member of the Cabinet of the United Way of Toronto and York Region. Mr. Lewis also serves as the Honorary Colonel Commandant of the Royal Canadian Chaplain Service of the Canadian Armed Forces.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since February 2005)	8 of 8	100%
Audit and Risk Committee* (since February 2016)	5 of 5	100%
Compensation, Leadership and Governance Committee (since February 2016)	5 of 5	100%
Special Committee* (since March 2017)	15 of 15	100%

Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: Enbridge Income Fund Holdings Inc. *(TSX)*

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

* Chair of Committee

Margaret (Peggy) Mulligan
Age: 59
Cameron, Ontario, Canada

Peggy Mulligan was the Executive Vice President and Chief Financial Officer, Valeant Pharmaceuticals International, Inc. until December 2010. Prior to this, she was a Principal at Priiva Consulting, and before that she served as Executive Vice President and Chief Financial Officer of Linamar Corporation. Prior to Linamar, Mrs. Mulligan was with the Bank of Nova Scotia for eleven years as Executive Vice President, Systems and Operations and Senior Vice President, Audit and Chief Inspector. Before joining Scotiabank, she was an Audit Partner with PricewaterhouseCoopers in Toronto. She holds a B. Math (Honours) from the University of Waterloo and was named a Fellow of the Institute of Chartered Professional Accountants of Ontario in 2003.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since December 2005)	7 of 8	88%
Compensation and Leadership and Governance Committee* (since February 2016)	5 of 5	100%
Darlington Refurbishment Committee (since May 2015)	4 of 4	100%
Special Committee (since March 2017)	14 of 15	93%

Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: Canadian Western Bank (*TSX),* ClearStream Energy Services Inc. *(TSX)* (*previously Tuckamore Capital*)

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

* Chair of Committee

Yezdi Pavri
Age: 68
North York, Ontario, Canada

Yezdi Pavri retired as Vice Chairman of Deloitte Canada in June 2012 after a career of more than 30 years. Prior to being named Vice Chairman, Mr. Pavri was a member of the firm's national Management Committee for over ten years and was the Managing Partner of the Toronto practice since June 2004. He founded Deloitte's national Enterprise Risk Services practice in 1990 and led it for 15 years. He was a founding member of the global firm's India Steering Committee and co-chaired the firm's first Diversity and Inclusion Committee.

Mr. Pavri holds a Bachelor's degree in Aeronautical Engineering from the Indian Institute of Technology in Bombay and a Master's degree in Thermal Power Engineering from Imperial College in London. He is a Fellow of the Chartered Professional Accountants of Ontario.

Mr. Pavri currently serves on the boards of ICICI Bank of Canada, Enterra Holdings Limited (the global parent of Golder Associates) and MD Financial Services, and is a past member of the board of directors of Hydro One. Mr. Pavri is also the immediate past chairman of the board of trustees of United Way Toronto.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since September 2015)	8 of 8	100%
Audit and Risk Committee (February 2016)	5 of 5	100%
Compensation, Leadership and Governance Committee (since February 2016)	5 of 5	100%
Special Committee (since March 2017)	15 of 15	100%

Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: None

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

Gerry Phillips
Age: 77
Ajax, Ontario, Canada

Gerry Phillips was the Member of Provincial Parliament in the Legislative Assembly of Ontario for the east Toronto riding of Scarborough-Agincourt from 1987 to 2011. He served in six cabinet portfolios, including twice as Ontario Minister of Energy, where he was OPG's Shareholder from 2007 to 2008 and again on an interim basis from November 2009 to January 2010, as well as, Minister responsible for Securities Regulation in Ontario. He was also the Chair of the Management Board of Cabinet from 2008 to 2011 and the Chair of the Select Committee on the TMX Transaction in 2011.

Before entering public life, Mr. Phillips graduated from the University of Western Ontario's School of Business and worked in the marketing department of Procter and Gamble. In 1970, he joined the consulting firm of Canadian Marketing Associates and became President in 1977. He later founded two successful spin-off companies – the Sales Development Group in 1979 and the Retail Resource Group in 1982. By 1987, he was Chair of all three companies, with a combined workforce of approximately 300.

Mr. Phillips has an Honours B.A. from the Western School of Business.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since January 2013)	8 of 8	100%
Audit and Risk Committee (since February 2016)	5 of 5	100%
Darlington Refurbishment Committee (since May 2015)	4 of 4	100%

Principal Occupation: Retired

Board Memberships for other Reporting Issuers: None

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

Jim Reinsch
Age: 74
Frederick, Maryland, U.S.A.

Jim Reinsch retired from the Bechtel Group where he was Senior Vice President and Partner, and past President of Bechtel Nuclear. In this role, he was responsible for the global profit/loss, customer relations, operations, project management, marketing and business development of Bechtel's three nuclear business segments: nuclear operating plant services, steam generator replacement, and operations of Bechtel's global nuclear activities. During his 40 years with Bechtel, he also presided over Bechtel Canada, and managed large regions in the United States and Asia. He served as the President of the American Nuclear Society, and was a member of the Nuclear Energy Institute as well as a member of their Executive Committee. Mr. Reinsch is also a member of several international nuclear energy organizations, including the WANO and the World Nuclear Association.

Mr. Reinsch holds a Bachelor of Science degree from the University of Maryland.

Mr. Reinsch currently serves on the board of directors for Frederick Memorial Hospital and the Hood College Board of Trustees, and is a past board member of Duke Energy and the Smithsonian National Portrait Gallery. Additionally, he serves on the Emirate Nuclear Energy Corporation's committee on nuclear power which reports to the board of directors, and is a member of the international advisory board of Terrestrial Power.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since August 2015)	7 of 8	88%
Generation Oversight Committee (since February 2016)	4 of 4	100%
Darlington Refurbishment Committee* (since August 2015)	4 of 4	100%

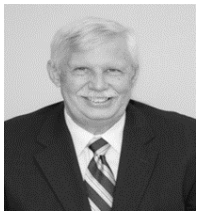
Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: None

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

*Chair of Committee



James Sheppard
Age: 69
Toronto, Ontario, Canada

Mr. Sheppard serves as an Independent Consultant. Mr. Sheppard served as Interim Senior Vice President for Southern California Edison Company and served as its Interim Chief Nuclear Officer from September 2010 to December 9, 2010. From 1993 to 2009, he held several senior positions associated with the South Texas Project nuclear power plant, including Chairman, President and Chief Executive Officer of STP Nuclear Operating Company, which operated the facility for its three owners. He served as Executive Officer of South Texas Project Electric Generating Station. He served as an executive at STP for ten years, he held the positions of Vice President and Assistant to the President and Chief Executive Officer; Vice President of Engineering and Technical Services; Vice President of Business Systems; Assistant to the executive vice president; and General Manager of Licensing. He has been an Independent Director at Xcel Energy Inc. since March 2011.

Mr. Sheppard holds a bachelor of science degree in aerospace engineering from the U.S. Naval Academy and a master's degree in business administration from the Duke University.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since March 2017)	6 of 6	100%
Darlington Refurbishment Committee (since March 2017)	3 of 3	100%
Generation Oversight Committee (since March 2017)	3 of 3	100%

Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: Xcel Energy Inc. *(NYSE)*

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

Nicole Boivin served as a Director from April 2014 to March 2017 and was a member of the Compensation, Leadership and Governance Committee and the Darlington Refurbishment Committee. Brendan Hawley was a Director from April 2014 to March 2017 and was a member of the Audit and Risk Committee and Darlington Refurbishment Committee. Ira Kagan was a Director from April 2014 to March 2017 and served as a member of the Audit and Risk Committee and the Generation Oversight Committee.

Orientation and Continuing Education

The Compensation, Leadership and Governance Committee is responsible for reviewing and recommending appropriate orientation programs for new Directors. New directors are provided relevant documentation relating to OPG's governance practices and policies and to its business. Directors attend plant tours of OPG generating facilities, where they also receive comprehensive introductory briefings from OPG senior executives on OPG's operations and business activities.

The Board supports and sponsors the continuing education of OPG Directors, both in the business of OPG and in their duties as Directors. This includes plant tours of OPG's major facilities, site visits to projects with OPG's Indigenous business partners, and special presentations by internal and external experts on topical business-related issues or on specific aspects of OPG's operations. In 2017, such topics included pension plan governance, the cap and trade program and OPG's dam safety program. Directors also are provided with articles and publications on current topics of interest. Board members have full access to all Board and Board committee materials and records. OPG has developed a Director Governance Handbook, which provides Directors with information necessary to fulfill their roles, including director duties and obligations under the OBCA, and relevant corporate policies and procedures. OPG also sponsors Director attendance at the Institute of Corporate Directors' Director Education Program, or equivalent, and sponsors attendance at the Goizueta Director program for members of Board committees responsible for oversight of nuclear operations.

Ethical Business Conduct

The Board has adopted a policy for ethical business behaviour and a Code of Business Conduct. The mandate of the Audit and Risk Committee requires that it receive regular reports throughout the year on the Code of Business Conduct in order to satisfy itself that appropriate code of conduct and compliance programs are in place and are being enforced, and remedial action is being taken. The Audit and Risk Committee receives quarterly reports from management on the Code of Business Conduct (including reports on any substantiated cases of fraud) and the disposition of cases including disciplinary action, as well as an annual report on the Code of Business Conduct and a report on the annual review of the Board policy. A copy of the Code of Business Conduct can be found on SEDAR at www.sedar.com and also is available on the Company's website at www.opg.com. The Audit and Risk Committee has procedures for the receipt, retention and treatment of complaints received pertaining to accounting, internal controls or auditing matters, and for the confidential anonymous submission by employees concerning such matters.

Nomination of Directors

The Compensation, Leadership and Governance Committee, which is comprised of six independent Directors within the meaning of NI 52-110, is responsible for conducting an annual review of the OPG Board's principles and systems of governance, and oversight of annual Board, Board committee and Director evaluations. The Compensation, Leadership and Governance Committee recommends candidates to the Shareholder. Nominations of Directors by the Shareholder also may be considered by the Compensation, Leadership and Governance Committee. When considering a potential candidate, the committee considers the qualities, experience, and skills that the Board, as a whole, should have in light of the business opportunities and risks facing OPG. The attributes the Compensation, Leadership and Governance Committee considers in a candidate include integrity, business judgment and experience, diversity, professional expertise, independence from management, financial literacy, and communication skills, as well as sufficient time available to fulfill his or her obligations as a Board member. The Board's policy on diversity is to interview a diverse candidate for every vacancy on the Board. OPG defines diversity to include: women, aboriginal peoples, people with disabilities, and visible minorities. These four

enumerated groups mirror the four enumerated groups in the definition of "designated groups" in the federal *Employment Equity Act*.

From time to time, the Compensation, Leadership and Governance Committee may engage outside advisors to assist in identifying potential candidates.

Director Tenure/Board Renewal

The OPG Board Charter guideline for board tenure is 10 to 15 years. When considering board renewal, the Compensation, Leadership and Governance Committee regularly reviews the OPG Board skills profile. The Board maintains an "evergreen list" of potential Board candidates. From time to time, the committee makes recommendations to add skills to the Board that reflect OPG's business opportunities and risks.

Diversity in Leadership

Board of Directors

As noted under the heading, *Nomination of Directors*, the Compensation, Leadership and Governance Committee interviews a diverse candidate for every vacancy on the Board, where diversity is defined as: women, aboriginal peoples, people with disabilities, and visible minorities. The Board has signed on to the Catalyst Accord, set a target for "diverse" representation on the Board of 50 percent, including 40 percent women by 2019 and adopted a target of 25 percent women on the Board by 2017. In 2017, three members were added to the Board, two of whom meet the diversity definition. As of the date of this AIF, overall diversity of the Board is at 50 percent. Representation of women on the Board is 29 percent (four Directors) as of the date of this AIF.

Senior Management

OPG strives to create a workforce that reflects diverse populations of the communities in which it operates. As of December 31, 2017, women filled 25 percent of Corporate Officer roles and 26 percent of senior management (senior managers and above) positions. In total, there were three women in Corporate Officer roles and 153 women in senior management positions. OPG tracks and monitors diversity succession planning metrics and strives to have a diverse candidates list for senior management positions.

Compensation

Executive Compensation Framework

In September 2016, the Government of Ontario introduced *Regulation 304/16: Executive Compensation Framework*. The regulation sets out how all employers, including OPG, designated under the *Broader Public Sector Executive Compensation Act, 2014* must establish and post compensation programs for executives. The regulation requires all designated employers to have a written Executive Compensation Program that describes the compensation they may provide to executives. The program must include the compensation philosophy, salary and performance-related pay caps, comparative analysis details, and a description of other elements of compensation. The regulation also requires that designated employers post their program on their website and provide a reasonable opportunity for members of the public to provide comments. OPG met the requirements of *Ontario Regulation 304/16* and posted its Executive Compensation Framework on the Company's website for public comment on November 30, 2016. OPG reviewed the comments received through the public consultation process and determined that there was no need to alter its Executive Compensation Program, which became effective on January 1, 2017. OPG's Executive Compensation Program applies to employees at the Vice President level and higher. A copy of OPG's Executive Compensation Program can be found on SEDAR at www.sedar.com and is also available on the Company's website at www.opg.com.

Director Compensation

As at March 8, 2018, OPG's Director compensation framework provides each Director who is not an employee of OPG with an annual retainer of $25,000. Directors also receive a $3,000 retainer for each Board committee of which they are a member. There are four standing committees of the Board and Directors serve on at least two committees. Directors receive an additional retainer for serving as committee chairs. The retainer for the chair of the Audit and Risk Committee is $8,000. The chairs of the other three committees receive retainers of $5,000.

In addition to the above, Directors are compensated for each regular and/or special meeting that they attend and receive a fee of $2,000 or $1,000 for a long or short meeting, respectively. The Board Chair may also determine that no fee is warranted.

In order to retain national and international expertise, non-resident Directors are compensated in U.S. dollars and Directors who travel over certain distances receive a travel fee to cover travel time related to Board and Board committee meetings they attend.

Since 2004, the Chair of the Board, in his role as non-executive Chair, receives an all-inclusive annual fee of $150,000 and is reimbursed for out-of-pocket expenses including travel and other expenses.

CEO Compensation

Among its other responsibilities, the Compensation, Leadership and Governance Committee oversees, on behalf of the Board, the setting of the CEO's annual goals and objectives and the annual review of CEO performance, and makes recommendations to the Board with respect to CEO compensation. The Committee may seek input from an independent advisor with regard to monitoring and benchmarking compensation trends.

In August 2015, when the current CEO was appointed, the CEO compensation terms were established based on the benchmarks recommended in the 2007 Report of the Agency Review Panel on Phase 1 of its Review of Ontario's Provincially Owned Electricity Agencies. The CEO's base pay and incentives compensation are compliant with *Ontario Regulation 304/16*. Other elements of the CEO's compensation will be compliant within the three-year period provided in the regulation to bring all elements of compensation into compliance.

For details regarding compensation paid to Directors and executive officers during the financial year ended December 31, 2017, see OPG's Statement of Executive Compensation (Form 51-102F6), which is available on SEDAR at www.sedar.com and incorporated by reference herein.

Committees of the Board of Directors

The following are the current standing Board committees as at March 8, 2018:

Audit and Risk Committee

This committee is responsible for the integrity, quality, and transparency of OPG's financial information, the adequacy of the financial reporting process, the systems of internal controls, and related principles, policies and procedures established by management. The Committee is responsible for the oversight of the Company's regulatory filings, financial statements, MD&A and press releases prior to their disclosures to the public, including approval of quarterly financial statements and recommending approval of the annual financial statements and various other annual disclosures to the Board. The committee is also responsible for recommending the appointment and compensation of the external auditor to the Board and for oversight of the external auditor.

The committee also provides oversight of OPG's corporate financing strategies including:

- policies related to financial exposure management;
- processes for identifying major financial risks;
- performance of the OPG Pension Fund, the Used Fuel Segregated Fund and the Decommissioning Segregated Fund;
- review and approval of the audited financial statements of the OPG Pension Fund, the Used Fuel Segregated Fund and the Decommissioning Segregated Fund; and
- review and approval of the statements of investment policies and procedures for the OPG Pension Fund and the Decommissioning Segregated Fund.

The Audit and Risk Committee also oversees risk and associated risk management activities, including the review of management's assessment of significant risks to achieving OPG's business plan objectives. The committee also is responsible for ensuring that an effective Code of Business Conduct is in place at OPG and monitors compliance with this code.

As of November 22, 2017, the Audit and Risk Committee assumed oversight of OPG's role as Financial Services Manager of the Fair Hydro Trust.

As of the date of this AIF, the Audit and Risk Committee consists of George Lewis (Chair), Elisabeth (Lisa) DeMarco, Ani Hotoyan-Joly, Wendy Kei, Yezdi Pavri, and Gerry Phillips.

For further details regarding the Audit and Risk Committee, see *Audit and Risk Committee Information*.

Compensation, Leadership and Governance Committee

This committee provides oversight of OPG's human resources and compensation policies and practices, including CEO objectives and compensation, disclosure on compensation and human resources matters, leadership talent review, succession planning, and collective bargaining negotiations. The committee also provides oversight of the design of OPG's benefit and pension plans.

The Compensation, Leadership and Governance Committee oversees the Board's governance program and practices to ensure that they are consistent with high standards of corporate governance, including annually reviewing and assessing the Board's system of corporate governance with a view to maintaining these high standards. The committee also is responsible for overseeing OPG's reputation management plan, and for identifying and recommending to the Board candidates for nomination to the Shareholder. Finally, the committee oversees OPG's processes for Board, Board committee, and Director assessments, as well as Director compensation and new Director orientation.

As of the date of this AIF, the Compensation, Leadership and Governance Committee consists of Margaret (Peggy) Mulligan (Chair), Bill Coley, JP Gladu, Ani Hotoyan-Joly, George Lewis and Yezdi Pavri.

Darlington Refurbishment Committee

The Darlington Refurbishment Committee is responsible for the oversight of the execution of the Darlington Refurbishment Program, including retaining external independent oversight advisors. The committee was also responsible for making a recommendation to the Board with respect to a final budget and schedule for the Darlington Refurbishment Program, which was subsequently approved by the Board of Directors in November 2015. The committee monitors and reports on the progress of the refurbishment program against the approved budget and schedule. The committee will make a recommendation to the Board with respect to the refurbishment of subsequent Darlington units, and other recommendations for approvals related to the refurbishment program as may be required from time to time.

As of the date of this AIF, the Darlington Refurbishment Committee consists of Jim Reinsch (Chair), Bill Coley, John Herron, Margaret (Peggy) Mulligan, Gerry Phillips, and James Sheppard.

Generation Oversight Committee

This committee is responsible for the oversight of safe, secure and efficient operations of OPG's generating facilities. Additionally, the committee is responsible for the development, risk management, financing, and execution of the Company's major generation projects including those related to nuclear waste management, other than the Darlington Refurbishment Program. The committee also is responsible for the oversight of OPG's environment and dam safety management systems and OPG's Indigenous relations. The committee reviews reports of internal and external advisors/assessors in respect of OPG's generation operations and management's response to the findings from such assessments. The committee provides oversight to ensure that OPG's generating facilities are in compliance with nuclear safety, industrial and occupational health and safety, and environmental laws and regulations.

As of the date of this AIF, the Generation Oversight Committee consists of John Herron (Chair), Bill Coley, Elisabeth (Lisa) DeMarco, JP Gladu, Wendy Kei, Jim Reinsch, and James Sheppard.

Special Committee of the Board

This Special Committee of the Board was established on March 10, 2017. The Special Committee was responsible for providing timely strategic and other guidance to OPG management in connection with the Province's announcement of Ontario's Fair Hydro Plan on March 2, 2017, which includes refinancing a portion of the Global Adjustment. The Committee was also responsible for making recommendations to the Board with respect to OPG's participation in the Province's implementation of the refinancing proposal. The mandate of the Special Committee concluded on November 22, 2017 and the Audit and Rick Committee will be responsible for the oversight of this process.

Assessments

The Compensation, Leadership and Governance Committee is responsible for the annual process for evaluating the performance of the Board, its committees and individual Directors. The Board and committee evaluations are based upon the completion of confidential questionnaires regarding assessment of performance and compliance with the Board and Committee Charters. The individual Director evaluations are based on self-assessment questionnaires, which are submitted in confidence to the Board Chair and the Chair of the Compensation, Leadership and Governance Committee. In addition, the process includes a follow-up one-on-one meeting between each Director and the Board Chair. The Compensation, Leadership and Governance Committee reports the results of the evaluations to the Board and the results are discussed amongst the Board. The Compensation, Leadership and Governance Committee makes recommendations to the Board for enhancing the Board's governance and effectiveness.

Further Information on OPG Governance

OPG provides additional information on the Company's governance on its website (www.opg.com) including:

- Memorandum of Agreement with the Shareholder
- Shareholder Directives
- List of Corporate Officers
- Board and Committee Charters
- Board and Committee Chair Position Descriptions
- Board of Directors Conflict of Interest Policy
- Indigenous Relations Policy
- Code of Business Conduct
- Disclosure Policy
- Environmental Policy
- Employee Health and Safety Policy
- Nuclear Safety Policy

- Safe Operations Policy
- Cyber Security Policy

Unless otherwise specifically stated, none of the information contained on, or connected to the Company's website nor any of the contents of the aforementioned additional information on OPG's governance are incorporated by reference herein.

EXECUTIVE OFFICERS

The following table sets forth the name, municipality of residence, position with the Company, and the date of commencement for each of the executive officers of the Company as of March 8, 2018:

Name and Municipality of Residence	**Current Position Held**	**Executive Officer Since**
Bernard Lord *Moncton, New Brunswick*	Board Chair	April 2014
Jeff Lyash *Toronto, Ontario*	President and Chief Executive Officer	August 2015
Carlo Crozzoli *Toronto, Ontario*	Senior Vice President, Corporate Business Development and Strategy	December 2011
Chris Ginther *Newmarket, Ontario*	Chief Administrative Officer	July 2012
Ken Hartwick *Milton, Ontario*	Chief Financial Officer & Senior Vice President – Finance	March 2016
Glenn Jager *Clarington, Ontario*	President, OPG Nuclear and Chief Nuclear Officer	November 2013
David Kaposi *Toronto, Ontario*	Vice President, Chief Investment Officer	November 2013
Barb Keenan *Toronto, Ontario*	Senior Vice President, People & Culture and Chief Ethics Officer	March 2010
Catriona King *Richmond Hill, Ontario*	Vice President, Corporate Secretary	February 2005
John Lee *Toronto, Ontario*	Vice President, Treasurer	July 2011
Mike Martelli *Etobicoke, Ontario*	President, Renewable Generation **[CONFIRM]**	July 2013
Dietmar Reiner *Clarington, Ontario*	Senior Vice President, Nuclear Projects	June 2014
Jennifer Rowe *Toronto, Ontario*	Senior Vice President, Corporate Affairs	January 2017

All of the executive officers of the Company have been engaged for more than five years in their current principal occupations, except as set out below:

- Mr. Lyash was Executive Vice President at Duke Energy from May 2008 to January 2012 and President at CB&I Power from July 2013 to July 2015.
- Mr. Crozzoli was Senior Vice President, Corporate Business Development and Chief Risk Officer at OPG from December 2011 to November 2015, Acting Senior Vice President, Finance, Strategy & Risk and Chief Financial Officer at OPG from November 2015 to March 2016 and Senior Vice-President, Corporate Business Development and Chief Risk Officer at OPG from March 2016 to August 2016.
- Mr. Ginther was Senior Vice President, Law and General Counsel and Chief Ethics Officer at OPG from July 2012 to January 2016 and Senior Vice President, Legal, Ethics and Compliance at OPG from January 2016 to February 2017.
- Mr. Hartwick was President and CEO at Just Energy Corp. from February 2008 to April 2014, Interim President and CEO at Atlantic Power Corporation from September 2014 to January 2015, Chief Financial Officer at Wellspring Financial Corporation from February 2015 to March 2016 and Senior Vice President, Finance, Strategy, Risk and Chief Financial Officer at OPG from March 2016 to February 2017.
- Mr. Jager was Senior Vice President, Pickering Nuclear Generating Station at OPG from January 2010 to November 2013 and Chief Nuclear Officer at OPG from November 2014 to March 2015.
- Mr. Kaposi was Global Head of Alternatives for Mercer (Canada) Inc. from November 2007 to June 2012 and Partner, Investor Relations at Bastion Infrastructure Group Inc. from July 2012 to September 2013.
- Ms. Keenan was Senior Vice President, People and Culture at OPG from March 2012 to January 2016 and Senior Vice President, People, Culture and Communications from January 2016 to February 2017.
- Ms. King was Vice President, Corporate Secretary at OPG from June 2005 to May 2012, Vice President, Corporate Secretary & Executive Operations from May 2012 to March 2017.
- Mr. Martelli was Plant Manager for the Niagara Plant Group at OPG from June 2010 to July 2013 and Senior Vice President, Hydro-Thermal Operations at OPG from July 2013 to January 2016.
- Mr. Reiner was Senior Vice President, Nuclear Refurbishment at OPG from March 2010 to April 2014.
- Ms. Rowe was Senior Managing Director – Marketing and Communications and VP Corporate Affairs at Manulife from January 2010 to October 2012 and Senior Vice President and Chief Marketing Officer at Meridan Credit Union from October 2012 to April 2016.

INDEBTEDNESS OF DIRECTORS AND EXECUTIVE OFFICERS

As of the date of this AIF, no director or executive officer of the Company or any of its subsidiaries had any outstanding indebtedness to the Company or any of its subsidiaries except routine indebtedness or had any indebtedness that was the subject of a guarantee, support agreement, letter of credit or other similar arrangement or understanding provided by the Company or any of its subsidiaries.

CEASE TRADE ORDERS, BANKRUPTCIES, PENALTIES OR SANCTIONS

To the knowledge of OPG, no director or executive officer is, at the date of the AIF, or was within 10 years before the date of the AIF, a director, chief executive officer, or chief financial officer of any company, that (a) was subject to an order that was issued while the director or executive officer was acting in the capacity as director, chief executive officer, or chief financial officer, or (b) was subject to an order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer, or chief financial officer, except for:

- Ani Hotoyan-Joly was the Chief Financial Officer of Coventree Inc. on November 8, 2011, when the Ontario Securities Commission issued an order that trading in any securities by Coventree cease and any exemptions contained in Ontario Securities law do not apply to Coventree until such time as Coventree completes it winding up. The order was made on the basis that Coventree had contravened Ontario Securities law by failing to issue and file certain news releases and material change reports in 2007.

- The events in question occurred before she became CFO of Coventree Inc. in May 2009. Coventree Inc. continues in the process of a court-supervised winding up and the order is still in effect.

To the knowledge of OPG, no director or executive officer of OPG, or a shareholder holding a sufficient number of securities of OPG to affect materially the control of OPG (a) is, as at the date of the AIF, or has been within the 10 years before the date of the AIF, a director or executive officer of any company (including OPG) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (b) has, within the 10 years before the date of the AIF, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager, or trustee appointed to hold the assets of the director, executive officer, or shareholder, except for:

- Bernard Lord was a director of AEA Technology from the fall of 2010 until the fall of 2012 when it became insolvent.
- Ani Hotoyan-Joly is currently the CFO and Corporate Secretary of Coventree Inc. from May 2009. On February 15, 2012 Coventree Inc. announced that the winding up of the Company will commence and that Duff & Phelpe Canada Restructuring Inc. (now known as KSV Advisory Inc.) was appointed the liquidator of the Company for the purpose of winding up its affairs.
- Peggy Mulligan was a director of MethylGene Inc. from May 2012 to June 2014. On May 9, 2013, MethylGene announced a plan of arrangement that was successfully completed on June 28, 2013.
- Bernard Lord, was a director of Clean Air Power, during September 2015 while it was subject to liquidation proceedings under the laws of Bermuda. Mr. Lord is no longer a director of Clean Air Power.
- William Coley is a director of Peabody Energy Corporation which declared voluntary Chapter 11 bankruptcy protection in April 2016 for most of its U.S. entities and is currently restructuring. As of April 13, 2017, Mr. Coley is no longer a director of the entity.

AUDIT AND RISK COMMITTEE INFORMATION

NI 52-110 has been implemented by Canadian securities regulatory authorities to encourage reporting issuers to establish and maintain strong, effective, and independent audit committees, to enhance the quality of financial disclosure, and to foster increased investor confidence in Canada's capital markets. The Audit and Risk Committee's Charter is attached to this AIF as Appendix A. Information on OPG's Audit and Risk Committee is as follows:

Composition of the Audit and Risk Committee

As at March 8, 2018, the members of the Audit and Risk Committee were George Lewis (Chair), Elisabeth (Lisa) DeMarco, Ani Hotoyan-Joly, Wendy Kei, Yezdi Pavri and Gerry Phillips. All members are independent within the meaning of NI 52-110 and have experience in business and financial matters. Each member has an understanding of internal controls and procedures for financial reporting. As part of OPG's Continuing Education Program for Directors, Audit and Risk Committee members are provided with access to both internal and external educational resources, including seminars and courses, in order to maintain or enhance their financial literacy.

Activities of the Audit and Risk Committee

The Chartered Professional Accountants of Canada (CPA Canada) and the Canadian Public Accountability Board have recommended that audit committees perform a comprehensive review of the external audit firm at least once every five years. CPA Canada issued guidelines in early 2014 to assist audit committees in implementing these recommendations. The Audit and Finance Committee of the Board conducted its first comprehensive review of the Company's external auditor, Ernst & Young LLP (EY) in 2014, for the period from 2009 to 2013, using the guidelines and format recommended by CPA Canada. EY has been OPG's external auditor since the Company's inception in 1999. EY provides audit and audit related services to OPG, including the audit of OPG's annual consolidated financial statements, reviews of OPG's quarterly financial statements, and audits of the financial statements of OPG's consolidated subsidiaries and other financial information.

In conducting the 2017 review of EY's performance, the Audit and Risk Committee considered input from management, EY, and OPG's internal audit function. The Committee performed this review taking into consideration the information submitted by these parties, as well as their individual experience. The results of the 2017 annual review were discussed at the Audit and Risk Committee meeting in August 2017. As part of the review, the Committee considered factors such as the auditor's independence, engagement team quality including the Committee's involvement in the selection of EY's lead engagement partner, and communication effectiveness between EY and OPG. Upon completion of the review, the Committee was satisfied with the performance of EY, concluded that their reappointment was in the best interests of OPG, and, in November 2017, recommended that the Board reappoint EY as the Company's auditor for the 2018 fiscal year. The Board reappointed EY as the Company's auditor for the 2018 fiscal year in November 2017.

External Auditor Service Fees [UPDATE]

The following fees were accrued by EY:

(thousands of dollars)	**2017**	**2016**
Audit fees		1,959
Audit-related fees		554
All other fees [1]		17

[1] Comprised of fees related to the subscription of an online accounting research tool and training.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Relationship with the Province and the OEFC

Relationship with the Shareholder

As a corporation created under and governed by the OBCA, OPG's management is supervised by its Board of Directors, which is obligated by law to act in the best interests of the Company. The Company's sole Shareholder, the Province, owns all of the Company's issued and outstanding common shares and thereby has the power to determine the composition of the Company's Board of Directors.

As one of several wholly-owned government business enterprises of the Province, OPG has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

Memorandum of Agreement

On August 17, 2005, OPG entered into the MOA with the Shareholder regarding OPG's role and responsibility as a power producer in Ontario. In July 2015, the MOA was revised. The MOA serves as the basis of agreement between OPG and the Shareholder regarding OPG's mandate, governance, performance, reporting and communications, and establishes the accountabilities between OPG and the Province. OPG's strategic imperatives are based on the Company's mandate as set out in the MOA. The MOA was reaffirmed for continuance by both the Ontario Minister of Energy and the OPG Board of Directors' Chair in the fourth quarter of 2016, as required by the MOA following a change in the Minister of Energy.

A copy of the MOA can be found on the Company's website at www.opg.com. ***Unless otherwise specifically stated, none of the information contained on, or connected to the Company's website nor any of the contents of the MOA are incorporated by reference herein.***

Shareholder Directives

The Shareholder may at times direct OPG to undertake special initiatives. A Shareholder directive is issued when the Shareholder finds it necessary to assume decision-making power and authority over certain aspects of the business operations of the Corporation. Under a Shareholder directive, the Shareholder assumes all the rights, powers, duties and liabilities of the Directors to manage or supervise the management of the business and the Directors are relieved of their duties and liabilities. Shareholder directives are communicated as written pursuant to section 108 of the OBCA. Copies of each Shareholder directive can be found on the Company's website at www.opg.com. ***Unless otherwise specifically stated, none of the information contained on, or connected to the Company's website nor any of the contents of the Shareholder directives are incorporated by reference herein.*** The Shareholder directives issued by the Shareholder to date are listed below in reverse chronological order:

- Sale of the Corporation's Lakeview site (June 9, 2016);
- Sale of the Corporation's Head Office (December 14, 2015);
- Bruce Power L.P. Lease Agreement and Used Fuel Agreement (November 30, 2015) – For further details, see *General Development of Business – Nuclear Business Development – Bruce Power Refurbishment and Bruce Lease Agreement*;
- Bruce Power L.P. Amended and Restated Heavy Water and Associated Services Agreement (November 30, 2015) – For further details, see *General Development of Business – Nuclear Business Development – Bruce Power Refurbishment and Bruce Lease Agreement*;
- Conversion of One Unit of Thunder Bay Generating Station to Advanced Biomass (May 1, 2014);
- Thunder Bay Generating Station Conversion (December 16, 2013);
- Early Closure of Ontario Power Generation's Lambton and Nanticoke Coal-Fired Generation Stations (March 7, 2013);
- First Nation Directive (April 1, 2011) – OPG was directed to pay a part of the Shareholder's portion of the settlement liability with a First Nation on its behalf;
- Atikokan Generating Station Conversion (March 8, 2011);
- Addressing Carbon Dioxide Emissions from the Use of Coal at Coal-Fired Generating Stations (May 20, 2010);
- Request for Indicative Prices for the Supply of Wood Pellet Fuel Declaration (Atikokan) (March 18, 2010);

- Request for Expressions of Interest for Supply and Transportation of Solid Biomass Fuel Declaration (January 13, 2009);
- Addressing Carbon Dioxide Emissions from the Use of Coal at Coal-Fired Generating Stations (May 15, 2008);
- Thunder Bay Gas Conversion Cancellation (July 12, 2006);
- Nuclear Directive (June 16, 2006) – OPG was directed to begin feasibility studies on refurbishing existing nuclear units, an environmental assessment on refurbishing Pickering B units, and federal approvals processes (including environmental assessment) for new nuclear units;
- Lower Mattagami River Agreement (May 23, 2006);
- Bruce Power Lease Agreement (October 14, 2005); and
- Thunder Bay Gas Conversion Declaration (October 6, 2005).

Ontario Nuclear Funds Agreement

The ONFA between OPG and the Province sets out the responsibility for funding the liabilities for the decommissioning of OPG's nuclear facilities and the long-term management of OPG's used nuclear fuel and other nuclear waste. Pursuant to the ONFA, the Company has established a Used Fuel Segregated Fund and a Decommissioning Segregated Fund to fund the future costs of these activities. Additional details can be found in the section, *Description of the Business* under the heading, *Regulated – Nuclear Waste Management Segment – Funding Mechanisms*.

OPG Debt Held by the OEFC

OPG's long-term debt has been financed predominantly by the OEFC. As at December 31, 2017, the OEFC held approximately $3.2 billion of OPG's long-term debt with maturities ranging from one month to 30 years. For additional details, see Note 6 to the Company's audited annual financial statements as at and for the year ended December 31, 2017.

Payments-In-Lieu of Corporate Income Taxes and Property Taxes

OPG and its wholly-owned subsidiaries are exempt from tax under the *Income Tax Act* (Canada) and *Taxation Act, 2007* (Ontario). However, under the *Electricity Act, 1998*, OPG is required to make proxy tax payments to the OEFC. These payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by the *Electricity Act, 1998* and related regulations. This results in OPG paying taxes similar to those imposed under the federal and Ontario tax acts.

OPG is subject to income tax audits by the Ontario Ministry of Finance. As of the date of this AIF, income tax audits up to and including the 2013 taxation year have been completed.

The *Electricity Act, 1998* also provides that OPG and certain of its subsidiaries are required to make payments in lieu of property tax to the OEFC on their non-hydroelectric generating station buildings and structures. These payments generally equal the difference between property taxes that would be otherwise payable if these assets were privately owned, and the amount payable to municipalities in respect of these assets as determined under the *Assessment Act, 1990* (Ontario). As with other hydroelectric generators in Ontario, OPG's hydroelectric generation operations are not subject to payments in lieu of property taxes because they are subject to the GRC regime. Additional details on the GRC regime can be found in the section, *Description of the Business* under the heading, *Generation Operations – Hydroelectric (Regulated – Hydroelectric and Contracted Generation Portfolio segments)*.

Stranded Debt

One of the OEFC's purposes under the *Electricity Act, 1998* is to manage "stranded debt," which was not transferred to any of Ontario Hydro's successor entities. The *Electricity Act, 1998* defines stranded debt as the amount of the debt and other liabilities of the OEFC that, in the opinion of the Minister of Finance, cannot reasonably be serviced and retired in a competitive electricity market. Although OPG has no obligations in connection with the stranded debt, the *Electricity Act, 1998* does provide for participants in the electricity sector, including OPG, Hydro One, and the municipal electricity utilities, to make payments to the OEFC, which the OEFC uses in managing the debt and other obligations. These payments include proxy taxes, payments in lieu of tax, including property tax, the Debt Retirement Charge levied on certain electricity consumers, and certain amounts that may be payable by municipal electricity utilities on the transfer of their electricity business.

Commented [GH5]: Not sure if we need to note that Hydro One no longer pays PILs here, given this is OPG's AIF.

Commented [JK6]: If this refers to PILs, then the next change is not needed.

Commented [MR-7]: We have removed this section in the next draft.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Legal Proceedings

OPG is potentially the subject of various legal proceedings and claims that arise in the ordinary course of business. The outcome of these proceedings and claims is uncertain. Based on information available as of the date of this AIF, management believes that none of the proceedings and claims, individually and in the aggregate, are expected to have a material impact on OPG.

British Energy Claim

On August 9, 2006, a Notice of Action and Statement of Claim filed with the Ontario Superior Court of Justice in the amount of $500 million was served against OPG and Bruce Power by British Energy Limited and British Energy International Holdings Limited (together British Energy). The action is for contribution and indemnity of any amounts British Energy was liable for in an arbitration against it by some of the owners of Bruce Power regarding an alleged breach of British Energy's representations and warranties to the claimants when they purchased British Energy's interest in Bruce Power (the Arbitration). Both the action and the Arbitration relate to corrosion to a steam generator unit discovered after OPG leased the Bruce nuclear generating stations to Bruce Power.

In 2012, the arbitrator found that British Energy was liable to the claimants for some of the damages they claimed. The final settlement amount was valued by British Energy at $71 million. In September 2014, British Energy amended its Statement of Claim (Amended Claim) to reduce the claim amount to $100 million to reflect that the purchasers of British Energy's interest in Bruce Power did not receive the full damages they originally claimed in the Arbitration. British Energy also added an allegation to its Amended Claim that OPG breached a covenant to maintain the steam generator between the time of the initial agreement to lease and the effective date of the lease in accordance with "Good Utility Practices".

In November 2016, British Energy obtained consent to a timetable for the remaining steps in the litigation, pursuant to which the matter must be set down for trial by December 31, 2018. OPG has delivered a statement of defence in accordance with an extension of the original June 30, 2017 delivery deadline set out in the timetable.

Regulatory Actions

OPG is not aware of any penalties or sanctions imposed by a court or securities regulatory authority or other regulatory body against the Company, nor has the Company entered into any settlement agreements before a court or with a securities regulatory authority.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business (unless otherwise required by applicable securities requirements to be disclosed), there were no material contracts entered into by the Company or

its subsidiaries during the most recently completed financial year, or before the most recently completed financial year that are still in effect.

INTERESTS OF EXPERTS

The external auditor of the Company is Ernst & Young LLP, Chartered Professional Accountants, 100 Adelaide Street West, P.O. Box 1, Toronto, Ontario M5H 0B3. Ernst & Young LLP has been the Company's auditors since OPG was formed in 1999, and is independent in accordance with the Rules of Professional Conduct of the Chartered Professional Accountants of Ontario.

GLOSSARY

ancillary service	a service necessary to maintain the reliability of the IESO-controlled grid.
availability	when used in reference to a generating unit, a measure of mechanical reliability represented by the percentage of time a generating unit is capable of providing service, whether or not it is actually in-service, relative to the total time for the period.
baseload facilities	electricity generation facilities that produce a constant supply of energy. In Ontario, baseload facilities are made up of nuclear, run-of-the-river hydroelectric and variable generation facilities such as wind and solar.
bilateral contract	a contract for the purchase and sale of notional electricity usually entered into directly between a generator and an end-user, or between a generator or end-user and a market intermediary.
biomass	plant material from agricultural and forest sources that can be used to produce energy, including beneficiated biomass, which includes torrefied, carbonized, and steam exploded biomass.
CANDU	an acronym for CANada Deuterium Uranium, a family of nuclear fission reactors developed in Canada which use pressurized heavy water coolant or deuterium oxide as a moderating agent and natural uranium (uranium dioxide) as fuel.
capacity factor	the ratio (usually specified as a percentage) of the amount of energy that a generating asset actually generated over a period of time divided by the amount of energy that the generating asset would have produced over the same period of time if it had operated continuously at full capacity.
decommissioning	actions taken in the interest of health, safety, security and protection of the environment to retire a facility permanently from service and render it to a predetermined end-state condition.
detritiation	the removal of tritium from heavy water.
deuterium oxide	see heavy water.
equivalent forced outage rate	the hours of unit failure given as a percentage of the total hours of the availability of that unit.
government business enterprises	Government organizations that are separate legal entities with the power to contract in their own name, have the financial and operating authority to carry on a business, are principally focused on the selling of goods and services to individuals and non-government organizations, and are able to maintain their operations and meet their obligations through revenues generated outside the government reporting entity.
heavy water (deuterium oxide)	water containing significantly more than the natural proportion of heavy hydrogen (deuterium) atoms to ordinary hydrogen atoms, used as a moderator in CANDU reactors.
in-service capacity	the portion of installed capacity (the highest level of output which a generating unit is designed to maintain indefinitely without damage to the unit) that has not been removed from service.

interconnection	a transmission line which carries power across the service area boundary of geographically adjacent jurisdictions.
kWh	a kilowatt hour, the commercial unit of electric energy (the amount of electricity consumed by ten 100 watt light bulbs burning for one hour).
load	the quantity of electricity consumption measured as either the energy consumed over a given period of time or the rate of energy consumption at a given time by a particular customer or group of customers.
MW	a megawatt, equal to 1,000,000 watts or 1,000 kilowatts.
MWh	a megawatt hour, equal to 1,000 kWh.
OEFC	an acronym for the Ontario Electricity Financial Corporation, the legal continuation of the former Ontario Hydro. The OEFC is responsible for managing the debt and certain other obligations not transferred to other successor companies of Ontario Hydro.
ONFA	an acronym for the Ontario Nuclear Funds Agreement between OPG and the Province that sets out the responsibility for funding the liabilities for the decommissioning of OPG's nuclear stations and the long-term management of OPG's used nuclear fuel and other nuclear waste.
Ontario NFWA Trust	a trust established by OPG pursuant to the *Nuclear Fuel Waste Act* (Canada) for the purpose of funding the implementation of Canada's long-term nuclear fuel waste management plan.
operating reserve	the capacity that can be called upon on short notice by the IESO to replace scheduled energy supply that is unavailable as a result of an unexpected outage or to augment scheduled energy as a result of unexpected demand or other contingencies.
reactive support	the control and maintenance of prescribed voltages on the IESO-controlled grid.
refurbishment	the work needed to extend the life of a reactor unit by replacing the major life-limiting components (such as pressure tubes, steam generators, etc).
Shareholder	the sole shareholder of OPG, the Province of Ontario.
surplus baseload generation	a condition that occurs when electricity generation from baseload facilities is greater than the electricity market demand.
tonne	1,000 kilograms or 2,204.6 pounds.
tritium	a radioactive substance that is created within CANDU reactors as a result of heavy water in the reactor moderator and heat transport systems.
TWh	a terawatt hour, equal to 1,000,000 MWh.
unit	an electrical generator, together with its driving turbine and auxiliary equipment.
watt	a scientific unit of electric power representing the rate of work of one joule per second.

APPENDIX A

ONTARIO POWER GENERATION INC.

AUDIT AND RISK COMMITTEE CHARTER

Audit and Risk Committee Charter

Purpose

The function and purpose of the Audit and Risk Committee is to assist the Board of Directors in their responsibility for oversight of matters relating to:

1. The integrity of OPG's financial statements and reporting
2. The integrity and adequacy of internal controls and standards of Codes of Conduct and ethics
3. The performance of OPG's internal audit function
4. The performance and independence of OPG's external auditors
5. Business and financial planning
6. The performance of OPG's pension, nuclear decommissioning, and used fuel investment funds
7. OPG's Enterprise Risk Management
8. Assessment of committee performance and board policies.

Management is responsible for the preparation, presentation and integrity of OPG's interim and annual financial statements and related disclosure documents. Management is responsible for maintaining appropriate accounting and financial reporting principles and policies and systems of internal and disclosure controls and procedures to comply with accounting standards and applicable laws and regulations which

provide reasonable assurance that the assets of the Company are safeguarded and transactions are authorized, executed, recorded and properly reported.

Management is also responsible for the identification, assessment, monitoring, and management of the risks to achieving OPG's strategic and business plan objectives and the development and implementation of policies and procedures to respond to such risks.

The Committee's role is to provide oversight that ensures the Company's assets are protected and safeguarded within reasonable business limits and report such to the Board.

Committee Responsibilities and Duties

The Committee shall perform the duties set out in this Charter and shall perform such other duties as may be necessary or appropriate under applicable law or securities rules, or as may be delegated to the Committee by the Board from time to time.

1. *The integrity of OPG's financial statements and reporting*

   The Committee reviews and makes recommendations to the Board with respect to:

   a) appointment or replacement of the Chief Financial Officer.

   b) OPG's annual financial statements and external audit report, including financial statements, MD&A, related footnotes and any documentation required by the Securities Act to be prepared and filed by OPG or that OPG otherwise files with securities regulators.

   c) OPG's Annual Information Form, if required, prior to filing with securities regulators.

   The Committee reviews and approves:

   d) OPG's quarterly financial statements and interim financial information and disclosures in the Management Discussion and Analysis (MD&A) and earnings press release, prior to filing.

   In carrying out its responsibilities for oversight of the integrity of OPG's financial statements and reporting the Committee will include in its review:

   e) Adequacy of procedures in place for the review of OPG's public disclosure of financial information extracted or derived from OPG's financial statements.

   f) significant accounting principles and reporting issues and impact on the financial statements, including complex or unusual transactions, highly judgmental areas, major issues regarding or changes to OPG's selection/application of accounting principles, financial presentations, the effect of regulatory and accounting initiatives, as well as off-balance sheet arrangements on OPG's financial statements.

   g) analysis prepared by Management and/or the external auditor detailing financial reporting issues and judgments made in connection with the preparation of financial information, including analysis of the effects of alternative generally accepted accounting principles methods.

   h) whether any other matters related to conduct have come to the Committee's attention that causes it to believe that the financial statements contain an untrue statement of material fact or omit to state a necessary material fact.

2. *Integrity and adequacy of Internal Controls and standards of Codes of Conduct and ethics*

In carrying out its responsibilities for the integrity and adequacy of internal controls, including compliance with legal and regulatory requirements and standards of codes of conduct and ethics, the Committee reviews:

a) legal, tax, or regulatory matters that may have a material impact on OPG's operations and the financial statements, including, but not limited to, violations of securities law or breaches of fiduciary duty.

b) the scope of review of internal control over financial reporting, significant findings, recommendations and Management's responses for implementation of actions to correct weaknesses in internal controls.

c) disclosures made by the Chief Executive Officer and Chief Financial Officer during the certification process regarding significant deficiencies in the design or operation of internal controls or any fraud that involves Management or other employees who have a significant role in OPG's internal controls.

d) procedures for the receipt, recording and treatment of complaints received by OPG regarding accounting, internal accounting controls, or auditing matters, and procedures for the confidential and anonymous submission by OPG employees of concerns regarding accounting or auditing matters.

e) expenses of the Board Chair, Board of Directors, President/CEO and the President/CEO's direct reports on an annual basis, and of any other senior officers and employees the Committee considers appropriate.

f) reports from the Chief Ethics Officer on independent reviews and investigations of fraud allegations, matters that may involve fraud and/or Codes of Conduct violations and compliance.

3. *Performance of OPG's internal audit function*

The Committee reviews and makes recommendations to the Board with respect to:

a) Appointment or replacement of the Chief Risk and Audit Executive.

The Committee reviews and approves:

b) The annual internal audit plan and all major changes to the plan, including the organizational structure, budget and the adequacy of resources.

c) the charter of the internal audit function triennially.

In carrying out its responsibilities for the performance of OPG's internal audit function the Committee reviews:

d) results of Internal audit reports, including: significant findings, the adequacy of the control processes, Management's response and the timetable for implementation of Management actions

to correct weaknesses, any difficulties encountered in the course of their work (such as restrictions on the scope of their work or access to information).

e) Internal Audit's confirmation of organizational independence and disclosure of any conflict of interest.

f) Internal Audit performance relative to the annual internal audit plan.

4. *Performance and Independence of External Auditor*

The Committee reviews and makes recommendations to the Board with respect to:

a) the external auditor to be annually appointed on behalf of the Shareholder and related compensation, including results of a cyclical performance review, and a comprehensive review of the external audit firm at least once every five years.

The Committee reviews and approves:

b) pre-approval of additional audit services and fees to be provided by the external auditors if such services are required further to the annual compensation approved by the Board. The Committee may delegate such pre-approval authority to the Committee Chair up to a limit of $250,000. Any decisions of the Committee Chair to whom pre-approval authority is delegated must be presented to the full Audit and Risk Committee at its next scheduled meeting.

In carrying out its responsibilities for the performance and independence of OPG's external audit function the Committee reviews:

c) the work and report of the external auditor engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for OPG, including the resolution of disagreements between Management and the external auditor regarding financial reporting.

d) the independence and qualifications of the external auditor.

e) the annual report by the external auditor describing the auditing firm's internal quality control procedures, any material issues raised by the most recent internal quality-control review or peer review of the auditing firm or by any inquiry or investigation by governmental or professional authorities within the preceding five years respecting one or more independent audits carried out

by the external auditor and any steps taken to deal with any such issues and all relationships between the external auditors and OPG.

f) scope and approach of the annual audit plan with the external auditors.

g) quality and acceptability of OPG's accounting principles including all critical accounting policies and practices used, any alternative treatments that have been discussed with Management as well as any other material communications with Management.

h) external auditor's process for identifying and responding to key audit and internal control risks.

i) rotation of the lead audit partner and other audit partners every seven years, and consider regular rotation of the audit firm.

j) all related-party transactions.

k) OPG's hiring policies regarding partners, employees and former partners and employees of the present and former external auditor of OPG.

5. *Business and Financial Planning*

The Committee reviews and makes recommendations to the Board on:

a) OPG's business plan, including overall financing plan in support of the Company's capital expenditures and medium – long term forecast.

b) OPG's rate applications to the Ontario Energy Board, including proposed payment amounts and any agreement arising from a Settlement Conference with intervenors.

c) corporate financing vehicles, credit facilities, including any plans to access capital debt markets and other related financing activities. The Board may delegate to an officer of the company authority to enter into such financing activities in such a manner as the Board shall determine at the time of

such delegation. Any decisions of the officer to whom authority is delegated must be presented to the full Audit and Risk Committee at its next scheduled meeting.

6. *Pension, Nuclear Decommissioning and Used Fuel Investment Funds*

The Committee reviews and makes recommendations to the Board on:

a) the appointment or replacement of the Chief Investment Officer.

b) the appointment of the auditor for the OPG Pension Fund and the Used Fuel Segregated Fund and Decommissioning Segregated Fund.

c) the broad objectives, governance frameworks and risk posture for the OPG Pension Fund and the Used Fuel Segregated Fund and Decommissioning Segregated Fund and annual status report on these Funds.

d) the tri-ennial valuation of the Pension Fund and annual valuation of the Supplementary Employee Retirement Pension Plans. (The Committee provides advice to the Compensation, Leadership and Governance Committee on the affordability of proposed pension benefit changes.)

The Committee reviews and approves:

e) the appointment of the members of OPG's Pension Committee. In addition, the Committee may, at any time, remove or replace any member of the Pension Committee or fill a vacancy on the Pension Committee. The Pension Committee Chair may temporarily appoint a senior management

employee to fill a vacancy on the Pension Committee until the next regularly scheduled Audit and Risk Committee meeting.

f) the annual audited financial statements for the OPG Pension Fund, the Used Fuel Segregated Fund and the Decommissioning Segregated Fund.

g) the investment policies and procedures, including the design of modifications, for the OPG Pension Fund, as required by the Ontario Pension Benefits Act and its regulations, and for the Decommissioning Segregated Funds, as required by the Ontario Nuclear Funds Agreement.

h) the appointment of the Pension Plan actuary.

In carrying out its responsibilities for the oversight of financial planning and investment funds the Committee reviews:

i) reports on a quarterly, annual or by exception basis, on compliance with and appropriateness of the asset mix policy; total fund and asset class returns relative to benchmarks; material compliance with breaches of policies or procedures; and work conducted by the plan actuary.

j) periodic reports on the calculation of OPG's nuclear waste liability.

7. *OPG's Enterprise Risk Management*

The Committee reviews and makes recommendations to the Board on:

a) the appointment or replacement of the Chief Risk and Audit Executive.

b) the Company's enterprise risk policy, framework, overall risk appetite and targets.

In carrying out its responsibilities for oversight of OPG's Enterprise Risk Management the Committee reviews:

c) the processes employed by Management for identifying and assessing the Company's principal risks.

d) periodic reports on Management's assessment of the principal risks to achieving the Company's strategic and business plan objectives, and the strategies for monitoring, managing and responding to those risks.

e) periodic reports on significant emerging and evolving risks and relevant external events that could potentially impact OPG's risk profile.

f) compliance metrics related to OPG's commercial operations trading, treasury, and fuels management.

g) regular reports on OPG's cyber security position and programs.

h) periodic reports on OPG's Insurance Program.

8. *Assessment of committee performance and board policies*

In carrying out its responsibilities for assessment of committee performance and board policies the Committee shall:

a) Review and assess Committee performance, including a review of the adequacy of and its compliance with this Charter, in accordance with the evaluation process approved by the Board and taking into account all legislative and regulatory requirements applicable to the Committee as well as any best practice guidelines recommended by regulators with whom OPG has a reporting relationship.

b) Provide oversight of the implementation of the following Board of Directors' policies, and review these policies at least annually (or as otherwise noted below) to ensure their continuing adequacy:

   i. Delegation and Exercise of Authority Policy
   ii. Disclosure Policy
   iii. Code of Business Conduct and Supplier Code of Conduct, including anti-bribery and corruption
   iv. Enterprise Risk Management Policy (reviewed every three years)
   v. Cyber Security Policy

c) Provide oversight of the development of any new policies deemed necessary by the Committee.

Organization

Members

The Audit and Risk Committee shall consist of three or more Directors as determined by the Board of Directors. All members of the Committee shall be independent as defined by the Ontario Securities Commission, and not "affiliated" with OPG.

The Board shall appoint the members of the Committee and the Chair of the Committee annually. The Board may appoint a member to fill a vacancy which occurs in the Committee between annual elections of Directors. Any member of the Committee may be removed or replaced at any time by the Board.

If a member of the Committee becomes "affiliated" with OPG, the member may continue as a member of the Committee with the approval of the Board Chair, in consultation with the Corporate Secretary.

As a "venture issuer", OPG is exempt from the statutory requirements of National Instrument 52-110 requiring members of Audit Committees be independent and financially literate. However, OPG considers such independence and financial literacy to be "best practice" and therefore each of the members of the Audit and Risk Committee shall satisfy the applicable independence and financial literacy requirements of the laws and regulations governing Audit Committees.

The Board of Directors shall confirm that each member of the Audit and Risk Committee is financially literate; as such qualification is interpreted by the Board of Directors in its business judgment, and in compliance with National Instrument 52-110 and its Companion Policy.

Meetings

The Committee shall meet as frequently as it determines but not less than quarterly. During quarterly meetings, the Committee will hold separate in camera sessions with the external auditors, the Chief Internal Audit Executive, the Chief Risk Officer and Management to discuss any matters that the Committee believes should be discussed and to provide a forum for any relevant issues to be raised.

Notice of the time and place of each meeting of the Committee must be given to each member of the Committee not less than 48 hours before the time of the meeting.

A quorum of the Committee shall be a majority of its members, but not less than two. The powers of the Committee may be exercised at a meeting at which a quorum of the Committee is present in person or by

telephone or other electronic means, or by a resolution signed by all members entitled to vote on that resolution at a meeting of the Committee. Each member is entitled to one vote in Committee proceedings.

The Chair shall preside at all meetings of the Committee at which he or she is present (or if not able to be present designate another member of the Committee to chair the meeting) and shall develop the agenda for each Committee meeting. The agenda for each meeting of the committee shall be delivered to each member of the Committee at least 48 hours prior to any meeting of the Committee, together with such other materials as the chair determines necessary.

Minutes shall be kept of all meetings of the Committee and shall be maintained by OPG's Corporate Secretary. The procedure at meetings is to be determined by the Committee unless otherwise determined by the by-laws of OPG, by a resolution of the Board or by this Charter.

The Committee may meet in camera (without management present) at any time during the meeting consistent with the Board guideline on the conduct of in camera sessions and the keeping of minutes from in camera sessions.

The Committee may invite any Director, officer or employee of OPG or OPG's counsel or any other person to attend meetings of the Committee to assist in the discussion and examination of the matters under consideration by the Committee.

Reports

The Committee will report its activities and actions to the Board of Directors with recommendations, as the Committee deems appropriate.

The Committee will provide for inclusion in OPG's financial information or regulatory filings any report from the Audit and Risk Committee required by applicable laws and regulations and stating among other things whether the Committee has:

i. Reviewed and discussed the audited financial statements with Management.
ii. Discussed pertinent matters with the internal and external auditors.
iii. Received disclosures from the external auditors regarding the auditors' independence and discussed with the auditors their independence.
iv. Recommended to the Board of Directors that the audited financial statements be included in OPG's Annual Report.

Authority

The Audit and Risk Committee shall have the authority to:

a) conduct or authorize investigations into any matters within the Committee's scope of responsibilities.

b) set and pay the compensation for any advisors employed by the Committee.

c) to communicate directly with the internal and external auditors.

While the Audit and Risk Committee has the responsibilities and powers set forth in this Charter, it is not the duty of the Audit and Risk Committee to plan or conduct audits or risk assessments, or to determine that OPG's financial statements and disclosures are complete and accurate and are in accordance with

generally accepted accounting principles and applicable rules and regulations. These are the responsibility of Management and, as appropriate, the external auditor.

Delegation of Authority

The Committee may not delegate its oversight responsibilities. The Committee may delegate to a sub-committee, the Chief Executive Officer or any employee of OPG the authority to exercise any right, power or responsibility that the Committee may have on such terms and conditions and within such limits as the Committee deems appropriate provided that the sub-committee, Chief Executive Officer or employee subsequently advises the Committee of any right, power or responsibility so exercised.

Access to Management and Outside Advisors

The Audit and Risk Committee shall have unrestricted access to members of Management and relevant information.

The Audit and Risk Committee has the authority to retain legal counsel, accountants or other advisors to assist it in the conduct of any investigation, as it determines necessary to carry out its duties.

ONTARIO POWER GENERATION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

DECEMBER 31, 2017

[DRAFT]

2017 YEAR-END REPORT

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ONTARIO POWER GENERATION INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) should be read in conjunction with the audited consolidated financial statements and accompanying notes of Ontario Power Generation Inc. (OPG or Company) as at and for the year ended December 31, 2017. OPG's consolidated financial statements are prepared in accordance with United States generally accepted accounting principles (US GAAP) and are presented in Canadian dollars.

As required by *Ontario Regulation 395/11*, as amended, a regulation under the *Financial Administration Act* (Ontario) (FAA), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. In 2014, the Ontario Securities Commission (OSC) approved an exemption which allows OPG to apply US GAAP up to January 1, 2019. The term of the exemption is subject to certain conditions, which may result in the expiry of the exemption prior to January 1, 2019. For details, refer to the section, *Critical Accounting Policies and Estimates* under the heading, *Exemptive Relief for Reporting under US GAAP*. This MD&A is dated March 8, 2018.

FORWARD-LOOKING STATEMENTS

The MD&A contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could", and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

All forward-looking statements involve inherent assumptions, risks, and uncertainties, including those set out in the section, *Risk Management,* and forecasts discussed in the section, *Core Business, Strategy, and Outlook.* All forward-looking statements could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's generating station performance and availability, fuel costs, surplus baseload generation (SBG), cost of fixed asset removal and nuclear waste management, performance and earnings of investment funds, refurbishment of existing facilities, development and construction of new facilities, pension and other post-employment benefit (OPEB) obligations and funds, income taxes, proposed new legislation, the ongoing evolution of Ontario's electricity industry, environmental and other regulatory requirements, health, safety and environmental developments, business continuity events, the weather, financing and liquidity, applications to the Ontario Energy Board (OEB) for regulatory prices, the impact of regulatory decisions by the OEB, Ontario's Fair Hydro Plan (Fair Hydro Plan or the Plan) and forecasts of earnings, cash flows, Funds from Operations (FFO) Adjusted Interest Coverage, Return on Common Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI), Total Generating Cost (TGC) and capital expenditures. Accordingly, undue reliance should not be placed on any forward-looking statement. The forward-looking statements included in this MD&A are made only as of the date of this MD&A. Except as required by applicable securities laws, OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events, or otherwise.

THE COMPANY

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG was established under the *Business Corporations Act* (Ontario) (OBCA) and is wholly owned by the Province of Ontario (Province or Shareholder).

As at December 31, 2017, OPG's electricity generation portfolio had an in-service capacity of 16,210 megawatts (MW). OPG operates two nuclear generating stations, 66 hydroelectric generating stations, three thermal generating stations, and one wind power turbine. In addition, OPG and TransCanada Energy Ltd. co-own the 550 MW Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS). OPG and ATCO Power Canada Ltd. co-own the 560 MW Brighton Beach gas-fired combined cycle GS (Brighton Beach). OPG's 50 percent share of the in-service capacity and generation volume of these co-owned facilities is included in the generation portfolio statistics set out in this report. The income from the co-owned facilities is accounted for using the equity method of accounting, and OPG's share of income is presented as income from investments subject to significant influence in the Contracted Generation Portfolio segment.

OPG also owns two other nuclear generating stations, the Bruce A GS and the Bruce B GS, which are leased on a long-term basis to Bruce Power LP (Bruce Power). Income from these leased stations is included in revenue under the Regulated – Nuclear Generation segment. The leased stations are not included in the generation portfolio statistics set out in this report.

All of OPG's owned and co-owned generating facilities are located in Ontario. OPG does not operate PEC, Brighton Beach, the Bruce A GS and the Bruce B GS.

OPG's Reporting Structure

Effective in the fourth quarter of 2017, following the establishment of the Fair Hydro Trust (the Trust) as the financing entity to implement the Fair Hydro Plan under the *Ontario Fair Hydro Plan Act, 2017* (the Fair Hydro Act or the Act), OPG has modified its reportable business segments to include the Fair Hydro Trust segment. Through its control over the key activities of the Trust and its obligation to absorb losses through ownership of the Trust's subordinated debt, the Company consolidates the financial results of the Trust in accordance with US GAAP. The Fair Hydro Trust segment reports the income related to OPG's role as Financial Services Manager under the Act and holder of subordinated debt issued by the Trust, including the financial results of the Trust. The Fair Hydro Plan and the Fair Hydro Trust are discussed in the section, *Recent Developments* and in the section, *Core Business, Strategy, and Outlook* under the heading, *Business Segments*.

The composition of OPG's reportable business segments is as follows:

- Regulated – Nuclear Generation
- Regulated – Nuclear Waste Management
- Regulated – Hydroelectric
- Contracted Generation Portfolio
- Services, Trading, and Other Non-Generation
- Fair Hydro Trust.

OPG receives regulated prices for electricity generated from most of its hydroelectric facilities and all of the nuclear facilities that it operates (collectively, prescribed facilities or regulated facilities). The regulated facilities comprise 54 hydroelectric generating stations across a number of major river systems in the province, the Pickering Nuclear GS (Pickering GS) and Darlington Nuclear GS (Darlington GS).

The operating results related to these regulated facilities are described under the Regulated – Nuclear Generation, Regulated – Nuclear Waste Management, and Regulated – Hydroelectric segments. For the remainder of OPG's operating generating facilities, the operating results are described under the Contracted Generation Portfolio segment. A description of all OPG's segments is provided under the section, *Business Segments*.

In-Service Generating Capacity

OPG's in-service generating capacity by business segment as of December 31 was as follows:

(MW)	**2017**	**2016**
Regulated – Nuclear Generation [1]	**5,728**	5,728
Regulated – Hydroelectric	**6,426**	6,421
Contracted Generation Portfolio [2]	**4,056**	4,028
Total	**16,210**	16,177

[1] The in-service generating capacity as of December 31, 2017 and December 31, 2016 excludes Unit 2 of the Darlington GS. The unit, which has a generating capacity of 878 MW, was taken offline in mid-October 2016 and is currently undergoing refurbishment.

[2] Includes OPG's share of in-service generating capacity of 275 MW for PEC and 280 MW for Brighton Beach.

The total in-service capacity as at December 31, 2017 increased by 33 MW compared to 2016. The increase was primarily due to the completion of the 28 MW Peter Sutherland Sr. hydroelectric GS, which was placed in-service in the first quarter of 2017, and the upgrade of Unit 10 of the Sir Adam Beck 1 hydroelectric GS, which was completed in June 2017. Further details on the Peter Sutherland Sr. GS project are found in the section, *Core Business, Strategy, and Outlook* under the heading, *Project Excellence*.

REVENUE MECHANISMS FOR REGULATED AND NON-REGULATED GENERATION

Regulated Generation

The OEB sets the prices for electricity generated from OPG's regulated nuclear and regulated hydroelectric facilities. The following table presents the OEB-authorized regulated prices for electricity generated from these facilities during the periods from January 1, 2016 to May 30, 2017, as well as new regulated prices retrospectively effective June 1, 2017 that OPG has calculated and submitted to the OEB, based on the OEB's decision on OPG's 2017-2021 application for new regulated prices issued on December 28, 2017:

($/MWh)	2017		2016
	January 1 to May 31	**June 1 to December 31** [1]	
Regulated – Nuclear Generation			
Base regulated price	**59.29**	**80.65**	59.29
Variance and deferral account rate rider	**-**	**-**	10.84 [2]
	59.29	**80.65**	70.13
Regulated – Hydroelectric			
Base regulated price	**40.72**	**41.67**	40.72
Variance and deferral account rate rider	**-**	**-**	3.19 [2]
	40.72	**41.67**	43.91

[1] Regulated prices for the June 1, 2017 to December 31, 2017 period were calculated and submitted to the OEB by OPG in January 2018 based on the OEB's December 28, 2017 decision on OPG's 2017-2021 application for new regulated prices. The final regulated prices will be determined by the OEB as part of the final payment amounts order process, which is expected to be completed in the first half of 2018. As part of the process, the OEB is expected to authorize separate rate riders to allow for the recovery of the shortfall between the new regulated prices and the previous regulated prices that OPG continues to receive during the period between June 1, 2017 and the implementation date of the new regulated prices pending the issuance of the final payment amounts order. The incremental revenue for the period between June 1, 2017 and December 31, 2017 arising from this retrospective application of new regulated prices was accrued in 2017. **[MONITOR]**

[2] The OEB authorized interim period rate riders for the period from October 1, 2015 to December 31, 2016 to allow for the recovery of the riders effective July 1, 2015 for the period from July 1, 2015 to September 30, 2015. The nuclear interim period rate rider was $2.17 per megawatt hour (MWh) and the regulated hydroelectric interim period rate rider was $0.64/MWh. These interim period rate riders have not been included in the above table. All rate riders in effect during 2016 expired on December 31, 2016.

Based on the OEB's December 2017 decision, the new base regulated prices are determined on an incentive ratemaking methodology for the hydroelectric operations and under a custom incentive regulation framework for the nuclear operations. For the hydroelectric facilities, the new base regulated price is determined using a formula that annually escalates the previous regulated prices, subject to some adjustments, based on inflation less a stretch factor to incent additional innovation and efficiency. For the nuclear facilities, the new regulated price is determined under a rate smoothing approach that defers a portion of the approved nuclear revenue requirement for future collection, with the aim of making more stable changes in OPG's production-weighted regulated prices year over year. The nuclear revenue requirement is based on the OEB-approved forecasts of operating costs as reduced by a stretch factor and a return on rate base. Rate base for OPG represents the average net level of investment in regulated fixed and intangible assets in service and an allowance for working capital. The OEB's December 2017 decision and OPG's new regulated prices are discussed further in the section, *Recent Developments*.

The base regulated prices in effect during 2016 were established by the OEB's November 2014 decision and December 2014 order, effective November 1, 2014, using a forecast cost-of-service methodology based on the OEB-approved revenue requirements for the 2014 to 2015 period, taking into account the OEB-approved forecasts of production and operating costs for the regulated facilities and a return on rate base.

The increase in base regulated prices for the Regulated – Nuclear Generation segment from those last approved in 2014 is impacted by lower production for Darlington GS for the duration of Unit 2's refurbishment. The increase also

reflects OPG's ability to earn a return on higher in-service capital and recover costs to enable Pickering to operate beyond 2020 in line with the Long-Term Energy Plan (LTEP).

Rate riders for OPG are typically established to recover or repay approved balances in OEB-authorized regulatory variance and deferral accounts (regulatory accounts). Variance and deferral accounts typically capture, for subsequent review and approval, differences between actual costs and revenues and the corresponding forecast amounts approved by the OEB in setting regulated prices, or record the impact of items not reflected in the approved regulated prices. The rate riders in effect to the end of 2016 were established by the OEB's October 2015 order on OPG's 2014 application to recover the December 31, 2014 variance and deferral account balances. Revenue received from the recovery of variance and deferral account balances is largely offset by amortization expense related to these balances.

Non-Regulated Generation

Electricity generated from most of OPG's non-regulated assets is subject to Energy Supply Agreements (ESAs) with the Independent Electricity System Operator (IESO).

During 2017, ESAs were in effect for the following thermal generating facilities:

- Lennox GS: Capacity and production provided by the station are subject to an ESA for the period from January 1, 2013 to September 30, 2022
- Atikokan GS: Capacity and production provided by the station are subject to a ten-year ESA expiring in July 2024
- Thunder Bay GS: Capacity and production provided by the station are subject to a five-year ESA expiring in January 2020.

In addition, long-term hydroelectric ESAs are in place for the following facilities, with expiry dates ranging from 2059 to 2067:

- Lac Seul and Ear Falls generating stations
- Healey Falls GS
- Sandy Falls, Wawaitin, Lower Sturgeon, and Hound Chute generating stations
- Little Long, Harmon, Smoky Falls, and Kipling generating stations (collectively the Lower Mattagami River generating stations)
- Peter Sutherland Sr. GS, which was placed in-service in March 2017.

HIGHLIGHTS

Overview of Results

This section provides an overview of OPG's operating results for the years ended December 31, 2017 and December 31, 2016.

(millions of dollars – except where noted)	**2017**	**2016**
Revenue	**5,158**	5,653
Fuel expense	**689**	727
Gross margin	**4,469**	4,926
Operations, maintenance and administration	**2,824**	2,747
Depreciation and amortization	**679**	1,257
Accretion on fixed asset removal and nuclear waste management liabilities	**960**	929
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(801)**	(746)
Earnings from Fair Hydro Trust	**(1)**	-
Income from investments subject to significant influence	**(38)**	(37)
Property taxes	**40**	46
Restructuring	**-**	6
	3,663	4,202
Income before other gains, interest, and income taxes	**806**	724
Other gains	**379**	17
Income before interest and income taxes	**1,185**	741
Net interest expense	**95**	120
Income before income taxes	**1,090**	621
Income tax expense	**209**	168
Net income	**881**	453
Net income attributable to the Shareholder	**860**	436
Net income attributable to non-controlling interest [1]	**21**	17
Electricity production (TWh) [2]	**74.1**	78.2
Cash flow		
Cash flow provided by operating activities	**944**	1,817

[1] Relates to the 25 percent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in the Lower Mattagami Limited Partnership, the 33 percent interest of Coral Rapids Power Corporation (CRP), a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership (PSS), and the 10 percent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP. CRP increased its partnership interest to 33 percent in April 2017.

[2] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach and excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS was excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

Net income attributable to the Shareholder was $860 million for 2017, representing an increase of $424 million compared to 2016. Income before interest and income taxes was $1,185 million for 2017, representing an increase of $444 million compared to 2016. The following summarizes the significant factors which contributed to the variance:

Significant factors that increased income before interest and income taxes:

- Higher revenue from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments of approximately $480 million recorded in the fourth quarter of 2017 to reflect the OEB's decision on OPG's application for new regulated rates issued in December 2017 with a retrospective effective date of June 1,

2017. This revenue increase for the June 1, 2017 to December 31, 2017 period was recorded as an increase in regulatory assets, based on new regulated prices for that period proposed in OPG's January 2018 submission to the OEB based on the findings in the December 2017 decision, net of a regulatory liability recognized in relation to OPG's nuclear rate smoothing proposal included in that submission. The new regulated prices, the future collection period for the retrospective revenue increase, and the rate smoothing proposal are pending the OEB's approval through the payment amounts order process, which typically follows the OEB's issuance of a decision on a major rates application. The OEB's approval of the final payment amounts order, including determinations on the new regulated prices and rate smoothing, are not expected to have a material impact on the total revenue recorded for the June 1, 2017 to December 31, 2017 period. The OEB is expected to issue the final payment amounts order in the first half of 2018. **[MONITOR]**

- Higher earnings of $377 million from the Services, Trading, and Other Non-Generation segment, primarily as a result of the gain on sale of OPG's head office premises and associated parking facility, a non-core asset of the business. A gain on sale of $283 million, which is net of tax effects of $95 million, was recognized in net income upon completion of the transaction in the second quarter of 2017. The sale was undertaken pursuant to a Shareholder Declaration and a Shareholder Resolution. Further details can be found under the heading, *Recent Developments – Shareholder Declarations and Shareholder Resolutions to Sell Certain Non-Core Real Estate Properties*.
- Higher earnings of $24 million from the Regulated – Nuclear Waste Management segment, primarily due to higher earnings from the nuclear fixed asset removal and nuclear waste management funds (Nuclear Segregated Funds), partially offset by an increase in accretion expense on the nuclear fixed asset removal and nuclear waste management liabilities (Nuclear Liabilities).

Significant factors that reduced income before interest and income taxes:

- Lower revenue of approximately $285 million, partially offset by a decrease in fuel expense of $31 million, reflecting lower electricity generation of 4.9 terawatt hours (TWh) from the Regulated – Nuclear Generation segment. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS since October 2016, partially offset by an increase in generation from the Pickering GS. The increase in generation from the Pickering GS was primarily due to outage cycle optimization, favourable unit conditions and execution of planned outage work resulting in fewer unplanned and planned outage days at the station.
- Higher operations, maintenance and administration (OM&A) expenses of $77 million, mainly in the Regulated – Nuclear Generation segment, reflecting planned expenditures related to the major maintenance activities occurring at the nuclear stations.
- Higher depreciation and amortization expense of $22 million in the Regulated – Nuclear Generation segment, excluding amortization expense related to balances in regulatory accounts, primarily due to new assets in service.
- A gain of $22 million recorded in the first quarter of 2016 to reflect the OEB's decision on OPG's motion asking the OEB to review and vary parts of its November 2014 decision on OPG's regulated prices.

The expiry of rate riders for the recovery of OEB-approved balances in regulatory accounts on December 31, 2016 contributed to the decrease in revenue in 2017, compared to 2016, but was largely offset by a decrease in the amortization expense related to regulatory account balances.

Net interest expense decreased by $25 million in 2017, compared to 2016, primarily due to a higher amount of interest costs capitalized for the Darlington Refurbishment project.

Income tax expense increased by $41 million in 2017, compared to 2016, primarily due to higher income before income taxes, partially offset by a higher amount of income tax expense deferred in regulatory assets in 2017.

Segment Results

The following table summarizes OPG's income before interest and income taxes by business segment. Significant factors which contributed to the higher income during 2017, compared to 2016, are discussed above. A detailed discussion of OPG's performance by reportable segment is included in the section, *Discussion of Operating Results by Business Segment*.

(millions of dollars)	**2017**	**2016**
Income (loss) before interest and income taxes		
Regulated – Nuclear Generation	**57**	4
Regulated – Hydroelectric	**614**	642
Contracted Generation Portfolio	**300**	282
Total electricity generation business segments	**971**	928
Regulated – Nuclear Waste Management	**(150)**	(174)
Services, Trading, and Other Non-Generation	**364**	(13)
Fair Hydro Trust	**-**	-
	1,185	741

Electricity Generation

Electricity generation for 2017 and 2016 was as follows:

(TWh)	**2017**	**2016**
Regulated – Nuclear Generation	**40.7**	45.6
Regulated – Hydroelectric	**30.7**	29.5
Contracted Generation Portfolio [1]	**2.7**	3.1
Total OPG electricity generation	**74.1**	78.2
Total electricity generation by other generators in Ontario [2]	**70.5**	72.7

[1] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

[2] Non-OPG generation is calculated as the Ontario electricity demand plus net exports, as published by the IESO, minus OPG electricity generation.

Total OPG electricity generation decreased by 4.1 TWh in 2017, mainly due to lower electricity generation of 4.9 TWh from the Regulated – Nuclear Generation segment. As expected, this was primarily the result of the removal from service of Unit 2 at the Darlington GS for the duration of the unit's refurbishment, which began in October 2016. This decrease in electricity generation was partially offset by an increase in generation from the Pickering GS, primarily due to outage cycle optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of outage days at the station, as well as higher electricity generation from the Regulated – Hydroelectric segment.

The higher electricity generation from the Regulated – Hydroelectric segment in 2017 was due to higher water flows primarily on the eastern Ontario river systems, net of forgone electricity generation as a result of SBG conditions, discussed below.

The lower electricity generation from the Contracted Generation Portfolio segment was primarily due to higher SBG conditions.

OPG's operating results are affected by changes in grid-supplied electricity demand resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. Ontario's electricity demand as reported

by the IESO was 132.1 TWh in 2017 and 137.0 TWh and 2016, respectively, which excludes electricity exports out of the province.

Power that is surplus to the Ontario market is managed by the IESO, mainly through generation reductions at hydroelectric and nuclear stations and other grid-connected renewable resources. Reducing hydroelectric production is a measure used by the IESO to manage SBG conditions. Baseload generation supply surplus in Ontario was more prevalent in 2017 than in 2016, mainly due to higher water flows and reduced electricity demand in the province during 2017. During 2017 and 2016, OPG lost 5.9 TWh and 4.7 TWh of hydroelectric generation due to SBG conditions, respectively. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions in 2017 and 2016 was offset by the impact of a regulatory variance account authorized by the OEB. OPG did not forgo any electricity production at its nuclear stations due to SBG conditions.

Average Sales Prices

The majority of OPG's generation is from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments. The regulated prices authorized by the OEB for electricity generated from OPG's nuclear and regulated hydroelectric generating stations are discussed in the section, *Revenue Mechanisms for Regulated and Non-Regulated Generation*.

The average sales price for the Regulated – Nuclear Generation segment during 2017 was 7.1 cents per kilowatt hour (¢/kWh), compared to 6.9 ¢/kWh during 2016. The increase in this average sales price was primarily due to an increase in revenue for the period June 1, 2017 to December 31, 2017 recorded in the fourth quarter of 2017 to reflect the OEB's December 2017 decision on OPG's application for new regulated prices, with an effective date of June 1, 2017. The increase was partially offset by the expiry of an OEB-authorized nuclear rate rider of $10.84 per MWh, on December 31, 2016, for the recovery of variance and deferral account balances. The average sales price for the Regulated – Hydroelectric segment during 2017 was 4.2 ¢/kWh, compared to 4.4 ¢/kWh during 2016. The decrease in this average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized regulated hydroelectric rate rider of $3.19/MWh for the recovery of variance and deferral account balances, partially offset by the impact of an increase in revenue for the period June 1, 2017 to December 31, 2017 recorded in the fourth quarter of 2017 to reflect the OEB's December 2017 decision. The rate riders that expired on December 31, 2016 were established to recover approved balances recorded in the variance and deferral accounts in prior years. As such, the year-over-year changes in revenue from the rate riders were largely offset by changes in amortization expense related to these balances.

Cash Flow from Operations

Cash flow provided by operating activities for 2017 was $944 million, compared to $1,817 million for 2016. The decrease in cash flow provided by operating activities was expected and primarily due to lower generation revenue receipts reflecting lower generation from the Regulated – Nuclear Generation segment as a result of the ongoing refurbishment of Unit 2 at the Darlington GS and the expiry, on December 31, 2016, of the OEB-authorized rate riders for nuclear and regulated hydroelectric generation. The decrease in cash flow was also due to higher income tax instalments during 2017, compared to 2016.

The decrease in cash flow provided by operating activities was partly offset by lower contributions to the Used Fuel Segregated Fund in 2017. Both the Used Fuel Segregated Fund and the Decommissioning Segregated Fund were determined to be fully funded based on an updated estimate of OPG's nuclear waste management and nuclear facilities decommissioning obligations pursuant to an Ontario Nuclear Funds Agreement (ONFA) reference plan approved by the Province, effective January 1, 2017. Pursuant to the ONFA, the reference plan is required to be updated at least once every five years. Contributions to either or both of the Nuclear Segregated Funds may be required in the future should the funds be in an underfunded position at the time of the next ONFA reference plan update. The decrease in cash flow compared to the prior year also was partially offset by the payment of a supplemental rent rebate to Bruce Power in the first quarter of 2016 in relation to a period in 2015. The lease

agreement for the Bruce nuclear generating stations was amended in late 2015 to eliminate this rebate provision going forward.

Funds from Operations Adjusted Interest Coverage

FFO Adjusted Interest Coverage is an indicator of OPG's ability to meet interest obligations from operating cash flow. The indicator is measured over a 12-month period. The FFO Adjusted Interest Coverage was 3.3 times for 2017 compared to 5.1 times for 2016. FFO Adjusted Interest Coverage in 2017 reflected a year-over-year decrease in FFO before interest due to lower cash flow provided by operating activities and changes to non-cash working capital balances, offset by the impact of a lower adjusted interest expense due to a decrease in the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets.

The decrease in the excess of interest on pension and OPEB benefit obligations over expected return on pension plan assets in 2017 was primarily due to the change in the method used to estimate the interest cost and service cost component of pension and OPEB costs prospectively adopted as of January 1, 2017. The change in the method is discussed in the section, *Critical Accounting Policies and Estimates* under the heading, *Pension and Other Post-Employment Benefits*.

Return on Common Equity Excluding Accumulated Other Comprehensive Income

ROE Excluding AOCI is an indicator of OPG's performance consistent with the Company's strategy to provide value to the Shareholder. ROE Excluding AOCI is measured over a 12-month period. ROE Excluding AOCI for 2017 was 7.5 percent, compared to 4.2 percent for 2016. ROE Excluding AOCI increased for 2017, compared to 2016, primarily due to higher net income attributable to the Shareholder as a result of the gain on the sale of OPG's head office premises and associated parking facility recorded during the second quarter of 2017 and an increase in revenue for the period June 1, 2017 to December 31, 2017 recorded in the fourth quarter of 2017 to reflect the OEB's December 2017 decision on OPG's application for new regulated prices, with an effective date of June 1, 2017. The increase in net income attributable to the Shareholder was partially offset by the impact of lower nuclear electricity generation reflecting the Unit 2 refurbishment outage at the Darlington GS.

Enterprise Total Generating Cost per Megawatt-Hour

The Enterprise TGC per megawatt-hour (MWh) was $50.66 for the year ended December 31, 2017, compared to $48.45 for the same period in 2016. The increase in Enterprise TGC per MWh was expected and primarily due to lower nuclear electricity generation as a result of the Unit 2 refurbishment outage at the Darlington GS and higher sustaining capital expenditures, partially offset by higher SBG-adjusted hydroelectric electricity generation reflecting higher water flows.

If Unit 2 at the Darlington GS was not currently undergoing refurbishment and had continued to operate in a manner consistent with the performance of the remaining units at the station, adjusting for generation constraints on these units related to the transition of the station toward refurbishment, the Enterprise TGC would have been approximately $4 to $5 per MWh lower for the year ended December 31, 2017. This sensitivity was calculated using the estimated incremental electricity generation and associated fuel cost that are expected to have had resulted in the absence of the refurbishment.

Nuclear Total Generating Cost per Megawatt-Hour

The Nuclear TGC per MWh was $70.95 for the year ended December 31, 2017, compared to $62.30 for the same period in 2016. The increase in Nuclear TGC per MWh was expected and primarily due to the decrease in nuclear electricity generation primarily as a result of the Unit 2 refurbishment outage at the Darlington GS and higher sustaining capital expenditures.

Hydroelectric Total Generating Cost per Megawatt-Hour

The Hydroelectric TGC per MWh was $23.91 for the year ended December 31, 2017, compared to $25.49 for the same period in 2016. The improvement in the Hydroelectric TGC per MWh was primarily due to higher SBG-adjusted hydroelectricity generation reflecting higher water flows.

ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are not measurements in accordance with US GAAP and should not be considered alternative measures to net income, cash flow provided by operating activities, or any other performance measure under US GAAP. OPG believes that these non-GAAP financial measures are effective indicators of its performance and are consistent with the Company's strategic imperatives and related objectives. The definition and calculation of ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are found in the section, *Supplementary Non-GAAP Financial Measures*.

Recent Developments

OEB's Decision on OPG's Application for New Regulated Prices

The OEB's decision on OPG's May 2016 five-year application for new regulated prices for its nuclear and regulated hydroelectric generation was issued on December 28, 2017, following a public hearing process. The OEB set an effective date for OPG's new regulated prices of June 1, 2017. OPG had requested an effective date of January 1, 2017. The decision reflected the terms of an OEB-approved partial settlement agreement reached by OPG and intervenors on a limited set of issues in the first quarter of 2017 (Settlement Agreement). For the first time since OPG's prescribed facilities became subject to rate regulation, the new prices have been determined on an incentive ratemaking methodology for the hydroelectric operations and a custom incentive regulation framework for the nuclear operations.

For the hydroelectric facilities, effective June 1, 2017, the base regulated prices in effect prior to June 1, 2017, with some adjustments, will be escalated for each of years 2017 to 2021 using a formula equal to an industry-specific weighted inflation factor based on indices published annually by the OEB for use in incentive regulation formulas, less a stretch factor adjustment. The OEB accepted OPG's proposal to set the annual stretch factor adjustment at 0.3 percent. Based on the approved formula, the 2017 increase in the base regulated price for the regulated hydroelectric facilities is 1.4 percent as of June 1, 2017 and the 2018 increase is 0.9 percent as of January 1, 2018. For the 2019-2021 period, the base regulated price for the regulated hydroelectric facilities will be determined annually before the beginning of each year using the approved formula and inflation indices published by the OEB.

For the nuclear operations, a revenue requirement is determined for each of the years 2017 to 2021 based on the OEB-allowed level of OPG's forecast operating costs, reduced by a stretch factor amount, as well as a return on rate base determined using OEB's generic prescribed rate of return and an OPG-specific deemed capital structure. OPG has calculated that the findings of the OEB's December 2017 decision with respect to the forecast operating costs, rate base and deemed capital structure for the nuclear generating facilities will result in nuclear revenue requirements totalling $15.9 billion over the five years.

The OEB's findings with respect to the nuclear revenue requirement include approval for inclusion in rate base of in-service amounts related to the Darlington Refurbishment of $5.5 billion by 2021, including $4.8 billion forecast in the first quarter of 2020 upon return to service of Unit 2, $0.4 billion forecast for pre-requisite projects excluding the Heavy Water Storage and Drum Handling Facility (HWSF) over the 2016-2021 period and $0.3 billion for pre-requisite projects placed in service prior to 2016. The OEB is expected to review the HWSF project as part of a future application. In the decision, the OEB concluded that it is appropriate to evaluate OPG's performance on the Darlington Refurbishment project at an overall level rather by individual cost component, with recovery of any increases over the approved in-service amounts subject to a future prudence review. The revenue requirement impact of differences between the approved in-service additions and the actual in-service additions will be recorded in

the Capacity Refurbishment Variance Account authorized by the OEB pursuant to *Ontario Regulation 53/05*. The $4.8 billion forecast in-service amount upon return to service of Unit 2 includes expenditures incurred during the definition and planning phase of the project.

The OEB also approved OPG's requested forecast costs of approximately $292 million for activities to enable Pickering operations beyond 2020 and agreed to inclusion of operating cost and generation impacts associated with continued operation of Pickering in 2021 in nuclear regulated prices. The differences between approved forecast enabling costs for continued Pickering operations and the actual amounts will be recorded in the Capacity Refurbishment Variance Account for future review and disposition by the OEB.

Excluding amounts that otherwise would have been recorded in OEB-authorized regulatory accounts for repayment to, or recovery from, customers in the future, the OEB's decision reduced OPG's proposed five-year nuclear revenue requirement by $0.6 billion. The main adjustments made by the OEB included a reduction of $100 million per year to requested OM&A costs, a reduction of 10 percent per year to forecast non-Darlington refurbishment capital in-service additions entering rate base over the 2017-2021 period, an increase and expansion of the scope of the stretch factor for nuclear costs that further reduced the revenue requirement, and a rejection of OPG's request to increase the equity component of the existing deemed capital structure of 45 percent equity and 55 percent debt. The OEB increased and expanded the annual stretch factor to 0.6 percent to most of OPG's OM&A expenses incurred directly for, or allocated to, the nuclear facilities, as well as to non-Darlington refurbishment capital in-service additions. The stretch factor is applied starting in 2018 and compounds in each year to 2021.

In accordance with *Ontario Regulation 53/05*, the nuclear revenue requirement continues to be adjusted by the amount of OPG's revenues, net of costs, from leasing the Bruce nuclear generating stations to Bruce Power. As directed by the OEB, OPG's revenues and costs related to the Bruce nuclear generating stations continue to be determined in accordance with US GAAP for the purposes of establishing the nuclear revenue requirement and are subject to the Bruce Lease Net Revenues Variance Account in accordance with *Ontario Regulation 53/05*. This includes costs related to the portion of the Nuclear Liabilities associated with the Bruce nuclear generating stations. The OEB's decision maintained the previously approved cost recovery methodology for the costs of the Nuclear Liabilities for the prescribed facilities and for the Bruce facilities, directing OPG to file a future study examining such methodologies jurisdictionally and for OPG's assets specifically. The decision fully incorporated the impacts of the updated estimate of OPG's obligations for nuclear waste management and nuclear facilities decommissioning as at December 31, 2016, including through a new ONFA reference plan effective January 1, 2017 and the change in the Nuclear Liabilities recorded on December 31, 2016.

As proposed by OPG, the OEB set recovery of pension and OPEB costs in the nuclear revenue requirement on the basis of OPG's cash payments for pension and OPEB plans, with differences between pension and OPEB accrual costs and cash payments continuing to be recorded in the Pension & OPEB Cash to Accrual Differential Deferral Account. The regulatory treatment of pension and OPEB costs is discussed further under the heading, *OEB's Report on Regulatory Treatment of Pension and OPEB Costs*.

The OEB accepted all variance and deferral account balances proposed for recovery that were not already accepted as part of the Settlement Agreement, resulting in approval of recovery of $305 million recorded in variance and deferral variance accounts as at December 31, 2015, without adjustments. The Settlement Agreement provided for the continuation of all applicable existing variance and deferral accounts. In addition to the Rate Smoothing Deferral Account discussed below, the OEB established, as of the effective date of the new regulated prices, new variance and deferral accounts to record costs related to implementing the Canadian Nuclear Safety Commission's (CNSC) Fitness for Duty program and to record differences between forecast and actual amount of Scientific Research & Experimental Development investment tax credits attributable to the nuclear facilities.

Consistent with the requirements of *Ontario Regulation 53/05*, OPG's overall production-weighted regulated prices will be smoothed, with a resulting portion of the approved annual nuclear revenue requirements for the 2017-2021 period deferred in the Rate Smoothing Deferral Account for future collection. The non-deferred portion of each year's

nuclear revenue requirement is divided by the OEB-approved forecast of OPG's nuclear electricity generation for the corresponding year to determine the base nuclear regulated price. The OEB approved the nuclear electricity generation forecast as requested by OPG.

As amended in March 2017, *Ontario Regulation 53/05* requires rate smoothing to be applied in a manner that makes changes in OPG's weighted-average nuclear and hydroelectric regulated prices more stable year over year. Previously, the regulation required that rate smoothing be applied with a view of making more stable year-over-year changes in OPG's nuclear regulated prices only. Per the regulation, the deferral account records interest at a long-term debt rate reflecting OPG's cost of long-term borrowing approved by the OEB, compounded annually. The regulation requires the OEB to authorize recovery of the balance in the account on a straight line basis over a period not to exceed ten years following the end of the Darlington Refurbishment project. OPG recognizes positive amounts deferred under rate smoothing as an increase in net regulatory assets and an increase in revenue in the period to which the underlying approved revenue requirement relates. Negative amounts determined under rate smoothing are correspondingly recorded as a decrease in net regulatory assets and a decrease to revenue.

On January 17, 2018, OPG submitted a draft payment amounts order to the OEB that proposed nuclear base regulated prices for each year of the 2017-2021 period, including a rate smoothing proposal, based on the December 2017 decision's findings. The rate smoothing proposal takes into account the near-term and future impacts on customers, while seeking to ensure that resulting nuclear regulated prices allow for sufficient cash flow to maintain the Company's investment grade credit rating and support availability of cost effective funding, while taking into account both near-term and future impacts on customers. Based on the OEB's direction, the draft payment amounts order also included proposed periods for recovery, through interim period shortfall rate riders, of the retrospective revenue shortfall for the period between June 1, 2017 and the implementation date of the new regulated prices based on proposed new regulated prices that would have been in effect during that period. The draft payment amounts also included proposed recovery periods, through variance and deferral account rate riders, for regulatory account balances approved for recovery in this application. **[MONITOR]**

To reflect the OEB's decision, in the fourth quarter of 2017, OPG recorded incremental revenue of approximately $480 million for the period June 1, 2017 to December 31, 2017 based on the draft payment amounts order. The revenue was recorded as an increase in regulatory assets for the June 1, 2017 to December 31, 2017 revenue shortfall based on proposed new regulated prices for nuclear facilities and regulated hydroelectric facilities, net of a regulatory liability recognized in relation to OPG's rate smoothing proposal. The OEB's approval of the final payment amounts order, including the allocation of the approved revenue requirement between nuclear regulated prices and rate smoothing deferrals, is not expected to have a material impact on the net revenue increase recorded in the fourth quarter of 2017. The OEB is expected to issue the final payment amounts order and implement new regulated prices in the first half of 2018. **[MONITOR]**

Consistent with the effective date of the OEB's December 2017 decision, for the period from January 1, 2017 to May 31, 2017, OPG continued to record additions to the existing variance and deferral accounts for the nuclear and regulated hydroelectric facilities pursuant to the OEB's previous decisions and orders. These additions reflected differences between actual and forecast amounts embedded in the regulated prices in effect prior to the June 1, 2017 effective date.

In January 2018, OPG filed a motion asking the OEB to review and vary the effective date of the new regulated prices to January 1, 2017. The motion did not impact OPG's financial results for the year ended December 31, 2017.

Ontario's 2017 Long-Term Energy Plan

On October 26, 2017, Ontario's Ministry of Energy issued the 2017 LTEP that outlines the Province's plans for the future development of Ontario's electricity system. The 2017 LTEP focuses on the affordability, reliability and flexibility of a clean energy supply in the province. The 2017 LTEP replaces the previous LTEP issued in 2013.

As it relates to the supply of electricity, the 2017 LTEP recognizes the refurbishment of Ontario's nuclear generating stations as the most cost-effective option for producing emission-free baseload generation to meet Ontario's needs and reaffirms the Province's support for the refurbishment of the four units at the Darlington GS and the six units at the Bruce generating stations, subject to the principles established in the 2013 LTEP. The 2017 LTEP also recognizes the value to customers of continuing to operate the Pickering GS until 2024, as planned. With respect to hydroelectric electricity generation, the 2017 LTEP highlights the opportunity to continue to invest in optimizing existing hydroelectric facilities, noting that pumped hydroelectric storage could play an important role in the reliability of the electricity system.

Additionally, the 2017 LTEP discusses the potential impact of a number of innovative technologies on the future of the electricity system. Among others, these include the increased electrification of the transportation sector, the emergence of energy storage, and the opportunity for Ontario to foster nuclear innovation technologies. OPG continues to assess how best to capitalize on potential business opportunities in these and other areas. The 2017 LTEP also recognizes the importance of Indigenous peoples' continuing role in shaping Ontario's energy planning, projects and policies.

Darlington Refurbishment

In October 2016, OPG commenced the refurbishment of the first Darlington GS unit, Unit 2, as part of the Darlington Refurbishment project. The de-fuelling of the reactor and islanding of Unit 2, the physical separation of the unit under refurbishment from the three operating units, were completed in the first half of 2017.

The disassembly of reactor components commenced in the third quarter of 2017, with the removal of feeder tubes completed in September 2017. The removal of fuel channel assemblies commenced in October 2017. As part of the fuel channel assemblies, the removal of pressure tubes is in progress and will be followed by the removal of calandria tubes. The second major segment and the removal of all reactor components is expected to be completed by mid-2018.

All of the pre-requisite projects, including construction of facilities, infrastructure upgrades and installation of safety enhancements, with the exception of the HWSF, have been completed and placed in service. The completion of the HWSF has been delayed due to challenges with construction, with construction activities suspended for a portion of 2017. Construction to complete the facility recommenced in the fourth quarter of 2017, including work to preserve and protect the facility during winter. The HWSF is expected to be completed by the second quarter of 2019 and is not on the critical path for the Darlington Refurbishment project, which continues to track on schedule. The increase in the cost estimate for the HWSF will be accommodated within the overall Darlington Refurbishment budget of $12.8 billion. Taking into account the execution performance of the Unit 2 refurbishment, the overall Darlington Refurbishment project continues to track on budget.

On November 21, 2017, the Financial Accountability Office of Ontario issued a report, "*An Assessment of the Financial Risks of the Nuclear Refurbishment Plan*". The report assesses the impact of OPG and Bruce Power's nuclear refurbishments on customers and the Province based on mechanisms in place for the recovery of the costs to refurbish and subsequently operate the nuclear stations. The report concludes that refurbishment of the four units at the Darlington GS and the six units at the Bruce nuclear generating stations provides the most cost effective, low emission generation source available to meet Ontario's baseload electricity requirements.

The Darlington Refurbishment project is discussed further in the section, *Core Business, Strategy, and Outlook* under the heading, *Project Excellence*.

Canadian Nuclear Safety Commission Safety Rating for the Darlington GS and the Pickering GS

The CNSC publishes an annual report on the safety performance of Canada's nuclear power plants. The report assesses how well plant operators are meeting regulatory requirements and program expectations in the areas of operational performance, safety analysis, radiation protection, waste management and conventional health and

safety. On September 8, 2017, the CNSC issued an executive summary of its 2016 annual report, giving both the Darlington GS and the Pickering GS the highest possible safety rating of "Fully Satisfactory". The Darlington GS achieved this rating for the eighth consecutive year, while the Pickering GS achieved this rating for the second consecutive year.

Ontario's Fair Hydro Plan

On March 2, 2017, the Province announced the Fair Hydro Plan aimed at reducing electricity bills for eligible residential, farm, small businesses ~~and other eligible~~ consumers (Specified Consumers) in the province by refinancing a portion of the Global Adjustment costs over a longer period of time. The Global Adjustment includes the difference between Ontario's electricity market clearing price used to dispatch generation and the prices paid to contracted and regulated generators in the province, and the cost of conservation and demand management programs. On June 1, 2017, the Fair Hydro Act received Royal Assent and the associated general regulation came into force in June 2017. The Act established a framework under which the costs and benefits associated with the Government of Ontario's clean energy initiatives are to be allocated between present and future consumers of electricity under the Fair Hydro Plan. The general regulation provides details on the structural, operational and financial elements required to implement the Fair Hydro Plan.

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Pursuant to the Act, effective May 1, 2017, the IESO began to defer a portion of the Global Adjustment costs. The Act allows the IESO to transfer a portion of the deferred balance to a financing entity that would fund the deferral in exchange for an irrevocable right to recover the balance and associated financing and other costs from Specified Consumers in the future (Investment Interest). The legislation appointed OPG as the Financial Services Manager under the Act and conveyed upon the Financial Services Manager statutory obligations, including the creation of one or more financing entities that may acquire Investment Interests from the IESO.

In November 2017, OPG's Board of Directors provided its final approval regarding OPG's involvement with the Trust on commercial terms following the fulfilment of all conditions it established in May 2017. Accordingly, the Fair Hydro Trust was established as the financing entity contemplated by the Act in December 2017. The majority unitholder and beneficiary of the Trust is a wholly-owned subsidiary of OPG. The Trust is structured to be bankruptcy remote and ring fenced from OPG in order to protect the Company's assets and operations.

In order for the Trust to finance the Investment Interest acquired from the IESO, it will incur senior debt from capital markets and subordinated debt from OPG. The Trust's investment will attract financing amounts and other related fees, which, under the general regulation, will be payable by the IESO as carrying costs until July 2021 and by Specified Consumers through the Clean Energy Adjustment to be invoiced by local distribution companies commencing in May 2021, with the three-month lag in 2021 intended to cover the billing and collection lag from the introduction of the Clean Energy Adjustment. The carrying costs include all financing and third-party costs other than payment of principal on debt.

Concurrent with every issuance of the Trust's senior notes, it is expected that OPG will purchase subordinated debt of the Trust in an aggregate amount not to exceed 49 percent of the Trust's total outstanding debt, with 44 percent of the funding to be provided by the Province through equity injections and five percent to be provided by OPG. The subordination level may vary over time, but must at least equal to, or be greater than 35 percent of all outstanding debt. Through OPG's control over the key activities of the Trust and its obligation to absorb losses through ownership of the Trust's subordinated debt, the Company consolidates the financial results of the Trust in accordance with US GAAP.

On December 21, 2017, the Trust purchased its first tranche of Investment Interest from the IESO in the amount of approximately $1.18 billion. Fifty-one percent of the funding requirement or $601 million was financed by the Trust through a revolving warehouse facility ranked as senior notes, and the remaining 49 percent was funded through the issuance of short-term subordinated debt to OPG. The Investment Interest has been classified as a financing receivable on OPG's consolidated balance sheet.

OPG's subordinated debt investment in the Trust was funded through the following sources:

- The Province provided 44 percent of the total funding requirement or $519 million, through an equity injection in OPG in exchange for approximately 12.2 million non-voting Class A common shares at a price of $42.46 per share. The Company's Articles of Amalgamation were amended effective December 1, 2017 to allow for the creation and issuance of Class A shares. Refer to Note 14 of OPG's 2017 audited consolidated financial statements for further details; and
- OPG provided five percent of the total funding requirement or approximately $60 million.

In February 2018, the Trust issued $500 million of senior notes payable with a coupon interest rate of 3.36 percent and an effective interest rate of 3.42 percent, payable semi-annually until maturity on May 15, 2033. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility issued in December 2017. By the end of the first quarter of 2018, the Trust is expected to acquire another tranche of Investment Interest from the IESO, which it expects to fund using its revolving warehouse facility.

Refer to the section, *Liquidity and Capital Resources* under the heading, *Financing Activities* for further details on the Trust's financing arrangements and OPG's public debt offering.

OEB's Report on Regulatory Treatment of Pension and OPEB Costs

On September 14, 2017, the OEB issued its final report on the guiding principles and policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the Ontario electricity and natural gas sectors. The report establishes the accrual basis of accounting as the method of determining pension and OPEB amounts for rate-setting purposes, unless the OEB finds that this method does not result in just and reasonable rates in the circumstances of a particular utility. The report also provides for the establishment of a generic variance account to record asymmetric carrying charges in favour of ratepayers on the differences between the accrual costs recovered and cash payments made by a utility in respect of pension and OPEB plans. Carrying charges on this differential are to be assessed at the OEB's prescribed interest rate, on a prospective basis from the effective date of the new variance account. For OPG, this differential will include amounts going back to November 1, 2014, with the charges calculated on the portion of the differential that has been recovered through regulated prices. None of this differential has been recovered to date. The prescribed interest rate is set quarterly by the OEB based on the quarterly return of a mid-term corporate bond index yield.

The OEB's September 2017 report and the OEB's December 2017 decision on OPG's application for new regulated prices require OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the Pension & OPEB Cash to Accrual Differential Deferral Account in effect since November 1, 2014, until such time as the OEB approves resumption of the accrual basis of recovery for OPG. The future recovery of amounts recorded in the account will be subject to this approval. The OEB's report did not impact OPG's financial results for the year ended December 31, 2017.

The Company recognizes the amount set aside in the Pension & OPEB Cash Versus Accrual Differential Deferral Account as a regulatory asset. As at December 31, 2017, the regulatory asset had a balance of $614 million. Consistent with the expectations set out in the OEB's December 2017 decision, in 2018, OPG plans to file an application with the OEB requesting disposition of the Pension & OPEB Cash Versus Accrual Differential Deferral Account balance as well as balances accumulated since December 31, 2015 in other regulatory accounts.

Shareholder Declarations and Shareholder Resolutions to Sell Certain Non-Core Real Estate Properties

In December 2015, OPG received a Shareholder Declaration and a Shareholder Resolution requiring the Company to sell its head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street in Toronto, Ontario. The sale was completed in April 2017, with a gain on sale of $283 million, which is net of tax effects of $95 million, recognized in net income in the second quarter of 2017. The pre-tax gain on sale was recorded

as an item of Other gains in the consolidated statement of income in the Services, Trading and Other Non-Generation segment. Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. The amount of designated proceeds transferred into the Consolidated Revenue Fund are expected to approximate ~~will be equal to~~ the after-tax gain on sale. **[MONITOR]** The transfer is expected to take place ~~as early as~~ in the first quarter of 2018, through a special dividend authorized by OPG's Board of Directors in March 2018. **[MONITOR]**

In June 2016, OPG received a Shareholder Declaration and a Shareholder Resolution that requires the Company to sell its former Lakeview GS site located in Mississauga, Ontario. OPG has entered into a purchase and sale agreement with a purchaser with the sale scheduled to close in March 2018. An estimated after-tax gain on sale of approximately $200 million is expected to be recognized in net income upon completion of the transaction in the first quarter of 2018. **[MONITOR]** Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. OPG anticipates the amount of designated proceeds transferred into the Consolidated Revenue Fund to approximate the after-tax gain on the sale. In accordance with the Shareholder Resolution, approximately one-third of the site is to be transferred to the City of Mississauga, by the purchaser, for parkland, institutional, and cultural uses.

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CORE BUSINESS, STRATEGY, AND OUTLOOK

OPG's mission is to provide low cost power in a safe, clean, reliable and sustainable manner for the benefit of its customers and its Shareholder. OPG also seeks to pursue, on a commercial basis, generation development projects and other business expansion opportunities to the benefit of the Shareholder.

OPG's four key strategic imperatives are as follows:

- Operational Excellence
- Project Excellence
- Financial Strength
- Social Licence.

Operational Excellence

Operational excellence at OPG is accomplished by the safe and environmentally responsible generation of reliable and cost-effective electricity from the Company's generating assets through a highly trained and engaged workforce.

Workplace Safety and Public Safety

Workplace safety and public safety are fundamental core values at OPG. OPG is committed to operating all of its facilities in a safe, secure, and reliable manner that minimizes risks to a reasonably achievable level. Safety is an overriding priority in all activities performed at OPG's generating and other facilities, and all employees and contractors are expected to conduct themselves in manner that ensures workplace safety and public safety in line with the Company's safety culture.

In the area of workplace safety, OPG is committed to achieving excellent performance through continuous improvement and a strong safety culture, with the ultimate goal of zero injuries. OPG utilizes an integrated health and safety management system and a set of operational risk control procedures to ensure continued monitoring of health and safety performance and to support continuous learning and improvement in this area. Over the past five years, OPG has repeatedly stood in the top quartile of its comparator Canadian electrical utilities in various safety performance metrics.

Workplace safety performance is measured using two primary indicators at OPG, All Injury Rate (AIR) and Accident Severity Rate (ASR). OPG's AIR and ASR results for employee workplace safety were as follows for the year ended December 31:

	2017	2016
AIR *(injuries per 200,000 hours worked)*	**0.48**	0.56
ASR *(days lost per 200,000 hours)*	**3.57**	2.59

In 2017, OPG's AIR improved from 2016 and was the third-best performance year in the Company's history. For those employee injuries that caused lost time from work, the total time lost from work in 2017 was greater than the previous year. OPG's analysis of the underlying safety events indicated that major contributors to the injuries and near misses included inadequate situational awareness and attention to detail, and suboptimal risk-based decisions, rather than missing or inadequate standards or programs. OPG continues to implement a number of initiatives to target the injury trends based on the analysis of the safety events, with a focus on the use of human performance tools including increased field supervisory oversight, situational awareness, communication, and procedural use and adherence.

In order to strengthen its safety performance, OPG continues to progress an organization-wide "iCare Enough to Act" initiative launched in 2016 and aimed at renewing employees' commitment to their own and each other's safety and well-being. Approaches to supervisory oversight, communication and safe work planning are being modified and updated to further strengthen safety as a foundational element of the Company's values-based culture.

Contractors are required to conduct work safely at OPG sites. In support of this requirement, OPG utilizes an independent contractor pre-qualification process, provides on-site safety support for many of its major projects, and works with contract partners to improve their health and safety programs to meet OPG's requirements. In the past nine years, OPG has consistently shown a Construction Contractor AIR that is markedly better than the Infrastructure Health and Safety Association Contractor AIR, a metric of construction contractor safety performance across Ontario. OPG has maintained this performance while engaging in the refurbishment of the Darlington GS, one of the largest infrastructure projects in Canada. The hours worked by contractors in 2017 were the largest in OPG's history, largely attributable to this project.

OPG continues to maintain a strong focus on the nuclear safety program and to invest in nuclear safety systems. To ensure continued public safety, radiation exposure to members of the public resulting from the operation of OPG's nuclear generating stations is estimated on an annual basis for individuals living or working near the stations. The annual dose to the public resulting from operations of each nuclear facility is expressed in microsieverts (μSv), which is an international unit of radiation dose measurement. For 2016, the annual public doses resulting from the Darlington GS operations and the Pickering GS operations were 0.6 μSv and 1.5 μSv, respectively, which is less than 0.1 and 0.2 percent of the annual legal limit of 1,000 μSv, respectively. While the public doses from OPG's nuclear operations for the 2017 operating year will not be finalized until the second quarter of 2018, they are not expected to differ significantly from the 2016 levels.

In June 2016 and August 2016, the CNSC released sampling results from its independent environmental monitoring program, which confirmed that the public and the environment around OPG's nuclear generating stations continued to be safe. In September 2017, the CNSC issued an executive summary of its 2016 annual report on the safety performance of Canada's nuclear power plants, which gave both the Pickering GS and the Darlington GS the highest possible safety rating of "Fully Satisfactory". For further details, refer to the CNSC safety rating discussion in the section, *Highlights* under the heading, *Recent Developments*.

OPG remains committed to high standards of public safety on waterways around hydroelectric generating stations and dams, and continues to make investments in waterway and dam safety upgrades. The Company's practices in this area are routinely reviewed by an independent panel comprised of internationally recognized experts, who have

concluded that OPG's Dam Safety Program is industry leading in a number of areas. During 2017, OPG continued its water safety campaign with a series of public service announcements illustrating the danger of water near hydroelectric dams and hydroelectric generating stations.

Electricity Generation Production and Reliability

Key strategic initiatives in support of operational excellence, specific to each of OPG's core generating operations, are discussed below. Generation and reliability performance for 2017 is discussed by operating segment in the section, *Discussion of Operating Results by Business Segment*.

Nuclear Operations

OPG is pursuing a number of strategic initiatives aimed at the continued safe and reliable operation of the Pickering GS and targeting top performance at the Darlington GS.

OPG's objective is to maximize the safe and reliable operating life of the Pickering units. As announced in 2016 and approved by the Province, OPG is continuing to execute on a plan to extend safe and reliable operation of the Pickering GS to 2024. In addition to providing Ontario with a clean, reliable source of baseload electricity during nuclear unit refurbishments at the Darlington GS and the Bruce nuclear generating stations, extending operations at the Pickering GS will provide continued employment for up to 4,000 full-time employees at OPG and help to reduce approximately 17 million tonnes of carbon dioxide emissions, which is equivalent to removing approximately 3.4 million cars from Ontario's roads.

As part of the plan to extend Pickering operations, OPG has been continuing to undertake the required technical work to confirm that the station's pressure tubes, a key life-limiting component of the station, will remain fit for service for operation to 2024. In the fourth quarter of 2017, OPG has confirmed that technical assessments completed to date provide sufficient confidence in the programs and provisions in place to assure fitness-for-service of fuel channel components in line with the planned extended operations period. This evaluation is consistent with the safety case reflected in OPG's operating licence renewal application for the Pickering GS submitted to the CNSC in 2017, discussed below. Taking these factors into account, OPG revised the accounting end-of-life assumptions for the Pickering GS from December 31, 2020 for all units to December 31, 2022 for Units 1 and 4 and December 31, 2024 for Units 5 to 8, effective December 31, 2017.

The change in the Pickering GS accounting end-of-life assumptions did not impact OPG's net income in 2017. The change is expected to decrease depreciation expense by $77 million in 2018, including the associated impact on the nuclear asset retirement obligation (ARO) recorded as of December 31, 2017 but before the impact of regulatory accounts. Regulatory accounts, including a new deferral account proposed by OPG in a December 2017 application to the OEB, are expected to largely offset the decrease in depreciation expense. The change in the nuclear ARO recorded in the fourth quarter of 2017 is discussed in the section, *Critical Accounting Policies and Estimates* under the heading, *Asset Retirement Obligation*. On December 29, 2017, OPG applied for an accounting order to establish a variance account to record, from January 1, 2018 until the effective date of the OEB's next payment amounts order, the revenue requirement impact of changes to nuclear liabilities and depreciation and amortization expense resulting from changes to station end-of-life dates for OPG's Pickering prescribed nuclear facilities that will be effective December 31, 2017. Pending the OEB's review of the application, an interim order was issued January 31, 2018 establishing the proposed variance account effective January 1, 2018. The OEB's final decision for the account is expected later in 2018.

OPG's current five-year operating licence for the Pickering GS was approved by the CNSC in 2013 and expires on August 31, 2018. This current licence was issued assuming that the station would shut down in 2020. On June 28, 2017, OPG confirmed to the CNSC that it intends to cease commercial operation of all Pickering units on December 31, 2024. On August 28, 2017, OPG submitted a ten-year licence renewal application to the CNSC. The requested licence term spans the planned extended commercial operations period, through to the planned period of de-fuelling,

de-watering and beginning to place the station in a safe storage state in 2028. In support of the licence renewal, OPG undertook a Periodic Safety Review (PSR), a comprehensive assessment of the station's design and operation to confirm that there is a high level of safety throughout the operating life and to determine what reasonable and practical enhancements can be made to further improve safety. The PSR also includes a component condition assessment of the station to identify the work required to support the station's continued operation. The PSR has confirmed that extending operations of the Pickering units will continue to pose minimal risk to the health, safety and security of workers, the public and the environment. The final major component of the PSR was submitted to the CNSC in November 2017. The CNSC's review of the PSR submission and licence application is in progress. Based on the evidence and documentation submitted to the CNSC, OPG is confident in obtaining a licence renewal that would support its extended operations plan for Pickering GS.

OPG's nuclear operations are regularly benchmarked against top performing nuclear facilities around the world. This allows OPG to identify, develop and implement initiatives to further improve performance. In September 2016, OPG hosted a team of experts from the International Atomic Energy Agency (IAEA) at the Pickering GS to conduct a standard Operational Safety Review Team mission. The team conducted an in-depth review of performance and adherence to international safety standards. In the second quarter of 2017, the IAEA's Operational Safety Review Team released the final report and confirmed that the Pickering GS demonstrates strong commitment to safety. In December 2017, OPG hosted a World Association of Nuclear Operators (WANO) peer evaluation for the Pickering GS, which focused on the safe and reliable operation of the station while evaluating the plant material condition, functional and cross-functional areas of the organization. Pickering showed significant improvement since its last review and has sustained its strong rating in 2018, resulting in its best ever WANO peer review.

OPG remains focused on improving reliability and increasing electricity generation output from its nuclear fleet. This includes improving equipment reliability, optimizing outages, implementing integrated asset management planning and enhancing maintenance programs. Improved equipment reliability generally results in fewer generation interruptions. Nuclear inspection and testing programs are largely driven by maintenance and regulatory requirements, and are designed to ensure that equipment is performing safely and reliably. Execution of this and other outage work continues to be a high priority. As part of its commitment to operational excellence, OPG continues to focus on improving the planning, execution, monitoring, and reporting of outage work.

OPG continues to make investments in the performance of the Pickering GS, with a focus on improving plant reliability and maximizing the value of the asset over its remaining life through implementing equipment modifications and fuel handling reliability improvements, reducing equipment maintenance backlogs, and completing critical and high priority work. OPG also continues to make investments in the Darlington GS necessary to sustain safe and reliable operations for the next three decades and aimed at positioning the station for industry-leading operating and cost performance in the longer term. This includes investments in life cycle and aging management projects, facility upgrades as well as work in support of regulatory commitments.

Delivering solutions that provide the best combination of safety, cost and effectiveness, as well as establishing challenging financial targets based on comprehensive benchmarking and taking into account the operating environment of the nuclear stations, continues to be a vital part of OPG's strategy to improve performance of the nuclear business unit. Financial and staffing targets continue to be reviewed and adjusted where necessary to reduce operating costs, while ensuring safety and reliability are not compromised.

In 2016, OPG submitted applications with the CNSC seeking a ten-year licence renewal for the Western Waste Management Facility (WWMF), located at the Bruce generating stations' site, to May 31, 2027, and a ten-year licence renewal for the Pickering Waste Management Facility (PWMF) to August 31, 2028. The licence renewal applications were presented to the CNSC at public hearings in April 2017. On May 30, 2017, the CNSC announced that the WWMF licence was renewed for a ten-year period and will be valid until May 31, 2027. On February 7, 2018, the CNSC announced that the PWMF licence was renewed for a ten-year period and will be valid until August 31, 2028.

In 2017, the CNSC approved regulatory document *REGDOC 2.2.4 – Fitness for Duty – Managing Alcohol and Drug Use* for use at Canadian nuclear power plants. This document sets out requirements for managing fitness for duty of workers in relation to alcohol and drug use at high-security sites, including for-cause alcohol and drug testing for workers in positions identified as safety-sensitive or safety-critical and random alcohol and drug testing for workers holding safety-critical positions. OPG intends to enhance its existing Fitness for Duty program to comply with these new requirements. OPG is working with its partners in the Canadian nuclear industry to develop a program suitable for Canada and its workers.

Hydroelectric Operations

The objectives of OPG's hydroelectric operations include operating and maintaining the generating facilities in a safe, efficient and cost-effective manner, while increasing the output from the facilities and pursuing opportunities to increase capacity. OPG aims to increase the facilities' output by improving operational flexibility, enhancing reliability, optimizing outage planning and, subject to water conditions, increasing availability to meet electricity system demand. OPG continues to evaluate and implement plans to increase capacity, maintain and improve operational performance, and extend the operating life of its hydroelectric generating assets.

OPG's hydroelectric operations are regularly benchmarked against peer utilities in North America. Based on 2016 data, 19 of the OPG's 25 large regulated hydroelectric facilities benchmarked in the top two quartiles for unit energy costs. This group of 19 facilities represents 94 percent of the energy delivered from the regulated hydroelectric fleet. Similarly, 18 of 25 large regulated hydroelectric facilities benchmarked in the top two quartiles for availability based on 2016 data. OPG continues to pursue innovation and technology-based improvements in its asset management and equipment maintenance strategies in order to increase reliability and further reduce costs of the hydroelectric fleet.

As part of OPG's ongoing strategy to reduce costs and increase operational efficiency, the operations of the Company's hydroelectric and thermal assets were previously combined into one organization, with five regional operations groups. In 2017, OPG reduced the number of regional operations groups to four, by integrating the Central Operations work centres into three of the other existing regional operations groups. In addition, during the third quarter of 2017, OPG opened an amalgamated control room located at the Saunders hydroelectric GS, combining the Chenaux and Saunders control rooms. The amalgamated control room will control all operational activities at the ten hydroelectric stations along the Madawaska, Ottawa and St. Lawrence rivers.

OPG's plans for its existing hydroelectric generating stations are accomplished through multi-year capital investment and other programs, including replacements and upgrades of turbine runners, and refurbishment or replacement of existing generators, transformers, and controls. The aim of OPG's runner replacement and upgrade program is to increase hydroelectric station capacity by leveraging efficiency enhancements in runner design. Where economical and practical, OPG also pursues opportunities to refurbish, expand or redevelop its existing hydroelectric stations. Over the next four years, OPG plans to increase the total capacity of its hydroelectric generating fleet by approximately 150 MW, which, in addition to the runner replacement and upgrade program, includes the Ranney Falls GS and Sir Adam Beck frequency conversion projects. OPG is also planning to repair, rehabilitate, or replace a number of aging civil hydroelectric structures.

As part of its commitment to operational excellence, OPG continues to make investments in its existing hydroelectric generating fleet. During 2017, OPG continued to execute a number of projects, including:

- Completion of the overhaul and upgrade of Unit 10 of the Sir Adam Beck 1 GS, which increased the station's capacity by 6 MW
- Continued work on the overhaul and rehabilitation of Unit 1 of the Sir Adam Beck Pump GS to ensure reliable unit operation for approximately the next 20 years
- Completion of the replacement of the Shebandowan Lake Control Dam at the Kakabeka Falls GS, which will maintain structural integrity and enhance dam safety for another 100 years

- Continued work on the overhaul and upgrade of Unit 1 of the Harmon GS with completion of the turbine upgrade, generator rehabilitation and upgrade of protection and control systems
- Continued work on the overhaul and upgrade of Unit 2 of the DeCew Falls GS, with turbine and generator rehabilitation and upgrade of protection and control systems completed during the year, and, in the fourth quarter of 2017, commencement of the overhaul and upgrade of Unit 2 of the Little Long GS
- Continued work on the overhaul and rehabilitation of Unit 2 of the Lower Notch GS, with generator rehabilitation completed during the year, and in the fourth quarter of 2017, commencement of the overhaul and rehabilitation of Unit 6 of the Sir Adam Beck Pump GS
- Commencement of definition phase work for the Water Conveyance System project to rehabilitate the Sir Adam Beck 1 GS canal and associated structures, ensuring their continued safe and reliable operations for approximately the next 50 years.

In 2018, OPG plans to commence execution of several major sustaining projects across the hydroelectric fleet, including the overhaul and upgrade of Unit 5 of the Sir Adam Beck 1 GS, the rehabilitation of Caribou Falls Block Dam No.2, and automatic sluicegates system replacement at the Whitedog Falls GS. Definition phase activities on several other major projects are also expected to commence in 2018, including frequency conversion of Units 1 and 2 of the Sir Adam Beck 1 GS and the overhaul and upgrade of the R.H. Saunders GS units.

Thermal Operations

OPG's thermal operations consist of biomass-fuelled generating units at each of Atikokan GS and Thunder Bay GS, and the oil/gas dual-fuelled Lennox GS.

These stations, which operate as peaking facilities under their respective energy supply requirements, provide Ontario's electricity system with the flexibility to meet changing daily system demand and capacity requirements and enable the system to accommodate the expansion of Ontario's renewable generation portfolio. The continued operation of these stations will continue to provide Ontario with over 2,000 MW of peaking generation capacity. The stations operate under their respective ESAs.

OPG's biomass-fuelled generating units are among the world's leading in their innovation. The Atikokan GS is the largest generating station in North America fuelled by 100 percent biomass, while the Thunder Bay GS unit uses advanced biomass that is thermally treated to allow it to be stored outdoors and withstand exposure to the weather.

Former thermal stations that are no longer available to generate electricity are included in the Services, Trading, and Other Non-Generation segment once they are removed from service. This includes the Lambton GS and Nanticoke GS sites, which ceased operations in 2013. Over 2015 and 2016, OPG announced that these stations would be decommissioned safely, securely and in an environmentally responsible manner. The costs of the decommissioning are charged to a previously established decommissioning provision.

During 2017, OPG substantially completed the demolition of the Nanticoke coal yard equipment and structures and issued a contract for the demolition of the Nanticoke powerhouse and associated structures. In the fourth quarter of 2017, the demolition contractor had been mobilized to prepare for the removal of the powerhouse and associated structures and initiated the preparatory work for the demolition of the stacks. The demolition of the stacks took place in February 2018. **[MONITOR]** A competitive bidding process for the demolition of the Lambton GS is in progress, with a contract for the removal of the powerhouse and associated structures expected to be issued during 2018. The decommissioning plan for the Nanticoke GS accommodates the construction and operation of the Nanticoke solar facility.

An update of the asset retirement obligations related to the Nanticoke and Lambton sites has been completed. For a discussion of the revaluation of this liability for non-nuclear fixed asset removal as at December 31, 2017, refer to the section, *Critical Accounting Policies and Estimates* under the heading, *Asset Retirement Obligations*.

Environmental Performance

OPG's Environmental Policy states that "OPG shall meet compliance obligations, including any environmental commitments that it makes, with the objective of exceeding these compliance obligations where it makes business sense". This policy commits OPG to:

- maintain an ISO 14001-registered environmental management system (EMS)
- work to prevent or mitigate adverse impacts on the environment with a long-term objective of continual improvement
- strive to be a leader in climate change mitigation
- manage sites in a manner that strives to maintain, or enhance where it makes business sense, significant natural areas and associated species of concern.

In 2017, OPG maintained the ISO 14001 registration of its company-wide EMS. Within the EMS, OPG has planning, operational control, and monitoring programs to manage the Company's positive and negative impacts on the environment. Significant environmental aspects of OPG's operations include: spills, chemical and thermal emissions to water, water flow and level changes, radiological emissions, low and intermediate level radioactive waste (L&ILW), enhancement and disruption of wildlife habitat, displacement of fossil fuels, and fish impingement and entrainment. Further details regarding OPG's environmental risks can be found in the section, *Risk Management* under the heading, *Environmental Risk*.

Environmental performance targets are set as part of the annual business planning process. These targets are based on past performance and external benchmarking to promote continual improvement. OPG met or outperformed its 2017 targets for spills, environmental infractions, carbon-14 emissions to air, and L&ILW. Targets for tritium emissions to air and water were not achieved due to equipment performance issues; however, emissions remained less than one percent of the regulatory limit. There were no significant environmental events during 2017.

In 2016, the Government of Ontario passed the *Climate Change Mitigation and Low-Carbon Economy Act, 2016* and the associated *Cap and Trade Program Regulation*. The legislation provides the foundation for regulating greenhouse gas (GHG) emissions in Ontario and establishes a cap and trade program, with the first compliance period being from January 1, 2017 to December 31, 2020.

The cap and trade program is a market mechanism intended to give Ontarians an incentive to reduce GHG emissions by putting a price on carbon. OPG has an internal program to meet its GHG emissions compliance obligations. With OPG's low GHG emitting fleet, these obligations are not expected to have a material financial impact on the Company.

OPG monitors actions being taken by the Government of Ontario and the Government of Canada to reduce GHG emission levels and transition to a low-carbon economy. In support of efforts to mitigate climate change, the Company continues to evaluate and implement plans to increase the generation capacity of its hydroelectric generating fleet, where economical, invest in other low-carbon technologies, and take a leadership role in the electrification of Ontario's transportation sector.

OPG has developed biodiversity management plans that identify priority natural areas, conservation goals, threats, and proposed actions to sustain biodiversity at its properties. To maximize benefits and manage impacts, initiatives include biodiversity monitoring, site naturalization, habitat creation, and control of invasive species.

OPG works with community partners to support regional ecosystems and biodiversity across Ontario. In 2017, OPG continued efforts to protect and restore habitat, promote biodiversity education and awareness, and help the recovery of species at risk. In November 2017, OPG's biodiversity program was recognized by the Canadian Electricity Association with the 2017 Sustainable Electricity award for Commitment to Continuous Performance Improvement.

OPG communicates its environmental performance internally to employees and to external stakeholders, including the Ontario Ministry of the Environment and Climate Change (MOECC), Environment and Climate Change Canada, the CNSC, and local communities. Details of OPG's environmental performance and initiatives to fulfill the Company's Environmental Policy can be found in OPG's 2016 Sustainability Report, available on the Company's website at www.opg.com.

Improving Efficiency and Reducing Costs

As part of its commitment to operational excellence, OPG remains strongly focused on reducing costs by pursuing sustainable efficiency and productivity improvements across operating business units and support functions, while ensuring that there is no adverse impact on the safety, reliability and environmental sustainability of the Company's operations. Building on significant efficiency achieved since 2011 under a more scalable, centre-led organizational model, this includes streamlining of processes, simplifying governance, upgrading technology, optimizing service delivery models, and continuing to leverage attrition to achieve human resource targets aligned with business requirements. Strategies to improve cost performance and organizational capability are being implemented at the enterprise and business unit level. These strategies are supported by continuing to embed an outcomes-driven culture that reinforces cost effectiveness, efficiency and organizational agility as part of business decision-making.

OPG is proceeding with an enterprise-wide process to evaluate the impact of the eventual shutdown of the Pickering GS on the Company's operating cost structure. This multi-year initiative, known as OPG25, involves identifying and implementing a coordinated set of plans and targets to ensure the optimization of the Company's longer-term operating model, business strategies and organizational design between now and the planned end of Pickering commercial operations. The overall aim of the initiative is to ensure ongoing cost effectiveness of the Company's operations after the eventual shutdown of the Pickering GS and to mitigate the cost impacts associated with the shutdown. Through this work and a continued focus on productivity enhancements, OPG expects to deliver increased value to customers and achieve improvement in outcomes of future applications for regulated prices under the OEB's incentive regulation framework.

In 2017, OPG also launched a strategy to accelerate the pace of digital transformation across the enterprise. The strategy is focused on making investments to modernize information technology infrastructure, enhance mobility, connectivity and field and office productivity, and improve equipment reliability and station performance through data management and data analysis. The strategy will increase operational efficiency, reduce operating costs and help to enable optimization initiatives in support of OPG25.

People and Culture

A well trained and engaged workforce is fundamental to the achievement of OPG's strategic imperatives. To succeed in a demanding business environment, OPG is focused on building a diverse, healthy, engaged workforce and fostering a culture of collaboration, accountability and innovation. OPG also continues to communicate and implement the values and behaviours expected from its employees in order to maintain a strong focus on safety, performance excellence, continuous improvement, and corporate citizenship.

The Company continues to focus on improving the capability of its workforce through leadership development, knowledge management, diversity and inclusion programs, and hiring in critical areas. Ability to secure the right talent mix in order to effectively meet the Company's immediate and longer term business needs on a timely basis is supported through workforce planning, resourcing and on-boarding strategies, both to acquire external talent into the organization and to develop existing employees. The goal of workforce planning and resourcing strategies is to ensure that the Company has a diverse workforce with the right skill set and capability for the safe and effective operation of the generating facilities and successful delivery of major projects, including the Darlington Refurbishment. These strategies take into account changes in anticipated staffing requirements leading up and subsequent to the end of planned commercial operations of the Pickering GS and the period to de-fuel, de-water and

place the station in a safe state condition after shutdown. The end of commercial operations at the Pickering GS is expected to lead to a significant reduction in OPG's workforce.

As part of the strategy to develop and engage employees and to build leadership talent in support of the Company's long-term success, OPG has an active succession planning program with a focus on accelerating development. This includes a company-wide high-potential leadership development program for qualified internal candidates. This 14-month cross-functional, competitive-entry program is designed to identify and develop candidates for future leadership positions while they are relatively early in their careers. OPG also has a talent management monitoring process to proactively assess staffing risks, challenges and opportunities.

Electricity generation involves complex technologies that require highly skilled and trained workers. Many positions at OPG have significant educational prerequisites and rigorous requirements for continuous training and periodic requalification. In addition to maintaining its internal training infrastructure, OPG relies on partnerships with government agencies, other electrical industry partners and educational institutions to meet the required level of qualification. Training delivery models are evaluated for effectiveness and efficiency.

Effective January 1, 2017, OPG implemented an Executive Compensation Program that is compliant with *Ontario Regulation 304/16: Executive Compensation Framework*, introduced in September 2016. While the Province released two subsequent amendments, *Ontario Regulation 187/17* and *Ontario Regulation 400/17* in June 2017 and November 2017, respectively, OPG's Executive Compensation Program continues to be subject to the original regulation's requirements. The regulation sets out how all employers designated under the *Broader Public Sector Executive Compensation Act, 2014*, including OPG, must establish and post compensation programs for executives. The program must include the compensation philosophy, salary and performance-related pay caps, comparative analysis details, and a description of other elements of compensation. OPG's Executive Compensation Program, which applies to employees at the Vice President level and higher, is designed to provide compensation that is at the 50th percentile of the market and focused on at-risk, performance based pay. The program will better enable OPG to attract, align and retain the executive talent critical to delivering Shareholder and customer value, while ensuring continued safe and reliable operations.

Project Excellence

OPG is pursuing a number of generation development and other major projects in support of Ontario's electricity planning initiatives. OPG also continues to plan and execute maintenance and capital improvement projects related to its existing assets. OPG strives for excellence in the planning and delivery of all projects across the Company.

OPG's vision for project excellence is to be an industry leader in project management capability and performance. As part of its commitment to project excellence, OPG continues to enhance and streamline its approach to project planning and execution, with the goal of delivering all projects safely, on time, on budget, and with high quality. Achieving project excellence at OPG involves, among other things, implementing a common, scalable project delivery model across all business units, establishing qualified project management teams, optimizing contracting strategies, engaging qualified and experienced vendors, and effectively monitoring and controlling performance.

The status updates for OPG's major projects as of December 31, 2017 are outlined below.

Project	Capital expenditures		Approved budget	Expected in-service date	Current status
(millions of dollars)	Year-to-date	Life-to-date			
Darlington Refurbishment	1,249	4,434	12,800 [1]	First unit - 2020 Last unit - 2026	All Unit 2 feeder tubes were removed safety in the fourth quarter of 2017 and the removal of fuel channel assemblies is in progress. Construction activities on the HWSF have recommenced in the fourth quarter. Planning and procurement activities for the refurbishment of Unit 3 are continuing. The overall project is tracking on schedule and on budget.
Peter Sutherland Sr. Hydroelectric GS	41	277	300	2017	The station was placed in-service on March 31, 2017, ahead of the originally planned schedule, and is expected to close below the approved budget. Project close-out activities are in progress.
Sir Adam Beck Pump GS Reservoir Refurbishment	3	49	58	2017	The refurbishment was completed and the reservoir was returned to service in February 2017, ahead of the originally planned in-service date and below the approved budget.
Ranney Falls Hydroelectric GS	25	28	77	2019	Excavation has been completed and construction is continuing in the expanded forebay, powerhouse and spillway area. Concrete placement of the new powerhouse and the spillway integrated structure is in progress. The project is tracking on schedule and on budget.
Nanticoke Solar Facility	2	3	107	2019	Significant contracts for equipment and engineering construction services have been executed, with construction planned to commence in the first quarter of 2018. **[MONITOR]**
Deep Geologic Repository (DGR) for L&ILW	9 [2]	204 [2]			On August 21, 2017, the federal Minister of Environment and Climate Change requested further information related to the project's environmental assessment (EA). OPG is working on a response to this information request.

[1] The total project budget of $12.8 billion is for the refurbishment of all four units at the Darlington GS.
[2] Expenditures are charged against the Nuclear Liabilities.

Darlington Refurbishment

The Darlington generating units are approaching their originally designed end-of-life. Refurbishment of the four generating units is expected to extend the operating life of the station by approximately 30 years. The approved budget for the four-unit refurbishment is $12.8 billion, which includes the costs of the pre-requisite projects in support of the execution phase of the refurbishment. The first refurbished unit is scheduled to be returned to service in the first quarter of 2020 and the last unit is scheduled to be completed by 2026. The project continues to track on schedule.

The Darlington Refurbishment project is a multi-phase program comprising the following five major sub-projects:

- **Retube and Feeder Replacement**, which includes the removal and replacement of fuel channel assemblies and feeder tubes in each reactor
- **Turbines and Generators**, which consists of inspections and repairs of turbine generator sets and the replacement of analog control systems with digital control systems
- **De-fuelling and Fuel Handling**, which involves the de-fuelling of the reactors and the refurbishment of the fuel handling equipment
- **Steam Generators**, which includes mechanical cleaning, water lancing, and inspection and maintenance work on the generators
- **Balance of Plant**, which consists of work on smaller projects to replace or repair certain other station components.

In 2016, the Darlington Refurbishment project transitioned from the planning phase to the execution phase, as OPG commenced the refurbishment of the first unit, Unit 2, in October 2016 as planned. The unit was taken offline on October 15, 2016. De-fuelling of the reactor was completed in January 2017, with a total of 480 fuel channels de-fuelled. Islanding of Unit 2, the physical separation of the unit under refurbishment from the three operating units, was completed in April 2017, signifying the completion of the first major segment of the project.

The second major segment includes preparatory work to support the removal of feeder tubes and fuel channel assemblies, followed by the removal of reactor components. The preparatory work was completed in the second quarter of 2017. The Re-tube Tooling Platform for hosting the tooling for the removal, inspection and installation activities, and the setup of specialized tooling and equipment needed for the removal and replacement of the reactor components were completed in the third quarter of 2017. The disassembly of reactor components commenced in August 2017, with the removal of all 960 feeder tubes completed safely in September 2017. The removal of fuel channel assemblies commenced in October 2017. As part of the fuel channel assemblies, the removal of pressure tubes is in progress and will be followed by the removal of calandria tubes. The second major segment and the removal of all reactor components is expected to be completed by mid-2018. Key projects in the second major segment finished in 2018 include the completion of the primary side steam generator layup and installation of steam generator access ports to support future inspections. Other key project activities being executed during the second segment include the continuation of the major turbine generator overhaul, which will be completed in the second quarter of 2018, and continued execution of the major electrical scope. OPG is also continuing to execute work to support the requirements set out in the CNSC-approved Integrated Implementation Plan for the station.

Most of the pre-requisite projects, including construction of facilities, infrastructure upgrades and installation of safety enhancements, have been completed and placed in-service. The Re-tube Waste Processing Building was completed in November 2017. Completion of the HWSF has been delayed due to challenges with construction. OPG suspended the project in the second quarter of 2017 to evaluate the best approach to optimize cost and schedule and complete the project. Construction to complete the facility recommenced in the fourth quarter of 2017. The HWSF is expected to be completed by the second quarter of 2019 and is not on the critical path for the Darlington Refurbishment project, which continues to track on schedule. The increase in the cost estimate for the HWSF will be accommodated within the overall Darlington Refurbishment budget of $12.8 billion. Taking into account the execution performance of the Unit 2 refurbishment, the overall Darlington Refurbishment project continues to track on budget.

In addition to the execution of refurbishment activities on Unit 2, OPG is continuing planning activities for the refurbishment of the second unit, Unit 3, and is entering into associated commitments to procure major components that require long lead times. As of December 31, 2017, $93 million has been invested in planning activities related to the refurbishment of the second unit, Unit 3. These planning activities are being undertaken in accordance with the refurbishment project schedule. In February 2018, the Province confirmed its commitment to proceed with Darlington's Unit 3 refurbishment in 2020. **[MONITOR]**

Peter Sutherland Sr. Hydroelectric GS

In March 2017, the project to construct the 28 MW two-unit Peter Sutherland Sr. hydroelectric GS successfully completed final testing and commissioning of the turbine and generator units, and both units were declared substantially complete. On March 31, 2017, the project received a permit from the MOECC to take water for operations to allow the station to operate commercially. This in-service date was well ahead of the originally planned schedule of the first half of 2018. The project's schedule was accelerated to take advantage of favourable weather conditions. The project is expected to close below the approved budget of $300 million. Project close-out activities are in progress. OPG began to receive contracted revenue for the project following the IESO's confirmation of the station's commercial operations as of March 31, 2017, under a hydroelectric ESA.

Under the partnership agreement, as the unit is placed in-service, the CRP, a corporation wholly owned by the Taykwa Tagamou Nation, may acquire up to a 33 percent partnership interest through its investment in PSS. In April 2017, the CRP acquired a 33 percent interest in PSS.

Sir Adam Beck Pump GS Reservoir Refurbishment

The Sir Adam Beck Pump GS refurbishment construction began in April 2016 and the 300-hectare reservoir was returned to service in February 2017 upon completion of the reservoir commissioning program. The Sir Adam Beck Pump GS facility allows OPG to pump and store water diverted from the Sir Adam Beck generating complex during periods of low electricity demand, to be used to generate up to 600 MW of electricity during subsequent periods of high electricity demand. The work on the project included installation of a new partial liner and construction of a grout curtain in the bedrock foundation of the reservoir dyke. The refurbishment is expected to add approximately 50 more years to the reservoir's life. The project was completed ahead of the originally planned in-service date of April 2017 and below the approved budget of $58 million. The Sir Adam Beck Pump GS is reported in the Regulated – Hydroelectric segment.

Ranney Falls Hydroelectric GS

In 2017, OPG began construction work on a 10 MW single-unit powerhouse on the existing Ranney Falls GS site, as part of the Regulated – Hydroelectric segment. The new unit will replace an existing unit that reached its end of life in 2014. The existing forebay structure has been demolished and the new concrete structure has been completed. Excavation has been completed and construction continues in the expanded forebay, powerhouse and spillway area. The new forebay concrete wall has been completed, and concrete placement of the new powerhouse and the spillway integrated structure is in progress. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget.

Nanticoke Solar Facility

The construction of a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands under a Large Renewable Procurement contract with the IESO, through Nanticoke Solar LP, a partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation, is planned to commence in the first quarter of 2018. During 2017, the partnership continued work to obtain approvals and permits required to enable the commencement of construction. Significant contracts for equipment and engineering construction services were executed in the first quarter of 2018. The facility is expected to be completed in the first quarter of 2019, with a budget of $107 million. **[MONITOR]**

Deep Geologic Repository for Low and Intermediate Level Waste

OPG has proposed a deep geologic repository as the preferred solution for the safe long-term management of the L&ILW produced from the continued operation of OPG-owned nuclear generating stations. Agreement has been reached with local municipalities for OPG to develop the L&ILW DGR on lands adjacent to the WWMF in Kincardine, Ontario. The environmental effects of the proposed L&ILW DGR were examined by the CNSC and Canadian Environmental Assessment Agency (CEAA)-appointed Joint Review Panel (JRP) to meet the requirements of the *Canadian Environmental Assessment Act*. The JRP submitted its report on the EA to the federal Minister of Environment in May 2015, concluding that, given mitigation, there is unlikely to be significant environmental impact from the project and recommending that the Minister approve the EA. In December 2016, at the request of the federal Minister of Environment and Climate Change, OPG submitted additional information on certain aspects of the EA, including information related to alternate locations for the project. Following its review of OPG's submission and a period of public comment, the CEAA requested further information that OPG subsequently provided in May 2017. In June 2017, the CEAA notified OPG that it had sufficient and adequate information to proceed with the next step of the environmental assessment process and advised that a draft report and updated terms and conditions would be prepared for public review.

On August 21, 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of potential cumulative effects of the project on the Saugeen Ojibway Nation's (SON) physical and cultural heritage, including a description of the potential effects of the project on the Nation's spiritual and cultural connection to the land, taking into account the results of the SON Community Process. OPG is working closely with the SON to formulate a response to the information request.

The L&ILW DGR at the WWMF site remains OPG's preferred solution for the safe long-term management of the L&ILW. The in-service date of the L&ILW DGR is expected to be approximately six to seven years from the start of construction.

Financial Strength

As a commercial enterprise, OPG's financial priority is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future expansion. Inherent in this priority are four objectives:

- Increasing revenue, reducing costs and achieving appropriate return
- Ensuring availability of cost effective funding for operational needs, generation development projects and other business opportunities, and long-term obligations
- Pursuing opportunities to expand the existing core business and capitalize on new growth paths
- Managing risks, which is discussed in the section, *Risk Management*.

Increasing Revenue, Reducing Costs and Achieving Appropriate Return

In line with its commercial mandate, OPG is focused on increasing revenue and net income and achieving an appropriate rate of return on the Shareholder's investment, while taking into account the impact on Ontario electricity customers by seeking further efficiencies in the Company's cost structure.

For the regulated operations, achievement of the above objectives is largely dependent on outcomes of rate applications to the OEB and growth of the asset base earning a return as part of the regulated prices.

With respect to rate application outcomes, OPG has been focused on demonstrating in its rate applications that the costs required to operate and invest in the assets are reasonable and being prudently incurred, and should be fully recovered, and that the Shareholder's investment in these assets should earn an appropriate rate of return. While the OEB's decision on OPG's 2017-2021 application for new regulated prices reduced OPG's forecasted costs used to set new regulated prices, the decision will result in a substantial increase in revenue and net income compared to

existing regulated prices. The existing base regulated prices were set in 2014 to allow the Company to recover its approved nuclear costs over a higher nuclear production volume, based on the 2014 and 2015 outage profile that did not include a Darlington refurbishment outage.

The OEB's decision to reduce recovery of OPG's forecasted cost levels, including through the use of stretch factors under an incentive rate-making model, will negatively impact OPG's ability to earn an appropriate return on the Shareholder's investment in the regulated assets. To improve the financial strength of the regulated operations, OPG will continue to focus on optimizing operational performance and outage plans across the generating fleet and on pursuing further efficiency improvements in the Company's cost structure and operating model. OPG's cost and productivity improvement strategies are discussed further in the section, *Core Business, Strategy and Outlook* under the heading, *Operational Excellence – Improving Efficiency and Reducing Costs*.

OPG continues to invest in the regulated asset base, with the Darlington Refurbishment project being the single largest such capital investment. In its decision on OPG's 2017-2021 application for new regulated prices, the OEB has allowed inclusion of a total of $5.5 billion in Darlington Refurbishment in-service capital additions by 2021, including pre-requisite projects other than HWSF and including in-service amounts upon planned return to service of Unit 2 in the first quarter of 2020. Once in-service, these assets will attract a return on equity of approximately 8.8 percent during the 2017-2021 period set by the OEB, based on a deemed capital structure of 45 percent equity and 51 percent debt. The average OEB-approved cost of deemed debt for the 2017-2021 period is approximately 4.6 percent. OPG also continues to pursue an extensive capital program across its regulated hydroelectric operations that includes expansion, redevelopment and life extension of the generating facilities, where economic. These renewable assets have long service lives and, with either maintenance efforts or rebuilding, will continue to supply electricity for the foreseeable future. The OEB's decision on OPG's application for new regulated prices is discussed further in the section, *Highlights* under the heading, *Recent Developments*.

For generation assets that do not form part of the assets regulated by the OEB, OPG's strategy has been to secure appropriate long-term revenue arrangements. In line with this strategy, virtually all of OPG's non-regulated operating facilities and assets under construction are subject to long-term ESAs or other long-term contracts with the IESO. This includes the Peter Sutherland Sr. GS, which was placed in service and began receiving contracted revenue under a hydroelectric ESA as of March 31, 2017. The Peter Sutherland Sr. GS ESA expires in 2067.

OPG's capital structure currently reflects lower levels of debt than the deemed capital structure reflected in the Company's existing regulated prices and maintained by the OEB's December 2017 decision on new regulated prices. OPG continues to evaluate strategies to enhance Shareholder returns by optimizing the Company's capital structure through better alignment with the deemed capital structure, taking into account the overall financial strength of the Company and the potential impact on the Company's investment grade credit rating.

Ensuring Availability of Cost Effective Funding

OPG actively monitors its funding requirements and forecasts availability of funds to ensure that it can meet the Company's operational needs, project commitments and long-term obligations. OPG utilizes multiple sources of funds, including funds generated from operations, commercial paper, securitization of assets, letters of credit, credit facilities, long-term corporate debt (sourced from both the OEFC and public debt offerings), credit facilities with the OEFC, private placement project financing, and equity issuance. The Company's financing strategy leverages the strength of its balance sheet to obtain cost effective long-term corporate debt. OPG also accesses the capital markets for private placement project financing, secured by the assets of the project, where the characteristics of the project support such financing. Maintaining an investment grade credit rating is critical to OPG's ability to access cost effective financing.

In April 2017, DBRS Limited (DBRS) re-affirmed the long-term credit rating on OPG's debt at 'A (low)' and OPG's commercial paper rating at 'R-1 (low)'. All ratings from DBRS have a stable outlook. In July 2017, S&P Global

Ratings (S&P) re-affirmed OPG's long-term credit rating at 'BBB+' with a stable outlook. S&P's commercial paper rating for OPG is 'A-1 (low)'.

OPG intends to continue to access the capital markets, where appropriate, to obtain cost effective financing for future generation development projects. The Company continues to evaluate arrangements that would appropriately support its financing needs, its capital expenditure programs, its financing of OPG's subordinated debt investment in the Trust, and the Trust's acquisition of Investment Interest from the IESO. OPG's liquidity and capital resources are discussed in the section, Liquidity and Capital Resources.

Building Our Business

Through pursuit of commercial-based opportunities to expand its business, OPG strives to be a leader in the North American transition toward a low carbon future while maintaining and expanding the Company's scale and energy industry leadership. This strategy considers the Company's financial position and anticipated future changes in the generating fleet, including the eventual end of Pickering commercial operations. The strategy is also informed by industry, technological, environmental, social, and economic external factors. Opportunities are evaluated using financial and risk-based analyses as well as strategic considerations.

Currently, OPG's strategy primarily focuses on the renewal and expansion of the Company's portfolio of generating assets in Ontario, including the redevelopment and expansion of existing sites and potential new developments. The strategy leverages OPG's operating and project development expertise as well as the Company's existing diverse physical asset base. Acquisition opportunities are considered as they arise, taking into account operating synergies, strategic benefits, financial returns and risk profile. OPG's current major generation development projects and asset life extension initiatives are discussed in the section, *Core Business, Strategy, and Outlook* under the headings, *Operational Excellence* and *Project Excellence*.

OPG also actively seeks to expand beyond its core generation business through investments in innovation and emergent low-carbon technologies, including selective solar generation, nuclear innovation, energy storage, distributed generation, electric vehicle infrastructure and other development. Additionally, OPG continues to consider potential paths to extend its business through broader electricity sector opportunities, within and outside Ontario. Business expansions opportunities may be pursued in partnership with other commercial entities where appropriate synergies exist and are aligned with OPG's business objectives.

Social Licence

As the largest electricity generator in Ontario with diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust. OPG is committed to maintaining high standards of public safety and corporate citizenship, including environmental stewardship, transparency, community engagement, and Indigenous relations. OPG works to maintain public trust with stakeholders by engaging site communities, sharing information, and being transparent about performance. In addition, OPG's operations are subject to extensive regulatory oversight, with public participation, by the CNSC, the OEB, and other bodies. OPG's commitment to safety is discussed in the section, *Core Business, Strategy, and Outlook* under the heading, *Workplace and Public Safety*.

OPG is focused on building long-term, mutually beneficial working relationships with Indigenous communities, businesses and organizations across Ontario, and continues to support procurement, employment and educational opportunities with its Indigenous community partners. The Company seeks to establish these relationships based on a foundation of respect for the languages, customs, and political, social and cultural organizations of the Indigenous communities.

OPG's commitment in this area includes pursuing generation-related development partnerships on the basis of long-term commercial arrangements, such as the construction of the Peter Sutherland Sr. GS in partnership with Taykwa Tagamou Nation and the development of the Nanticoke solar facility in partnership with the Six Nations of the Grand

River. During 2017, OPG also continued to engage with Indigenous communities regarding the Company's nuclear waste management operations, through regularly scheduled meetings and ongoing dialogue in connection with OPG's proposed L&ILW DGR, the re-licensing of the PWMF and the WWMF, and the Pickering GS re-licensing. Engagement was also conducted with First Nations in southwestern Ontario regarding the demolition of the Lambton and Nanticoke generating stations and with the Mississaugas of New Credit regarding the Shareholder-directed sale of the former Lakeview GS site.

OPG is also committed to improving Indigenous access to procurement and employment opportunities, including increasing the profile of the nuclear generation industry in Indigenous communities. In 2017, OPG launched an Indigenous Business Engagement (IBE) Initiative. The purpose of this initiative is to increase access to procurement opportunities for Indigenous businesses interested in supplying materials and services to OPG. The IBE Initiative is based on a strategy that will identify opportunities in contracts, scopes of work and business plans for potential Indigenous business engagement; include criteria related to suppliers' ability to engage or partner with Indigenous people or businesses in assessing procurement proposals; and invest in relationships with Indigenous communities by increasing outreach efforts to enhance understanding of how to do business with OPG. OPG has been engaging with Indigenous businesses and communities as well as its suppliers to promote the IBE Initiative, including the Mohawk Council of Akwesasne as well as the Williams Treaties First Nations, located proximate to the Pickering and Darlington nuclear generating stations.

OPG has been actively developing recruitment plans targeting Indigenous peoples. As part of this initiative, during the fourth quarter of 2017, OPG participated in several Indigenous-specific career fairs, hosted a Day in the Trades event for Indigenous students and job seekers as part of an open house at the Darlington Energy Centre, and approved plans aimed at increasing the number of Indigenous apprentices as part of the nuclear operations' recruitment program.

OPG also contributes to the well-being of its host communities through the Company's Corporate Citizenship Program (CCP), which supports charitable and non-profit grassroots initiatives in the areas of environment, education, and community involvement, including support for Indigenous initiatives. In 2017, OPG's CCP provided support to over 800 initiatives, of which 84 were Indigenous.

OPG has a strategy to help position the Company as a leader in transportation electrification in the province. The strategy aims to leverage the Company's clean, reliable and cost-effective electricity to power transportation, capitalize on future commercial growth opportunities, and enhance the Company's social licence. OPG is pursuing initiatives to increase the use of electric vehicles within its operations, and is assessing vehicle grid integration and hydrogen applications for the transportation sector. Ontario's climate change plan aims for electric and hydrogen passenger vehicles to represent five percent of new vehicle sales in the province by 2020.

As part of its commitment to help de-carbonize Ontario's transportation sector, OPG is a founding sponsor of Plug'n Drive, a non-profit organization working to accelerate the adoption of electric vehicles and to maximize their environmental and economic benefits. In May 2017, Plug'n Drive announced the opening of the world's first experiential learning facility dedicated to electric vehicle education and awareness, with OPG sponsoring the Centre's training facility.

Further details regarding OPG's commitment to sustainable development, including information regarding the Company's environmental and social performance and initiatives, are provided in OPG's 2016 Sustainability Report available on the Company's website at www.opg.com.

Outlook

The financial performance of OPG's regulated operations is driven, in large part, by the outcome of applications for regulated prices to the OEB. Subject to the OEB's issuance of the final payment amounts order expected in the first half of 2018, the OEB's December 2017 decision on OPG's application for new regulated prices provides substantial

price certainty for the regulated business for the 2017 to 2021 period. During this period, OPG will continue to focus on optimizing operational performance and outage plans across the generating fleet and on pursuing further efficiency improvements in the Company's cost structure and operating model.

The OEB's decision established June 1, 2017 as the effective date of the new regulated prices, which negatively affected OPG's net income and ROE Excluding AOCI in 2017 relative to OPG's requested effective date of January 1, 2017. The full-year effect of new regulated prices in 2018 is expected to contribute to an improvement in net income and ROE Excluding AOCI over the 2017 results.

Subject to the OEB's final determination on nuclear rate smoothing as part of the payment amounts order process, OPG expects an improvement in cash flow from operating activities in 2018, compared to 2017. This will reflect OPG beginning to receive revenue from the IESO based on new regulated prices following the OEB's implementation of these prices, expected in the first half of 2018. Additionally, the Fair Hydro Trust segment will begin to contribute positive cash flow from operating activities in 2018. OPG expects to continue to have the necessary financial capacity and sufficient access to cost effective financing sources to continue to fund its capital requirements and other disbursements, including the financing of the Fair Hydro Trust.

Several OEB-authorized regulatory variance and deferral accounts currently in place contribute to reducing the relative variability of the Company's net income and ROE Excluding AOCI. Among others, the regulatory accounts include those related to the revenue impact of variability in water flows and forgone production due to SBG conditions at the regulated hydroelectric stations. As there are no variance or deferral accounts in place related to the impact of generation performance of the nuclear stations on revenue from base regulated prices, the Regulated – Hydroelectric segment generally is expected to produce overall more predictable earnings. OPG continues to operate and maintain its nuclear facilities with a view to optimize their performance and availability, while focusing on improving the overall reliability and predictability of the fleet.

Electricity generated from most of OPG's non-regulated assets is subject to ESAs or other long-term contracts with the IESO. Based on these agreements, OPG expects the Contracted Generation Portfolio segment to continue to contribute a generally stable level of earnings and cash flow from operating activities going forward.

Lower nuclear generation due to the Darlington Refurbishment outages will continue, as planned, to negatively impact the Enterprise TGC and Nuclear TGC metrics for the duration of the refurbishment project. Lower hydroelectric generation due to outages related to various refurbishment and operational projects may negatively impact Enterprise TGC and Hydroelectric TGC for the duration of these projects. Variability in sustaining capital investment expenditures and nuclear outage profile may also impact TGC metrics in future periods.

OPG's total forecast capital expenditures for the 2018 year are approximately $2.1 billion. **[CONFIRM]** This includes amounts for the Darlington Refurbishment project, hydroelectric and other development projects including the Ranney Falls GS redevelopment and construction of the Nanticoke solar facility, and sustaining capital investments across the generating fleet. OPG's major projects are discussed in the section, *Project Excellence*.

In addition to the operating and financial performance of the electricity generation business, OPG's results are affected by the earnings on the Nuclear Segregated Funds, which are reported in the Regulated – Nuclear Waste Management segment. While the Nuclear Segregated Funds are managed to achieve, in the long term, the target rate of return based on the discount rate specified in the ONFA, the rates of return earned in a given period can be subject to various external factors including financial market conditions and, for the portion of the Used Fuel Segregated Fund guaranteed by the Province under the ONFA, changes in the Ontario consumer price index (CPI). In the near term, these factors can be volatile and cause fluctuations in the Company's income. This volatility is partially mitigated by the impact of the OEB-authorized Bruce Lease Net Revenues Variance Account and the funded status of the two segregated funds, discussed below.

As OPG does not have the right to withdraw surplus amounts from the Nuclear Segregated Funds, OPG limits the amount of Nuclear Segregated Funds assets reported on the balance sheet to the present value of the underlying life cycle funding liabilities per the most recently approved ONFA Reference Plan. This reduces the volatility of earnings on the Nuclear Segregated Funds reflected in net income when the funds are in a fully funded or overfunded position. As at December 31, 2017, the Decommissioning Segregated Fund was overfunded by approximately 27 percent, and the Used Fuel Segregated Fund was marginally overfunded, by less than one percent, based on the 2017 ONFA Reference Plan. Variability in asset performance due to volatility inherent in financial markets and changes in Ontario CPI, or changes in funding liability estimates, may result in either or both funds becoming underfunded in the future.

OPG's results are also affected by the earnings from the Fair Hydro Trust segment. Management expects an increase in 2018 earnings from the segment, primarily related to interest income from OPG's investment in subordinated debt of the Trust. OPG's involvement with the Fair Hydro Plan over time is expected to put downward pressure on ROE Excluding AOCI as a result of increases in shareholder's equity through future issuances of Class A common shares to partially fund OPG's subordinated debt investment in the Trust.

KEY OPERATING AND FINANCIAL PERFORMANCE INDICATORS

OPG evaluates the performance of its generating stations using a number of key indicators. Key operating performance indicators aligned with corporate strategic imperatives are measures of production reliability, cost effectiveness, environmental performance, and safety performance. Certain of the measures used vary depending on the generating technology.

Enterprise TGC, Nuclear TGC, Hydroelectric TGC, ROE Excluding AOCI, and FFO Adjusted Interest Coverage ratio discussed below are not measurements in accordance with US GAAP. They should not be considered as alternative measures to net income or any other measure of performance under US GAAP. However, OPG believes that these non-GAAP financial measures are effective indicators of its performance and are consistent with the Company's strategic imperatives and related objectives. The definition and calculation of Enterprise TGC per MWh, Nuclear TGC per MWh, Hydroelectric TGC per MWh, ROE Excluding AOCI, and FFO Adjusted Interest Coverage are found in the section, *Supplementary Non-GAAP Financial Measures*.

Enterprise Total Generating Cost per Megawatt-Hour

Enterprise TGC per MWh is used to measure OPG's overall organizational cost performance. Enterprise TGC per MWh is defined as OM&A expenses (excluding the Darlington Refurbishment project and other generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to OPG's electricity generation business), fuel expense for OPG-operated stations including hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures (excluding the Darlington Refurbishment project and other generation development projects) incurred during the period, divided by total electricity generation from OPG-operated generating stations plus electricity generation forgone due to SBG conditions during the period.

Nuclear Total Generating Cost per Megawatt-Hour

Nuclear TGC per MWh is used to measure the cost performance of OPG's nuclear generating assets. Nuclear TGC per MWh is defined as OM&A expenses of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to OPG's nuclear electricity generation business), nuclear fuel expense for OPG-operated stations (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs) incurred during the period, divided by nuclear electricity generation for the period.

Hydroelectric Total Generating Cost per Megawatt-Hour

Hydroelectric TGC per MWh is used to measure the cost performance of OPG's hydroelectric generating assets. Hydroelectric TGC per MWh is defined as OM&A expenses of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segments (excluding generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the hydroelectric electricity generation business), hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding expenditures related to the Peter Sutherland Sr. GS, Ranney Falls GS, and other hydroelectric generation development projects) incurred during the period, divided by total hydroelectric electricity generation plus hydroelectric electricity generation forgone due to SBG conditions during the period. OPG reports hydroelectric gross revenue charge and water rental payments as fuel expense.

Nuclear Unit Capability Factor

OPG's nuclear stations are baseload facilities that are not designed for fluctuating production levels to meet peaking demand. The nuclear Unit Capability Factor is a key measure of nuclear station performance. It measures the amount of energy that the unit(s) generated over a period of time, adjusted for externally imposed constraints such as transmission or demand limitations, as a percentage of the amount of energy that would have been produced over the same period had the unit(s) produced maximum generation. Capability factors are primarily affected by planned and unplanned outages. By industry definition, capability factors exclude production losses beyond plant management's control, such as grid-related unavailability. The nuclear Unit Capability Factor also excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS is excluded from the measure effective October 15, 2016, when the unit was taken offline as part of the Darlington Refurbishment project.

Hydroelectric Availability

OPG's hydroelectric stations operate as baseload, intermediate, or peaking stations. Hydroelectric Availability represents the percentage of time the generating unit is capable of providing service, whether or not it is actually generating electricity, compared to the total time for the respective period.

Thermal Equivalent Forced Outage Rate

Equivalent Forced Outage Rate (EFOR) is an index of the reliability of a generating unit at OPG's thermal stations. It is measured by the ratio of time a generating unit is forced out of service by unplanned events, including any forced deratings, compared to the amount of time the generating unit was available to operate.

Return on Common Equity Excluding Accumulated Other Comprehensive Income

ROE Excluding AOCI is an indicator of OPG's performance consistent with its objective to deliver value to the Shareholder. ROE Excluding AOCI is defined as net income attributable to the Shareholder for the period divided by average equity attributable to the Shareholder excluding AOCI for that period, and is measured over a period of 12 months.

Funds from Operations Adjusted Interest Coverage

The FFO Adjusted Interest Coverage ratio is an indicator of OPG's ability to meet interest obligations from operating cash flow and is consistent with the Company's objective of ensuring availability of cost effective funding. The FFO Adjusted Interest Coverage ratio is defined as FFO before interest divided by adjusted interest expense, and is measured over a period of 12 months.

Other Key Indicators

In addition to production reliability, cost effectiveness, and financial performance indicators, OPG has identified certain environmental and safety performance measures. These measures are discussed in the section, *Core Business, Strategy, and Outlook*.

BUSINESS SEGMENTS

Effective in the fourth quarter of 2017, OPG has the following six reportable business segments:

- Regulated – Nuclear Generation
- Regulated – Nuclear Waste Management
- Regulated – Hydroelectric
- Contracted Generation Portfolio
- Services, Trading, and Other Non-Generation
- Fair Hydro Trust.

Regulated – Nuclear Generation Segment

The Regulated – Nuclear Generation business segment operates in Ontario, generating and selling electricity from the Pickering GS and the Darlington GS, both owned and operated by OPG. The business segment also includes revenue under the terms of a long-term lease arrangement and related agreements with Bruce Power related to the Bruce nuclear generating stations. This revenue includes lease revenue, fees for nuclear waste management, and revenue from heavy water sales and detritiation services. The segment also earns revenue from isotope sales and ancillary services supplied by OPG from the nuclear stations it operates. Ancillary revenues are earned through voltage control and reactive support. Revenues under the agreements with Bruce Power, including a portion of heavy water sales, and from existing isotope sales contracts and ancillary services are included by the OEB in the determination of the regulated prices for production from OPG's nuclear facilities, which has the effect of reducing these prices.

Regulated – Nuclear Waste Management Segment

OPG's Regulated – Nuclear Waste Management segment reports the results of the Company's operations associated with the management of nuclear used fuel and L&ILW, the decommissioning of OPG's nuclear generating stations including the stations on lease to Bruce Power and other facilities, the management of the Nuclear Segregated Funds, and related activities including the inspection and maintenance of the waste storage facilities. Accordingly, accretion expense, which is the increase in the Nuclear Liabilities carried on the consolidated balance sheets in present value terms due to the passage of time, and earnings from the Nuclear Segregated Funds are reported under this segment.

As the nuclear generating stations operate over time, OPG incurs incremental costs related to used nuclear fuel and L&ILW, which increase the Nuclear Liabilities. OPG charges these incremental costs to current operations in the Regulated – Nuclear Generation segment to reflect the cost of producing energy from the Pickering and Darlington nuclear generating stations and earning revenue under the Bruce Power lease arrangement and related agreements. Since the incremental costs increase the Nuclear Liabilities reported in the Regulated – Nuclear Waste Management segment, OPG records an inter-segment charge between the Regulated – Nuclear Generation and the Regulated – Nuclear Waste Management segments. The impact of the inter-segment charge is eliminated in the consolidated statements of income and balance sheets.

The Regulated – Nuclear Waste Management segment is considered rate regulated because OPG's costs associated with the Nuclear Liabilities are included in the OEB's determination of regulated prices for production from the Pickering and Darlington nuclear generating stations.

Regulated – Hydroelectric Segment

OPG's Regulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from most of the Company's hydroelectric generating stations. The business segment comprises the results of 54 hydroelectric generation stations across a number of major river systems in the province.

In addition, the business segment includes ancillary and other revenues from OPG's regulated hydroelectric stations. Ancillary revenues are earned through offering available generating capacity as operating reserve and through the supply of other ancillary services including voltage control and reactive support, certified black start facilities, regulation service, and other services. These ancillary revenues and other revenues are included by the OEB in the determination of the regulated prices for production from OPG's prescribed hydroelectric facilities, which has the effect of reducing these prices.

Contracted Generation Portfolio Segment

The Contracted Generation Portfolio business segment operates in Ontario, generating and selling electricity from the Company's generating stations that are not prescribed for rate regulation. The segment primarily includes generating facilities that are under an ESA with the IESO or other long-term contracts.

The Contracted Generation Portfolio segment also includes OPG's share of equity income from its 50 percent ownership interests in the PEC and Brighton Beach stations. Brighton Beach operates under an energy conversion agreement between Brighton Beach and Shell Energy North America (Canada) Inc., and the PEC station is operated under the terms of an Accelerated Clean Energy Supply contract with the IESO. OPG's share of the in-service generating capacity and generation volume from its interests in the PEC and Brighton Beach stations are reported in this segment.

The business segment also includes ancillary revenues and other revenues from the stations included in the segment, which are earned through offering available generating capacity as operating reserve, and the supply of other ancillary services including voltage control and reactive support, certified black start facilities, regulation service, and other services.

Services, Trading, and Other Non-Generation Segment

The Services, Trading, and Other Non-Generation segment is a non-generation segment that is not subject to rate regulation. It includes the revenue and expenses related to OPG's trading and other non-hedging activities. As part of trading activities, OPG transacts with counterparties in Ontario and neighbouring energy markets in predominantly short-term trading activities of typically one year or less in duration. These activities relate to electricity that is purchased and sold at the Ontario border, financial energy trades, financial risk management energy product revenues, and sales of energy-related products. In addition, OPG has a wholly owned trading subsidiary that transacts solely in the United States (US) market. The results of this subsidiary are reported in this segment. All contracts that are not designated as hedges are recorded as assets or liabilities at fair value on the consolidated balance sheets, with changes in fair value recorded in the revenue of this segment.

In addition, the segment includes revenue from real estate rentals and non-regulated services, gains or losses on disposition of non-regulated real estate assets, costs associated with non-regulated business development activities, and costs related to the Lambton GS and Nanticoke GS sites.

Fair Hydro Trust Segment

The Fair Hydro Trust segment is a non-generation segment that is not subject to rate regulation. It includes OPG's earnings from the Fair Hydro Trust, which includes the financial results of the Trust, as well as income related to OPG's role as Financial Services Manager of the Fair Hydro Trust and holder of subordinated debt issued by the Trust. Earnings include interest income from OPG's investment in subordinated debt of the Trust of up to 49 percent of the Trust's total outstanding debt, recovery of third-party costs and fees for financial management and ongoing administration services, partially offset by interest costs on debt issued by OPG to fund five percent of the subordinated investment in the Trust, incurred third-party costs, and other incurred costs related to the management and administration of the Trust.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

Regulated – Nuclear Generation Segment

(millions of dollars)	**2017**	**2016**
Revenue	**3,095**	3,481
Fuel expense	**284**	315
Gross margin	**2,811**	3,166
Operations, maintenance and administration	**2,293**	2,210
Depreciation and amortization	**431**	925
Property taxes	**26**	26
Income before other losses, interest, and income taxes	**61**	5
Other gains	**4**	1
Income before interest and income taxes	**57**	4

Income before interest and income taxes from the segment increased by $53 million in 2017, compared to 2016. Segment earnings were favourably affected by the OEB's decision on OPG's application for new regulated prices issued in December 2017 with a retrospective effective date of June 1, 2017. The revenue increase of approximately $465 million in relation to the June 1, 2017 to December 31, 2017 period resulting from the OEB's decision was recorded as an increase in net regulatory assets in the fourth quarter of 2017. This revenue increase was based on new regulated prices for that period proposed in OPG's January 2018 submission to the OEB based on the findings in the decision and is net of a regulatory liability recognized in relation to OPG's nuclear rate smoothing proposal in that submission.

Segment earnings were unfavourably affected by a reduction in electricity generation of 4.9 TWh in 2017, compared to 2016. This reduced revenue by approximately $285 million, partially offset by a decrease in fuel expense. The lower electricity generation was primarily due to the ongoing Unit 2 refurbishment outage at the Darlington GS that began in October 2016, partially offset by the higher electricity generation from the Pickering GS. The income impact of OEB-approved regulatory accounts also contributed to the decrease in income for the year.

The increase in OM&A expenses of $83 million in 2017, compared to 2016, reflected planned expenditures related to the major maintenance activities and higher project expenditures occurring at the nuclear stations. Depreciation and amortization expenses, excluding amortization expense related to regulatory account balances, increased by $22 million primarily due to new assets in service in 2017.

The expiry of a nuclear rate rider for the recovery of OEB-approved balances in regulatory accounts on December 31, 2016 contributed to the decrease in segment revenue in 2017, compared to 2016, but was largely offset by a decrease in amortization expense related to these balances.

The Unit Capability Factors for the Darlington GS and Pickering GS for 2017 and 2016 were as follows:

	2017	2016
Unit Capability Factor *(%)* [1]		
Darlington GS	**85.2**	89.5
Pickering GS	**80.0**	75.2

[1] The nuclear Unit Capability Factor excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS was excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

The lower Unit Capability Factor at the Darlington GS in 2017, compared to 2016, reflected the higher number of planned outage days in 2017, largely driven by constraints related to the transition of the station's operating units toward refurbishment.

The increase in the Unit Capability Factor at the Pickering GS in 2017, compared to 2016, was primarily due to outage cycle optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station compared to 2016.

The definition of the nuclear Unit Capability Factor is found in the section, *Key Operating and Financial Performance Indicators.*

Regulated – Nuclear Waste Management Segment

(millions of dollars)	2017	2016
Revenue	**121**	138
Operations, maintenance and administration	**129**	146
Accretion on nuclear fixed asset removal and nuclear waste management liabilities	**943**	912
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(801)**	(746)
Loss before interest and income taxes	**(150)**	(174)

Earnings from the segment improved by $24 million in 2017 compared to 2016. The improvement was primarily due to higher earnings from the Nuclear Segregated Funds, partially offset by an increase in accretion expense on the Nuclear Liabilities. Accretion expense represents a financing cost due to the increase in the present value of the underlying liabilities with the passage of time.

The year-over-year increase in the earnings from the funds was primarily due to a reduction in the earnings recorded in the fourth quarter of 2016 to reflect an accounting adjustment to limit Nuclear Segregated Funds assets reported on the consolidated balance sheet to the underlying funding liabilities based on an updated ONFA reference plan approved by the Province. The updated ONFA reference plan resulted in a reduction in the funding liabilities. As both the Decommissioning Segregated Fund and the Used Fuel Fund have been in an overfunded position since the beginning of 2017, the earnings on the funds recognized in net income during the year reflected the growth rate in the present value of the funding liabilities and were not impacted by market returns and the rate of return guaranteed by the Province for the portion of the Used Fuel Segregated Fund. Further details on the accounting for the Nuclear Segregated Funds can be found in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

The year-over-year increase in accretion on nuclear fixed removal and nuclear waste management liabilities in 2017, compared to 2016, was primarily due to the impact on accretion expense related to the increase in asset retirement obligation associated with the life extension of the Bruce nuclear assets from the agreement executed between Bruce Power and the Province in late 2015. This increase was offset in 2016 due to the Bruce Lease Net Revenues Variance Account but is reflected in accretion with the resetting of base rates in 2017. This increase was partially

offset by the impact of the decrease in Nuclear Liabilities to reflect an updated estimate as part of the ONFA reference plan update process.

As of December 31, 2016, OPG recorded a decrease of approximately $1,570 million to the Nuclear Liabilities and associated asset retirement costs capitalized as part of the carrying value of the nuclear generating stations to reflect an updated estimate of OPG's obligations for nuclear waste management and nuclear facilities decommissioning determined as part of the ONFA reference plan update process. The resulting year-over-year decreases in accretion expense recorded in the Regulated – Nuclear Waste Management segment and depreciation and fuel expenses recorded in the Regulated – Nuclear Generation segment were offset by the impact of the OEB-authorized Bruce Lease Net Revenues Variance Account and Nuclear Liability Deferral Account recorded in the corresponding segments for the period up to May 31, 2017, and by the retrospective revenue impact of the OEB's decision for the period from June 1, 2017 to December 31, 2017 recorded in the Regulated – Nuclear Generation segment.

Regulated – Hydroelectric Segment

(millions of dollars)	**2017**	**2016**
Revenue [1]	**1,436**	1,527
Fuel expense	**351**	353
Gross margin	**1,085**	1,174
Operations, maintenance and administration	**330**	325
Depreciation and amortization	**139**	225
Property tax	**1**	1
Income before other gains, interest and income taxes	**615**	623
Other losses (gains)	**1**	(19)
Income before interest and income taxes	**614**	642

[1] During 2017 and 2016, the Regulated – Hydroelectric segment revenue included incentive payments of $12 million and $14 million, respectively, related to the OEB-approved hydroelectric incentive mechanism. The mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers.

The decrease in income before interest and income taxes of $28 million in 2017, compared to 2016, was primarily due to a gain of $22 million recognized during the first quarter of 2016 to reflect the OEB's January 2016 decision reversing a portion of an earlier capital cost disallowance related to the Niagara Tunnel project expenditures, in response to a motion by OPG. The income impact of OEB-approved regulatory accounts and higher OM&A expenses also contributed to the decrease in income for the year. The higher OM&A expenses were primarily related to overhaul work and civil repairs completed during the year.

These factors were partially offset by the recognition of a revenue increase of approximately $15 million in the fourth quarter of 2017 to reflect the OEB's decision on OPG's application for new regulated prices. This incremental revenue was in relation to the June 1, 2017 to December 31, 2017 period based on the June 1, 2017 retrospective effective date of the new regulated prices and was recorded as an increase to regulatory assets.

The decrease in revenue from the segment for the year ended December 31, 2017, compared to the same period in 2016, was largely due to the expiry of an OEB-authorized hydroelectric rate rider on December 31, 2016. As the rate rider allowed for the recovery of approved balances in OEB-authorized regulatory accounts, this decrease in revenue was largely offset by lower amortization expense related to these balances.

The Hydroelectric Availability for the stations included in the Regulated – Hydroelectric segment was as follows:

	2017	2016
Hydroelectric Availability *(%)*	**88.0**	89.0

The Hydroelectric Availability decreased during 2017, compared to 2016, primarily due to a higher number of unplanned outage days at the Northwestern Ontario, Niagara, and Eastern Ontario regions' hydroelectric stations, partially offset by higher availability from the Sir Adam Beck Pump GS due to a higher number of planned outages days in 2016 as a result of the refurbishment of the station's reservoir.

The definition of Hydroelectric Availability is found in the section, *Key Operating and Financial Performance Indicators*.

Contracted Generation Portfolio Segment

(millions of dollars)	2017	2016
Revenue	**579**	573
Fuel expense	**53**	58
Gross margin	**526**	515
Operations, maintenance and administration	**169**	178
Depreciation and amortization	**79**	75
Accretion on fixed asset removal liabilities	**9**	9
Property taxes	**7**	7
Income from investments subject to significant influence	**(38)**	(37)
Income before other losses, interest, and income taxes	**300**	283
Other losses	**-**	1
Income before interest and income taxes	**300**	282

Income before interest and income taxes increased by $18 million during 2017, compared to 2016. The increase in earnings primarily resulted from revenues from the Peter Sutherland Sr. GS that was placed in-service at the end of the first quarter of 2017 and lower OM&A expenses, partially offset by lower revenues from the Lower Mattagami River hydroelectric generating stations and Atikokan GS. The lower OM&A expenses were mainly due to the prospective adoption of the full yield curve approach to the estimation of the service and interest cost components of pension and OPEB costs starting in 2017.

The Hydroelectric Availability and the Thermal EFOR for the Contracted Generation Portfolio segment were as follows:

	2017	2016
Hydroelectric Availability *(%)*	**74.6**	77.3
Thermal EFOR *(%)*	**2.4**	1.6

Lower Hydroelectric Availability during 2017, compared to 2016, was primarily due to an increase in the number of planned outage days at the Lower Mattagami River hydroelectric generating stations.

The higher thermal EFOR in 2017, compared to 2016, was primarily due to a higher number of unplanned outage days at a Lennox GS unit as a result of a transmission outage and a generator-related outage in 2017.

The definitions of Hydroelectric Availability and Thermal EFOR are found in the section, *Key Operating and Financial Performance Indicators*.

Services, Trading, and Other Non-Generation Segment

(millions of dollars)	2017	2016
Revenue	**43**	68
Fuel expense	**1**	1
Gross margin	**42**	67
Operations, maintenance and administration	**18**	22
Depreciation and amortization	**30**	32
Accretion on fixed asset removal liabilities	**8**	8
Property taxes	**6**	12
Restructuring	**-**	6
Loss before other gain, interest, and income taxes	**(20)**	(13)
Other gains	**(384)**	-
Income before interest and income taxes	**364**	(13)

Segment earnings improved by $377 million in 2017 compared to 2016. The increase in earnings mainly reflected the gain on the sale of OPG's head office premises and associated parking facility recorded during the second quarter of 2017 of $283 million, which is net of tax effects of $95 million, partially offset by a decrease in rental revenue due to the sale of the head office premises.

The year-over-year decrease in OM&A expenses in 2017 reflected higher expenses incurred in 2016 prior to the decision taken in the fourth quarter of 2016 to proceed with the decommissioning of the Lambton GS, largely offset by a higher write-off of previously incurred project expenditures in 2017.

During the fourth quarter of 2017, OPG recorded $12 million in Other gains related to the revaluation of the asset retirement obligations for Lambton and Nanticoke generating stations in line with the current decommissioning plans and cost estimates. During each of 2017 and 2016, OPG recorded a charge against earnings to adjust the scrap value estimate for the Lambton GS, as a reduction to Other gains.

Fair Hydro Trust Segment

(millions of dollars)	2017
Operations, maintenance and administration	**1**
Earnings from Fair Hydro Trust	**(1)**
Income before interest and income taxes	**-**

The Fair Hydro Trust was established on December 20, 2017. The Fair Hydro Trust segment includes the revenue and expenses related to OPG's role as Financial Services Manager of the Fair Hydro Trust and holder of subordinated debt issued by the Trust, including the financial results of the Trust. Earnings from Fair Hydro Trust were $1 million in 2017, primarily due to net interest income earned on OPG's subordinated debt investment for the 11-day period following the acquisition of the first tranche of Investment Interest from the IESO on December 21, 2017. The earnings were offset by an allocation of OM&A expenses for labour costs relating to OPG's employees that are not exclusively dedicated to the segment but who provided services to set up the Trust during the year. Pursuant to the general regulation of the Fair Hydro Act, such labour costs are not recoverable as part of OPG's fees for 2017. Refer to the section, *Recent Developments* under the heading, *Ontario's Fair Hydro Plan* and the section, *Business Segments* under the heading, *Fair Hydro Trust Segment* for further details on the Fair Hydro Trust.

LIQUIDITY AND CAPITAL RESOURCES

OPG's primary sources of liquidity and capital are funds generated from operations, bank financing, credit facilities provided by the Ontario Electricity Financial Corporation (OEFC), long-term corporate debt, including public debt offerings and notes payable to the OEFC, private placement project financing, and equity issuance. These sources are used for multiple purposes including: to invest in plants and technologies, to undertake major projects, to fund long-term obligations such as contributions to the pension fund and the Nuclear Segregated Funds, to make payments under the OPEB plans, to fund expenditures on Nuclear Liabilities not eligible for reimbursement from the Nuclear Segregated Funds, and to service and repay long-term debt, to provide general working capital, and to fund a portion of OPG's subordinated debt investment in the Fair Hydro Trust and the Trust's acquisition of Investment Interest from the IESO.

Changes in cash and cash equivalents for 2017 and 2016 were as follows:

(millions of dollars)	**2017**	**2016**
Cash and cash equivalents, beginning of period	**186**	464
Cash flow provided by operating activities	**944**	1,817
Cash flow used in investing activities	**(2,478)**	(1,919)
Cash flow provided by (used in) financing activities	**1,582**	(176)
Net increase (decrease) in cash and cash equivalents	**48**	(278)
Cash and cash equivalents, end of period	**234**	186

For a discussion regarding cash flow provided by operating activities and the FFO Adjusted Interest Coverage ratio, refer to the details in the section, *Highlights* under the heading, *Overview of Results*.

Investing Activities

Electricity generation is a capital-intensive business. It requires continued investment in plants and technologies to maintain and improve operating performance including asset reliability, safety and environmental performance, to increase the generating capacity of existing stations, and to invest in the development of new generating stations, emerging technologies and other business growth opportunities.

Cash flow used in investing activities in 2017 increased by $834 million compared to 2016. The increase in net cash flow used in investing activities was primarily due to the Trust's acquisition of the first tranche of Investment Interest from the IESO in the amount of approximately $1.18 billion in December 2017 and higher expenditures on the Darlington Refurbishment project in 2017.

The increase in net cash flow used in investing activities was partially offset by the receipt of proceeds from the sale of OPG's head office premises and associated parking facility in 2017 and the acquisition of nine million common shares of Hydro One Limited (Hydro One) in 2016. OPG acquired the Hydro One shares for investment purposes, to mitigate the risk of future price volatility related to the Company's future share delivery obligations under the current collective agreements with the Power Workers' Union (PWU) and The Society of Energy Professionals (The Society).

Financing Activities

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. In the second quarter of 2017, OPG renewed and extended the expiry date of both tranches from May 2021 to May 2022. There were no amounts outstanding under the bank credit facility as at December 31, 2017.

There was $100 million of commercial paper outstanding under OPG's commercial paper program as at December 31, 2017.

As at December 31, 2017, OPG also maintained $25 million of short-term, uncommitted overdraft facilities, and a further $468 million of short-term, uncommitted credit facilities which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other general corporate purposes. As at December 31, 2017, a total of $390 million of Letters of Credit had been issued under these facilities. This included $353 million for the supplementary pension plans, $36 million for general corporate purposes, and $1 million related to the operation of the PEC.

The Company has an agreement to sell an undivided co-ownership interest in its current and future accounts receivable to an independent trust, expiring on November 30, 2018. The maximum amount of co-ownership interest that can be sold under this agreement is $150 million. As at December 31, 2017, no borrowings were issued under this agreement and there were Letters of Credit outstanding under this agreement of $150 million, which were issued in support of OPG's supplementary pension plans.

As at December 31, 2017, Lower Mattagami Energy Limited Partnership (LME) maintained a $400 million bank credit facility to support the funding requirements for the Lower Mattagami River project including support for LME's commercial paper program. The facility consists of a $300 million tranche maturing in August 2022 and a $100 million tranche maturing in August 2018. As at December 31, 2017, there was $160 million commercial paper outstanding under LME's commercial paper program. A letter of credit of $55 million was issued in July 2017 and remains outstanding as at December 31, 2017 under the $300 million tranche of LME's credit facility.

In June 2016, OPG entered into a $700 million general corporate credit facility agreement with the OEFC, with an expiry date of December 31, 2017. During 2017, the agreement was amended to increase the credit facility to $2,350 million and to extend its expiry date to December 31, 2018. As at December 31, 2017, there were outstanding long-term borrowings of $800 million under this credit facility.

In February 2017, OPG issued senior notes payable to the OEFC totalling $200 million and maturing in February 2047. The effective interest rate and coupon interest rate of these notes was 4.12 percent. In June 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in June 2047. The effective interest rate and coupon interest rate of these notes was 3.65 percent. In August 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in August 2047. The effective interest rate and coupon interest rate of these notes was 3.86 percent. In September 2017, OPG issued senior notes payable to the OEFC totalling $400 million and maturing in September 2047. The effective interest rate and coupon interest rate of these notes was 4.07 percent.

In October 2017, OPG issued $500 million of senior notes payable under a Medium Term Note Program. The notes bear a coupon interest rate of 3.32 percent and an effective rate of 3.43 percent, payable semi-annually until maturity on October 4, 2027. The offering was made under OPG's $2 billion short form base shelf prospectus dated September 12, 2017. The net proceeds will be used for general corporate purposes.

In December 2017, the Fair Hydro Trust entered into an $800 million revolving warehouse facility agreement with an expiry date of December 21, 2019. As at December 31, 2017, there were outstanding senior notes of $601 million under this credit facility, which were used to finance 51 percent of the Trust's funding requirement for the acquisition of the first tranche of Investment Interest from the IESO in December 2017.

In February 2018, the Trust issued $500 million of senior notes payable with a coupon interest rate of 3.36 percent and an effective interest rate of 3.42 percent, payable semi-annually until maturity on May 15, 2033. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility issued by the Trust in December 2017. By the end of the first quarter of 2018, the Trust is expected to acquire another tranche of Investment Interest from the IESO, which it expects to fund using its revolving warehouse facility.

As at December 31, 2017, OPG's long-term debt outstanding was $5,735 million, including $398 million due within one year and excluding Fair Hydro Trust's senior debt included in OPG's consolidated balance sheets. The Fair Hydro Trust's senior debt outstanding was $601 million as at December 31, 2017.

Contractual Obligations

OPG's contractual obligations as at December 31, 2017, are as follows:

(millions of dollars)	2018	2019	2020	2021	2022	Thereafter	Total
Fuel supply agreements	158	125	115	88	67	67	620
Contributions to the OPG registered pension plan [1]	215	219	-	-	-	-	434
OPG long-term debt repayment	398	368	663	413	172	3,721	5,735
Interest on OPG long-term debt	244	226	204	175	161	3,006	4,016
Fair Hydro Trust senior debt repayment [2]	-	601	-	-	-	-	601
Interest on Fair Hydro Trust senior debt	15	15	-	-	-	-	30
Commitments related to Darlington Refurbishment project [3]	473	-	-	-	-	-	473
Commitments related to Ranney Falls GS project	29	5	-	-	-	-	34
Operating licences	40	41	24	28	28	87	248
Operating lease obligations	28	24	24	22	22	79	199
Unconditional purchase obligations	59	58	56	5	-	-	178
Accounts payable and accrued charges	957	8	-	-	-	16	981
Other	57	30	2	1	1	64	155
Total	2,673	1,720	1,088	732	451	7,040	13,704

[1] The pension contributions include ongoing funding requirements and additional funding requirements towards the deficit, in accordance with the actuarial valuation of the OPG registered pension plan as at January 1, 2017. The next actuarial valuation of the OPG registered pension plan must have an effective date no later than January 1, 2020. The pension contributions are affected by various factors including market performance, changes in actuarial assumptions, plan experience, changes in the pension regulatory environment, and the timing of funding valuations. Funding requirements after 2019 are excluded due to significant variability in the assumptions required to project the timing of future cash flows. The amount of OPG's additional, voluntary contribution, if any, is revisited from time to time.

[2] The notes were issued by the Fair Hydro Trust under an $800 million two-year revolving warehouse facility in December 2017. In February 2018, the Trust issued $500 million of senior notes payable to repay the majority of the outstanding balance of the revolving warehouse facility.

[3] Represents estimated currently committed costs to close the project, including accruals for completed work, demobilization of project staff and cancellation of existing contracts and material orders.

Other Commitments

Collective Agreements

As of December 31, 2017, OPG had approximately 9,200 regular employees. Most of OPG's regular employees are represented by two unions:

- The PWU – This union represents approximately 4,850 OPG employees or approximately 53 percent of OPG's regular workforce as at December 31, 2017. Union membership includes operators, technicians, skilled trades, clerical, and security personnel. The current collective agreement between OPG and the PWU has a three-year term, expiring on March 31, 2018. Negotiations for a new labour agreement with the PWU are underway. **[MONITOR]**
- The Society – This union represents approximately 3,250 OPG employees or approximately 35 percent of OPG's regular workforce as at December 31, 2017. Union membership includes supervisors, professional engineers, scientists, and other professionals. The current collective agreement between OPG and The Society has a three-year term, expiring on December 31, 2018.

In addition to the regular workforce, construction work is performed through 19 craft unions with established bargaining rights at OPG facilities. These bargaining rights are established either through the Electrical Power Systems Construction Association (EPSCA) or directly with OPG. Collective agreements between the Company and its construction unions are negotiated either directly or through EPSCA. All of these collective agreements currently have multi-year terms, expiring on April 30, 2020.

BALANCE SHEET HIGHLIGHTS

The following section provides other highlights of OPG's audited consolidated financial position using selected balance sheet data as at December 31:

(millions of dollars)	**2017**	**2016**
Property, plant and equipment – net	**21,322**	19,998
The increase was primarily due to capital expenditures on the Darlington Refurbishment project, partially offset by depreciation expense.		
Nuclear fixed asset removal and nuclear waste management funds *(current and non-current portions)*	**16,724**	15,984
The increase was primarily due to earnings on the Nuclear Segregated Funds, partially offset by reimbursement of eligible expenditures on nuclear fixed asset removal and nuclear waste management activities.		
Regulatory assets and liabilities – net *(current and non-current portions)*	**6,637**	5,545
The increase was primarily due to the addition of the Interim period revenue shortfall account, increases in the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB AOCI regulatory asset. In addition, there was no amortization recorded in 2017 consistent with OPG's proposal in the Draft Payment Amounts Order filed with the OEB in January 2018.		
Long-term debt *(current and non-current portions)*	**6,319**	5,520
The increase was primarily due to the issuance of senior notes payable by the Trust to finance the acquisition of an Investment Interest in the shortfall from the rate reductions mandated by the Fair Hydro Act of $601 million, issuance of senior notes payable totaling $804 million during 2017 primarily with the OEFC, and issuance of senior notes totaling $500 million under the Medium Term Note Program. The balance is offset by the debt repayment of $1 billion in 2017.		
Fixed asset removal and nuclear waste management liabilities	**20,421**	19,484
The increase was primarily a result of accretion expense representing the increase in the present value liabilities due to the passage of time, and an increase in the estimate for the nuclear ARO of $188 million recorded in 2017, which is discussed in *Critical Accounting Policies and Estimates* under the heading, Asset Retirement *Obligation*. The increase was partially offset by expenditures on nuclear fixed asset removal and waste management activities.		
Pension liabilities	**3,423**	3,012
The increase was primarily due to the re-measurement of the liabilities at the end of 2017 reflecting lower discount rates, partially offset by the excess of actual returns on pension plan assets over interest costs on the liabilities during 2017, as discussed in the section, *Critical Accounting Policies and Estimates* under the *heading, Pension and Other Post-Employment Benefits.*		
Other post-employment benefit liabilities	**3,092**	2,897
The increase was primarily due to the remeasurement of the liabilities at the end of 2017 reflecting lower discount rates, partially offset by the updated lower per capital health care claims costs assumption as part of the 2017 actuarial valuation.		

Off-Balance Sheet Arrangements

In the normal course of operations, OPG engages in a variety of transactions that, under US GAAP, are either not recorded in the Company's interim consolidated financial statements or are recorded in the Company's interim consolidated financial statements using amounts that differ from the full contract amounts. Principal off-balance sheet activities for OPG include guarantees and long-term contracts.

Guarantees

As part of normal business, OPG and certain of its subsidiaries and joint ventures enter into various agreements to provide financial or performance assurance to third parties. Such agreements include guarantees, standby Letters of Credit and surety bonds. For more details on guarantees issued by the company, refer to Note 15 of OPG's audited consolidated financial statements.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

OPG's significant accounting policies, including the impact of major recent accounting pronouncements, are outlined in Note 3 of the audited consolidated financial statements. Certain of these policies are recognized as critical accounting policies by virtue of the subjective and complex judgments and estimates required around matters that are inherently uncertain and could result in materially different amounts being reported under different conditions or assumptions. The critical accounting policies and estimates that affect OPG's US GAAP consolidated financial statements are highlighted below.

Exemptive Relief for Reporting under US GAAP

As required by *Ontario Regulation 395/11,* as amended, under the FAA, OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. Since January 1, 2012, OPG also has received exemptive relief from the OSC from the requirements of section 3.2 of National Instrument 52-107 *Acceptable Accounting Policies and Auditing Standards* (NI 52-107). The exemption allows OPG to file consolidated financial statements with the OSC based on US GAAP, rather than International Financial Reporting Standards (IFRS), without becoming a U.S. Securities and Exchange Commission registrant.

The current OSC exemption, received in 2014, will terminate on the earliest of the following:

- January 1, 2019
- The financial year that commences after OPG ceases to have activities subject to rate regulation
- The effective date prescribed by the International Accounting Standards Board (IASB) for the mandatory application of a standard within IFRS specific to entities with rate-regulated activities.

As a result of OPG's 2011 decision to adopt US GAAP, as required by the FAA regulation, OPG's earlier plan to convert to IFRS, effective January 1, 2012, was discontinued. OPG had substantively completed its IFRS conversion project, which included separate diagnostic, development, and implementation phases, when it suspended the project. If a future transition to IFRS for the purposes of OPG's consolidated financial statements is required, conversion work can be effectively restarted with sufficient lead time to evaluate and conclude on changes that occurred subsequent to the decision to suspend the project. OPG continues to monitor the IASB's current standard-setting project related to entities with rate-regulated activities and is evaluating alternatives with respect to the Company's future financial reporting.

Rate Regulated Accounting

The *Ontario Energy Board Act, 1998* and *Ontario Regulation 53/05* provide that OPG receives regulated prices for electricity generated from 54 hydroelectric generating stations and the Pickering and Darlington nuclear generating stations. OPG's regulated prices for these facilities are determined by the OEB.

The OEB is a self-funding Crown corporation. Its mandate and authority come from the *Ontario Energy Board Act, 1998*, the *Electricity Act, 1998*, and a number of other provincial statutes. The OEB is an independent, quasi-judicial tribunal that reports to the Legislature of the Province through the Ontario Ministry of Energy. It regulates market participants in Ontario's natural gas and electricity industries. The OEB carries out its regulatory functions through public hearings and other more informal processes such as consultations.

US GAAP recognizes that rate regulation can create economic benefits and obligations that are required by the regulator to be obtained from, or settled with, the customers. When the Company assesses that there is sufficient assurance that incurred costs in respect of the regulated facilities will be recovered in the future, those costs are deferred and reported as a regulatory asset. When the Company is required to refund amounts to customers in the future in respect of the regulated facilities, including amounts related to costs that have not been incurred and for which the OEB has provided recovery through regulated prices, the Company records a regulatory liability.

Certain of the regulatory assets and liabilities recognized by the Company relate to variance and deferral accounts authorized by the OEB, including those authorized pursuant to *Ontario Regulation 53/05.* The measurement of these regulatory assets and liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of *Ontario Regulation 53/05* and the OEB's decisions. The estimates and assumptions made in the interpretation of the regulation and the OEB's decisions are reviewed as part of the OEB's regulatory process.

Regulatory assets and liabilities for variance and deferral account balances approved by the OEB for inclusion in regulated prices are amortized based on approved recovery or repayment periods.

In addition to regulatory assets and liabilities for variance and deferral accounts, OPG recognizes regulatory assets and liabilities for unamortized amounts recorded in AOCI in respect of pension and OPEB obligations, and deferred income taxes, in order to reflect the expected recovery or repayment of these amounts through future regulated prices charged to customers. There are measurement uncertainties related to these balances due to the assumptions made in the determination of pension and OPEB obligations and deferred income taxes that are attributed to rate regulated business segments.

The regulatory asset for unamortized pension and OPEB amounts recorded in AOCI has reflected the OEB's use, since April 1, 2008, of the accrual basis of accounting for including pension and OPEB amounts in approved regulated prices for OPG. This is also the manner in which these costs are recognized in OPG's consolidated financial statements. Therefore, unamortized amounts in respect of OPG's pension and OPEB plans recognized in AOCI generally would not be reflected in regulated prices until they have been reclassified from AOCI and recognized as amortization components of the benefit costs for these plans.

Since November 1, 2014, the OEB has limited amounts for pension and OPEB costs included in the approved revenue requirements and regulated prices to the regulated business portion of the Company's cash expenditures for its pension and OPEB plans. The difference between actual pension and OPEB costs determined using the accrual method applied in OPG's audited consolidated financial statements and OPG's corresponding actual cash expenditures for these plans is captured in OEB-authorized Pension & OPEB Cash Versus Accrual Differential Deferral Account for future consideration. In 2017, the OEB issued a report outlining the guiding principles and policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the Ontario electricity and natural gas sectors. The report establishes the accrual basis of accounting as the method of determining pension and OPEB amounts for rate-setting purposes, unless the OEB finds that this method does not result in just and reasonable rates in the circumstances of a particular utility. The OEB's report and the OEB's December 2017 decision on OPG's

application for new regulated prices require OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the existing deferral account, until such time as the OEB approves resumption of the accrual basis of recovery for OPG. The future recovery of amounts recorded in the account will be subject to this approval. Further details on the OEB's 2017 report can be found in the section, *Highlights* under the heading, *Recent Developments – OEB's Decision on OPG's Application for New Regulated Prices*.

It remains the Company's position that, taken collectively, OEB's decisions on OPG's applications for regulated prices and the OEB's 2017 report in this area do not constitute a change in the basis of OPG's rate recovery of pension and OPEB costs. The Company continues to believe that there is sufficient likelihood that unamortized pension and OPEB amounts that have not yet been reclassified from AOCI will be included in future regulated prices, or in an OEB-authorized regulatory account for future recovery, as they are recognized in benefit costs. Similarly, the Company continues to believe that there is sufficient likelihood that amounts recorded in the Pension & OPEB Cash Versus Accrual Differential Deferral Account will be recovered, and consistent with the expectations set out in the OEB's December 2017 decision, plans to file an application with the OEB in 2018 requesting recovery of the account balance. Therefore, the Company continues to recognize regulatory assets for the above amounts.

See Notes 3, 5, 8, 9, and 11 of OPG's 2017 audited consolidated financial statements for additional disclosures related to the OEB's decisions, regulatory assets and liabilities, and rate regulated accounting.

Useful Lives of Long-Lived Assets

OPG reviews estimated station useful lives for its generating assets on a regular basis.

Nuclear Generating Stations

For the nuclear stations, this process involves reviewing major life limiting components (such as pressure tubes, feeders and steam generators) to determine an appropriate end-of-life date for the station. Useful lives are set such that, with normal and customary maintenance activities, stations are expected to be operational until such time as their life-limiting component's threshold is expected to be reached.

Hydroelectric and Thermal Generating Stations

Although there is a link between the age of a facility and the capital investment required to maintain that facility, age does not establish an upper limit on the expected useful life of hydroelectric facilities and dams. Regular maintenance and the replacement of specific components typically allow hydroelectric stations to operate for very long periods. For hydroelectric generating stations, an upper age limit of 100 years have been set.

Thermal generating stations reported in the Contracted – Generation Portfolio business segment primarily have useful lives that are in line with the term of the Energy Supply Agreements with the IESO.

Financing Receivables

Financing receivables consist of the current and irrevocable right of the Fair Hydro Trust to collect payments from Specified Consumers in the future in accordance with the Fair Hydro Act and associated general regulation. These amounts are measured at the transaction price entered into with the IESO on market terms upon acquisition and subsequently measured on an amortized cost basis. The basis of amortization follows the effective interest method.

Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

In accordance with the ONFA, OPG sets aside and invests funds that are held in segregated custodian and trustee accounts specifically for discharging its obligation for nuclear facilities decommissioning and long-term nuclear waste management. The Decommissioning Segregated Fund was established to fund the future costs of nuclear fixed asset removal and long-term L&ILW management, and certain costs of used fuel storage incurred after the stations are shut down. The Used Fuel Segregated Fund was established to fund the future costs of long-term nuclear used

fuel management and certain costs of used fuel storage incurred after the stations are shut down. Costs for L&ILW management and used fuel storage incurred during station operation are not funded by the Nuclear Segregated Funds. They are funded through the Company's operating cash flow or other sources of liquidity.

Based on the current approved ONFA reference plan, starting in 2017, OPG is not currently required to make overall contributions to the Used Fuel Segregated Fund or the Decommissioning Segregated Fund. Prior to 2017, OPG made contributions to the Used Fuel Segregated Fund quarterly, including a one-time special payment in earlier years, as required by the ONFA. These contributions reflected ONFA requirements to fund the majority of the underlying used fuel liability by the end of the initial estimated useful lives of the nuclear stations assumed in the ONFA, resulting in significantly higher contributions to the Used Fuel Segregated Fund in the earlier years of OPG's existence. OPG has not been required to make contributions to the Decommissioning Segregated Fund, which was fully funded at its inception through the initial contribution made by the Ontario Electricity Financial Corporation (OEFC), an agency of the Province, and, taking into account asset performance and changes in underlying funding obligations over time, at the time of every subsequent approved ONFA reference plan. Contributions to either or both funds may be required in the future should the funds be in an underfunded position when a new reference plan is prepared. Such may be the case as a result of variability in asset performance due to volatility inherent in financial markets and, for the portion of the Used Fuel Segregated Fund guaranteed by the Province, changes in the Ontario CPI. Future contribution levels also are dependent on changes in baseline cost and liability estimates and underpinning assumptions used to establish the funding obligations in subsequent ONFA reference plans.

Commented [MR-5]: Updated this change. Ontario Electricity Financial Corporation is defined earlier so updated wording to:
"[…] OEFC, an agency of the […]"

Commented [MR-6]: Did not take this change. The liability is covered by "to establish the funding obligations (e.g., liabilities) in subsequent ONFA reference plans.

Decommissioning Segregated Fund

Upon termination of the ONFA, the Province has the sole right to any excess funds in the Decommissioning Segregated Fund. Accordingly, when the Decommissioning Segregated Fund is overfunded, OPG limits the fund earnings it recognizes in the consolidated financial statements by recording an amount due to the Province, such that the fund asset recognized on the consolidated balance sheet is equal to the cost estimate of the liability based on the most recently approved ONFA reference plan. Additionally, OPG recognizes the portion of the surplus that it may direct to the Used Fuel Segregated Fund, which is possible when the surplus is such that the underlying liabilities, as defined by the most recently approved ONFA reference plan, are at least 120 percent funded. In those circumstances, OPG may direct, at the time a new or amended reference plan is approved, up to 50 percent of the surplus over 120 percent to the Used Fuel Segregated Fund, with the OEFC entitled to a distribution of an equal amount. Therefore, when the Decommissioning Segregated Fund is at least 120 percent funded, OPG recognizes 50 percent of the excess greater than 120 percent in income, up to the amount by which the Used Fuel Segregated Fund is underfunded.

The amount due to the Province in respect of the Decommissioning Segregated Fund could be reduced in subsequent periods in the event that the fund earns less than is target rate of return, a new ONFA reference plan is approved with a higher underlying liability, or the amount of the underfunding in the Used Fuel Segregated Fund increases.

When the Decommissioning Segregated Fund is underfunded, the earnings on the fund reflect actual fund returns based on the market value of the assets.

Used Fuel Segregated Fund

Under the ONFA, the Province guarantees OPG's annual return in the Used Fuel Segregated Fund at 3.25 percent plus the change in the Ontario CPI, as defined in the ONFA, for funding related to the first 2.23 million used fuel bundles ("committed return"). OPG recognizes the committed return on the Used Fuel Segregated Fund as earnings on the Nuclear Segregated Funds. The difference between the committed return and the actual market return determined based on the fair value of the fund's assets related to the first 2.23 million used fuel bundles is recorded as due to or due from the Province. This amount represents the amount OPG would pay to, or receive from, the Province if the committed return were to be settled as of the consolidated balance sheet date. Upon approval of a

new or amended ONFA reference plan, the Province is obligated to make an additional contribution to the Used Fuel Segregated Fund in relation to the first 2.23 million used fuel bundles if the fund's assets earned a rate of return that is less than the guaranteed rate of return. If the return on the fund's assets exceeds the Province's guaranteed rate of return, the Province is entitled to withdraw any portion of the excess related to the 2.23 million used fuel bundles, upon approval of a new or amended ONFA reference plan. The 2.23 million threshold represents the estimated total life cycle fuel bundles based on the initial estimated useful lives of the nuclear stations assumed in the ONFA.

As prescribed under the ONFA, OPG's contributions attributed to the used fuel bundles in excess of 2.23 million are not subject to the rate of return guaranteed by the Province, and earn a return based on changes in the market value of the assets of the Used Fuel Segregated Fund.

If there is a surplus in the Used Fuel Segregated Fund such that the funding liabilities, as defined by the most recently approved ONFA Reference Plan, are at least 110 percent funded, the Province has the right, at any time, to access the excess amount greater than 110 percent. Upon termination of the ONFA, the Province is entitled to any surplus in the fund. Accordingly, when the Used Fuel Segregated Fund is overfunded, OPG limits the fund earnings it recognizes in the consolidated financial statements by recording an amount due to the Province, such that the balance of the fund is equal to the cost estimate of the liability based on the most recently approved ONFA reference plan. In accordance with the ONFA, neither OPG nor the Province have a right to direct any amounts from the Used Fuel Segregated Fund to the Decommissioning Segregated Fund.

Provincial Guarantee

In accordance with the *Nuclear Safety and Control Act* (Canada), the CNSC requires OPG to have sufficient funds available to discharge its existing nuclear waste management and nuclear decommissioning obligations. The CNSC process requires the CNSC financial guarantee requirement to be updated once every five years and for OPG to provide an annual report to the CNSC on the assumptions, asset values, and resulting financial guarantee requirements. The CNSC financial guarantee requirement calculation takes into account nuclear waste expected to be generated to the end of each year.

In November 2017, the CNSC accepted OPG's proposed 2018-2022 CNSC financial guarantee requirement to be satisfied by the forecast fair market value of the Nuclear Segregated Funds without the requirement of a Provincial Guarantee for the 2018-2022 period. As ~~required~~ provided for by the terms of the ONFA, the Province is committed to provide a Provincial Guarantee to the CNSC as required, on behalf of OPG, should there be a shortfall between the CNSC financial guarantee requirement and the fair market value of the Nuclear Segregated Funds in the 2018-2022 period, as it has done in the past. OPG pays the Province an annual guarantee fee equal to 0.5 percent of the outstanding amount, if any, of the Provincial Guarantee.

Commented [MR-7]: Accepted this change.

The value of the Provincial Guarantee in effect through to the end of 2017 was $1,551 million. Based on this guarantee amount, OPG paid a guarantee fee of $8 million to the Province for each of 2016 and 2017.

Pension and Other Post-Employment Benefits

The determination of OPG's pension and OPEB costs and obligations is based on accounting policies and assumptions, as discussed below.

Accounting Policy

OPG's post-employment benefit programs consist of a contributory defined benefit registered pension plan, a defined benefit supplementary pension plan, and other post retirement benefits (OPRB) including group life insurance and health care benefits, and long-term disability (LTD) benefits. Post-employment benefit programs also are provided by the Nuclear Waste Management Organization (NWMO), which is consolidated into OPG's financial results. Unless otherwise noted, information on the Company's post-employment benefit programs is presented on a consolidated basis.

OPG accrues its obligations under pension and OPEB plans in accordance with US GAAP. The obligations for pension and OPRB are determined using the projected benefit method pro-rated on service. The obligation for LTD benefits is determined using the projected benefit method on a terminal basis. Pension and OPEB obligations are impacted by factors including interest rates, adjustments arising from plan amendments, demographic assumptions, experience gains or losses, salary levels, inflation, and health care cost escalation assumptions. Pension and OPEB costs and obligations are determined annually by independent actuaries using management's best estimate assumptions.

Pension fund assets include equity securities, corporate and government debt securities, pooled funds, real estate, infrastructure and other investments. These assets are managed by professional investment managers. The pension fund does not invest in equity or debt securities issued by OPG. Pension fund assets are valued using market-related values for purposes of determining the amortization of actuarial gains or losses and the expected return on plan assets. The market-related value recognizes gains and losses on equity assets relative to a six percent assumed real return over a five-year period.

Pension and OPEB costs include current service costs, interest costs on the obligations, the expected return on pension plan assets, adjustments for plan amendments and adjustments for actuarial gains or losses, which result from changes in assumptions and experience gains and losses. Past service costs or credits arising from pension and OPRB plan amendments are amortized on a straight-line basis over the expected average remaining service life to full eligibility of the employees covered by the corresponding plan. Past service costs or credits arising from amendments to LTD benefits are immediately recognized as OPEB costs in the period incurred. Due to the long-term nature of pension and OPRB liabilities, the excess of the net cumulative unamortized gain or loss, over 10 percent of the greater of the benefit obligation and the market-related value of the plan assets (the corridor) for each plan is amortized over the expected average remaining service life of the employees covered by the plan, which represents the period during which the associated economic benefits are expected to be realized by the Company. Actuarial gains or losses for LTD benefits are immediately recognized as OPEB costs in the period incurred.

OPG recognizes the funded status of its defined benefit plans on the consolidated balance sheets. The funded status is measured as the difference between the fair value of plan assets and the benefit obligation, on a plan-by-plan basis.

Actuarial gains or losses and past service costs or credits arising during the year that are not recognized immediately as components of benefit costs are recognized as increases or decreases in other comprehensive income (OCI), net of income taxes. These unamortized amounts in AOCI are subsequently reclassified and recognized as amortization components of pension and OPRB costs as described above.

As at December 31, 2017, the unamortized net actuarial loss and unamortized past service costs for the pension and OPEB plans totalled $4,148 million (2016 – $3,668 million). Details of the unamortized net actuarial loss and unamortized past service costs as at December 31, 2017 and 2016 are as follows:

(millions of dollars)	Registered Pension Plans 2017	2016	Supplementary Pension Plans 2017	2016	Other Post-Employment Benefits 2017	2016
Net actuarial gain not yet subject to amortization due to use of market-related values	**(418)**	(570)	**-**	-	**-**	-
Net actuarial loss not subject to amortization due to use of the corridor	**1,735**	1,619	**36**	34	**299**	267
Net actuarial loss subject to amortization	**2,333**	2,238	**80**	72	**79**	3
Unamortized net actuarial loss	**3,650**	3,287	**116**	106	**378**	270
Unamortized past service costs	**-**	-	**-**	-	**4**	5

OPG records an offsetting regulatory asset or liability for the portion of the adjustments to AOCI that is attributable to the regulated operations in order to reflect the expected recovery or refund of these amounts through future regulated prices charged to customers. For the recoverable or refundable portion attributable to regulated operations, OPG records a corresponding change in this regulatory asset or liability for the amount of the increases or decreases in OCI and for the reclassification of AOCI amounts into benefit costs during the period.

When the recognition of the transfer of employees and employee-related benefits gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement. A curtailment is the loss by employees of the right to earn future benefits under the plan. A settlement is the discharge of a plan's liability.

Accounting Assumptions

Assumptions are significant inputs to actuarial models that measure pension and OPEB obligations and related effects on operations. Discount rate, inflation rate and changes in salary levels are three critical assumptions in the determination of benefit costs and obligations. In addition, the expected long-term rate of return on plan assets is a critical assumption in the determination of registered pension plan cost, and the health care cost trend rate is a critical assumption in the determination of OPEB cost and obligations. These assumptions, as well as other assumptions involving demographic factors such as retirement age, mortality, and employee turnover, are evaluated periodically by management in consultation with independent actuaries. During the evaluation process, the assumptions are updated to reflect past experience and expectations for the future. Actual results in any given year will often differ from actuarial assumptions because of economic and other factors giving rise to actuarial gains and losses.

The discount rates, which are representative of the AA corporate bond yields, are used to calculate the present value of the expected future cash flows on the measurement date in order to determine the projected benefit obligations for the Company's employee benefit plans. A lower discount rate increases the benefit obligations. The weighted-average discount rate used to determine the projected pension and OPEB benefit obligations as at December 31, 2017 was 3.6 percent. This represents a decrease compared to the 3.9 percent discount rate that was used to determine the obligations as at December 31, 2016.

In 2016 and prior years, benefit costs were calculated using the same single weighted-average discount rates as reflected in the calculation of the benefit obligations. Effective January 1, 2017, OPG adopted a full yield curve approach to the estimation of the service and interest cost components of pension and OPEB costs, by applying the specific spot rates along the yield curve used in the determination of the projected benefit obligations to the relevant projected cash flows. The change improves the correlation between projected benefit cash flows and the corresponding yield curve spot rates, and provides a more precise measurement of service and interest costs. This change in the method was accounted for prospectively, as a change in estimate. The resulting reduction in pension and OPEB costs is estimated at approximately $135 million for the twelve months ended December 31, 2017. Approximately 90 percent of this reduction in pension and OPEB costs was attributed to the Company's regulated

business segments and therefore was offset by the impact of OEB-authorized regulatory accounts. The change does not affect the measurement of the total benefit obligation as the change in the current service and interest cost components from the previous method is offset by a corresponding change in the actuarial gain or loss recorded in AOCI.

The expected rate of return on plan assets is determined based on the pension fund's asset allocation and the expected return considering long-term risks and returns associated with each asset class within the plan portfolio. A lower expected rate of return on plan assets increases pension cost.

A new actuarial valuation of the OPG registered pension plan was filed with the Financial Services Commission of Ontario in September 2017 with an effective date of January 1, 2017. The annual funding requirements in accordance with the new actuarial valuation are outlined in the section, *Liquidity and Capital Resources* under the heading, *Contractual and Commercial Commitments*. OPG conducted a comprehensive actuarial valuation for accounting purposes of its pension and OPEB plans in 2017, using demographic data as at January 1, 2017 consistent with the new funding valuation and using assumptions as at December 31, 2017. As part of the valuation, the plans' demographic and other assumptions were reviewed and revised, as necessary, by independent actuaries.

The deficit for the registered pension plan, for accounting purposes, increased from $2,693 million as at December 31, 2016 to $3,081 million as at December 31, 2017. This increase was largely due to a re-measurement of the liabilities at the end of 2017 reflecting lower discount rates, partially offset by the excess of actual returns on the pension plan assets over interest costs on the liabilities during the year.

The projected benefit obligations for OPEB increased from $2,992 million as at December 31, 2016 to $3,190 million as at December 31, 2017. This increase was largely due to a re-measurement of the liabilities at the end of 2017 reflecting a decrease in the discount rates, partially offset by the updated, lower per capita health care claims costs assumption as part of the 2017 actuarial valuation.

A change in the following assumptions, holding all other assumptions constant, would increase (decrease) pension and OPEB costs for the year ended December 31, 2017 as follows:

(millions of dollars)	**Registered Pension Plans [1]**	**Supplementary Pension Plans [1]**	**Other Post-Employment Benefits [1]**
Expected long-term rate of return			
0.25% increase	(32)	n/a	n/a
0.25% decrease	32	n/a	n/a
Discount rate			
0.25% increase	(56)	(1)	(2)
0.25% decrease	59	1	13
Inflation			
0.25% increase	98	1	-
0.25% decrease	(91)	(1)	-
Salary increases			
0.25% increase	22	3	-
0.25% decrease	(20)	(2)	-
Health care cost trend rate			
1% increase	n/a	n/a	77
1% decrease	n/a	n/a	(29)

n/a – change in assumption not applicable.

[1] Excludes the impact of regulatory accounts.

Asset Retirement Obligation

OPG recognizes ARO for fixed asset removal and nuclear waste management liabilities, discounted for the time value of money. OPG estimates both the amount and timing of future cash expenditures based on the plans for fixed asset removal and nuclear waste management. The ARO is comprised of expected costs to be incurred up to and beyond termination of operations and the closure of nuclear and thermal generating plant facilities and other facilities. Costs are expected to be incurred for activities such as preparation for safe storage and safe storage of nuclear stations, dismantlement, demolition and disposal of facilities and equipment, remediation and restoration of sites, and the ongoing and long-term management of nuclear used fuel bundles and L&ILW material. The liabilities associated with the decommissioning of the nuclear generating stations and the long-term management of used nuclear fuel comprise the most significant amounts of the total obligation.

The nuclear decommissioning liability includes the estimated costs of closing the nuclear stations after the end of their service lives, which includes preparation and placement of the stations into a safe state condition followed by an assumed 30-year safe store period prior to station dismantlement and site restoration. Activities associated with the placement of stations into a safe state condition include de-fuelling and de-watering of the nuclear reactors. OPG is responsible for the nuclear waste management and nuclear decommissioning obligations associated with the Bruce nuclear generating stations and includes the associated costs in its ARO. Pursuant to the lease agreement, Bruce Power must return the two Bruce stations to OPG together, in a de-fuelled and de-watered state. As such, these de-watering and de-fuelling costs are not part of OPG's ARO.

The life cycle costs of L&ILW management include the costs of processing and storage of such radioactive wastes during and following the operation of the nuclear stations, as well as the costs of the ultimate long-term management of these wastes. The current assumptions used to establish the obligation for these costs include an L&ILW DGR facility to be constructed and operated by OPG, as discussed in the section, *Core Business, Strategy, and Outlook* under the heading, *Project Excellence*. To estimate the liability for nuclear used fuel management, OPG has adopted an approach consistent with the Adaptive Phased Management concept approved by the Government of Canada, which assumes a deep geologic repository for the long-term management of Canada's nuclear used fuel waste. The NWMO is responsible for the design and implementation of Canada's plan for the long-term management of used nuclear fuel.

The following costs are recognized as a liability on OPG's consolidated balance sheets:

- the present value of the costs of decommissioning the nuclear and thermal production facilities and other facilities after the end of their useful lives
- the present value of the fixed cost portion of nuclear waste management programs that are required based on the total volume of waste expected to be generated over the assumed lives of the stations
- the present value of the variable cost portion of nuclear waste management programs taking into account waste volumes generated to date.

The significant assumptions underlying operational and technical factors used in the calculation of the accrued liabilities are subject to periodic review. Changes to these assumptions, including changes to assumptions on the timing of the programs including construction of assumed waste disposal facilities, station end-of-life dates, waste disposal methods, financial indicators, decommissioning strategy, and the technology employed may result in significant changes to the value of the accrued liabilities. With programs of such long-term duration and the evolving technology to handle nuclear waste, there is a significant degree of inherent uncertainty surrounding the measurement of the costs for these programs. These costs may increase or decrease over time.

The estimates for the Nuclear Liabilities are reviewed on an ongoing basis as part of the overall nuclear waste management program. A comprehensive reassessment of all underlying assumptions and baseline cost estimates is performed periodically, at least once every five years, in line with the required ONFA reference plan update process. Changes in the Nuclear Liabilities resulting from changes in assumptions or estimates that impact the amount or

timing of the estimated undiscounted future cash flows are recorded as an adjustment to the liabilities. Upward revisions in the Nuclear Liabilities represent the present value of a net increase in future undiscounted cash flows determined using a current credit-adjusted risk-free rate. Downward revisions in the Nuclear Liabilities represent the present value of a net decrease in future undiscounted cash flows determined using the weighted average discount rate reflected in the existing liability. Resulting changes in the related asset retirement costs are capitalized as part of the carrying amount of nuclear fixed assets in service.

As of December 31, 2017, OPG recorded an increase of $188 million in the Nuclear Liabilities and associated asset retirement costs capitalized as part of carrying value of property, plant and equipment (PP&E) reflecting the change in the Pickering GS accounting end-of-life assumptions from December 31, 2020 for all operating units to December 31, 2022 for Units 1 and 4 and December 31, 2024 for Units 5 to 8. The increase in the liabilities is primarily due to higher fixed costs associated with the Used Fuel Disposal and L&ILW Storage programs, discounted using the current credit-adjusted risk-free rate of 2.94 percent. The adjustment did not impact net income for 2017. The adjustment is not expected to have a material impact on net income in 2018 as the associated impact on expenses is expected to be largely offset by OEB-authorized regulatory accounts. The change in accounting end-of-life assumptions for the Pickering GS are discussed in further detail in the section, *Core Business, Strategy, and Outlook* under the heading, *Operational Excellence – Electricity Generation Production and Reliability*.

For the purposes of calculating OPG's Nuclear Liabilities, as at December 31, 2017, consistent with the current accounting end-of-life assumptions, nuclear station decommissioning activities are projected to occur over approximately the next 80 years.

The liability for nuclear fixed asset removal and nuclear waste management on a present value basis as at December 31, 2017 was $20,077 million (2016 – $19,103 million). As at December 31, 2017, the undiscounted cash flows of expenditures for OPG's Nuclear Liabilities in 2017 dollars are as follows:

(millions of dollars)	**2018**	**2019**	**2020**	**2021**	**2022**	**Thereafter**	**Total**
Expenditures for nuclear fixed asset removal and nuclear waste management [1]	323	326	323	311	598	40,513	42,394

[1] The majority of the expenditures are expected to be reimbursed by the Nuclear Segregated Funds established by the ONFA. Any contributions required under the ONFA are not included in these undiscounted cash flows. Accounting for the Nuclear Segregated Funds is discussed in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

The liability for non-nuclear fixed asset removal was $344 million as at December 31, 2017 (2016 – $381 million). This liability primarily represents the present value of estimated costs of decommissioning OPG's thermal generating stations at the end of their service lives. OPG has updated the asset retirement obligations for the thermal generating stations as of December 31, 2017, based on a review of required decommissioning, clean-up and restoration activities, underlying economic assumptions and anticipated timing of these activities in line with current accounting end-of-life assumptions for the operating sites. For the shutdown Nanticoke and Lambton generating stations, the update reflects the estimated cost of executing current decommissioning plans. For the currently operating sites, OPG recognized a decrease of $18 million in the non-nuclear fixed asset removal liabilities and associated asset retirement costs capitalized as part of the carrying value of PP&E as at December 31, 2017. For the Nanticoke and Lambton sites, a reduction in the non-nuclear fixed asset removal liabilities and a gain of approximately $12 million was recorded in net income in the fourth quarter of 2017, in the, Services, Trading, and Other Non-Generation segment.

For the purpose of measuring the non-nuclear fixed asset removal liability, asset removal activities are assumed to take place approximately over the next one to 12 years. The amount of undiscounted estimated future cash flows associated with the thermal liabilities is approximately $400 million.

OPG has no legal obligation associated with the decommissioning of its hydroelectric generating facilities and the costs cannot be reasonably estimated because of the long service life of these assets. With either maintenance efforts or rebuilding, the water control structures are assumed to be used for the foreseeable future. Accordingly, OPG has not recognized a liability for the decommissioning of its hydroelectric generating facilities.

Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly arm's-length transaction between market participants at the measurement date. Fair value measurements are required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model.

The fair value of financial assets and liabilities for which quoted prices in an active market are available, including exchange traded derivatives and other financial instruments, are determined directly from those quoted market prices.

For financial instruments for which quoted market prices are not directly available, fair values are estimated using forward price curves developed from observable market prices or rates. The estimation of fair value may include the use of valuation techniques or models, based wherever possible on assumptions supported by observable market prices or rates prevailing at the consolidated balance sheet dates. This is the case for over-the-counter derivatives and securities, which include energy commodity derivatives, foreign exchange derivatives, interest rate swap derivatives, and fund investments. Pooled fund investments are valued at the unit values supplied by the pooled fund administrators. The unit values represent the underlying net assets at fair values, determined using closing market prices. Valuation models use general assumptions and market data and therefore do not reflect the specific risks and other factors that may affect a particular instrument's fair value. The methodologies used for calculating the fair value adjustments are reviewed on an ongoing basis to ensure that they remain appropriate. If the valuation technique or model is not based on observable market data, specific valuation techniques are used, primarily based on recent comparable transactions, comparable benchmark information, bid/ask spread of similar transactions, and other relevant factors.

For the financing receivables related to the Investment Interest acquired from the IESO, fair value is estimated to equal the fair value of the underlying debt due to the direct relationship of the asset, and the debt instruments that financed the acquisition.

OPG's use of financial instruments exposes the Company to certain risks, including credit risk, foreign currency risk and interest rate risk. A discussion of how OPG manages these and other risks is found under the section, *Risk Management*.

Recent Accounting Pronouncements Not Yet Adopted

The recent US GAAP accounting pronouncements related to revenue recognition, leases, and financial instruments are described below. Other recent accounting pronouncements applicable to OPG are outlined in Note 3 of the audited consolidated financial statements.

Revenue from Contracts with Customers

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09, *Revenue from Contracts with Customers* (Topic 606), which supersedes nearly all existing revenue recognition guidance, including industry-specific guidance, under US GAAP. The core principle of Topic 606 is to recognize revenues when promised goods or services are transferred to customers in an amount that reflects the consideration to which an entity expects to be entitled for those goods or services. Either a full retrospective

application or a modified retrospective application is required for annual periods beginning on or after January 1, 2018, including interim periods within that year. Early adoption is permitted.

OPG has assessed the impact of the standard on accounting for the Company's revenue streams and consolidated financial statements. OPG's major revenue streams include regulated generation revenue from base regulated prices and rate riders established by the OEB, as well as revenue from generation assets under long-term contractual arrangements with the IESO. OPG has completed its analyses of the impact of Topic 606 on all of its revenue streams, and has not identified any material differences in the timing or amount of revenue recognition for these streams.

The Company will apply the new revenue standard in its 2018 first quarter interim financial statements and is in the process of evaluating the additional disclosures required under the new standard.

Lease Accounting

In February 2016, the FASB issued ASU No. 2016-02, *Leases* (Topic 842). The update includes comprehensive changes to existing guidance for lease accounting, particularly for lessees, and aims to increase transparency and comparability among organizations by requiring the recognition of lease assets and lease liabilities on the balance sheet. The standard is effective for annual periods beginning after December 15, 2018, including interim periods within that year.

Under the current guidance, entities are required to use a modified retrospective approach for leases that exist, or are entered into, after the beginning of the earliest comparative period presented in the financial statements of the period of adoption. Under this method, Topic 842 would effectively be implemented by recognizing any adjustments stemming from the transition, as of beginning of the earliest comparative period presented in the entities' financial statements. Full retrospective application is prohibited. In January 2018, the FASB issued a proposed ASU wherein entities would be able to utilize an additional optional transition method of recording the cumulative impact of adopting the new lease standard to the opening balance in the initial period of adoption; with comparative periods continuing to be presented in accordance with the existing leasing standard, Topic 840 - *Leases*, including disclosures. [**MONITOR**] The Company will continue to monitor the status of this proposed ASU.

The FASB also issued ASU No. 2018-01, *Land Easement Practical Expedient for Transition to Topic 842* in January 2018. The amendments therein allows an entity to choose not to evaluate under Topic 842 land easements that exist or expired before the entity's adoption of the new leasing standard and that were not previously accounted for as leases under Topic 840.

The Company continues to implement and execute a comprehensive project governance framework, which comprises a Steering Committee, Implementation & Stakeholder Committee, Project Management Office, and various working groups in order to evaluate the implement the new standard. The working groups are represented by cross functional finance and non-finance stakeholders who will support the financial and operational implementation of the standard. The Company continues to evaluate the impact of the new leasing standard on its consolidated financial statements.

Recognition and Measurement of Financial Assets and Financial Liabilities

In January 2016, the FASB issued ASU No. 2016-01, *Financial Instruments – Overall: Recognition and Measurement of Financial Assets and Financial Liabilities*. Under the updated guidance, entities will have to measure equity investments at fair value and recognize any changes in fair value in net income. The update will be effective for OPG's 2018 fiscal year, including interim periods. As a result of this update, effective January 1, 2018, the available-for-sale (AFS) classification for equity securities will no longer be available, with any unrealized gains and losses related to such securities recognized in net income instead of OCI. Any unrealized gains and losses for AFS securities reported by OPG in AOCI as of the end of 2017 will be reclassified to retained earnings as of January 1, 2018. OPG's equity shareholdings in Hydro One are currently the Company's only AFS securities. As at December

31, 2017, these shares are valued on the consolidated balance sheet at $188 million, for which a loss of $8 million has been recorded in AOCI. OPG does not expect the new standard to have any other significant impact on its consolidated financial statements.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost

In March 2017, the FASB issued ASU No. 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. Under the new guidance, employers that sponsor defined benefit plans for pensions and/or other postretirement benefits are required to present the service cost component of net periodic benefit cost in the same statement of income line item as other employee compensation costs arising from services rendered during the period. The other components of the net periodic benefit cost are to be presented separately from the line item that includes the service cost and outside of any subtotal of income from operations, if such a subtotal is presented. In addition, the new guidance requires that only the service cost component of net benefit cost be eligible for capitalization.

This guidance is effective for fiscal years beginning after December 15, 2017, including interim periods of those years. The guidance is not expected to have a material impact on OPG's consolidated financial statements, as OPG currently capitalizes only the service cost component of post-retirement benefits costs. Additionally, OPG already includes the service cost component of post-retirement benefit costs with other compensation costs, within the operations, maintenance and administration expenses line item in the consolidated statements of income, and does not show a subtotal of income from operations. As such, the new guidance is not expected to affect the presentation of OPG's consolidated financial statements.

RISK MANAGEMENT

Overview

OPG faces various risks that could significantly impact the achievement of its strategic imperatives. The objective of risk management is to identify, assess and mitigate key risks, and to preserve and increase the value of the Shareholder's investment in the Company.

The Audit and Risk Committee is mandated to fulfill the oversight responsibilities of the Board of Directors for matters relating to the identification and management of the Company's key business risks. OPG's Enterprise Risk Management framework is designed to identify and evaluate risks on the basis of their potential impact on the Company's strategic imperatives and business plan objectives. Formal risk management policies, procedures and systems are in place to identify, assess and mitigate risks to the Company. Senior management also establishes set limits for the market risk, credit risk and energy trading activities of the Company.

The key risks to OPG's strategic imperatives are briefly described below. These are key risks that management believes could materially affect its business, revenues, net income, assets or capital resources. There may be further risks and uncertainties that are not presently known, or that are not currently believed to be material, that may in the future adversely affect the Company's performance or financial condition.

Risks to Achieving Operational Excellence

OPG is exposed to variable output from its existing generating stations that could adversely impact its financial performance. The operational risks of a station are generally a function of its age, human performance, and the technology used.

Asset Conditions and Generation Variability

The uncertainty associated with electricity production by OPG's generating units is primarily driven by the condition of station components and systems, which are subject to the effects of aging and the manner in which the units operate. To safely operate the units to meet electricity system requirements, a unit could be derated resulting in reduced generation. The primary implications of these risks may include additional safety requirements, lower than expected generation and revenues, and higher operating or capital costs. To respond to this risk, OPG continues to:

- monitor performance, implement extensive inspection and maintenance programs;
- identify future work required to sustain and, as appropriate, upgrade a station equipment; and
- undertake projects required to reliably operate within design and operating parameters.

Extension of Commercial Operations at Pickering to 2024

In January 2016, the Province of Ontario announced its approval of OPG's plan to pursue the continued safe and reliable operation of the Pickering GS to 2024. Under OPG's plan, the six operating units at the Pickering GS would operate until 2022, at which point two units would be shut down and the remaining four units would continue to operate until 2024. The current operating licence for the Pickering GS, which expires in August 2018, was issued in 2013 assuming that the station would shut down in 2020. Technical assessments have been completed to determine the ability of the Pickering units to continue to be fit for service to support extended operations. There is high technical confidence in the programs and provisions in place to operate the station to the end of 2024.

Inability to extend operations as planned would result in a reduction of OPG's future generation revenue and cash flows and lead to the advancement of station shutdown and decommissioning expenditures.

Risk factors for extended operations include the discovery of unexpected conditions, equipment failures, the state of critical plant components that are reaching end-of-life and a requirement for significant plant modifications. To mitigate these risks, OPG has implemented actions recommended from the technical assessments as part of the outage work program. OPG has also incorporated those actions into the comprehensive inspection and maintenance program under the Life Cycle Management Plan.

Supply Chain

OPG's ability to operate effectively is in part dependent upon timely access to equipment, materials, and service suppliers. Loss of key equipment, materials and service suppliers, particularly for the nuclear business, could affect OPG's operations and execution of major capital projects. OPG mitigates this risk, to the extent possible, through contract negotiations, contract terms, vendor monitoring, diversification of supplier base and business continuity plans.

Cyber Security

OPG's operations depend in part, on the efficient operation and management of the Company's complex information technology and operational systems in a secure, vigilant and resilient manner that minimizes cyber risks. Cyber security incidents may have an adverse impact on OPG's reputation, energy production, and public and employee safety.

Cyber security incidents have been on the rise for the past few years and this trend is only expected to intensify as global reliance on technology increases. OPG has strategies in place to prepare for, respond to, and recover from cyber security incidents. OPG continuously monitors, assesses, and improves the effectiveness of its strategies and program considering leading industry practices and remains proactive in information and intelligence sharing to learn and adapt to the changing cyber environment. In 2017, the media reported several worldwide cyber-attacks, such as WannaCry and Petya, which impacted multiple sectors including power and utilities. OPG's operational responses to those cyber-attacks were timely and effective resulting in no or low operational impact to OPG.

As a registered Ontario market participant, OPG must comply with reliability standards that apply to the Bulk Electric System elements specified under North American Electric Reliability Corporation and the relevant Bulk Power System facilities as determined by the Northeast Power Coordinating Council. In addition, OPG's nuclear cyber assets are subject to CNSC licensing conditions and regulatory requirements. For other cyber assets not subject to applicable regulatory requirements, OPG has adopted a risk-based approach based on the National Institute of Standards and Technology cyber security framework to manage its cyber security. Policies are in place to manage the Company's cyber risks and programs which are subject to oversight by management and the Board.

Regulatory Compliance

OPG is subject to extensive federal and provincial legislation and regulations by various entities such as the OEB, CNSC and the IESO.

The uncertainty associated with nuclear regulatory compliance is driven by plant aging, changes to technical codes, and challenges raised by the public at regulatory hearings, particularly in the areas of safety, environment and emergency preparedness. Addressing these requirements could add to the cost of operations, including replacement or modification of a station component or additional requirements for waste management. In some instances, these requirements may result in a reduction or elimination of the productive capacity of a station.

The Provincial agency, Office of the Fire Marshal and Emergency Management (OFMEM) is required to periodically update the Provincial Nuclear Emergency Response Plan (PNERP). In 2016, the CNSC advised the OFMEM to consider more severe accidents in the update to the PNERP, which may result in potential changes to the planning basis. Potentially, these changes may include new protective requirements and expansion of the emergency plan requirements for Pickering. In December 2017, the Province approved the updated PNERP Master Plan. The development of a detailed Implementing Plan for the Pickering GS is in progress. To date, there is no significant impact on OPG from the updated PNERP.

In December 2015, the CNSC granted the Darlington GS a ten-year operating licence, valid until November 30, 2025. The new licence spans most of the planned duration of the Darlington Refurbishment project, which provides greater regulatory stability and reduces regulatory risk. As discussed in the section, *Core Business, Strategy and Outlook*, under the heading, *Nuclear Operations*, the plan to extend Pickering operations to 2024 is subject to the CNSC's approval of the Pickering licence renewal application and other regulatory requirements as set out by the CNSC.

Nuclear Waste Management

The handling, storage and disposal of nuclear waste exposes OPG to various risks that it manages in accordance with the applicable regulatory requirements. Additionally, the interim storage of nuclear waste is subject to rigorous oversight and monitoring.

Currently, there are no licenced facilities in Canada for the permanent disposal of used nuclear fuel or L&ILW. The risks to OPG's proposed L&ILW DGR for the safe long-term management of L&ILW are discussed below under the heading, *Risks to Achieving Project Excellence – Deep Geologic Repository for Low and Intermediate Level Waste*.

Human Resources and Organizational Structure

The development of new leaders and retention of staff in critical roles is a key factor to OPG's success. The risk associated with the alignment and availability of skilled and experienced resources continues to exist for OPG in specific areas, including leadership and project management positions. To mitigate this risk, OPG continues to focus on succession planning, leadership development and knowledge management programs to improve the capability of its workforce. OPG expects to meet the human resource needs of the business by developing existing employees and hiring in specific areas, while continuing to leverage attrition through realignment of work and streamlining of processes, where appropriate.

Labour Relations

As of December 31, 2017, approximately 88 percent of OPG's regular labour force was represented by a union. The collective agreements with the PWU and The Society are due for renewal in 2018. There is a risk that OPG may not be able to negotiate terms that allow for compensation levels consistent with its rate orders.

OPG's current collective agreements with the PWU expires on March 31, 2018 and renewal negotiations began in early 2018. In the event of a labour disruption by the PWU, OPG could face financial or reputational implications. OPG has contingency plans in place to minimize the impact. **[MONITOR]**

The collective agreement between OPG and The Society expires on December 31, 2018 and renewal negotiations are expected to begin in mid-2018. The parties do not have the right to strike or lock-out. If the parties are unable to reach an agreement, the terms of the new collective agreement would be decided through interest mediation/arbitration.

Health and Safety

OPG's operations involve inherent occupational safety risks and hazards that could impact the achievement of the Company's health and safety goals. OPG is committed to continuous improvement and achievement of its ultimate goal of zero injuries through a formal enterprise-wide safety management system and by continuing to foster a strong health and safety culture among its employees and contractors. The safety management system serves to focus the Company on proactively managing safety risks and hazard exposures to employees and contractors. OPG also strategically engages with external parties for benchmarking and auditing. This ensures that OPG's management system achieves its intended results and maximizes the opportunity to incorporate program improvements.

Business Continuity and Emergency Management

OPG may be exposed to natural, technological or human-caused hazards including significant events against which it is not fully insured or indemnified; or to parties that fail to meet their indemnification obligations. These hazards have the potential to disrupt operations resulting in decreased generation revenue or additional costs to repair damages and restore operations.

OPG's business continuity program provides a framework to build resilience into critical business processes to ensure continued operation of critical business functions. OPG's emergency management program is designed to ensure that the Company can manage an emergency in a timely and effective manner. OPG's plans and implementation procedures identify immediate response actions to be taken to protect the health and safety of workers and the public, and to limit the impact of the incident on site security, production capability and the environment. The program elements are designed to meet legal and regulatory requirements.

Risks to Achieving Project Excellence

OPG is undertaking several capital intensive projects with significant investments. There may be an adverse effect on the Company if it is unable to: obtain necessary approvals; raise the necessary funds; effectively manage the projects on time and on budget; or fully recover capital costs and earn an appropriate return on investment. These projects may also have a significant impact on OPG's borrowing capacity and credit rating. Some projects may be ultimately reassessed as being uneconomic. The risks associated with OPG's current major projects are described below.

Darlington Refurbishment

There are financial and reputational risk exposures for OPG if actual costs exceed the budget or if OPG does not meet the project schedule. In addition, failure to achieve the objectives of the refurbishment project may result in future forced outages and more complex planned outages, potentially impacting the post-refurbishment performance or useful life of the units. Failure to carry out the refurbishment of the first unit as planned may result in the Province

exercising an off-ramp for the refurbishment of the remaining units. In January 2018, Refurbishment senior management met with the Minister of Energy, Cabinet and Treasury Board to provide an update on the status of the Darlington Refurbishment project and to request a decision to not exercise the Unit 3 off-ramp. The request was based on the performance to date on the Unit 2 project. Additionally, OPG continues to apply lessons learned that have been captured on the execution of Unit 2 into the planning of future units.

Commented [JK8]: Is Energy okay with this wording? Does such disclosure normally reference meetings of Cabinet or its committees?

Commented [PR-&CC9R8]: This disclosure was updated in the next draft and thus the wording was subsequently removed.

There are a number of specific risks that OPG is managing and mitigating in relation to the Darlington Refurbishment project, which include OPG and vendor performance risks, delay or productivity risks, financial risks related to escalation of costs, technical risks such as equipment conditions resulting in additional scope and execution risks. A large portion of the costs for the Darlington Refurbishment project is being paid to contractors and suppliers, including vendors that will engineer, procure and construct components of the project. There is a risk that, as the volume of work increases significantly, vendor capability, capacity and performance shortfalls may impact project objectives and deliverables.

OPG systematically manages the risks associated with the Darlington Refurbishment project through robust risk management practices to achieve project deliverables on time and budget with quality. OPG engaged in an extensive five-year project planning phase to determine the project scope and to rigorously estimate costs. During this phase, OPG also took into account major lessons learned from other nuclear refurbishments and large scale, complex projects. In order to fully define the scope and material requirements for the project, the planning phase included the completion of detailed designs before proceeding with the execution of the unit refurbishments. Further risk mitigation has been implemented through the construction of a full scale model training reactor, which allows for simulations and training for unit refurbishment execution tasks.

OPG's risk management strategy aims to ensure that contractors are held accountable and appropriate incentives and disincentives are in place. There is also an increased risk of contractor initiated safety events, which may impact OPG's reputation. Mitigating actions include:

- Collaborative training and planning with vendors on executing work safely;
- An enhanced human performance program;
- Increased field presence by supervisory staff; and
- Collaboration with Bruce Power to streamline processes and reduce burden on vendors.

OPG is also managing other ongoing risks that could potentially impact the project, including those related to continuity of skilled leaders within OPG and its vendor partners, as well as the availability of technical resources to support the project through execution.

Both management and Board of Directors have engaged Independent, third-party oversight for the execution phase of the project.

Deep Geologic Repository for Low and Intermediate Level Waste

OPG, with the support of Bruce County municipalities, is proposing to construct and operate a deep geologic repository for the safe long-term management of L&ILW. While broad local community support for the proposed L&ILW DGR is stable, OPG continues its engagement with the SON towards securing support for the project.

In August 2017, the federal Minister of Environment and Climate Change wrote to OPG and commended OPG for its collaborative work with the SON and for the practical demonstration of reconciliation practices. In light of that work, the Minster requested OPG to update its analysis of the potential cumulative effects of the DGR project on the physical and cultural heritage of the SON, taking into account the results of the SON Community Process. OPG continues to work with the SON, however the timing and outcome of the SON Community Process and the EA decision by the Minister are uncertain.

Commented [PR-&CC10]: This disclosure was updated in the next draft and thus the word was subsequently removed.

Risks to Maintaining Financial Strength

Risks related to rate regulation, financial markets and long-term obligations could significantly impact OPG's financial performance. The Company is also exposed to risks such as weak electricity demand, displacement of generation by competitors and financial risk associated with energy trading.

Rate Regulation

There is an inherent risk that regulated prices established by the OEB may not provide for the recovery of actual costs incurred by OPG's regulated operations or allow the regulated operations to earn an appropriate rate of return. This could occur if, in setting regulated prices, the OEB makes adjustments to forecasts submitted by OPG, if actual production and costs significantly differ from the forecasts approved by the OEB, or if OPG is unable to achieve OEB-approved stretch factors included in regulated prices under incentive ratemaking. Differences between OPG's actual and forecast production and costs could be due to factors such as outages or project execution risks. In providing evidence in support of its applications for regulated prices, OPG aims to clearly demonstrate to the OEB that the costs for the regulated operations are reasonable, prudently incurred and should be fully recovered from customers.

Certain differences between elements of OEB-approved revenue requirements and OPG's actual results are recorded in OEB-approved variance and deferral accounts for future review by the OEB. Additionally, these accounts may be subject to an OEB prudence review. There is uncertainty associated with the outcomes of future proceedings for the recovery or refund of these balances.

Nuclear Rate Smoothing Proposal

Consistent with the requirements of *Ontario Regulation 53/05*, OPG's nuclear rates will be smoothed as a result of OPG deferring a portion of the approved annual nuclear revenue requirements during the period from January 1, 2017 to the end of the Darlington Refurbishment project in a Rate Smoothing Deferral Account.

There is a risk that the magnitude of the deferral ordered by the OEB will result in regulated prices that do not provide sufficient cash flow to the Company for meeting its financial objectives in an optimal manner, including ensuring sufficient liquidity, cost effectively funding the Darlington Refurbishment project and other expenditures and maintaining the Company's investment grade credit rating. Maintaining adequate levels of credit metrics will support OPG's investment grade credit rating. As such, OPG requested the OEB to consider the impact on its credit rating when smoothing the nuclear base rates. **[MONITOR]**

Post-Employment Benefit Obligations Risk

OPG's post-employment benefit obligations include pension, group life insurance, health care benefits, and LTD benefits. OPG's post-employment benefit obligations and costs and pension plan contributions could be materially affected in the future by numerous factors including: changes in discount rates, inflation rates and other actuarial assumptions; future investment returns; experience gains and losses; the funded status of the pension plans; changes in benefits; changes in the regulatory environment including potential changes to the *Pension Benefits Act* (Ontario); changes in OPG's operations and the measurement uncertainty incorporated into the actuarial valuation process.

The OPG registered pension plan, which covers most of OPG's employees and retirees, is a contributory defined benefit plan that is indexed to inflation up to a certain maximum. Contributions to the OPG registered pension plan are determined by actuarial valuations, which are filed with the appropriate regulatory authorities at least every three years. Future actuarial valuations could increase OPG's funding requirements due to market and economic-related conditions. A significant decline in the financial markets could trigger an immediate requirement to update the actuarial valuation based on declines in the funded status. OPG continues to assess the requirements for contributions to the registered pension plan, including the timing of future actuarial valuations. OPG's OPEB

obligations are not funded and the associated employee benefits are paid from cash flows provided by operating activities or other sources of liquidity.

Nuclear Liabilities and Nuclear Segregated Funds

As required by the CNSC, OPG is responsible for the management of used nuclear fuel and L&ILW and the decommissioning of its nuclear stations and waste management facilities. The cost estimates for OPG's nuclear waste management and decommissioning obligations are based on multiple underlying assumptions and estimates that are inherently uncertain and may evolve over time. The assumptions include station end-of-life dates, waste volumes, waste disposal methods, the timing of construction of assumed waste disposal facilities, waste packaging systems, decommissioning strategy and financial indicators. To address the inherent uncertainty, OPG undertakes to perform a comprehensive review of the underlying assumptions and baseline cost estimates at least once every five years, in line with the required ONFA Reference Plan update process.

The most recent comprehensive update of the nuclear waste management and decommissioning obligations was approved by the Province in December 2016 as part the 2017 ONFA Reference Plan. An approved ONFA Reference Plan determines OPG's contributions to the Nuclear Segregated Funds. Based on the 2017 ONFA Reference Plan, no contributions are currently required to the Nuclear Segregated Funds. Additional contributions may be required should the Nuclear Segregated Funds be in an underfunded position in the future.

Nuclear Funds are segregated under ONFA in order to fund the long-term waste management, used fuel management and decommissioning expenditures. These funds are managed to achieve, in the long term, the target rate of return based on the discount rate specified in the ONFA. Investments in the Nuclear Segregated Funds are allocated to certain asset classes including fixed income securities, domestic and international equity securities, pooled funds, infrastructure, agriculture and real estate. The rates of return earned on these segregated funds may vary depending on current and future financial market conditions. The asset mix of the funds is determined jointly by OPG and the Province in accordance with the ONFA.

Under ONFA, OPG bears the market risk related to the portion of the Nuclear Segregated Funds set aside for:

- decommissioning of Pickering and Darlington nuclear generating stations; and
- long-term management of the irradiated used fuel bundles in excess of the first 2.23 million bundles and L&ILW after the respective Pickering GS and Darlington GS shut down.

A significant drawdown in the Nuclear Funds would first reduce the surplus in the respective funds before impacting OPG's net income. As such, the income statement impact of this risk is reduced when the Nuclear Segregated Funds are in a fully funded position.

Liquidity

OPG operates in a capital intensive business. Significant financial resources are required to fund major development and other capital improvement projects, including the Darlington Refurbishment project. In addition, the Company has other significant disbursement requirements including pension contributions, payments towards OPEB and other benefit plans, funding ongoing operations, debt maturities with the OEFC, OPG's investment in the Fair Hydro Plan and investments in new generating capacity and other business development opportunities. OPG must ensure that it has the financial capacity and sufficient access to cost effective financing sources to fund its capital requirements and other disbursements. In support of this objective, OPG utilizes multiple sources and forecasts availability of funds, actively monitors funding requirements and is focused on maintaining its investment grade credit rating. The Company's ability to arrange sufficient and cost-effective debt financing could be adversely affected by a number of factors, including, financial market and general economic conditions, the regulatory environment in Ontario, the Company's results of operations and financial conditions, the ratings assigned to the Company by credit rating agencies and the current timing of debt maturities.

A discussion of corporate liquidity is included in the section, *Liquidity and Capital Resources*.

Commodity Markets

Changes in the market price of fuels used to produce electricity can adversely impact OPG's earnings and cash flow from operations.

To manage the risk of unpredictable increases in the price of fuels, the Company has fuel hedging programs, which include using fixed price and indexed contracts.

The percentages hedged of OPG's fuel requirements are shown in the following table. These amounts are based on yearly forecasts of generation and supply mix and, as such, are subject to change as these forecasts are updated.

	2018	2019	2020
Estimated fuel requirements hedged [1]	72.9%	68.2%	65.3%

[1] Represents the approximate portion of megawatt-hours of expected generation production (and year-end inventory targets) from each type of OPG-operated facility (nuclear, hydroelectric and thermal) for which the Company has entered into contractual arrangements or obligations in order to secure the price of fuel, or which is subject to regulation. In the case of hydroelectric generation, this represents the gross revenue charge and water rental charges. Excess fuel inventories (nuclear and thermal) in a given year are attributed to the next year for the purpose of measuring hedge ratios.

Foreign Exchange

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are primarily denominated in, or tied to US dollars (USD). To manage this risk, OPG employs various financial instruments such as forwards and other derivative contracts, in accordance with approved risk management policies. As at December 31, 2017, OPG had total foreign exchange contracts outstanding with a notional value of USD $5 million.

Trading

OPG's financial performance can be affected by its trading activities. OPG's electricity trading operations are closely monitored, with total exposures measured and reported to senior management on a daily basis. The main metric used to measure the financial risk of trading activity is Value at Risk (VaR). VaR is defined as a probabilistic maximum potential future loss expressed in monetary terms for a portfolio based on normal market conditions over a set period of time. During 2017, the VaR utilization ranged between $0.1 million and $0.4 million, compared to between nil and $1.5 million in 2016.

Credit

The Company's credit risk exposure is a function of its electricity sales, trading and hedging activities, treasury activities including investing and commercial transactions with various suppliers of goods and services. OPG's credit risk exposure relating to electricity sales is considered low as the majority of sales are through the IESO-administered spot market. The IESO oversees the credit worthiness of all market participants. In accordance with the IESO's prudential support requirements, market participants are required to provide collateral to cover funds that they might owe to the market.

The following table summarizes OPG's credit exposure to all counterparties from electricity transactions and trading as at December 31, 2017:

	All Counterparties		Largest Counterparties	
Credit Rating [1]	**Number of Counterparties** [2]	**Potential Exposure** [3] *(millions of dollars)*	**Number of Counterparties**	**Potential Exposure** *(millions of dollars)*
Investment grade	15	18	5	14
IESO [4]	1	360	1	360
Total	16	378	6	374

[1] Credit ratings are based on OPG's own analysis, taking into consideration external rating agency analysis where available, as well as recognizing explicit credit support provided through parental guarantees, Letters of Credit or other forms of security.

[2] OPG's counterparties are defined on the basis of individual master agreements.

[3] Potential exposure is OPG's statistical assessment of maximum exposure over the life of each transaction at a 95 percent confidence interval.

[4] Credit exposure is an estimate of the short-term receivable amount arising from OPG's electricity sales into the IESO market. The credit exposure and associated receivable vary each month based on electricity sales. The monthly receivable from the IESO is typically paid to OPG in the subsequent month as per the IESO payment schedule.

Other major components of OPG's credit risk exposure include those associated with vendors that are contracted to provide services or products. OPG manages its exposure to various suppliers or counterparties by evaluating their financial condition and ensuring that the Company holds appropriate collateral or other forms of security.

Contracted Generation

The Company's generating stations that operate under ESAs with the IESO or other long-term contracts are subject to several obligations, including but not limited to:

- availability targets;
- monthly and annual reporting; and
- must offer obligations, as specified in their respective contracts.

OPG could incur penalties up to and including termination of the respective contract if these facilities fail to meet their contractual obligations. This risk is mitigated through:

- education of staff who work with these facilities;
- continuous communication between staff managing the contracts and staff managing the stations;
- processes that monitor and address contractual obligations and milestones; and
- the implementation of maintenance, capital investment (approved by the IESO when required by the contracts) and other programs.

OPG's owned and co-owned thermal generating stations operate under ESAs with the IESO or other long-term agreements. While OPG expects that its thermal generating stations will continue to provide capacity to the market over the term of the respective agreements, there is a risk that, upon expiry of the current agreements, subsequent contracts for these stations may not be available or may not be financially viable. The Thunder Bay Biomass ESA is the first such contract to reach the end of its term, scheduled for early 2020.

Ontario Electricity Market

OPG's revenue can be impacted by external factors related to the electricity market including: the entrance of new participants into the Ontario market; the competitive actions of market participants; Ontario electricity demand; changes in the regulatory environment; and wholesale electricity prices in the interconnected markets.

The IESO is in the preliminary stages of a Market Renewal Program, which is expected to result in a fundamental redesign of Ontario's electricity markets and may impact OPG depending on the market design that is implemented. To mitigate this risk, OPG is actively participating in Market Renewal stakeholder committees as well as continuing to collaborate with the IESO.

Ownership by the Province

The Province owns all of OPG's issued and outstanding common shares. Accordingly, the Province, as represented by the Ontario Ministry of Energy, has the authority to make appointments to OPG's Board of Directors. OPG could be subject to Shareholder direction, under Section 108 of the OBCA that can directly influence major decisions. These directions could include those related to project development, timing and strategy of applications for regulated prices, acquisitions and asset divestitures, financing and capital structure. As a result, OPG could be required to undertake activities that result in increased expenditures, or that reduce revenues or cash flows relative to the business activities or strategies that would have otherwise been undertaken. In addition, the obligation of OPG's Shareholder to respond to a broad range of matters in its role as the Government of Ontario may compete with OPG's commitment to maximize the return on the Shareholder's investment in the Company. This includes, but is not limited to, the Province's response to mitigate the impact of rising electricity prices on consumers.

Government Legislation and Regulation Change

OPG's core business and strategy may be impacted by changes in federal and provincial legislation and regulations. Matters that are subject to regulation include, among others, rate regulation, electricity generating operations, nuclear waste management and nuclear decommissioning, the Ontario electricity market and taxation. Regulatory bodies may change or enact regulations or rules that could increase OPG's costs, decrease OPG's revenue, or limit the Company's ability to recover appropriate costs or earn a return on the assets.

The next Ontario provincial election is set to take place in June 2018 and electricity rates are a focus of each party's platform. Depending on the outcome of the election, there may be significant legislative changes that could impact OPG.

Since legal requirements are subject to change and to interpretation, OPG is unable to predict the impact of such changes on the Company and its operations. To mitigate legislative risks, OPG continues to monitor and actively engage with the federal and provincial governments in order to determine if future legislation will impact the Company.

Litigation

OPG or its subsidiaries are involved in various legal proceedings covering a range of matters arising out of their business activities. Each of these matters is subject to various uncertainties and some of these matters may be resolved unfavourably. Refer to Note 16 of OPG's 2017 audited consolidated financial statements under the heading, *Litigation* for further details.

Risks to Maintaining Social Licence

OPG is exposed to risks associated with its social licence and public profile due to changes in the opinions of:

- Various stakeholders, including Ontario electricity customers, local communities, government agencies; and
- Indigenous communities.

Maintaining public trust and meeting stakeholders and Indigenous communities' expectations are critical to OPG's success. OPG focuses on building and maintaining its social licence and corporate reputation through safe, reliable, environmentally-responsible operations as well as corporate citizenship initiatives across the province. The inability to maintain safe, reliable operations could negatively impact OPG's reputation and result in a loss of public support.

Ontario Fair Hydro Plan Act

The Fair Hydro Act received Royal Assent and came into force on June 1, 2017. As the Financial Services Manager under the Act, OPG's reputation could potentially be adversely impacted through this involvement and through stakeholder opinions related to this involvement.

Indigenous Communities

The quality of OPG's relationships and the outcome of negotiations with Indigenous communities may impact OPG's project and financial performance, as well as its social licence to operate.

OPG may be subject to claims by Indigenous communities. These claims stem from projects and generation development related to the operations of OPG and historic operations of OPG's predecessor company, Ontario Hydro, which may have impacted the Aboriginal and/or Treaty rights of Indigenous communities.

OPG has an Indigenous Relations Policy, which sets out the Company's commitment to proactively build and maintain positive relationships with Indigenous communities. OPG has been successful in working collaboratively with Indigenous communities to resolve a number of past grievances. However, the outcome of ongoing and any future negotiations depends on a number of factors, including legislation and regulations and precedents created by court rulings, which are subject to change over time. OPG pursues generation-related developments in partnerships with Indigenous communities on the basis of long-term mutually beneficial commercial arrangements.

Environmental Risks

OPG's operations and facilities are subject to environmental compliance obligations at the municipal, provincial and federal levels that include protection of land, water, air, living organisms and natural systems. A failure to comply with applicable environmental laws may result in enforcement actions, remediation actions or restrictions to operations. Changes in compliance obligations can result in new operational requirements and increased costs.

OPG has an ISO 14001 registered EMS to manage its environmental responsibilities. For further information, see discussion in the section, *Core Business, Strategy, and Outlook* under the heading, *Environmental Performance*.

OPG recognizes that efforts are required to plan for the impacts of climate change and has identified climate change adaptation as a strategic priority for the company. OPG monitors developments in climate science, adaptation activities, and potential changes to policy and regulatory requirements. OPG continues to work with stakeholders to better define adaptation requirements through analysis and understanding of impacts on watersheds, equipment and the electricity market. OPG undertakes a risk-based analysis to determine the extent of adaptation requirements to reduce the impact of climate change on its operations, and also collaborates with all levels of government and industry to increase the resiliency of the electricity infrastructure.

A carbon cap and trade program became effective in Ontario in January 2017. The program is not expected to have a material adverse economic impact on OPG due to the Company's low GHG emissions. Further details can be found in the section, *Core Business, Strategy and Outlook* under the heading, *Environmental Performance*.

RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One, the IESO and the OEFC. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly-owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions for the years ended December 31 are summarized below:

	2017		2016	
(millions of dollars)	**Revenue**	**Expense**	**Revenue**	**Expense**
Hydro One				
Electricity sales	**8**	**-**	6	-
Services	**1**	**10**	1	5
Dividends	**7**	**-**	6	-
Province of Ontario				
Change in Decommissioning Segregated Fund amount due to Province [1]	**-**	**456**	-	192
Change in Used Fuel Segregated Fund amount due to Province [1]	**-**	**591**	-	235
Hydroelectric gross revenue charge	**-**	**110**	-	120
ONFA guarantee fee	**-**	**8**	-	8
Other	**-**	**2**	-	-
OEFC				
Hydroelectric gross revenue charge	**-**	**216**	-	203
Interest expense on long-term notes	**-**	**158**	-	169
Income taxes, net of investment tax credits	**-**	**246**	-	104
IESO				
Electricity related revenue	**4,802**	**-**	5,082	-
Fair Hydro Trust	**4**	**3**	-	-
	4,822	**1,800**	5,095	1,036

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at December 31, 2017 and December 31, 2016, the Nuclear Segregated Funds were reported net of amounts due to the Province of $4,462 million and $3,415 million, respectively.

The receivable, AFS securities, payable and long-term debt balances between OPG and its related parties are summarized below:

(millions of dollars)	**December 31 2017**	**December 31 2016**
Receivables from related parties		
Hydro One	**1**	1
IESO – Electricity related receivables	**354**	421
IESO – Fair Hydro Trust [1]	**7**	-
OEFC	**-**	1
PEC	**4**	4
Province of Ontario	**3**	2
Financing receivables		
IESO – Fair Hydro Trust	**1,179**	-
Available-for-sale securities		
Hydro One shares	**188**	212
Accounts payable and accrued charges		
Hydro One	**1**	-
OEFC	**52**	61
Province of Ontario	**9**	2
IESO – Electricity-related payables	**5**	2
IESO – Fair Hydro Trust	**3**	-
Long-term debt (including current portion)		
Notes payable to OEFC	**3,195**	3,295

[1] Balance consists of unbilled revenue.

OPG holds interest-bearing Province of Ontario bonds in the Nuclear Segregated Funds and the OPG registered pension fund. As at December 31, 2017, the Nuclear Segregated Funds held $1,503 million of interest-bearing Province of Ontario bonds. As at December 31, 2016, the Nuclear Segregated Funds and the registered pension fund held $1,652 million and $284 million of interest-bearing Province of Ontario bonds, respectively. These bonds are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

In December 2017, the Trust purchased its first tranche of Investment Interest from the IESO for an exchange amount of $1.18 billion, which has been classified as a financing receivable on OPG's consolidated balance sheet. The transaction was settled in cash using proceeds from the Trust's issuance of senior and subordinated debt. Pursuant to the general regulation of the Act, the IESO is required to pay and remit carrying costs of the Trust, excluding repayment of principal on any debt obligations, up to July 31, 2021. Commencing May 1, 2021, Specified Consumers will be invoiced by their local distribution company for the Clean Energy Adjustment to pay financing and other costs of the Trust. These funds will be remitted to the Trust through the IESO and will be used to settle all funding and other related expenses of the Trust that underlie the financing receivable.

As at December 31, 2017, OPG's consolidated balance sheet included approximately $7 million of unbilled revenue from the IESO primarily for OPG's general fee for 2017 as Financial Services Manager relating to incurred third-party and certain direct labour costs. In February 2018, OPG submitted to the OEB its proposed general fee for 2017 in the amount of approximately $6 million for review pursuant to the requirements of the general regulation of the Fair Hydro Act. Once approved, the fees will be remitted to the Trust by the IESO and the Trust will pay OPG's fees as Financial Services Manager.

INTERNAL CONTROLS OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

Management, including the President and Chief Executive Officer (President and CEO) and the Chief Financial Officer (CFO), are responsible for maintaining Disclosure Controls and Procedures (DC&P) and Internal Controls over Financial Reporting (ICOFR). DC&P is designed to provide reasonable assurance that all relevant information is gathered and reported to senior management, including the President and CEO and the CFO, on a timely basis so that appropriate decisions can be made regarding public disclosure. ICOFR is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the financial statements in accordance with US GAAP.

There were no changes in OPG's ICOFR during the year ended December 31, 2017 that have materially affected or are reasonably likely to materially affect OPG's ICOFR.

Management, including the President and CEO and the CFO, concluded that, as of December 31, 2017, OPG's DC&P and ICOFR (as defined in National Instrument 52-109 – *Certification of Disclosure in Issuers' Annual and Interim Filings*) were effective.

FOURTH QUARTER

Discussion of Results

(millions of dollars) (unaudited)	Three Months Ended December 31 2017	2016
Revenue	**1,619**	1,388
Fuel expense	**171**	186
Gross margin	**1,448**	1,202
Operations, maintenance and administration	**770**	686
Depreciation and amortization	**162**	316
Accretion on fixed asset removal and nuclear waste management liabilities	**251**	233
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(222)**	(126)
Earnings from Fair Hydro Trust	**(1)**	-
Income from investments subject to significant influence	**(9)**	(9)
Property taxes	**10**	11
Restructuring	**-**	6
Income before other losses, interest, and income taxes	**487**	85
Other losses	**1**	6
Income before interest and income taxes	**486**	79
Net interest expense	**39**	28
Income before income taxes	**447**	51
Income tax expense	**81**	59
Net income (loss)	**366**	(8)
Net income (loss) attributable to the Shareholder	**362**	(13)
Net income attributable to non-controlling interest	**4**	5

Net income attributable to the Shareholder for the fourth quarter was $362 million, compared to a net loss of $13 million for the same quarter in 2016.

Income before interest and income taxes was $486 million during the fourth quarter of 2017, an increase of $407 million compared to income before interest and income taxes of $85 million during the same period in 2016. The following summarizes the significant factors which contributed to the variance:

Significant factors that increased income before interest and income taxes:

- Higher revenue from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments totaling approximately $480 million recorded in the fourth quarter of 2017 to reflect the OEB's decision on OPG's application for new regulated rates issued in December 2017 with a retrospective effective date of June 1, 2017.
- Higher earnings of $77 million from the Regulated – Nuclear Waste Management segment, primarily due to higher earnings from the Nuclear Segregated Funds reflecting the growth rate in the present value of the funding liabilities, partially offset by an increase in accretion expense on the Nuclear Liabilities.

Significant factors that decreased income before interest and income taxes:

- Lower revenue from the nuclear base regulated price of approximately $55 million, partially offset by a decrease in fuel expense of $9 million, reflecting lower electricity generation of 0.9 terawatt hours (TWh) from the Regulated – Nuclear Generation segment. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS since October 2016, partially offset by an increase in generation from the Pickering GS. The increase in generation from the Pickering GS was primarily due to outage cycle optimization, favourable unit conditions and execution of planned outage work resulting in fewer unplanned and planned outage days at the station.
- Higher OM&A expenses of $55 million, mainly in the Regulated – Nuclear Generation segment, reflected planned expenditures related to the major maintenance expenditures occurring at the nuclear stations.

The increase in income tax expense during the fourth quarter of 2017, compared to the same quarter in 2016, was primarily due to higher income before income taxes, partially offset by a higher amount of tax expense deferred in regulatory assets in 2017.

Average Sales Prices

The average sales price for the Regulated – Nuclear Generation segment during the fourth quarter of 2017 was 11.0 ¢/kWh, compared to 6.9 ¢/kWh during the same quarter in 2016. The increase in the average sales price was primarily due to the OEB ruling issued in December 2017, in which OPG received a base rate increase, retroactive to June 1, 2017. The average sales price for the Regulated – Hydroelectric segment during 2017 was 4.3 ¢/kWh, compared to 4.4 ¢/kWh during 2016. The decrease in this average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized regulated hydroelectric rate rider of $3.19/MWh for the recovery of variance and deferral account balances. The rate riders were established to recover approved balances recorded in the variance and deferral accounts in prior years. As such, the year-over-year changes in revenue from the rate riders were largely offset by changes in amortization expense related to these balances.

Electricity Generation

OPG's electricity generation for the three months ended December 31, 2017 and 2016 was as follows:

(TWh)	Three Months Ended December 31 2017	2016
Regulated – Nuclear Generation	**10.1**	11.0
Regulated – Hydroelectric	**7.2**	6.7
Contracted Generation Portfolio [1]	**0.8**	0.6
Total OPG electricity generation	**18.1**	18.3
Total electricity generation by all other generators in Ontario [2]	**18.8**	18.9

[1] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

[2] Non-OPG generation is calculated as the Ontario electricity demand plus net exports, as published by the IESO, minus OPG electricity generation.

The decrease in OPG's electricity generation of 0.2 TWh during the fourth quarter of 2017, compared to the same quarter in 2016, was mainly due to lower electricity generation of 0.9 TWh from the Regulated – Nuclear Generation segment. This was mainly the result of more planned outage days at Pickering in 2017 as well as the refurbishment of Unit 2 at the Darlington GS, which began in mid-October 2016 and continued for all of 2017. This was largely offset by higher production from the Regulated - Hydroelectric and Contracted Generation Portfolio segments mainly due to higher water flows on the eastern Ontario river systems.

Ontario's electricity demand as reported by the IESO was 33.6 TWh during the fourth quarter of 2017, compared to 33.2 TWh during the fourth quarter of 2016.

Liquidity and Capital Resources

Cash flow provided by operating activities during the three months ended December 31, 2017 was $246 million, compared to $606 million for the same period in 2016. The decrease in cash flow was primarily due to lower generation revenue receipts and higher OM&A expenditures during the fourth quarter of 2017.

Cash flow used in investing activities during the three months ended December 31, 2017 was $1,758 million, compared to $666 million during the same period in 2016. The increase was primarily due to the acquisition of the Fair Hydro Trust financing receivables and higher expenditures on the Darlington Refurbishment project in 2017.

Cash flow provided by financing activities during the three months ended December 31, 2017 was $1,466 million, compared to cash flow used in financing activities of $180 million for the same period in 2016. The increase in cash flow provided by financing activities was primarily due to higher net issuance of long-term debt and short-term notes by the Trust, as well as issuance of Class A shares in the four quarter of 2017. The increase was partially offset by the repayment of short term notes.

QUARTERLY FINANCIAL HIGHLIGHTS

The following tables set out selected annual financial information for the last three years and financial information for each of the eight most recently completed quarters. This information is derived from OPG's unaudited interim consolidated financial statements and the audited consolidated financial statements, and has been prepared in accordance with US GAAP.

Annual Financial Information

(millions of dollars – except where noted)	**2017**	**2016**	**2015**
Revenue	**5,158**	5,653	5,476
Net income attributable to the Shareholder	**860**	436	402
Earnings per common share *(dollars)*	**$3.35**	$1.70	$1.57
Total assets	**48,822**	44,372	44,250
Total long-term liabilities	**34,933**	31,460	32,404
Weighted average common shares outstanding *(millions)*	**256.7**	256.3	256.3

Quarterly Financial Information

(millions of dollars – except where noted) *(unaudited)*	**2017 Quarters Ended**				
	December 31	**September 30**	**June 30**	**March 31**	**Total**
Revenue	**1,619**	**1,217**	**1,146**	**1,176**	**5,158**
Net income	**366**	**140**	**307**	**68**	**881**
Less: Net income attributable to non-controlling interest	**4**	**9**	**4**	**4**	**21**
Net income attributable to the Shareholder	**362**	**131**	**303**	**64**	**860**
Earnings per common share, attributable to the Shareholder *(dollars)*	**$1.41**	**$0.51**	**$1.18**	**$0.25**	**$3.36**

Quarterly Financial Information

(millions of dollars – except where noted) *(unaudited)*	**2016 Quarters Ended**				
	December 31	**September 30**	**June 30**	**March 31**	**Total**
Revenue	1,388	1,400	1,387	1,478	5,653
Net (loss) income	(8)	198	135	128	453
Less: Net income attributable to non-controlling interest	5	4	3	5	17
Net (loss) income attributable to the Shareholder	(13)	194	132	123	436
Per common share, attributable to the Shareholder *(dollars)*	($0.05)	$0.76	$0.51	$0.48	$1.70

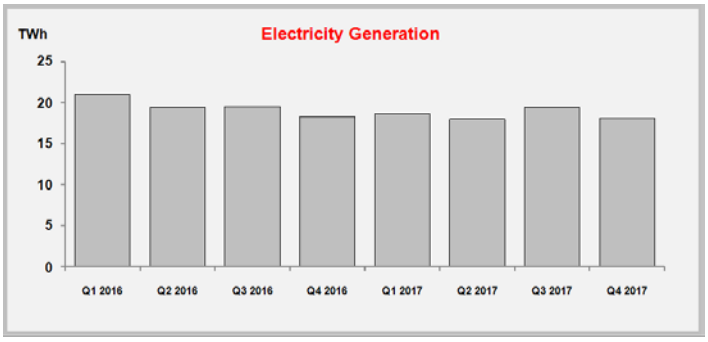
Trends

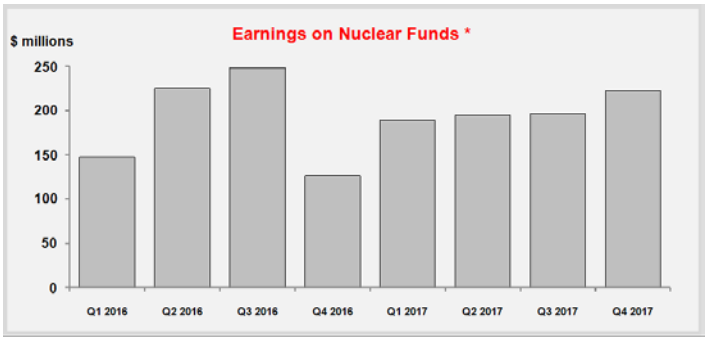
OPG's quarterly results are affected by changes in grid-supplied electricity demand, primarily resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. Weather conditions affect water flows, electricity demand, and prevalence of SBG conditions. Historically, OPG's revenues have been higher in the first quarter of a fiscal year as a result of winter heating demands and in the third quarter due to air conditioning and cooling demands. The financial impact of forgone production due to SBG conditions at the regulated hydroelectric stations and the financial impact of differences between forecast water flows reflected in OEB-approved regulated prices and the actual water flows are offset by regulatory variance accounts authorized by the OEB.

The timing of planned outages at a nuclear generating station during the year can cause variability in year-over-year operating results for partial periods of a fiscal year, including the impact on revenue and OM&A expenses, but is not a significant driver of variability for full fiscal year results.

OPG's electricity generation was reduced as a result of the Unit 2 refurbishment outage at the Darlington GS, which began in October 2016 and is expected to continue until early 2020.

OPG's financial results are also affected by the earnings on the Nuclear Segregated Funds, net of the impact of the Bruce Lease Net Revenues Variance Account. The volatility of the earnings on the Nuclear Segregated Funds is mitigated by their funded status.





*net of regulatory variance account

SUPPLEMENTARY NON-GAAP FINANCIAL MEASURES

In addition to providing net income and other financial information in accordance with US GAAP, certain non-GAAP financial measures are also presented in OPG's MD&A. These non-GAAP measures do not have any standardized meaning prescribed by US GAAP and, therefore, may not be comparable to similar measures presented by other issuers. OPG utilizes these measures to make operating decisions and assess performance. Readers of the MD&A would utilize these measures in assessing the Company's financial performance from ongoing operations. The Company believes that these indicators are important since they provide additional information about OPG's performance, facilitate comparison of results over different periods, and present measures consistent with the Company's strategies to provide value to the Shareholder, improve cost performance, and ensure availability of cost effective funding. These non-GAAP financial measures have not been presented as an alternative to net income, cash flow provided by operating activities, or any other measure in accordance with US GAAP, but as indicators of operating performance.

The definitions of the non-GAAP financial measures are as follows:

(1) ROE Excluding AOCI is defined as net income attributable to the Shareholder divided by average equity attributable to the Shareholder excluding AOCI, for the period.

ROE Excluding AOCI is measured over a 12-month period and is calculated as follows for the period ended December 31:

(millions of dollars – except where noted) (unaudited)	**2017**	**2016**
ROE Excluding AOCI		
Net income attributable to the Shareholder	**860**	436
Divided by: Average equity attributable to the Shareholder, excluding AOCI	**11,498**	10,442
ROE Excluding AOCI *(percent)*	**7.5**	4.2

(2) **FFO Adjusted Interest Coverage** is defined as FFO before interest divided by adjusted interest expense. FFO before interest is defined as cash flow provided by operating activities adjusted for interest paid, interest capitalized to fixed and intangible assets, and changes to non-cash working capital balances for the period. Adjusted interest expense is calculated as net interest expense plus interest income, interest capitalized to fixed and intangible assets, interest related to regulatory assets and liabilities, and the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets, for the period.

FFO Adjusted Interest Coverage is measured over a 12-month period and is calculated as follows for the period ended December 31:

(millions of dollars – except where noted) (unaudited)	**2017**	**2016**
FFO before interest		
Cash flow provided by operating activities	**944**	1,817
Add: Interest paid	**258**	269
Less: Interest capitalized to fixed and intangible assets	**(162)**	(141)
Less: Changes to non-cash working capital balances	**(54)**	(180)
FFO before interest	**986**	1,765
Adjusted interest expense		
Net interest expense	**95**	120
Add: Interest income	**9**	7
Add: Interest capitalized to fixed and intangible assets	**162**	141
Add: Interest related to regulatory assets and liabilities	**30**	30
Add: Excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets [1]	**-**	45
Adjusted interest expense	**296**	343
FFO Adjusted Interest Coverage *(times)*	**3.3**	5.1

[1] A value of nil is used in the calculation when interest on pension and OPEB projected benefit obligations is equal to, or lower than, expected return on pension plan assets.

(3) **Enterprise Total Generating Cost per MWh** is used to measure OPG's overall organizational cost performance. Enterprise TGC per MWh is defined as OM&A expenses (excluding the Darlington Refurbishment project and other generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to OPG's electricity generation business), fuel expense for OPG-operated stations including hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures (excluding the Darlington Refurbishment project and other generation development projects) incurred during the period, divided by total electricity generation from OPG-operated generating stations plus electricity generation forgone due to SBG conditions during the period.

Enterprise TGC per MWh is calculated as follows for the 12-month period ended December 31:

(millions of dollars – except where noted)	**2017**	**2016**
Enterprise TGC		
Total OM&A expenses	**2,824**	2,747
Total fuel expense	**689**	727
Total capital expenditures	**1,926**	1,704
Less: Darlington Refurbishment capital and OM&A costs	**(1,285)**	(1,022)
Less: Other generation development project capital and OM&A costs	**(65)**	(163)
Add: OM&A and fuel expenses (refundable through) deferred in regulatory variance and deferral accounts	**(1)**	62
Less: Nuclear fuel expense for non OPG-operated stations	**(57)**	(67)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**69**	49
Less: OM&A expenses ancillary to electricity generation business	**(18)**	(28)
Other adjustments	**(43)**	(19)
	4,039	3,990
Adjusted electricity generation *(TWh)*		
Total OPG electricity generation	**74.1**	78.2
Adjust for electricity generation forgone due to SBG conditions and OPG's share of electricity generation from co-owned facilities	**5.6**	4.1
	79.7	82.3
Enterprise TGC per MWh *($/MWh)* [1]	**50.66**	**48.45**

[1] Amounts may not calculate due to rounding.

(4) **Nuclear Total Generating Cost per MWh** is used to measure the cost performance of OPG's nuclear generating assets. Nuclear TGC per MWh is defined as OM&A expenses of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the nuclear electricity generation business), nuclear fuel expense for OPG-operated stations (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs) incurred during the period, divided by nuclear electricity generation for the period.

Nuclear TGC per MWh is calculated as follows for the 12-month period ended December 31:

(millions of dollars – except where noted)	**2017**	**2016**
Nuclear TGC		
Regulated – Nuclear Generation OM&A expenses	**2,293**	2,210
Regulated – Nuclear Generation fuel expense	**284**	315
Regulated – Nuclear Generation capital expenditures	**1,631**	1,338
Less: Darlington Refurbishment capital and OM&A costs	**(1,285)**	(1,022)
Add: Regulated – Nuclear Generation OM&A and fuel expenses deferred in regulatory variance and deferral accounts	**35**	81
Less: Nuclear fuel expense for non OPG-operated stations	**(57)**	(67)
Less: Regulated – Nuclear Generation OM&A expenses ancillary to electricity generation business	**(6)**	(10)
Other adjustments	**(10)**	(4)
	2,885	2,841
Nuclear electricity generation *(TWh)*	**40.7**	45.6
Nuclear TGC per MWh *($/MWh)* [1]	**70.95**	62.30

[1] Amounts may not calculate due to rounding.

(5) **Hydroelectric Total Generating Cost per MWh** is used to measure the cost performance of OPG's hydroelectric generating assets. Hydroelectric TGC per MWh is defined as OM&A expenses of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the hydroelectric electricity generation business), hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding expenditures related to the Peter Sutherland Sr. GS, Ranney Falls GS, and other hydroelectric generation development projects) incurred during the period, divided by total hydroelectric electricity generation plus hydroelectric electricity generation forgone due to SBG conditions during the period. OPG reports hydroelectric gross revenue charge and water rental payments as fuel expense.

Hydroelectric TGC per MWh is calculated as follows for the 12-month period ended December 31:

(millions of dollars – except where noted)	**2017**	**2016**
Hydroelectric TGC		
Regulated – Hydroelectric OM&A expenses	**330**	325
Regulated – Hydroelectric fuel expense	**351**	353
Contracted Generation Portfolio OM&A expenses	**169**	178
Contracted Generation Portfolio fuel expense	**53**	58
Regulated – Hydroelectric and Contracted Generation Portfolio capital expenditures	**226**	330
Less: Regulated – Hydroelectric and Contracted Generation Portfolio Generation Portfolio generation development project capital and OM&A costs	**(63)**	(158)
Less: Thermal OM&A and fuel expenses and capital expenditures in the Contracted Generation Portfolio	**(166)**	(177)
Less: Regulated – Hydroelectric OM&A and fuel expenses refundable through regulatory variance and deferral accounts	**(36)**	(24)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**69**	49
Other adjustments	**(1)**	(1)
	932	933
Adjusted hydroelectric electricity generation *(TWh)*		
Regulated – Hydroelectric electricity generation	**30.7**	29.5
Contracted Generation Portfolio electricity generation	**2.7**	3.1
Adjust for hydroelectric electricity generation forgone due to SBG conditions and non-hydroelectric electricity generation of the Contracted Generation Portfolio, including OPG's share of electricity generation from co-owned facilities	**5.5**	4.0
	38.9	36.6
Hydroelectric TGC per MWh *($/MWh)* [1]	**23.91**	25.49

[1] Amounts may not calculate due to rounding.

(6) **Gross margin** is defined as revenue less fuel expense**.**

For further information, please contact:	Investor Relations	416-592-6700
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		1-877-592-4008

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ONTARIO POWER GENERATION INC.

CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2017

[DRAFT]

19. RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One, the IESO and the OEFC. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly-owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions for the years ended December 31 are summarized below:

	2017		2016	
(millions of dollars)	**Income**	**Expense**	**Income**	**Expense**
Hydro One				
Electricity sales	**8**	**-**	6	-
Services	**1**	**10**	1	5
Dividends	**7**	**-**	6	-
Province of Ontario				
Change in Decommissioning Segregated Fund amount due to Province [1]	**-**	**456**	-	192
Change in Used Fuel Segregated Fund amount due to Province [1]	**-**	**591**	-	235
Hydroelectric gross revenue charge	**-**	**110**	-	120
ONFA guarantee fee	**-**	**8**	-	8
Other	**-**	**2**	-	-
OEFC				
Hydroelectric gross revenue charge	**-**	**216**	-	203
Interest expense on long-term notes	**-**	**158**	-	169
Income taxes, net of investment tax credits	**-**	**246**	-	104
IESO				
Electricity related revenue	**4,802**	**-**	5,082	-
Earnings from Fair Hydro Trust	**1**	**-**	-	-
	4,819	**1,797**	5,095	1,036

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at December 31, 2017 and December 31, 2016, the Nuclear Segregated Funds were reported net of amounts due to the Province of $4,462 million and $3,415 million, respectively.

The receivable, AFS securities, payable and long-term debt balances between OPG and its related parties are summarized below:

(millions of dollars)	**December 31 2017**	**December 31 2016**
Receivables from related parties		
Hydro One	**1**	1
IESO − Electricity related receivables	**354**	421
IESO − Fair Hydro Trust [1]	**7**	-
OEFC	**-**	1
PEC	**4**	4
Province of Ontario	**3**	2
Financing receivables		
IESO − Fair Hydro Trust	**1,179**	-
Available-for-sale securities		
Hydro One shares	**188**	212
Accounts payable and accrued charges		
Hydro One	**1**	-
OEFC	**52**	61
Province of Ontario	**9**	2
IESO − Electricity-related payables	**5**	2
IESO − Fair Hydro Trust	**3**	-
Long-term debt (including current portion)		
Notes payable to OEFC	**3,195**	3,295

[1] Balance consists of unbilled revenue.

OPG holds interest-bearing Province of Ontario bonds in the Nuclear Segregated Funds and the OPG registered pension fund. As at December 31, 2017, the Nuclear Segregated Funds held $1,503 million of interest-bearing Province of Ontario bonds, while the registered pension fund had no such holdings. As at December 31, 2016, the Nuclear Segregated Funds and the registered pension fund held $1,652 million and $284 million of interest-bearing Province of Ontario bonds, respectively. These bonds are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

In December 2017, the Fair Hydro Trust purchased its first tranche of Investment Interest from the IESO for an exchange amount of $1.18 billion, which has been classified as a financing receivable on OPG's consolidated balance sheet. The transaction was settled in cash using proceeds from the Trust's issuance of senior and subordinated debt. Pursuant to the general regulation of the Fair Hydro Act, the IESO is required to pay and remit carrying costs of the Trust, excluding repayment of principal on any debt obligations, up to July 31, 2021. Commencing May 1, 2021, Specified Consumers will be invoiced by their local distribution company for the Clean Energy Adjustment to pay the carrying costs of the Trust. These funds will be remitted to the Trust through the IESO and will be used to settle all funding and other related expenses of the Trust that underlie the financing receivable.

As at December 31, 2017, OPG's consolidated balance sheet included approximately $7 million of unbilled revenue from the IESO, primarily for OPG's general fee for 2017 as the Financial Services Manager under the Act relating to incurred third-party and certain direct labour costs.

~~Under one of the Trust's program agreements, the~~The Province has provided a limited guarantee to specified creditors of the Fair Hydro Trust. The limited guarantee would be triggered in the event that the Trust's ability to receive amounts in respect of its Investment Interest to pay for certain funding obligations is adversely affected due to the occurrence of any one of the following: the Province changes the Fair Hydro Act or any other legislation or

regulation; Ontario's electricity market significantly changes due to actions undertaken by the Province; or a court declares that the Act is ~~declared~~ invalid or unconstitutional.

Commented [MR-1]: Accepted this change.

ONTARIO POWER GENERATION INC.

CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2017

[DRAFT]

STATEMENT OF MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL INFORMATION

Ontario Power Generation Inc.'s (OPG) management is responsible for the presentation and preparation of the annual consolidated financial statements and Management's Discussion and Analysis (MD&A).

The consolidated financial statements have been prepared in accordance with United States generally accepted accounting principles (US GAAP). The MD&A has been prepared in accordance with the requirements of securities regulators, including National Instrument 51-102 of the Canadian Securities Administrators and its related published requirements.

The consolidated financial statements and information in the MD&A necessarily include amounts based on informed judgments and estimates of the expected effects of current events and transactions with appropriate consideration to materiality. Something is considered material if it is reasonably expected to have a significant impact on the Company's earnings, cash flow, value of an asset or liability, or reputation. In addition, in preparing the financial information, we must interpret the requirements described above, make determinations as to the relevancy of information to be included, and make estimates and assumptions that affect the reported information. The MD&A also includes information regarding the impact of current transactions and events, sources of liquidity and capital resources, operating trends, and risks and uncertainties. Actual results in the future may differ materially from our present assessment of this information because future events and circumstances may not occur as expected.

In meeting our responsibility for the reliability of the financial information, we maintain and rely on a comprehensive system of internal controls and internal audits, including organizational and procedural controls and internal controls over financial reporting. Our system of internal controls includes: written communication of our policies and procedures governing corporate conduct and risk management; comprehensive business planning; effective segregation of duties; delegation of authority and personal accountability; careful selection and training of personnel; and accounting policies, which we regularly update. This structure ensures appropriate internal controls over transactions, assets and records. We also regularly test internal controls. These controls and testing are designed to provide us with reasonable assurance that the financial records are reliable for preparing financial statements and other financial information, assets are safeguarded against unauthorized use or disposition, liabilities are recognized, and we are in compliance with all regulatory requirements.

Management, including the President and Chief Executive Officer (CEO) and the Chief Financial Officer (CFO), is responsible for maintaining disclosure controls and procedures (DC&P) and internal controls over financial reporting (ICOFR). DC&P is designed to provide reasonable assurance that all relevant information is gathered and reported to senior management, including the President and CEO and the CFO, on a timely basis so that appropriate decisions can be made regarding public disclosure. ICOFR is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements in accordance with US GAAP.

An evaluation of the effectiveness of the design and operation of OPG's DC&P and ICOFR was conducted as of December 31, 2017. Accordingly, we, as OPG's President and CEO and CFO, will certify OPG's annual disclosure documents filed with the Ontario Securities Commission, which includes attesting to the design and effectiveness of OPG's DC&P and ICOFR.

The Board of Directors, based on recommendations from its Audit and Risk Committee, reviews and approves the consolidated financial statements and the MD&A, and oversees management's responsibilities for the presentation and preparation of financial information, maintenance of appropriate internal controls, management and control of major areas of financial risk, and assessment of significant and related party transactions.

The consolidated financial statements have been audited by Ernst & Young LLP, independent external auditors appointed by the Board of Directors. The Independent Auditors' Report outlines the auditors' responsibilities and the scope of their examination and their opinion on OPG's consolidated financial statements. The independent external auditors, as confirmed by the Audit and Risk Committee, had direct and full access to the Audit and Risk Committee, with and without the presence of management, to discuss their audit and their findings therefrom, as to the integrity of OPG's financial reporting and the effectiveness of the system of internal controls.

Jeff Lyash
President and Chief Executive Officer

Ken Hartwick
Chief Financial Officer and Senior Vice President – Finance

March 8, 2018

INDEPENDENT
AUDITORS' REPORT

To the Shareholder of Ontario Power Generation Inc.

We have audited the accompanying consolidated financial statements of Ontario Power Generation Inc., which comprise the consolidated balance sheets as at December 31, 2017 and 2016, and the consolidated statements of income, comprehensive income, cash flows and changes in shareholder's equity for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with United States generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Ontario Power Generation Inc. as at December 31, 2017 and 2016, and the results of its operations and its cash flows for the years then ended in accordance with United States generally accepted accounting principles.

Toronto, Canada

March 8, 2018

Ernst & Young LLP

Chartered Professional Accountants,
Licensed Public Accountants

CONSOLIDATED STATEMENTS OF INCOME

Years Ended December 31 *(millions of dollars except where noted)*	**2017**	**2016**
Revenue *(Note 17)*	**5,158**	5,653
Fuel expense *(Note 17)*	**689**	727
Gross margin	**4,469**	4,926
Operations, maintenance and administration *(Note 17)*	**2,824**	2,747
Depreciation and amortization *(Note 4)*	**679**	1,257
Accretion on fixed asset removal and nuclear waste management liabilities *(Note 8)*	**960**	929
Earnings on nuclear fixed asset removal and nuclear waste management funds *(Note 8)*	**(801)**	(746)
Earnings from Fair Hydro Trust *(Note 17)*	**(1)**	-
Income from investments subject to significant influence	**(38)**	(37)
Property taxes	**40**	46
Restructuring	**-**	6
	3,663	4,202
Income before other gains, interest and income taxes	**806**	724
Other gains *(Note 17)*	**379**	17
Income before interest and income taxes	**1,185**	741
Net interest expense *(Note 6)*	**95**	120
Income before income taxes	**1,090**	621
Income tax expense *(Note 9)*	**209**	168
Net income	**881**	453
Net income attributable to the Shareholder	**860**	436
Net income attributable to non-controlling interest	**21**	17
Basic and diluted net income per common share *(dollars) (Note 15)*	**3.35**	1.70

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Years Ended December 31 *(millions of dollars)*	2017	2016
Net income	**881**	453
Other comprehensive income, net of income taxes *(Note 10)*		
Actuarial loss on re-measurement of liabilities for pension and other post-employment benefits [1]	**(23)**	(6)
Reclassification to income of amounts related to pension and other post-employment benefits [2]	**10**	12
Reclassification to income of losses on derivatives designated as cash flow hedges [3]	**18**	19
Unrealized loss on available-for-sale securities [4]	**(8)**	(1)
Other comprehensive (loss) income for the year	**(3)**	24
Comprehensive income	**878**	477
Comprehensive income attributable to the Shareholder	**857**	460
Comprehensive income attributable to non-controlling interest	**21**	17

[1] Net of income tax recovery of $7 million and $2 million for 2017 and 2016, respectively.
[2] Net of income tax expenses of $3 million and $4 million for 2017 and 2016, respectively.
[3] Net of income tax expenses of $2 million for each of 2017 and 2016.
[4] Net of income tax recovery of $2 million and nil for 2017 and 2016, respectively.

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31 *(millions of dollars)*	2017	2016
Operating activities		
Net income	**881**	453
Adjust for non-cash items:		
Depreciation and amortization *(Note 4)*	**679**	1,257
Accretion on fixed asset removal and nuclear waste management liabilities	**960**	929
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(801)**	(746)
Pension and other post-employment benefit costs *(Note 11)*	**412**	464
Deferred income taxes	**19**	(36)
Mark-to-market on derivative instruments	**(3)**	3
Provision for used nuclear fuel and low and intermediate level nuclear waste	**116**	118
Regulatory assets and liabilities	**(558)**	(170)
Provision for materials and supplies	**33**	42
Other gains	**(371)**	-
Other	**1**	(25)
	1,368	2,289
Contributions to nuclear fixed asset removal and nuclear waste management funds	**-**	(150)
Expenditures on fixed asset removal and nuclear waste management	**(313)**	(275)
Reimbursement of eligible expenditures on nuclear fixed asset removal and nuclear waste management	**79**	70
Contributions to pension funds and expenditures on other post-employment benefits and supplementary pension plans	**(322)**	(363)
Expenditures on restructuring	**(4)**	(6)
Distributions received from investments subject to significant influence	**50**	52
Net changes to other long-term assets and liabilities	**32**	20
Net changes to non-cash working capital balances *(Note 18)*	**54**	180
Cash flow provided by operating activities	**944**	1,817
Investing activities		
Acquisition of Fair Hydro Trust financing receivables *(Notes 3 and 19)*	**(1,179)**	-
Purchase of available-for-sale securities	**-**	(213)
Proceeds from deposit note	**70**	110
Net proceeds from sale of property, plant and equipment	**484**	-
Investment in property, plant and equipment and intangible assets	**(1,853)**	(1,816)
Cash flow used in investing activities	**(2,478)**	(1,919)
Financing activities		
Issuance of Class A shares *(Note 14)*	**519**	-
Issuance of long-term debt *(Note 6)*	**1,301**	334
Repayment of long-term debt	**(1,103)**	(273)
Issuance of long-term debt by Fair Hydro Trust *(Note 6)*	**601**	-
Distribution to non-controlling interest	**(15)**	(14)
Capital contribution from non-controlling interest	**19**	-
Issuance of short-term notes	**1,960**	3,108
Repayment of short-term debt	**(1,700)**	(3,331)
Cash flow provided by (used in) financing activities	**1,582**	(176)
Net increase (decrease) in cash and cash equivalents	**48**	(278)
Cash and cash equivalents, beginning of year	**186**	464
Cash and cash equivalents, end of year	**234**	186

See accompanying notes to the consolidated financial statements

CONSOLIDATED BALANCE SHEETS

As at December 31 *(millions of dollars)*	2017	2016
Assets		
Current assets		
Cash and cash equivalents [1]	**234**	186
Available-for-sale securities	**188**	212
Receivables from related parties *(Note 19)*	**369**	429
Nuclear fixed asset removal and nuclear waste management funds *(Notes 8 and 17)*	**23**	24
Fuel inventory *(Note 17)*	**309**	310
Materials and supplies *(Note 17)*	**103**	100
Prepaid expenses	**192**	198
Other current assets	**146**	298
	1,564	1,757
Property, plant and equipment *(Notes 4 and 17)*	**29,950**	29,315
Less: accumulated depreciation	**8,628**	9,317
	21,322	19,998
Intangible assets *(Notes 4 and 17)*	**565**	503
Less: accumulated amortization	**432**	404
	133	99
Other assets		
Nuclear fixed asset removal and nuclear waste management funds *(Notes 8 and 17)*	**16,701**	15,960
Financing receivables *(Note 19)*	**1,179**	-
Long-term materials and supplies *(Note 17)*	**355**	345
Regulatory assets *(Note 5)*	**7,231**	5,855
Investments subject to significant influence *(Note 20)*	**309**	321
Other long-term assets	**28**	37
	25,803	22,518
	48,822	44,372

[1] Includes $4 million restricted for Fair Hydro Trust purposes.

See accompanying notes to the consolidated financial statements

CONSOLIDATED BALANCE SHEETS

As at December 31 *(millions of dollars)*	2017	2016
Liabilities		
Current liabilities		
Accounts payable and accrued charges *(Note 19)*	**1,228**	1,164
Short-term debt *(Note 7)*	**260**	2
Deferred revenue due within one year	**12**	12
Long-term debt due within one year *(Note 6)*	**398**	1,103
Income taxes payable	**80**	123
	1,978	2,404
Long-term debt *(Notes 6 and 17)*	**5,921**	4,417
Other liabilities		
Fixed asset removal and nuclear waste management liabilities *(Notes 8 and 17)*	**20,421**	19,484
Pension liabilities *(Note 11)*	**3,423**	3,012
Other post-employment benefit liabilities *(Note 11)*	**3,092**	2,897
Long-term accounts payable and accrued charges	**252**	213
Deferred revenue	**351**	298
Deferred income taxes *(Note 9)*	**879**	829
Regulatory liabilities *(Note 5)*	**594**	310
	29,012	27,043
Equity		
Common shares [1] *(Note 14)*	**5,126**	5,126
Class A shares [2] *(Note 14)*	**519**	-
Retained earnings	**6,396**	5,534
Accumulated other comprehensive loss *(Note 10)*	**(295)**	(295)
Equity attributable to the Shareholder	**11,746**	10,365
Equity attributable to non-controlling interest *(Note 22)*	**165**	143
Total equity	**11,911**	10,508
	48,822	44,372

[1] 256,300,010 common shares outstanding at a stated value of $5,126 million as at December 31, 2017 and December 31, 2016.

[2] 12,217,616 Class A shares outstanding at a stated value of $519 million as at December 31, 2017.

Commitments and Contingencies *(Notes 6, 9, 11 and 16)*

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY

Years Ended December 31 *(millions of dollars)*	**2017**	**2016**
Common shares	**5,126**	5,126
Class A shares *(Note 14)*	**519**	-
Retained earnings		
Balance at beginning of year	**5,534**	5,098
Net income attributable to the Shareholder	**860**	436
Reclassification of non-controlling interest on change in ownership interest *(Note 22)*	**2**	-
Balance at end of year	**6,396**	5,534
Accumulated other comprehensive loss, net of income taxes		
Balance at beginning of year	**(295)**	(319)
Other comprehensive (loss) income	**(3)**	24
Reclassification of non-controlling interest on change in ownership interest *(Note 22)*	**3**	-
Balance at end of year	**(295)**	(295)
Equity attributable to the Shareholder	**11,746**	10,365
Equity attributable to non-controlling interest		
Balance at beginning of year	**143**	140
Equity contribution from non-controlling interest *(Note 22)*	**21**	-
Reclassification of non-controlling interest on change in ownership interest *(Note 22)*	**(5)**	-
Distribution to non-controlling interest	**(15)**	(14)
Income attributable to non-controlling interest	**21**	17
Balance at end of year	**165**	143
Total equity	**11,911**	10,508

See accompanying notes to the consolidated financial statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the years ended December 31, 2017 and 2016

1. DESCRIPTION OF BUSINESS

Ontario Power Generation Inc. (OPG or the Company) was incorporated on December 1, 1998 pursuant to the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the Province or the Shareholder). OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario.

2. BASIS OF PRESENTATION

These consolidated financial statements have been prepared and presented in accordance with United States generally accepted accounting principles (US GAAP).

As required by *Ontario Regulation 395/11,* as amended, under the *Financial Administration Act* (Ontario), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. Since January 1, 2012, OPG also has received exemptive relief from the Ontario Securities Commission (OSC) from the requirements of section 3.2 of National Instrument 52-107, *Acceptable Accounting Policies and Auditing Standards*. The exemption allows OPG to file consolidated financial statements based on US GAAP, rather than International Financial Reporting Standards (IFRS), without becoming a US Securities and Exchange Commission registrant, or issuing public debt.

The current OSC exemption, received in 2014, will terminate on the earliest of the following:

- January 1, 2019
- The financial year that commences after OPG ceases to have activities subject to rate regulation
- The effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within IFRS specific to entities with rate-regulated activities.

All dollar amounts are presented in Canadian dollars, except in tabular format where noted. Certain of the 2016 comparative amounts have been reclassified from financial statements previously presented to conform to the 2017 consolidated financial statement presentation.

3. SIGNIFICANT ACCOUNTING POLICIES AND ESTIMATES

Consolidation

The consolidated financial statements of the Company include the accounts of OPG and its majority-owned subsidiaries, and variable interest entities (VIEs) where OPG is the primary beneficiary. All significant intercompany balances and intercompany transactions have been eliminated on consolidation.

Where OPG does not control an investment, but has significant influence over operating and financing policies of the investee, the investment is accounted for under the equity method. OPG co-owns the Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS) with TransCanada Energy Ltd. and co-owns the Brighton Beach gas-fired combined cycle GS (Brighton Beach) with ATCO Power Canada Ltd. OPG accounts for its 50 percent ownership interest in each of these jointly controlled entities using the equity method.

Variable Interest Entities

OPG performs ongoing analysis to assess whether it holds any VIEs. VIEs of which OPG is deemed to be the primary beneficiary are consolidated. The primary beneficiary of a VIE has both the power to direct the activities of the entity that most significantly impact its economic performance and the obligation to absorb losses of the entity that could potentially be significant to the Company. In circumstances where OPG is not deemed to be the primary beneficiary, the VIE is not recorded in OPG's consolidated financial statements.

Nuclear Waste Management Organization (NWMO)

In 2002, OPG and other Canadian nuclear waste producers established a separately incorporated NWMO in accordance with the *Nuclear Fuel Waste Act* (Canada) (NFWA). The primary long-term mandate of the NWMO is to implement an approach to address the long-term management of used nuclear fuel in Canada. In addition to the above mandate, the NWMO currently provides project management services for OPG's proposed Deep Geologic Repository (DGR) for the long-term management of low and intermediate level waste (L&ILW) and certain other nuclear life cycle liability management services. OPG has the majority of voting rights at the NWMO Board of Directors' and members' level. The NFWA requires the nuclear fuel waste owners to establish and make payments into trust funds for the purpose of funding the implementation of the long-term nuclear used fuel management plan in accordance with the NFWA. OPG provides over 90 percent of NWMO's funding, primarily towards the design and implementation of Canada's Adaptive Phased Management plan for the long-term management of nuclear used fuel. As a result, OPG is expected to absorb a majority of the NWMO's expected losses through future funding in the event of any shortfall. Therefore, OPG holds a variable interest in the NWMO, of which it is the primary beneficiary. Accordingly, the applicable amounts in the accounts of the NWMO, after elimination of all significant intercompany transactions, are consolidated.

Fair Hydro Trust

On March 2, 2017, the Province announced Ontario's Fair Hydro Plan (the Fair Hydro Plan) aimed at reducing electricity bills for eligible~~all~~ residential customers, and as many as half a million farm and~~,~~ small businesses ~~and other eligible consumers~~ (Specified Consumers) in the province on average by 25 percent. The rate reduction is inclusive of an eight percent rebate equivalent to the provincial portion of the harmonized sales tax granted by the Ontario government in January 2017. As part of the Fair Hydro Plan, a portion of the Global Adjustment costs ~~resulting from the Fair Hydro Plan shortfall~~ will be refinanced over a longer time period. The Global Adjustment includes the difference between Ontario's electricity market clearing price used to dispatch generation and the prices paid to contracted and regulated generators in the province, and the cost of conservation and demand management programs. On June 1, 2017, the *Ontario Fair Hydro Plan Act, 2017* (the Fair Hydro Act or the Act) received Royal Assent and the associated general regulation came into force in June 2017. Effective May 1, 2017, the Independent Electricity System Operator (IESO) began to defer a portion of the Global Adjustment costs. The Act allows for the IESO to transfer a portion of the balance in the variance account to a financing entity that will fund the deferral in exchange for the right to recover the balance and associated financing and other costs from Specified Consumers in the future (Investment Interest).

In December 2017, the Fair Hydro Trust (the Trust) was established as the financing entity contemplated by the Fair Hydro Act. Immediately after the establishment, OPG entered into a management agreement with the Trust which conveys to OPG all of the powers and duties of managing the Trust, including determining whether to acquire Investment Interests from the IESO related to the shortfall from the rate reduction mandated by the Fair Hydro Act, negotiating and executing all agreements, fulfilling all reporting requirements, and administering all of its day-to-day activities. In addition to the powers and duties delegated to OPG as manager under the management agreement, OPG is also required to comply with its duties as Financial Services Manager under the Fair Hydro Act and the regulations.

Commented [MR-1]: Did not update as the current wording is consistent with prior quarter(s) disclosure.

Commented [MR-2]: Did not take this change.

The Trust is essentially all debt funded and has minimal equity at risk to finance its activities. As part of the funding structure of the Trust, concurrent with every issuance of senior debt, it is expected that OPG will purchase subordinated debt of the Trust in an aggregate amount equal to, but no more than 49 percent of all of the required funding. The subordination level may vary over time, but must at least equal to, or be greater than 35 percent of all outstanding debt. Approximately 90 percent of such amount is expected to be funded through equity investments in OPG by the Province, with the remainder being funded from OPG's available funds, including all or a portion of the proceeds from OPG's medium term notes program. Based on management's assessment, it is concluded that OPG holds a variable interest in the Trust through its ownership of the most subordinated debt, of which it is the primary beneficiary. Accordingly, the applicable amounts in the accounts of the Trust, after elimination of all significant intercompany transactions, have been consolidated by OPG.

PSS Generating Station Limited Partnership (PSS or the Partnership)

As at December 31, 2017, PSS has recognized sufficient level of income and has eliminated deficits within the partnership. Hence, the Partnership has met the criteria of having sufficient equity at risk to finance its activities, and ceased being classified as a variable interest entity. Since OPG is the primary beneficiary of PSS, it continues to consolidate the Partnership.

Use of Management Estimates

The preparation of consolidated financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the consolidated financial statements, and the reported amounts of revenues and expenses for the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in the period incurred. Significant estimates are included in the determination of pension and other post-employment benefit (OPEB) balances, asset retirement obligations (AROs) and associated asset retirement costs capitalized as part of property, plant and equipment (PP&E), income taxes (including deferred income taxes), contingencies, regulatory assets and liabilities, valuation of investments in segregated funds, depreciation and amortization expenses. Actual results may differ significantly from these estimates.

Cash and Cash Equivalents and Short-Term Investments

Cash and cash equivalents include cash on deposit and money market securities with a maturity of less than 90 days on the date of purchase. All other money market securities with a maturity on the date of purchase that is greater than 90 days, but less than one year, are recorded as short-term investments and classified as current assets. These securities are valued at the lower of cost and market.

Inventories

Inventories, consisting of fuel and materials and supplies, are measured at the lower of cost and net realizable value. Cost is determined as weighted average cost for fuel inventory and average cost for materials and supplies.

Property, Plant and Equipment, Intangible Assets and Depreciation and Amortization

PP&E and intangible assets are recorded at cost. Interest costs incurred during construction and development are capitalized as part of the cost of the asset based on the interest rates on OPG's long-term debt. Expenditures for replacements of major components are capitalized.

Depreciation and amortization rates for the various classes of assets are based on their estimated service lives. Asset removal costs that have not been specifically provided for in current or previous periods are charged to operations, maintenance and administration (OM&A) expenses when incurred. Repairs and maintenance costs also are expensed when incurred.

PP&E are depreciated on a straight-line basis, except for computers, which are depreciated on a declining balance basis. Intangible assets, which consist of major application software, are amortized on a straight-line basis.

As at December 31, 2017, the amortization periods of PP&E and intangible assets are as follows:

Nuclear generating stations and major components	15 to 74 years [1]
Thermal generating stations and major components	5 to 50 years
Hydroelectric generating stations and major components	10 to 100 years
Administration and service facilities	10 to 50 years
Computers – declining balance	12% to 40% per year
Major application software	5 years
Service equipment	5 to 10 years

[1] As at December 31, 2017, the end of station life for depreciation purposes for the Darlington, Pickering, Bruce A and Bruce B nuclear generating stations ranged between 2022 and 2061. Major components are depreciated over the lesser of the station life and the life of the components.

Asset Impairment

Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. The review is based on the presence of impairment indicators such as the future economic benefit of the assets and external market conditions. The net carrying amount of assets is considered impaired if it exceeds the sum of the estimated undiscounted cash flows expected to result from the asset's use and eventual disposition. In cases where the sum of the undiscounted expected future cash flows is less than the carrying amount, an impairment loss is recognized. This loss equals the amount by which the carrying amount exceeds the fair value. Fair value is determined using expected discounted cash flows when quoted market prices are not available. The impairment is recognized in income in the period in which it is identified.

The carrying values of investments accounted for under the equity method are reviewed annually for the presence of any indicators of impairment. If an impairment exists and is determined to be other-than-temporary, an impairment charge is recognized. This charge equals the amount by which the carrying value exceeds the investment's fair value.

Rate Regulated Accounting

The *Ontario Energy Board Act, 1998* and *Ontario Regulation 53/05* provide that OPG receives regulated prices for electricity generated from the Sir Adam Beck 1, 2 and Pump hydroelectric generating stations, the DeCew Falls 1 and 2 hydroelectric generating stations, the R.H. Saunders Hydroelectric GS, the 48 hydroelectric generating stations prescribed for rate regulation effective in 2014, and the Pickering and Darlington nuclear generating stations (collectively, prescribed facilities or regulated facilities). OPG's regulated prices for these facilities are determined by the Ontario Energy Board (OEB).

The OEB is a self-funding Crown corporation. Its mandate and authority come from the *Ontario Energy Board Act, 1998,* the *Electricity Act, 1998*, and a number of other provincial statutes. The OEB is an independent, quasi-judicial tribunal that reports to the Legislature of the Province through the Ontario Ministry of Energy. It regulates market participants in Ontario's natural gas and electricity industries. The OEB carries out its regulatory functions through public hearings and other more informal processes such as consultations.

US GAAP recognizes that rate regulation can create economic benefits and obligations that are required by the regulator to be obtained from, or settled with, the customers. When the Company assesses that there is sufficient assurance that incurred costs in respect of the regulated facilities will be recovered in the future, those costs are deferred and reported as a regulatory asset. When the Company is required to refund amounts to customers in the future in respect of the regulated facilities, including amounts related to costs that have not been incurred but for which the OEB has provided recovery through regulated prices, the Company records a regulatory liability.

Certain of the regulatory assets and liabilities recognized by the Company relate to variance and deferral accounts authorized by the OEB, including those authorized pursuant to *Ontario Regulation 53/05*. Variance and deferral accounts typically capture differences between actual costs and revenues and the corresponding forecast amounts

approved by the OEB in setting regulated prices, or record the impact of items not reflected in the approved regulated prices. The measurement of these regulatory assets and liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of *Ontario Regulation 53/05* and the OEB's decisions. The estimates and assumptions made in the interpretation of the regulation and the OEB's decisions are reviewed as part of the OEB's regulatory process.

Regulatory assets and liabilities for variance and deferral account balances approved by the OEB for inclusion in regulated prices are amortized based on approved recovery or repayment periods. Disallowed balances are charged to operations in the period that the corresponding OEB decision is issued.

Regulatory assets and liabilities for variance and deferral account balances approved by the OEB are classified as current if they are expected to be recovered from, or refunded to, customers within 12 months of the end of the reporting period, based on recovery or repayment periods authorized by the OEB. All other regulatory asset and liability balances are classified as non-current on the consolidated balance sheets.

In addition to regulatory assets and liabilities for variance and deferral accounts, OPG recognizes regulatory assets and liabilities for unamortized amounts recorded in accumulated other comprehensive income (AOCI) in respect of pension and OPEB obligations, and deferred income taxes, in order to reflect the expected recovery or repayment of these amounts through future regulated prices charged to customers. There are measurement uncertainties related to these balances due to the assumptions made in the determination of pension and OPEB obligations and deferred income taxes that are attributed to rate regulated business segments.

The regulatory asset for unamortized pension and OPEB amounts recorded in AOCI has reflected the OEB's use, since April 1, 2008, of the accrual basis of accounting for including pension and OPEB amounts in approved regulated prices for OPG. This is also the manner in which these costs are recognized in OPG's consolidated financial statements. Therefore, unamortized amounts in respect of OPG's pension and OPEB plans recognized in AOCI generally would not be reflected in regulated prices until they have been reclassified from AOCI and recognized as amortization components of the benefit costs for these plans. The regulatory asset is reversed as underlying unamortized balances are amortized as components of the benefit cost.

In setting OPG's regulated prices effective November 1, 2014, the OEB limited amounts for pension and OPEB costs allowed in the approved revenue requirements to the regulated business portion of the Company's cash expenditures on its pension and OPEB plans. It is the Company's position that this decision by the OEB does not constitute a change in the basis of rate recovery for OPG's pension and OPEB costs. This position is based on the OEB's establishment of the Pension & OPEB Cash Versus Accrual Differential Deferral Account pursuant to its November 2014 decision, and the expectation expressed by the OEB in that decision that a transition from the accrual basis of recovery for OPG, if required, would be addressed in a future OPG rate proceeding, informed by the outcome of an OEB generic proceeding related to the regulatory treatment and recovery of pension and OPEB costs. Effective November 1, 2014, the Pension & OPEB Cash Versus Accrual Differential Deferral Account records the difference between OPG's actual pension and OPEB costs for the regulated business determined using the accrual method applied in OPG's audited consolidated financial statements and OPG's corresponding actual cash expenditures for these plans. The OEB's November 2014 decision indicated that the future recovery, if any, of amounts recorded in the deferral account would be subject to the outcome of an OEB generic proceeding on the regulatory treatment and recovery of pension and OPEB costs. In May 2015, the OEB began a consultation process to develop standard principles to guide its future review of pension and OPEB costs of rate regulated utilities in the electricity and natural gas sectors, including establishing appropriate regulatory mechanisms for cost recovery. The consultation is continuing. On September 14, 2017, the OEB issued its final report on the guiding principles and the policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the Ontario electricity and natural gas sectors. The report establishes the accrual basis of accounting as the method of determining pension and OPEB amounts for rate-setting purposes, unless the OEB finds that this method does not result in just and reasonable rates in the circumstances of a particular utility.

In consideration of the above factors, the Company continues to believe that there is sufficient likelihood that unamortized pension and OPEB amounts that have not yet been reclassified from AOCI will be included in future regulated prices or in an OEB-authorized deferral or variance account for future recovery, as they are recognized in benefit costs. Therefore, the Company continues to recognize a regulatory asset for these unamortized amounts and also has recognized a regulatory asset for the balance of the Pension & OPEB Cash Versus Accrual Differential Deferral Account discussed in Note 5.

See Notes 5, 8, 9, and 11 for additional disclosures related to the OEB's decisions, regulatory assets and liabilities, and rate regulated accounting.

Revenue Recognition

All of OPG's electricity generation is offered into the real-time energy spot market administered by the IESO. Revenue is recognized as electricity is generated and metered to the IESO.

Revenue Recognition – Regulated Generation

Energy revenue generated from OPG's regulated facilities is based on regulated prices determined by the OEB that include a base regulated price and, as applicable, rate riders for the recovery or repayment of approved variance and deferral account balances.

The base regulated prices in effect during 2016 were established by the OEB's November 2014 decision and December 2014 order, using a forecast cost-of-service rate-setting methodology based on the OEB-approved revenue requirements, taking into account the OEB-approved forecasts of production and operating costs for the regulated facilities for 2014 and 2015 and a return on rate base. Rate base is a regulatory construct that, for OPG, represents the average net level of investment in regulated fixed and intangible assets in-service and an allowance for working capital. The revenues from the regulated hydroelectric facilities are also subject to the OEB-approved hydroelectric incentive mechanism. This mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers.

The rate riders in effect during 2016 were established by the OEB in its October 2015 order on OPG's application to recover balances in most of the Company's authorized variance and deferral accounts as at December 31, 2014. The OEB-authorized variance and deferral accounts are discussed in Note 5.

The OEB's decision and order on OPG's May 2016 five-year application for new regulated prices for its nuclear and regulated hydroelectric generation was issued on December 28, 2017, following a public hearing process. The OEB set an effective date for OPG's new regulated prices of June 1, 2017. OPG had requested an effective date of January 1, 2017 and has filed a motion with the OEB in January 2018 to review and vary this aspect of the OEB's December 2017 decision. [**MONITOR**] See Note 5 for further information on OPG's May 2016 application.

Revenue Recognition – Non-regulated Generation and Other Revenue

The electricity generation from OPG's non-regulated assets receives the Ontario electricity spot market price, except where an energy supply agreement (ESA) with the IESO or another contractual agreement is in place. As at December 31, 2017, most of OPG's operating non-regulated assets are subject to an ESA. Revenue from the generating stations subject to an ESA is recognized in accordance with the terms of the agreement.

OPG also sells into, and purchases from, interconnected markets of other provinces and the northeast and midwest regions of the US. All contracts that are not designated as hedges are recorded on the consolidated balance sheets at market value, with gains or losses recorded in the consolidated statements of income. Gains and losses on energy trading contracts (including those to be physically settled) are recorded on a net basis in the consolidated statements of income. Accordingly, power purchases of $15 million were netted against revenue in 2017 (2016 – $19 million).

OPG derives non-energy revenue under the terms of a lease arrangement and associated agreements with Bruce Power L.P. (Bruce Power) related to the Bruce nuclear generating stations. This includes lease revenue and revenue from heavy water sales, detritiation services and waste management services. OPG's net revenues from the lease of these stations and related agreements, including a portion of heavy water sales, are credited to customers and therefore have reduced regulated prices for the generation from the nuclear facilities owned and operated by OPG. The minimum lease payments are recognized in revenue on a straight-line basis over the term of the lease.

In addition, non-energy revenue includes isotope sales, real estate rentals and other service revenues. Revenues from these activities are recognized as services are provided, or as products are delivered, in accordance with the terms stipulated in the respective contracts.

Fixed Asset Removal and Nuclear Waste Management Liabilities

OPG recognizes AROs for fixed asset removal and nuclear waste management, discounted for the time value of money. OPG estimates both the amount and timing of future cash expenditures based on the plans for fixed asset removal and nuclear waste management. The liabilities are initially recorded at their estimated fair value, which is based on a discounted value of the expected costs to be paid.

On an ongoing basis, the liabilities for nuclear fixed asset removal and nuclear waste management (Nuclear Liabilities) are increased by the present value of the incremental (variable) cost portion for the nuclear waste generated each year, with the corresponding amounts charged to OM&A expenses. Variable expenses relating to L&ILW are charged to OM&A expenses. Variable expenses relating to the management and storage of nuclear used fuel are charged to fuel expense. The liabilities may also be adjusted due to changes in the estimated amount or timing of the underlying future cash flows, with resulting changes in the related asset retirement costs capitalized as part of the carrying amount of the related fixed assets in service. A comprehensive reassessment of all underlying assumptions and baseline cost estimates for the Nuclear Liabilities is performed periodically. Changes in the Nuclear Liabilities resulting from changes in assumptions or estimates that impact the amount or timing of the originally estimated undiscounted future cash flows are recorded as an adjustment to the liabilities. Upward revisions in the Nuclear Liabilities represent the present value of increases in future undiscounted cash flows determined using a current credit-adjusted risk-free rate. Downward revisions in the Nuclear Liabilities represent the present value of decreases in future undiscounted cash flows determined using the weighted average discount rate reflected in the existing liability. Upon settlement of the liabilities, a gain or loss would be recorded.

Accretion arises because the fixed asset removal and nuclear waste management liabilities are reported on a net present value basis. Accretion expense is the increase in the carrying amount of the liabilities due to the passage of time.

The asset retirement cost is capitalized by increasing the carrying value of the related fixed assets in service. The capitalized cost is depreciated over the remaining service life of the related fixed assets and is included in depreciation and amortization expenses.

OPG has no legal obligation associated with the decommissioning of its hydroelectric generating facilities and the costs cannot be reasonably estimated because of the long service life of these assets. With either maintenance efforts or rebuilding, the water control structures are assumed to be used for the foreseeable future. Accordingly, OPG has not recognized a liability for the decommissioning of its hydroelectric generating facilities.

Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

Pursuant to the Ontario Nuclear Funds Agreement (ONFA) between OPG and the Province, OPG has established and sets aside funds in a Used Fuel Segregated Fund and a Decommissioning Segregated Fund (together the Nuclear Segregated Funds). The Used Fuel Segregated Fund is intended to fund expenditures associated with the long-term management of radioactive used nuclear fuel bundles and certain costs of used fuel storage incurred after the nuclear stations are shut down, while the Decommissioning Segregated Fund was established to fund the costs

of nuclear fixed asset removal and long-term L&ILW management, and certain costs of used fuel storage incurred after the nuclear stations are shut down. OPG's funding obligations and resulting contributions to the Nuclear Segregated Funds are determined based on periodically updated reference plans approved by the Province under the ONFA. OPG maintains the Nuclear Segregated Funds in third-party custodial and trust accounts that are segregated from the rest of OPG's assets.

OPG's investments in the Nuclear Segregated Funds and the corresponding amounts payable to/receivable from the Province are classified as held-for-trading. The Nuclear Segregated Funds are measured at fair value based on the bid prices of the underlying equity and fixed income securities, and, in the case of the alternative investment portfolio, using appropriate valuation techniques as outlined in Note 13, with realized and unrealized gains and losses recognized in OPG's consolidated statements of income.

Financing Receivables

Financing receivables consist of the current and irrevocable right of the Fair Hydro Trust to collect payments from Specified Consumers in the future in accordance with the Fair Hydro Act and associated general regulation. These amounts are measured at the transaction price entered into with the IESO on market terms upon acquisition and subsequently measured on an amortized cost basis. The basis of amortization follows the effective interest method.

Derivatives

All derivatives, including embedded derivatives that must be separately accounted for, generally are classified as held-for-trading and recorded at fair value in the consolidated balance sheets. Transaction costs are expensed as incurred for financial instruments classified or designated as held-for-trading.

Derivatives qualify for hedge accounting if they meet stringent documentation requirements, and if the derivative instrument that is designated as a hedge is expected to effectively hedge the identified risk throughout the life of the hedged item. At the inception of a hedging relationship, OPG documents the relationship between the hedging instrument and the hedged item, its risk management objective, and its strategy for undertaking the hedge. A documented assessment is made, both at the inception of a hedge and on an ongoing basis, of whether or not the derivatives that are used in hedging transactions are highly effective in offsetting the changes attributable to the hedged risks in the fair values or cash flows of the hedged items.

All derivative contracts not designated as hedges are recorded on the consolidated balance sheets as derivative assets or liabilities at fair value, with changes in the fair value recorded in the revenue of the Services, Trading, and Other Non-Generation segment. Refer to Note 12 for a discussion of OPG's risk exposures and the derivative instruments used to manage these risks.

Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly arm's-length transaction between market participants at the measurement date. Fair value measurements are required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model. OPG uses a fair value hierarchy, grouping assets and liabilities into three levels based on the relative objectivity of the inputs used to measure fair value, with Level 1 representing the most objective. Refer to Note 13 for a discussion of fair value measurements and the fair value hierarchy.

Available-for-Sale Securities

Available-for-sale (AFS) securities are measured at fair value, with unrealized gains and losses due to changes in fair value recognized in other comprehensive income (OCI). Gains and losses are realized and included in net income when the securities are sold or awarded. Related transaction costs are expensed as incurred, and dividend income

is included in net income in the period dividends are declared. Equity securities are initially measured at the transaction price.

Research and Development

Research and development costs are expensed as incurred. Research and development costs incurred to discharge long-term obligations for which specific provisions have already been made, such as the Nuclear Liabilities, are charged to the related liability.

Leases

Leases are evaluated and classified as either operating or capital leases for financial reporting purposes. Capital leases, which transfer substantially all of the risks and benefits incidental to ownership of the leased item, are capitalized at the inception of the lease at the fair value of the leased property or, if lower, at the present value of the minimum lease payments. Capital leases are depreciated over the shorter of the estimated useful life of the asset and the lease term.

Leases where the lessor retains substantially all the risks and benefits incidental to ownership of the asset are classified as operating leases. Operating lease payments, other than contingent rentals, are recognized as an expense in the consolidated statements of income on a straight-line basis over the lease term. Where the amount of rent expense recognized is different from the actual operating lease payment, other than contingent rentals, the difference is deferred and included as assets or liabilities on the consolidated balance sheets.

Pension and Other Post-Employment Benefits

OPG's post-employment benefit programs consist of a contributory defined benefit registered pension plan, a defined benefit supplementary pension plan, and other post-retirement benefits (OPRB) including group life insurance and health care benefits, and long-term disability (LTD) benefits. Post-employment benefit programs are also provided by the NWMO, which is consolidated into OPG's financial results. Unless otherwise noted, information on the Company's post-employment benefit programs is presented on a consolidated basis.

OPG accrues its obligations under pension and OPEB plans in accordance with US GAAP. The obligations for pension and OPRB are determined using the projected benefit method pro-rated on service. The obligation for LTD benefits is determined using the projected benefit method on a terminal basis. Pension and OPEB obligations are impacted by factors including interest rates, adjustments arising from plan amendments, demographic assumptions, experience gains or losses, salary levels, inflation, and health care cost escalation assumptions. Pension and OPEB costs and obligations are determined annually by independent actuaries using management's best estimate assumptions.

Assumptions are significant inputs to actuarial models that measure pension and OPEB obligations and related effects on operations. Discount rate, inflation rate, and changes in salary levels are three critical assumptions in the determination of benefit costs and obligations. In addition, the expected long-term rate of return on plan assets is a critical assumption in the determination of registered pension plan cost and the health care cost trend rate is a critical assumption in the determination of OPEB cost and obligations. These assumptions, as well as other assumptions involving demographic factors such as retirement age, mortality, and employee turnover, are evaluated periodically by management in consultation with independent actuaries. During the evaluation process, the assumptions are updated to reflect past experience and expectations for the future. Actual results in any given year will often differ from actuarial assumptions because of economic and other factors giving rise to actuarial gains and losses. In accordance with US GAAP, for pension and OPRB, the impact of these updates and differences on the respective benefit obligations is accumulated and amortized over future periods. For LTD benefits, the impact of these updates and differences is immediately recognized as OPEB costs in the period incurred.

The discount rates, which are representative of AA corporate bond yields, are used to calculate the present value of the expected future cash flows on the measurement date in order to determine the projected benefit obligations for the Company's employee benefit plans. A lower discount rate increases the benefit obligations and increases benefit costs. The expected rate of return on plan assets is based on the pension fund's asset allocation and the expected return considering long-term risks and returns associated with each asset class within the plan portfolio. A lower expected rate of return on plan assets increases pension cost.

Pension fund assets include equity securities, corporate and government debt securities, pooled funds, real estate, infrastructure, and other investments. These assets are managed by professional investment managers. The pension fund does not invest in equity or debt securities issued by OPG. Pension fund assets are valued using market-related values for purposes of determining the amortization of actuarial gains or losses and the expected return on plan assets. The market-related value recognizes gains and losses on equity assets relative to a six percent assumed real return over a five-year period.

Pension and OPEB costs include current service costs, interest costs on the obligations, the expected return on pension plan assets, adjustments for plan amendments, and adjustments for actuarial gains or losses, which result from changes in assumptions and experience gains and losses. Past service costs or credits arising from pension and OPRB plan amendments are amortized on a straight-line basis over the expected average remaining service life to full eligibility of the employees covered by the corresponding plan. Past service costs or credits arising from amendments to LTD benefits are immediately recognized as OPEB costs in the period incurred. Due to the long-term nature of pension and OPRB liabilities, the excess of the net cumulative unamortized gain or loss, over 10 percent of the greater of the benefit obligation and the market-related value of the plan assets (the corridor), is amortized over the expected average remaining service life of the employees, which represents the period during which the associated economic benefits are expected to be realized by the Company. Actuarial gains or losses for LTD benefits are immediately recognized as OPEB costs in the period incurred.

OPG recognizes the funded status of its defined benefit plans on the consolidated balance sheets. The funded status is measured as the difference between the fair value of plan assets and the benefit obligation, on a plan-by-plan basis.

Actuarial gains or losses and past service costs or credits arising during the year that are not recognized immediately as components of benefit costs are recognized as increases or decreases in OCI, net of income taxes. These unamortized amounts in AOCI are subsequently reclassified and recognized as components of pension and OPRB costs as described above.

OPG records an offsetting regulatory asset or liability for the portion of the adjustments to AOCI that is attributable to the regulated operations in order to reflect the expected recovery or refund of these amounts through future regulated prices charged to customers. For the recoverable or refundable portion attributable to regulated operations, OPG records a corresponding change in this regulatory asset or liability for the amount of the increases or decreases in OCI and for the amounts reclassified from AOCI into benefit costs during the period.

When the recognition of the transfer of employees and employee-related benefits gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement. A curtailment is the loss by employees of the right to earn future benefits under the plan. A settlement is the discharge of a plan's liability.

Income Taxes and Investment Tax Credits

OPG is exempt from income taxes under the *Income Tax Act* (Canada). However, under the *Electricity Act, 1998*, OPG is required to make payments in lieu of corporate income taxes to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by the *Electricity Act, 1998* and related regulations. This results in OPG paying taxes similar to those imposed under the federal and Ontario tax acts.

OPG's operations are complex and the computation of the provision for income taxes involves interpretation of the various tax statutes and regulations. OPG has taken certain filing positions in calculating the amount of its income tax provision. These filing positions may be challenged on audit by the Ontario Ministry of Finance and some of them possibly disallowed, resulting in a potential significant change in OPG's tax provision upon reassessment. A change in the tax provision upon reassessment impacting regulated operations may be recoverable from or refundable to customers through the Income and Other Taxes Variance Account authorized by the OEB.

OPG follows the liability method of accounting for income taxes. Under the liability method, deferred income tax assets and liabilities are determined based on differences between the accounting and tax bases of assets and liabilities. Deferred amounts are measured using the enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect of a change in tax rates on deferred income tax assets and liabilities is included in income in the period the change is enacted.

If management determines that it is more likely than not that some, or all, of a deferred income tax asset will not be realized, a valuation allowance is recorded to report the balance at the amount expected to be realized.

OPG recognizes deferred income taxes associated with its regulated operations and records an offsetting regulatory asset or liability for the deferred income taxes that are expected to be recovered or refunded through future regulated prices charged to customers.

Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return and investment tax credits are recorded only when the more likely than not recognition threshold is satisfied. Tax benefits and investment tax credits recognized are measured at the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement.

Investment tax credits are recorded as a reduction to income tax expense. OPG classifies interest and penalties associated with unrecognized income tax benefits as income tax expense.

Change in Accounting Estimates

Change in Nuclear Liabilities Estimate

In the fourth quarter of 2017, OPG achieved sufficient confidence in the Company's plans to pursue the continued safe and reliable operation of two units at the Pickering GS to 2022 and the four remaining units to 2024. This resulted in a change to the useful lives for the Pickering GS, for the purposes of calculating depreciation. Effective December 31, 2017, the change to the estimated service live of the Pickering GS has been reflected in an increase to the estimate of the Nuclear Liabilities of $188 million, and a corresponding changes in the carrying value of the nuclear generating stations to which the liabilities relate. The increase in the liabilities is primarily due to higher fixed costs associated with the Used Fuel Disposal and L&ILW Storage programs, discounted using the current credit-adjusted risk-free rate of 2.94 percent.

OPG filed an application with the OEB (EB-2018-0002) on December 29, 2017 to seek approval to establish a deferral account to record, from January 1, 2018 until the effective date of the OEB's next payment amounts order, the revenue requirement impact of changes to nuclear liabilities and depreciation and amortization expense resulting from changes to station end-of-life dates for OPG's Pickering prescribed nuclear facilities that were effective December 31, 2017. On January 31, 2018 the OEB issued an interim order (EB-2018-0002) for the establishment of the Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account, pending the outcome of the proceeding.

Pension and Other Post-Employment Benefits

Effective January 1, 2017, OPG changed the method used to estimate the service and interest cost components of pension and OPEB costs. OPG adopted a full yield curve approach to the estimation of these cost components, by applying the specific spot rates along the yield curve used in the determination of the projected benefit obligations to the relevant projected cash flows. Under the previous method, these components of pension and OPEB costs were calculated using the same single weighted-average discount rates as reflected in the calculation of the benefit obligations. This change in the method was accounted for prospectively, as a change in estimate. The resulting reduction in pension and OPEB costs is estimated at approximately $135 million in 2017. Approximately 90 percent of this reduction in pension and OPEB costs was attributed to the Company's regulated business segments and therefore was offset by the impact of regulatory variance and deferral accounts authorized by the OEB. This change does not affect the measurement of the total benefit obligation as the change in the current service and interest cost components from the previous method will be offset by a corresponding change in the actuarial gain and loss recorded in AOCI.

Pension Plan Actuarial Valuation

A new actuarial valuation of the OPG registered pension plan was filed with the Financial Services Commission of Ontario in September 2017 with an effective date of January 1, 2017. The annual funding requirements in accordance with the new actuarial valuation are $212 million for 2017, $215 million for 2018, and $219 million for 2019.

Recent Accounting Pronouncements Not Yet Adopted

Revenue from Contracts with Customers

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09, *Revenue from Contracts with Customers* (Topic 606), which supersedes nearly all existing revenue recognition guidance, including industry-specific guidance, under US GAAP. The core principle of Topic 606 is to recognize revenues when promised goods or services are transferred to customers in an amount that reflects the consideration to which an entity expects to be entitled for those goods or services. Either a full retrospective application or a modified retrospective application is required for annual periods beginning on or after January 1, 2018, including interim periods within that year. Early adoption is permitted.

OPG has assessed the impact of the standard on accounting for the Company's revenue streams and consolidated financial statements. OPG's major revenue streams include regulated generation revenue from base regulated prices and rate riders established by the OEB, as well as revenue from generation assets under long-term contractual arrangements with the IESO. OPG has completed its analyses of the impact of Topic 606 on all of its revenue streams, and has not identified any material differences in the timing or amount of revenue recognition for these streams.

The Company will apply the new revenue standard in its 2018 first quarter interim financial statements and is in the process of evaluating the additional disclosures required under the new standard.

Lease Accounting

In February 2016, the FASB issued ASU No. 2016-02, *Leases* (Topic 842). The update includes comprehensive changes to existing guidance for lease accounting, particularly for lessees, and aims to increase transparency and comparability among organizations by requiring the recognition of lease assets and lease liabilities on the balance sheet. The standard is effective for annual periods beginning after December 15, 2018, including interim periods within that year.

Under the current guidance, entities are required to use a modified retrospective approach for leases that exist, or are entered into, after the beginning of the earliest comparative period presented in the financial statements of the period of adoption. Under this method, Topic 842 would effectively be implemented by recognizing any adjustments stemming from the transition, as of beginning of the earliest comparative period presented in the entities' financial statements. Full retrospective application is prohibited. In January 2018, the FASB issued a proposed ASU wherein entities would be able to utilize an additional optional transition method of recording the cumulative impact of adopting the new lease standard to the opening balance in the initial period of adoption; with comparative periods continuing to be presented in accordance with the existing leasing standard, Topic 840 - *Leases*, including disclosures. [**MONITOR**] The Company will continue to monitor the status of this proposed ASU.

The FASB also issued ASU No. 2018-01, *Land Easement Practical Expedient for Transition to Topic 842* in January 2018. The amendments therein allows an entity to choose not to evaluate under Topic 842 land easements that exist or expired before the entity's adoption of the new leasing standard and that were not previously accounted for as leases under Topic 840.

The Company continues to implement and execute a comprehensive project governance framework, which comprises a Steering Committee, Implementation & Stakeholder Committee, Project Management Office, and various working groups in order to evaluate the implement the new standard. The working groups are represented by cross functional finance and non-finance stakeholders who will support the financial and operational implementation of the standard. The Company continues to evaluate the impact of the new leasing standard on its consolidated financial statements.

Recognition and Measurement of Financial Assets and Financial Liabilities

In January 2016, the FASB issued ASU No. 2016-01, *Financial Instruments – Overall: Recognition and Measurement of Financial Assets and Financial Liabilities*. Under the updated guidance, entities will have to measure equity investments at fair value and recognize any changes in fair value in net income. The update will be effective for OPG's 2018 fiscal year, including interim periods. As a result of this update, effective January 1, 2018, the AFS classification for securities will no longer be available, with any unrealized gains and losses related to such securities recognized in net income instead of OCI. Any unrealized gains and losses for AFS securities reported by OPG in AOCI as of the end of 2017 will be reclassified to retained earnings as of January 1, 2018. OPG's Hydro One share holdings are currently the Company's only AFS securities. As at December 31, 2017, these shares are valued on the consolidated balance sheet at $188 million (December 31, 2016 − $212 million), for which a loss of $8 million (2016 − $1 million) has been recorded in AOCI. OPG continues to evaluate whether the new standard will have any further impact on its consolidated financial statements.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost

In March 2017, the FASB issued ASU No. 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. Under the new guidance, employers that sponsor defined benefit plans for pensions and/or other postretirement benefits are required to present the service cost component of net periodic benefit cost in the same statement of income line item as other employee compensation costs arising from services rendered during the period. The other components of the net periodic benefit cost are to be presented separately from the line item that includes the service cost and outside of any subtotal of income from operations, if such a subtotal is presented. In addition, the new guidance requires that only the service cost component of net benefit cost be eligible for capitalization.

This guidance is effective for fiscal years beginning after December 15, 2017, including interim periods of those years. The guidance is not expected to have a material impact on OPG's consolidated financial statements, as OPG currently capitalizes only the service cost component of post-retirement benefits costs. Additionally, OPG already includes the service cost component of post-retirement benefit costs with other compensation costs, within the OM&A expenses line item in the consolidated statements of income, and does not show a subtotal of income from operations. As such, the new guidance is not expected to affect the presentation of OPG's consolidated financial statements.

4. PROPERTY, PLANT AND EQUIPMENT, INTANGIBLE ASSETS AND DEPRECIATION AND AMORTIZATION

PP&E as at December 31 consist of the following:

(millions of dollars)	**2017**	**2016**
Nuclear generating stations	**11,985**	11,057
Regulated hydroelectric generating stations	**9,566**	9,430
Contracted generation portfolio generating stations	**3,935**	3,751
Other property, plant and equipment	**372**	1,595
Construction in progress	**4,092**	3,482
	29,950	29,315
Less: accumulated depreciation		
Generating stations	**8,480**	7,948
Other property, plant and equipment	**148**	1,369
	8,628	9,317
	21,322	19,998

Construction in progress as at December 31 consists of the following:

(millions of dollars)	**2017**	**2016**
Darlington Refurbishment	**3,507**	2,563
Peter Sutherland Sr. GS	**17**	236
Other	**568**	683
	4,092	3,482

Intangible assets as at December 31 consist of the following:

(millions of dollars)	**2017**	**2016**
Nuclear generating stations	**122**	122
Regulated hydroelectric generating stations	**6**	7
Contracted generation portfolio generating stations	**5**	4
Computer software and other intangible assets	**393**	350
Development in progress	**39**	20
	565	503
Less: accumulated amortization		
Generating stations	**123**	120
Computer software and other intangible assets	**309**	284
	432	404
	133	99

Depreciation and amortization expenses, including amounts recognized in regulatory variance and deferral accounts authorized by the OEB, for the years ended December 31 consist of the following:

(millions of dollars)	**2017**	**2016**
Depreciation	**649**	602
Amortization of intangible assets	**30**	27
Amounts recognized in regulatory variance and deferral accounts	**-**	26
Amortization of regulatory assets and liabilities *(Note 5)*	**-**	602
	679	1,257

Interest capitalized to construction in progress during 2017 was $162 million (2016 – $141 million), at an average rate of five percent (2016 – five percent).

5. REGULATORY ASSETS AND LIABILITIES

OPG's May 2016 application with the OEB for new regulated prices included a request for new rate riders to recover or repay the December 31, 2015 balances in all of the Company's OEB-authorized variance and deferral accounts, with the exception of the Pension & OPEB Cash Versus Accrual Differential Deferral Account, less amounts previously approved for recovery or repayment for these accounts in 2016. The application also requested the continuation of all applicable existing variance and deferral accounts. In March 2017, the OEB approved a settlement agreement reached by OPG and intervenors on a limited set of issues in the application (Settlement Agreement). Among the settled issues, the agreement provided for the continuation of all applicable existing variance and deferral accounts and accepted a number of variance and deferral account balances for recovery, as requested in OPG's application. The periods of recovery or repayment for the accepted variance and deferral account balances were excluded from the scope of the Settlement Agreement.

In the OEB's December 2017 Decision and Order, the OEB accepted all applicable variance and deferral account balances for recovery that were not already accepted as part of the partial Settlement Agreement that was reached by OPG and intervenors. That OEB-approved Settlement Agreement also provided for the continuation of all applicable existing variance and deferral accounts effective June 1, 2017. The December 2017 decision and order allows for recovery of $305 million recorded in certain variance and deferral accounts as at December 31, 2015, without adjustments. OPG's draft Payment Amounts Order proposed the recovery period to be January 1, 2019 to December 31, 2021.

Consistent with the effective date of the OEB's December 2017 decision and order, for the period from January 1, 2017 to May 31, 2017, OPG continued to record additions to the existing variance and deferral accounts for the nuclear and regulated hydroelectric facilities pursuant to the OEB's previous decisions and orders. These additions reflected differences between actual and forecast amounts embedded in the regulated prices in effect prior to June 1, 2017.

In its December 2017 decision and order on OPG's rate application, the OEB granted OPG approval to request disposal of applicable audited deferral and variance account balances, including the Pension & OPEB Cash Versus Accrual Differential Account, in calendar year 2018. Under the requirements of US GAAP, the period of deferring amounts recorded in the Pension & OPEB Cash Versus Accrual Differential Deferral Account must not exceed five years from the time that they were incurred. Accordingly, such amounts recorded during November 2014 must begin to be recovered no later than November 2019 and must be fully recovered within 20 years of November 2014 or OPG will be required to write off the regulatory asset for these amounts.

The regulatory assets and liabilities recorded as at December 31 are as follows:

(millions of dollars)	**2017**	**2016**
Regulatory assets		
Variance and deferral accounts authorized by the OEB		
Pension and OPEB Cost Variance Account	**716**	716
Pension & OPEB Cash Versus Accrual Differential Deferral Account *(Note 11)*	**614**	497
Hydroelectric Surplus Baseload Generation Variance Account	**360**	210
Bruce Lease Net Revenues Variance Account	**121**	95
Other variance and deferral accounts	**124**	107
	1,935	1,625
Interim Period Revenue Shortfall Account	**544**	-
Pension and OPEB Regulatory Asset *(Note 11)*	**3,855**	3,392
Deferred Income Taxes	**897**	838
Total regulatory assets	**7,231**	5,855
Regulatory liabilities		
Variance and deferral accounts authorized by the OEB		
Hydroelectric Water Conditions Variance Account	**150**	51
Pension & OPEB Cash Variance Account	**140**	58
Impacts Resulting from Changes in Station End-of-Life Dates Deferral Account	**103**	71
Rate Smoothing Deferral Account	**63**	-
Other variance and deferral accounts	**138**	130
Total regulatory liabilities	**594**	310

The changes in the regulatory assets and liabilities during 2017 and 2016 are as follows:

(millions of dollars)	Pension and OPEB Cost Vari-ance	Pension & OPEB Cash vs Accrual Differen-tial Deferral	Hydro-electric Surplus Baseload Genera-tion Variance	Bruce Lease Net Reve-nues Variance	Water Condit-ions variance	Pension & OPEB Cash	Impact Resulting from Changes in Station End-of-Life Dates Deferral Account	Rate Smooth-ing Deferral Account	Other Vari-ance and Deferral (net)	Interim Period Revenue Shortfall Account	Pension and OPEB Regula-tory Asset	Deferred Income Taxes
Net regulatory assets (liabilities) January 1, 2016	865	315	114	95	(23)	28	-	-	260	-	3,362	792
Increase (decrease)	-	182	126	143	(33)	(86)	(71)	-	-	-	30	46
Interest	-	-	2	-	(1)	-	0	-	1	-	-	-
Amortization	(149)	-	(32)	(143)	6	-	0	-	(284)	-	-	-
Net regulatory assets (liabilities) December 31, 2016	716	497	210	95	(51)	(58)	(71)	-	(23)	-	3,392	838
Increase (decrease)	**-**	**117**	**146**	**25**	**(98)**	**(81)**	**(32)**	**(62)**	**10**	**544**	**463**	**59**
Interest	**-**	**-**	**4**	**1**	**(1)**	**(1)**	**0**	**(1)**	**(1)**	**-**	**-**	**-**
Net regulatory assets (liabilities) December 31, 2017	**716**	**614**	**360**	**121**	**(150)**	**(140)**	**(103)**	**(63)**	**(14)**	**544**	**3,855**	**897**

Pension and OPEB Cost Variance Account

As authorized by the OEB, for the period from March 1, 2011 to October 30, 2014, the Pension and OPEB Cost Variance Account recorded the differences between OPG's actual pension and OPEB costs for the regulated business determined on an accrual basis and related tax impacts, and corresponding forecast amounts reflected in the regulated prices then in effect. In its November 2014 decision, the OEB determined that the pension and OPEB amounts reflected in OPG's regulated prices established by that decision effective November 1, 2014 would be limited to the Company's estimated minimum contributions to its registered pension plan and a forecast of OPG's expenditures on the OPEB and supplementary pension plans. As such, the OEB ordered the Pension and OPEB Cost Variance Account to record only amortization beginning on November 1, 2014.

In its October 2015 order, the OEB approved the continuation of the previously authorized recovery of 10/12 of the account balance as at December 31, 2012 over a 144-month period to December 31, 2024. Amounts recorded in the account in 2013 and 2014 were approved for recovery over a 72-month period to June 30, 2021 by the OEB's October 2015 order. In OPG's draft payment amounts order, the recovery period was adjusted to extend beyond June 30, 2021 and December 31, 2024 to account for the break in recovery of the account in the 2017 and 2018 periods as proposed by OPG.

Pension & OPEB Cash Versus Accrual Differential Deferral Account

In its November 2014 decision and December 2014 order, the OEB established the Pension & OPEB Cash Versus Accrual Differential Deferral Account. Effective November 1, 2014, this deferral account records the difference between OPG's actual pension and OPEB costs for the regulated business determined on an accrual basis under US GAAP and OPG's corresponding actual cash expenditures for these plans. The balance in the account as at

December 31, 2017 represents the excess of costs calculated using the accrual basis over the cash basis for the period from November 1, 2014 to December 31, 2017. The Company has recognized the amount set aside in the deferral account as a regulatory asset.

The OEB's November 2014 decision indicated that the future recovery, if any, of amounts recorded in the deferral account would be subject to the outcome of the OEB generic proceeding on the regulatory treatment and recovery of pension and OPEB costs. On September 14, 2017, the OEB issued its final report on the guiding principles and the policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the Ontario electricity and natural gas sectors. The report establishes the accrual basis of accounting as the method of determining pension and OPEB amounts for rate-setting purposes, unless the OEB finds that this method does not result in just and reasonable rates in the circumstances of a particular utility. The OEB's September 2017 report and the OEB's December 2017 decision on OPG's application for new regulated prices require OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the Pension & OPEB Cash to Accrual Differential Deferral Account in effect since November 1, 2014, until such time as the OEB approves resumption of the accrual basis of recovery.

Consistent with the expectations set out in the OEB's December 2017 decision, in 2018, OPG plans to file an application with the OEB requesting disposition of the Pension & OPEB Cash Versus Accrual Differential Deferral Account balance.

Hydroelectric Surplus Baseload Generation Variance Account

The Hydroelectric Surplus Baseload Generation Variance Account records the impact of forgone production at OPG's regulated hydroelectric facilities due to surplus baseload generation conditions.

In its December 2017 Decision and Order, the OEB approved the disposition of the Hydroelectric Surplus Baseload Generation Variance Account balance as at December 31, 2015, as proposed. OPG has proposed a recovery period of January 1, 2019 to December 31, 2021.

Bruce Lease Net Revenues Variance Account

In accordance with *Ontario Regulation 53/05*, the OEB is required to include the difference between OPG's revenues and costs associated with the two nuclear generating stations on lease to Bruce Power in the determination of the regulated prices for production from OPG's regulated nuclear facilities. Based on *Ontario Regulation 53/05* requirements, the OEB has established a variance account that captures differences between OPG's actual revenues and costs related to these stations and the corresponding forecasts included in approved nuclear regulated prices, including the costs associated with OPG's Nuclear Liabilities and the earnings from the portion of the Nuclear Segregated Funds related to the Bruce stations.

In 2013, the OEB ordered the portion of the balance in the Bruce Lease Net Revenues Variance Account related to the impact of the derivative liability embedded in the terms of the lease agreement between OPG and Bruce Power related to the Bruce nuclear generating stations (Bruce Lease) in effect prior to December 2015 to be recovered on the basis of OPG's expected rent rebate payments to Bruce Power and associated income tax impacts. The OEB's October 2015 order reaffirmed this approach and included, in amounts authorized for recovery over the period to the end of 2016, amounts for the derivative liability. In December 2015, as a result of amendments to the Bruce Lease, OPG reversed the derivative liability, with a corresponding reduction to the regulatory asset for the Bruce Lease Net Revenue Variance Account. Amounts collected from customers for the derivative liability for periods after its reversal are subject to refund in the future and have been recognized as a regulatory liability as part of the variance account balance.

The regulatory asset balance for the Bruce Lease Net Revenues Variance Account as at December 31, 2017 reflects a net amount of $190 million recoverable from customers for non-derivative variances recorded in 2015 through 2017, which is partially offset by a liability of $69 million to customers for amounts recovered for the derivative liability

since its reversal in December 2015. Non-derivative amounts recorded during 2017 included those arising from the adjustment to the Nuclear Liabilities and related changes to the estimated service lives of OPG's nuclear stations, for accounting purposes, effective December 31, 2015 and the updated 2017 ONFA reference plan approved by the province.

In its December 2017 Decision and Order, the OEB approved the disposition of the Bruce Lease Net Revenues Account balance as at December 31, 2015, as proposed. OPG has proposed a recovery period of January 1, 2019 to December 31, 2021.

Interim Period Revenue Shortfall Account

The Interim Period Revenue Shortfall regulatory asset records the revenue shortfall between proposed Nuclear and Regulated Hydroelectric rates and existing Nuclear and Regulated Hydroelectric rates from June 1, 2017 through December 31 2017 based on actual production. The recovery of this account is expected to begin January 1, 2019 through to December 31, 2021. [**UPDATE**]

Pension and OPEB Regulatory Asset

The Pension and OPEB Regulatory Asset represents unamortized amounts in respect of OPG's pension and OPEB plans that have been recognized in OCI and not yet reclassified into the amortization component of the benefit costs in respect of these plans. These amounts are expected to be recovered from customers through future regulated prices. The regulatory asset is reversed as underlying unamortized balances are amortized as components of benefit costs. For further details, refer to Note 3 under the heading, *Rate Regulated Accounting*. The AOCI amounts related to pension and OPEB plans are presented in Note 11.

Deferred Income Taxes

OPG is required to record a regulatory asset or liability for the deferred income taxes that are expected to be recovered or refunded through future regulated prices charged to customers for generation from OPG's regulated facilities. In addition, OPG is required to recognize a deferred income tax liability or asset for the regulatory asset or liability for the amount of deferred income taxes expected to be included in future regulated prices and paid to, or recovered, from customers. Income taxes are discussed in Note 9.

Hydroelectric Water Conditions Variance Account

The Hydroelectric Water Conditions Variance Account captures the impact of differences in regulated hydroelectric electricity production due to differences between forecast water conditions underlying the production forecast approved by the OEB in setting regulated hydroelectric prices, and the actual water conditions.

In its December 2017 Decision and Order, the OEB approved the disposition of the Hydroelectric Water Conditions Variance Account balance as at December 31, 2015, as proposed. OPG has proposed a recovery period of January 1, 2019 to December 31, 2021.

Pension & OPEB Cash Payment Variance Account

The Pension & OPEB Cash Payment Variance Account was approved in EB-2013-0321 and continued in EB-2014-0370. The account records the difference between OPG's actual registered pension plan contributions and OPEB plan payments (including the long-term disability benefit plan) attributed to the prescribed generating facilities, and such forecast amounts reflected in the revenue requirement approved by the OEB.

In its December 2017 Decision and Order, the OEB approved the disposition of the Pension & OPEB Cash Payment Variance Account balance as at December 31, 2015, as proposed. OPG has proposed a recovery period of January 1, 2019 to December 31, 2021.

Impact Resulting from Changes in Station End-of-Life Dates Deferral Account

In December 2015, as required by the OEB's previous decisions and orders, OPG applied to the OEB for an accounting order to establish a new deferral account to record the revenue requirement impact on the Pickering and Darlington nuclear generating stations of changes to the Nuclear Liabilities and depreciation expense arising from extensions in the estimated useful lives of OPG's nuclear stations, for accounting purposes, effective December 31, 2015. These impacts were not reflected in the existing regulated prices. In March 2016, the OEB issued its final decision and order establishing the requested account, the Impact Resulting from Changes in Station End-of-Life Dates Deferral Account, effective January 1, 2016. The deferral account recorded these impacts until new regulated prices reflecting the above changes came into effect on June 1, 2017.

The extensions to the estimated useful lives of OPG's nuclear generating stations effective December 31, 2015, for accounting purposes, included those of the Bruce A GS and the Bruce B GS to reflect the estimated end-of-life dates per the updated refurbishment agreement between the IESO and Bruce Power announced in December 2015, a one-year extension for the Darlington GS to reflect the approval of the refurbishment schedule in 2015, and an extension of less than one year for the Pickering GS. To reflect these changes, OPG recognized a total increase of $2,330 million in the Nuclear Liabilities and a corresponding increase in the related asset retirement costs capitalized to PP&E, effective December 31, 2015.

Rate Smoothing Deferral Account

In accordance with section 5.5 of *Ontario Regulation 53/05*, OPG shall establish a Rate Smoothing Deferral Account. This account shall record, for each respective year, the difference between: (i) the total annual revenue requirement for the prescribed nuclear facilities approved by the OEB; and, (ii) the portion of that revenue requirement in (i) that is used in connection with setting the approved nuclear payment amounts in each year.

Consistent with the requirements of *Ontario Regulation 53/05*, OPG's overall production weighted payment amounts will be smoothed, with a resulting portion of the approved annual nuclear revenue requirements for the 2017-2021 period deferred in the Rate Smoothing Deferral Account for future collection. The non-deferred portion of each year's nuclear revenue requirement will be divided by the OEB-approved forecast of OPG's nuclear electricity generation for the corresponding year to determine the base nuclear regulated price. Per the regulation, the deferral account records interest at a long-term debt rate reflecting OPG's cost of long-term borrowing approved by the OEB, compounded annually. The regulation also requires the OEB to authorize recovery of the balance in the account on a straight line basis over a period not to exceed ten years following the end of the Darlington Refurbishment project. OPG recognizes positive amounts deferred under rate smoothing as an increase in net regulatory assets and an increase in revenue in the period to which the underlying approved revenue requirement relates. Negative amounts determined under rate smoothing are correspondingly recorded as a decrease in net regulatory assets and a decrease to revenue.

On January 17, 2018, OPG submitted a draft payment amounts order to the OEB that proposed nuclear base regulated prices for each year of the 2017-2021 period. The proposed regulated prices reflected the December 2017 decision's findings in calculating the 2017-2021 nuclear revenue requirements and reflected a rate smoothing proposal developed by OPG in accordance with *Ontario Regulation 53/05* and OEB's direction. As at December 31, 2017 OPG recorded a liability of $63 million and is expected to have a regulatory asset balance of approximately $750 million by 2021.

Other Variance and Deferral Accounts

Regulatory assets

As at December 31, 2017 and 2016, regulatory assets for Other variance and deferral accounts included amounts for the Nuclear Liability Deferral Account, the Nuclear and Hydroelectric Deferral and Variance Over/Under Recovery Variance Account, the Nuclear Development Account, and the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account and the Fitness for Duty Deferral Account.

Pursuant to *Ontario Regulation 53/05*, the Nuclear Liability Deferral Account has been authorized by the OEB in connection with changes to OPG's liabilities for nuclear used fuel management and nuclear decommissioning and L&ILW management associated with the nuclear facilities owned and operated by OPG, which are comprised of the Pickering and Darlington nuclear generating stations. The deferral account records the revenue requirement impact associated with the changes in these liabilities arising from an approved reference plan, in accordance with the terms of the ONFA.

The Nuclear and Hydroelectric Deferral and Variance Over/Under Recovery Variance Accounts records any shortfall or over-recovery of the approved variance and deferral account balances due to differences between actual and forecast nuclear and hydroelectric production respectively.

The Nuclear Development Variance Account records variances between the actual non-capital costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities and the corresponding forecasts reflected in the regulated prices approved by the OEB.

The Fitness for Duty Deferral Account was approved by the OEB in the EB-2016-0152 Decision and order, effective June 1, 2017. The account shall record the costs related to implementing the Canadian Nuclear Safety Commission (CNSC) Fitness for Duty program. The Fitness for Duty program is a drug, alcohol, psychological and physical testing program for employees in nuclear facilities, which is anticipated to be a license requirement of the CNSC.

Regulatory liabilities

As at December 31, 2017 and 2016, regulatory liabilities for Other variance and deferral accounts included amounts for the Ancillary Services Net Revenue Variance Account, the Income and Other Taxes Variance Account, the Hydroelectric Incentive Mechanism Variance Account, the SR&ED ITC Variance Account and the Capacity Refurbishment Variance Account.

The Ancillary Services Net Revenue Variance Account has been authorized by the OEB to capture differences between actual nuclear and regulated hydroelectric ancillary services net revenue and the forecast amounts of such revenue approved by the OEB in setting regulated prices.

The Income and Other Taxes Variance Account includes deviations in income taxes for the regulated business, from those approved by the OEB in setting regulated prices, caused by changes in tax rates and rules, as well as reassessments.

The Hydroelectric Incentive Mechanism Variance Account records a credit to customers equal to 50 percent of OPG's hydroelectric incentive mechanism revenues above a specified threshold for the regulated hydroelectric facilities.

As at December 31, 2017, regulatory liabilities for Other variance and deferral accounts also included the SR&ED ITC Variance Account and the Capacity Refurbishment Variance Account. The SR&ED ITC Variance Account was approved by the OEB in its EB-2016-0152 Decision, effective June 1, 2017. This account will record the tax expense impact for the nuclear facilities as a result of the difference between actual SR&ED ITCs (attributed to the nuclear facilities) as determined after any tax audits and the forecast SR&ED ITCs included in the nuclear revenue requirement approved by the OEB. Pursuant to *Ontario Regulation 53/05*, the OEB has authorized the Capacity Refurbishment Variance Account. The account captures variances from the forecasts reflected in the regulated prices for capital and non-capital costs incurred to increase the output of, refurbish, or add operating capacity to one or more of the regulated facilities. The balance in the account as at December 31, 2017 includes variances related to

the refurbishment of the Darlington nuclear generating station, life extension initiatives at the Pickering nuclear generation station, and other projects.

6. LONG-TERM DEBT AND NET INTEREST EXPENSE

Long-term debt consists of the following as at December 31: [1]

(millions of dollars)	**2017**	**2016**
Notes payable to the OEFC [2]		
Senior Notes		
bear interest at rates ranging from 3.12% to 5.44%; maturity dates ranging from 2018 to 2047	**3,195**	3,295
Medium Term Note Program [3]		
Senior Notes		
3.32% due 2027	**500**	-
UMH Energy Partnership [4]		
Senior Notes		
7.86% due 2041	**181**	184
PSS Generating Station Limited Partnership [5]		
Senior Notes		
4.90% due 2067	**245**	245
Lower Mattagami Energy Limited Partnership [6]		
Senior Notes		
bear interest at rates ranging from 2.4% to 5.26%; maturity dates ranging from 2021 to 2052	**1,595**	1,795
Fair Hydro Trust [7]		
Senior notes		
2.32% due 2019	**601**	-
Other	**19**	15
	6,336	5,534
Less: bond issuance fees	**(17)**	(14)
Less: due within one year	**(398)**	(1,103)
Long-term debt	**5,921**	4,417

[1] The interest rates disclosed reflect the effective interest rate of the debt, except for the Fair Hydro Trust notes which reflect the weighted average interest rate during the period the notes were outstanding from December 21 to December 31, 2017.

[2] OEFC is entitled to receive in full amounts owing in respect of the senior debt.

[3] These notes are direct unsecured obligations of OPG and rank *pari passu* with all other OPG's unsubordinated and unsecured obligations.

[4] These notes are secured by the assets of the Upper Mattagami and Hound Chute project. Principal repayments of $3 million per year are made on a semi-annual basis until maturity in 2041, at which time the remaining principal balance of $116 million becomes due.

[5] These notes are secured by the assets of the Peter Sutherland Sr. GS project. The notes have an interest-only feature until 2025 and will be amortized with blended semi-annual principal and interest payments thereafter until maturity in 2067, at which time the remaining principal balance of $49 million becomes due.

[6] These notes are secured by the assets of the Lower Mattagami River project, including existing and new operating facilities.

[7] The notes were issued under an $800 million two-year revolving warehouse facility discussed below and are secured by the assets of the Fair Hydro Trust.

In June 2016, OPG entered into a $700 million general corporate credit facility agreement with the OEFC, which expired on December 31, 2017. In September 2017, the agreement was amended, with the credit facility increased to $2,350 million and the expiry date extended to December 31, 2018. As of December 31, 2017, $800 million were outstanding from the credit facility.

In February 2017, OPG issued senior notes payable to the OEFC totalling $200 million and maturing in February 2047. The effective interest rate and coupon interest rate of these notes was 4.12 percent. In June 2017,

OPG issued senior notes payable to the OEFC totalling $100 million and maturing in June 2047. The effective interest rate and coupon interest rate of these notes was 3.65 percent. In August 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in August 2047. The effective interest rate and coupon interest rate of these notes was 3.86 percent. In September 2017, OPG issued senior notes payable to the OEFC totalling
$400 million and maturing in September 2047. The effective interest rate and coupon interest rate of these notes was 4.07 percent.

In October 2017, OPG issued $500 million of senior notes payable under a Medium Term Note Program. The notes bear a coupon interest rate of 3.32 percent and an effective rate of 3.43 percent, payable semi-annually until maturity in October 2027. The offering was made under OPG's $2 billion short form base shelf prospectus filed in September 2017.

In 2015, PSS, a subsidiary of OPG, issued long-term debt totalling $245 million in support of the Peter Sutherland Sr. Generating Station (GS) project. The majority of the debt proceeds, totalling $180 million, were invested in a structured deposit note with staggered maturity dates ranging from January 2016 to April 2017. As at December 31, 2017, the deposit note had matured.

In October 2016, Lower Mattagami Energy Limited Partnership (LME) issued senior notes totalling $220 million maturing in October 2026. The effective interest rate and coupon interest rate of these notes were 2.40 percent and 2.31 percent, respectively.

In December 2017, the Trust entered into an $800 million revolving warehouse facility agreement with an expiry date of December 21, 2019. As at December 31, 2017, there were outstanding senior notes of $601 million under this credit facility, which were used to finance 51 percent of the Trust's funding requirement for the acquisition of the first tranche of Investment Interest from the IESO in December 2017. The outstanding balance has been classified as long-term debt to reflect the terms and substance of the facility agreement. The interest incurred on this debt is recorded within Earnings from Fair Hydro Trust on the consolidated statements of income. Please refer to Note 17 for additional information on Fair Hydro Trust's financial information.

In February 2018, the Trust issued $500 million of senior notes payable with a coupon interest rate of 3.36 percent and an effective interest rate of 3.42 percent, payable semi-annually until maturity on May 15, 2033. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility issued by the Trust in December 2017. By the end of the first quarter of 2018, the Trust is expected to acquire another tranche of Investment Interest from the IESO, which it expects to fund using its revolving warehouse facility. **[MONITOR]**

The following table summarizes the net interest expense:

(millions of dollars)	December 31 **2017**	**2016**
Interest on long-term debt	**289**	290
Interest on short-term debt	**7**	8
Interest income	**(9)**	(7)
Interest capitalized to property, plant and equipment and intangible assets	**(162)**	(141)
Interest related to regulatory assets and liabilities [1]	**(30)**	(30)
Net interest expense	**95**	120

[1] Includes interest to recognize the cost of financing related to regulatory variance and deferral accounts, as authorized by the OEB, and interest deferred in the Bruce Lease Net Revenues Variance Account, the Capacity Refurbishment Variance Account, and the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account.

Interest paid in 2017 was $258 million (2016 – $269 million), of which $ 251 million (2016 – $261 million) relates to interest paid on long-term debt.

The net book value of the pledged assets of PSS, UMH, LME, and Lower Mattagami Limited Partnership against their debt as at December 31, 2017 was $3,645 million (2016 – $3,510 million).

7. SHORT-TERM DEBT

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. During 2017, OPG renewed and extended the expiry date of both tranches to May 2022. There were no amounts outstanding under the bank credit facility. There was $100 million of commercial paper outstanding under OPG's commercial paper program as at December 31, 2017. The Commercial paper program is used to provide short-term funding requirement for the Company, at rates of approximately one percent and are less than one year in duration.

As at December 31, 2017, the LME maintained a $400 million bank credit facility to support the funding requirements for the Lower Mattagami River project including support for LME's commercial paper program. The facility consists of a $300 million tranche maturing in August 2022 and a $100 million tranche maturing in August 2018. As at December 31, 2017, there was $160 million commercial paper outstanding under LME's commercial paper program (December 31, 2016 – nil). A letter of credit of $55 million was issued in July 2017 and remains outstanding as at December 31, 2017 under the first tranche of LME's credit facility.

As at December 31, 2017, OPG maintained $25 million of short-term, uncommitted overdraft facilities and $468 million of short-term, uncommitted credit facilities, which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other general corporate purposes. As at December 31, 2017, a total of $390 million of Letters of Credit had been issued under these facilities. This included $353 million for the supplementary pension plans, $36 million for general corporate purposes, and $1 million related to the operation of the PEC.

The Company has an agreement to sell an undivided co-ownership interest in its current and future accounts receivable to an independent trust. The maximum amount of co-ownership interest that can be sold under this agreement is $150 million, expiring on November 30, 2018. As at December 31, 2017, there were Letters of Credit outstanding under this agreement of $150 million (December 31, 2016 – $150 million), which were issued in support of OPG's supplementary pension plans.

UMH Energy Partnership has entered into an $8 million short-term, uncommitted overdraft facility and $16 million of irrevocable, standby Letters of Credit facilities in support of its operations. As at December 31, 2017, total Letters of Credit of $15 million had been issued under these facilities.

8. NUCLEAR FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT FUND AND FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT LIABILITIES

The liabilities for fixed asset removal and nuclear waste management on a present value basis as December 31, consist of the following:

(millions of dollars)	**2017**	**2016**
Liability for nuclear used fuel management	**11,970**	11,292
Liability for nuclear decommissioning and nuclear low and intermediate level waste management	**8,107**	7,811
Liability for non-nuclear fixed asset removal	**344**	381
Fixed asset removal and nuclear waste management liabilities	**20,421**	19,484

The changes in the fixed asset removal and nuclear waste management liabilities for the years ended December 31 are as follows:

(millions of dollars)	**2017**	**2016**
Liabilities, beginning of year	**19,484**	20,169
Increase in liabilities due to accretion [1]	**974**	1,024
Decrease in liabilities resulting from the ONFA reference plan update process	**-**	(1,567)
Net change in liabilities reflecting changes to the estimated useful lives *(Note 3)*	**158**	-
Increase in liabilities due to changes in estimates of nuclear used fuel and nuclear waste management expenses and other expenses [1]	**118**	133
Liabilities settled by expenditures on fixed asset removal and nuclear waste management	**(313)**	(275)
Liabilities, end of year	**20,421**	19,484

[1] Amounts shown exclude the impact of regulatory variance and deferral accounts.

OPG's fixed asset removal and nuclear waste management liabilities are comprised of expected costs to be incurred up to and beyond termination of operations and the closure of nuclear and thermal generating facilities, and other facilities. Costs will be incurred for activities such as preparation for safe storage and safe storage of the nuclear stations, dismantlement, demolition and disposal of facilities and equipment, remediation and restoration of sites, and the ongoing and long-term management of nuclear used fuel and L&ILW material.

The determination of the accrual for fixed asset removal and nuclear waste management costs requires significant assumptions since these programs are long-term in nature. The most recent comprehensive update of the cost estimates for the Nuclear Liabilities is contained in the 2017−2021 ONFA reference plan, which was finalized and approved by the Province in the fourth quarter of 2016 (2017 ONFA Reference Plan).

For the purposes of calculating OPG's Nuclear Liabilities, as at December 31, 2017, consistent with the current accounting end-of-life assumptions, nuclear station decommissioning activities are projected to occur over approximately the next 80 years. The estimates for the Nuclear Liabilities include cash flow estimates for decommissioning the nuclear stations for approximately 40 years after stations are shut down and to 2088 for placement of used fuel into the assumed long-term disposal repository, followed by extended monitoring.

The significant assumptions underlying operational, technical, and economic factors used in the calculation of the accrued Nuclear Liabilities are subject to periodic review. Changes to these assumptions, including changes to assumptions on the timing of the nuclear waste programs including construction of waste disposal facilities, station end-of-life dates, waste disposal methods, financial indicators, or the technology employed, may result in significant changes to the value of the accrued liabilities. With programs of this long-term duration and the evolving technology to handle the nuclear waste, there is a significant degree of inherent uncertainty surrounding the measurement of the costs for these programs. These costs may increase or decrease over time.

Liability for Nuclear Used Fuel Management Costs

The liability for nuclear used fuel management represents the cost of managing the highly radioactive used nuclear fuel bundles. The federal NFWA, proclaimed into force in 2002, required that Canada's nuclear fuel waste owners form a nuclear waste management organization, and that each waste owner establish a trust fund for used fuel management costs as specified in the NFWA. This organization, the NWMO, is responsible for the design and implementation of Canada's plan for the long-term management of nuclear used fuel waste. To estimate its liability for nuclear used fuel management costs, OPG has adopted an approach consistent with the Adaptive Phased Management concept approved by the Government of Canada, which assumes a deep geologic repository as part of the long-term management of nuclear used fuel, with an in-service date of 2043 at the earliest.

Liability for Nuclear Decommissioning and L&ILW Management Costs

The liability for nuclear decommissioning and L&ILW management represents the estimated costs of decommissioning the nuclear generating stations after the end of their service lives, as well as the cost of managing L&ILW generated by the stations. The significant assumptions used in estimating future nuclear fixed asset removal costs include a deferred dismantlement basis for decommissioning of the stations, whereby the reactors will be de-watered and de-fueled immediately after the station has ceased operations and thereafter will remain in a safe state condition for a 30-year period, prior to an approximate 10-year dismantlement period.

The life cycle costs of L&ILW management include the costs of processing and storage of such radioactive wastes during and following the operation of the nuclear stations, as well as the costs of the ultimate long-term management of these wastes. The current assumptions used to establish the accrued costs for the management of L&ILW include an L&ILW DGR to be owned and operated by OPG. Agreement was previously reached with local municipalities for OPG to develop a deep geologic repository for the long-term management of L&ILW adjacent to OPG's Western Waste Management Facility in Kincardine, Ontario.

Liability for Non-Nuclear Fixed Asset Removal Costs

The liability for non-nuclear fixed asset removal primarily represents the estimated costs of decommissioning OPG's thermal generating stations at the end of their services lives. The liability is based on third-party cost estimates following an in-depth review of plant sites and an assessment of required clean-up and restoration activities completed in 2017.

OPG performed a revaluation of the liability for non-nuclear fixed asset removal as at December 31, 2017. OPG recognized a decrease in the non-nuclear fixed asset removal liabilities of approximately $30 million, resulting in an decrease in asset retirement costs of $18 million capitalized as part of the carrying value of PP&E, and a gain of $12 million recorded to net income in 2017.

Ontario Nuclear Funds Agreement

In accordance with the ONFA, OPG sets aside and invests funds that are held in segregated custodian and trustee accounts specifically for discharging its life cycle obligation for nuclear decommissioning and long-term nuclear waste management. The Used Fuel Segregated Fund and the Decommissioning Segregated Fund were established under the ONFA for this purpose. OPG makes contributions to the Nuclear Segregated Funds based on the approved ONFA reference plan in effect. ONFA reference plans are subject to approval by the Province.

Since inception, OPG has been making quarterly payments to the Used Fuel Segregated Fund over the assumed lives of its nuclear generating stations, as specified in the ONFA, including contributions to the NFWA Trust established by OPG pursuant to the NFWA. The NFWA Trust forms part of the Used Fuel Segregated Fund, with any OPG contributions to the Used Fuel Segregated Fund, as well as any portion of the fund currently not in the trust, being able to be applied towards the NFWA Trust's annual contribution requirements pursuant to the NFWA. As a result, required funding of the Used Fuel Segregated Fund for 2017 was nil (2016 – $150 million). ONFA

requirements have resulted in the majority of the underlying used fuel management obligation being funded through OPG contributions over the initial estimated useful lives of the nuclear generating stations assumed in the ONFA, which did not reflect subsequent extensions to the nuclear station lives to reflect refurbishment and life extension decisions.

OPG has not been required to make contributions to the Decommissioning Segregated Fund, which was fully funded at its inception through an initial contribution made by the Province and, taking into account asset performance and changes in underlying funding obligation over time, at the time of every subsequent approved ONFA reference plan.

The 2017 ONFA Reference Plan was approved by the Province in December 2016, with an effective date of January 1, 2017. Based on the funded status of the Used Fuel Segregated Fund and the Decommissioning Segregated Fund reflecting the life cycle liability estimates per the 2017 ONFA Reference Plan, no overall contributions to either fund are currently required starting in 2017. Contributions may be required in the future should either or both of the funds be in an underfunded position when a new reference plan is prepared.

The *Nuclear Safety and Control Act* (Canada) requires OPG to have sufficient funds available to discharge its existing nuclear waste management and nuclear facilities decommissioning obligations. As required by the terms of the ONFA, the Province has provided a Provincial Guarantee to the CNSC since 2003, on behalf of OPG. The Provincial Guarantee provides for any shortfall between the CNSC consolidated financial guarantee requirement and the value of the Nuclear Segregated Funds. OPG pays the Province an annual guarantee fee of 0.5 percent of the amount of the Provincial Guarantee. The value of the Provincial Guarantee amount in effect through to the end of 2017 was $1,551 million. Based on this guarantee amount, OPG paid a guarantee fee of $8 million to the Province for each of 2017 and 2016.

Commented [DS3]: Realize that these financial statements are only through Dec. 31, 2017, but to be safe, wanted to flag the CNSC decision in November 2017 such that the Province no longer provides a Provincial Guarantee as of Jan. 1, 2018.

OPG – adjusted wording to reflect that.

The *Nuclear Safety and Control Act* (Canada) requires OPG to have sufficient funds available to discharge its existing nuclear waste management and nuclear facilities decommissioning obligations. As required by the terms of the ONFA, the Province has provided a Provincial Guarantee to the CNSC since 2003, on behalf of OPG. The Provincial Guarantee provides for any shortfall between the CNSC consolidated financial guarantee requirement and the value of the Nuclear Segregated Funds. OPG pays the Province an annual guarantee fee of 0.5 percent of the amount**, if any,** of the Provincial Guarantee. The value of the Provincial Guarantee amount in effect through to the end of 2017 was $1,551 million. Based on this guarantee amount, OPG paid a guarantee fee of $8 million to the Province for each of 2017 and 2016.

The investments in the Nuclear Segregated Funds include a diversified portfolio of equities and fixed income securities that are invested across geographic markets, as well as investments in infrastructure, real estate, and agriculture. The Nuclear Segregated Funds are invested to fund long-term liability requirements and, as such, the portfolio asset mix is structured to achieve the required return over a long-term horizon. While short-term fluctuations in market value will occur, managing the long-term return of the Nuclear Segregated Funds remains the primary goal. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

Decommissioning Segregated Fund

Under the ONFA, OPG is wholly responsible for cost estimate changes and investment returns in the Decommissioning Segregated Fund. As at December 31, 2017 and 2016, the Decommissioning Segregated Fund was in an overfunded position.

Upon termination of the ONFA, the Province has the sole right to any excess funds in the Decommissioning Segregated Fund, which is the excess of the fair market value of the fund's assets over the underlying estimated future costs, as per the most recently approved ONFA reference plan. Accordingly, when the Decommissioning Segregated Fund is overfunded, OPG limits the fund earnings recognized in the consolidated financial statements by recording an amount due to the Province, such that the asset recognized for the fund on the consolidated balance sheet is equal to the cost estimate of the liability based on the most recently approved ONFA reference plan. Additionally, OPG recognizes the portion of the surplus that it may direct to the Used Fuel Segregated Fund, which is possible when the surplus in the Decommissioning Segregated Fund is such that the underlying liabilities, as defined by the most recently approved ONFA reference plan, are at least 120 percent funded. In those circumstances, OPG may direct, at the time a new reference plan is approved, up to 50 percent of the surplus over 120 percent to the Used Fuel Segregated Fund, with the OEFC entitled to a distribution of an equal amount. Therefore, when the Decommissioning Segregated Fund is at least 120 percent funded, OPG recognizes 50 percent of the excess greater than 120 percent in income, up to the amount by which the Used Fuel Segregated Fund is underfunded. Based on the 2017 ONFA Reference Plan, the Used Fuel Segregated Fund was in a marginally overfunded position as at December 31, 2016, for the first time since inception. As a result, OPG recognized a due to the Province amount

such that the Decommissioning Segregated Fund asset on the consolidated balance sheet as at December 31, 2017 and 2016 was limited to the value of the underlying liability per the 2017 ONFA Reference Plan. The payable to the Province may be reduced in subsequent periods in the event that the Decommissioning Segregated Fund earns less than its target rate of return, a new ONFA reference plan is approved with a higher underlying funding liability, or the Used Fuel Segregated Fund changes to an underfunded status. When the Decommissioning Segregated Fund is underfunded, the earnings on the fund reflect actual fund returns based on the market value of the assets.

When the Decommissioning Segregated Fund is in an overfunded status at less than 120 percent, OPG recognized its annual earnings on the fund at 3.25 percent plus the long-term Ontario Consumer Price Index (CPI) specified in the most recently approved ONFA reference plan, which is the rate of growth in the underlying funding liability. The same treatment is applied to the Decommissioning Segregated Fund when it is in an overfunded status at greater than 120 percent, if the Used Fuel Segregated Fund is fully funded.

Used Fuel Segregated Fund

OPG is responsible for cost increases in the funding liability for used fuel waste management under the ONFA, subject to specified graduated liability thresholds, pursuant to which the Province limits OPG's total financial exposure for the first 2.23 million nuclear used fuel bundles at approximately $15.7 billion in present value dollars as at December 31, 2017. The graduated liability thresholds do not apply to used fuel bundles beyond the 2.23 million threshold.

Under the ONFA, the Province guarantees OPG's annual return in the Used Fuel Segregated Fund at 3.25 percent plus the change in the Ontario CPI, as defined by ONFA, for funding related to the first 2.23 million used fuel bundles, (committed return). OPG recognizes the committed return on the Used Fuel Segregated Fund as Earnings on the Nuclear Segregated Funds. The difference between the committed return and the actual market return determined based on the fair value of the fund assets related to the first 2.23 million used fuel bundles is recorded as due to or due from the Province. This amount due to or due from the Province represents the amount that would be paid to or received from the Province if the committed return were to be settled as at the consolidated balance sheets date. The 2.23 million threshold represents the estimated total life cycle fuel bundles based on the initial estimated useful lives of the nuclear stations assumed in the ONFA.

As prescribed under the ONFA, OPG's contributions for fuel bundles in excess of 2.23 million are not subject to the rate of return guaranteed by the Province, and earn a return based on changes in the market value of the assets of the Used Fuel Segregated Fund.

If there is a surplus in the Used Fuel Segregated Fund such that the liabilities, as defined by the most recently approved ONFA reference plan, are at least 110 percent funded, the Province, has the right, at any time, to access the excess amount greater than 110 percent. Upon termination of the ONFA, the Province is entitled to any surplus in the fund, which is the excess of the fair market value of the Used Fuel Segregated Fund assets over the estimated future costs, as per the most recently approved ONFA reference plan. Neither OPG nor the Province has a right to direct any amounts from the Used Fuel Segregated Fund to the Decommissioning Segregated Fund. Therefore, when the Used Fuel Fund is overfunded, OPG limits the earnings it recognizes by recording an amount due to the Province, such that the asset recognized for the fund on the consolidated balance sheets is equal to the cost estimate of the liability per the most recently approved ONFA reference plan. This results in OPG recognizing annual earnings on the fund at 3.25 percent plus the long-term Ontario CPI specified in the most recently approved ONFA reference plan, which is the rate of growth in the underlying funding liability, when the fund is overfunded.

As at December 31, 2017, the Used Fuel Segregated Fund was marginally overfunded in accordance with the 2017 ONFA Reference Plan, and OPG recognized a due to the Province amount of $55 million such that the asset recognized for the fund was limited to the value of the underlying funding liability. This payable to the Province may be reduced in subsequent periods in the event that the Used Fuel Segregated Fund earns less than its target rate of return or in the event that a new ONFA reference plan is approved with a higher underlying funding liability.

Nuclear Segregated Funds

The nuclear fixed asset removal and nuclear waste management funds as at December 31 consist of the following:

(millions of dollars)	Fair Value 2017	2016
Decommissioning Segregated Fund	**9,099**	8,317
Due to Province – Decommissioning Segregated Fund	**(1,933)**	(1,477)
	7,166	6,840
Used Fuel Segregated Fund [1]	**12,087**	11,082
Due to Province – Used Fuel Segregated Fund	**(2,529)**	(1,938)
	9,558	9,144
Total Nuclear Segregated Funds	**16,724**	15,984
Less: current portion	**23**	24
Non-current Nuclear Segregated Funds	**16,701**	15,960

[1] The Ontario NFWA Trust represents $3,882 million as at December 31, 2017 (2016 – $3,688 million) of the Used Fuel Segregated Fund on a fair value basis.

The fair value of the securities invested in the Nuclear Segregated Funds as at December 31 is as follows:

(millions of dollars)	Fair Value 2017	2016
Cash and cash equivalents and short-term investments	**227**	354
Alternative investments	**2,357**	1,989
Pooled funds	**1,713**	1,329
Marketable equity securities	**10,457**	9,503
Fixed income securities	**6,405**	6,181
Net receivables/payables	**27**	43
	21,186	19,399
Due to Province	**(4,462)**	(3,415)
	16,724	15,984

The historical cost, gross unrealized aggregate appreciation and depreciation of investment, gross unrealized foreign exchange gains, and fair value of the Nuclear Segregated Funds as at December 31, 2017 and 2016 are summarized as follows:

	2017		
(millions of dollars)	**Decommissioning Segregated Fund**	**Used Fuel Segregated Fund**	**Total**
Historical cost	**7,327**	**9,902**	**17,229**
Gross unrealized gains (losses)			
Aggregate appreciation	**1,789**	**2,188**	**3,977**
Aggregate depreciation	**(134)**	**(180)**	**(314)**
Foreign exchange	**117**	**177**	**294**
	9,099	**12,087**	**21,186**
Due to Province	**(1,933)**	**(2,529)**	**(4,462)**
Total fair value	**7,166**	**9,558**	**16,724**
Less: current portion	**5**	**18**	**23**
Non-current fair value	**7,161**	**9,540**	**16,701**

	2016		
(millions of dollars)	**Decommissioning Segregated Fund**	**Used Fuel Segregated Fund**	**Total**
Historical cost	6,896	9,385	16,281
Gross unrealized gains (losses)			
Aggregate appreciation	1,326	1,564	2,890
Aggregate depreciation	(165)	(222)	(387)
Foreign exchange	260	355	615
	8,317	11,082	19,399
Due to Province	(1,477)	(1,938)	(3,415)
Total fair value	6,840	9,144	15,984
Less: current portion	8	16	24
Non-current fair value	6,832	9,128	15,960

Net realized and unrealized gains or losses from investments for the years ended December 31, 2017 and 2016 are summarized as follows:

(millions of dollars)	2017 Decommissioning Segregated Fund	2017 Used Fuel Segregated Fund	2017 Total
Net realized gains			
Realized gains excluding foreign exchange	**198**	**245**	**443**
Realized foreign exchange gains	**54**	**65**	**119**
Net realized gains	**252**	**310**	**562**
Net unrealized gains			
Unrealized gains excluding foreign exchange	**494**	**666**	**1,160**
Unrealized foreign exchange losses	**(143)**	**(178)**	**(321)**
Net unrealized gains	**351**	**488**	**839**

(millions of dollars)	2016 Decommissioning Segregated Fund	2016 Used Fuel Segregated Fund	2016 Total
Net realized gains			
Realized gains excluding foreign exchange	84	180	264
Realized foreign exchange gains	30	41	71
Net realized gains	114	221	335
Net unrealized gains			
Unrealized gains excluding foreign exchange	360	442	802
Unrealized foreign exchange losses	(165)	(216)	(381)
Net unrealized gains	195	226	421

The change in the Nuclear Segregated Funds for the years ended December 31 is as follows:

(millions of dollars)	Fair Value 2017	Fair Value 2016
Decommissioning Segregated Fund, beginning of year	**6,840**	6,549
Increase in fund due to return on investments	**807**	505
Decrease in fund due to reimbursement of eligible expenditures	**(25)**	(22)
Increase in due to Province	**(456)**	(192)
Decommissioning Segregated Fund, end of year	**7,166**	6,840
Used Fuel Segregated Fund, beginning of year	**9,144**	8,587
Increase in fund due to contributions made	**-**	150
Increase in fund due to return on investments	**1,059**	690
Decrease in fund due to reimbursement of eligible expenditures	**(54)**	(48)
Increase in due to Province	**(591)**	(235)
Used Fuel Segregated Fund, end of year	**9,558**	9,144

The earnings from the Nuclear Segregated Funds during 2017 and 2016 were impacted by the Bruce Lease Net Revenues Variance Account authorized by the OEB. The earnings on the Nuclear Segregated Funds for the years ended December 31 are as follows:

(millions of dollars)	**2017**	**2016**
Decommissioning Segregated Fund	**351**	313
Used Fuel Segregated Fund	**468**	455
Bruce Lease Net Revenues Variance Account	**(18)**	(22)
Total earnings	**801**	746

9. INCOME TAXES

OPG follows the liability method of accounting for income taxes. The Company records an offsetting regulatory asset or liability for the deferred income taxes that are expected to be recovered or refunded through future regulated prices charged to customers for generation from OPG's regulated facilities.

A reconciliation between the statutory and the effective rate of income taxes is as follows:

(millions of dollars)	**2017**	**2016**
Income before income taxes	**1,090**	621
Combined Canadian federal and provincial statutory enacted income tax rates	**26.5%**	26.5%
Statutory income tax rates applied to accounting income	**289**	165
(Decrease) increase in income taxes resulting from:		
Income tax (recovery) expense deferred in regulatory assets and liabilities	**(20)**	65
Scientific Research and Experimental Development investment tax credits	**(47)**	(48)
Manufacturing and processing credit	**(16)**	(9)
Other	**3**	(5)
	(80)	3
Income tax expense	**209**	168
Effective rate of income taxes	**19.1%**	27.0%

Significant components of the income tax expense are presented in the table below:

(millions of dollars)	**2017**	**2016**
Current income tax expense	**190**	204
Deferred income tax expense (recovery)	**19**	(36)
Income tax expense	**209**	168

The income tax effects of temporary differences that give rise to deferred income tax assets and liabilities as at December 31 are as follows:

(millions of dollars)	**2017**	**2016**
Deferred income tax assets:		
Fixed asset removal and nuclear waste management liabilities	**5,096**	4,861
Other assets and liabilities	**2,057**	1,813
	7,153	6,674
Deferred income tax liabilities:		
Property, plant and equipment and intangible assets	**(1,923)**	(1,807)
Nuclear fixed asset removal and nuclear waste management funds	**(4,181)**	(3,996)
Other assets and liabilities	**(1,928)**	(1,700)
	(8,032)	(7,503)
Net deferred income tax liabilities	**(879)**	(829)

During 2017, OPG recorded an increase in the deferred income tax liability for the income taxes that are expected to be recovered or refunded through regulated prices charged to customers of $59 million (2016 – $46 million). Since these deferred income taxes are expected to be refunded through future regulated prices, OPG recorded a corresponding increase to the regulatory asset for deferred income taxes. As a result, the deferred income tax expense for 2017 and 2016 was not impacted.

The following table summarizes the deferred income tax liabilities recorded for the rate regulated operations that are expected to be recovered through future regulated prices:

(millions of dollars)	**2017**	**2016**
January 1:		
Deferred income tax liabilities on temporary differences related to regulated operations	**627**	592
Deferred income tax liabilities on temporary differences related to the regulatory asset for the deferred income tax liabilities	**211**	200
	838	792
Changes during the year:		
Increase in deferred income tax liabilities on temporary differences related to regulated operations	**44**	35
Increase in deferred income tax liabilities on temporary differences related to the regulatory asset for the deferred income tax liabilities	**15**	11
Balance as at December 31	**897**	838

The tax benefit associated with an income tax position is recognized only when it is more likely than not that such a position will be sustained upon examination by the taxing authorities based on the technical merits of the position. The current and deferred income tax benefit is equal to the largest amount, considering possible settlement outcomes, that is greater than 50 percent likely of being realized upon settlement with the taxing authorities.

A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

(millions of dollars)	**2017**	**2016**
Unrecognized tax benefits, beginning of year	**77**	72
Additions based on tax positions related to the current year	**21**	19
Additions for tax positions of prior years	**-**	2
Reductions for tax positions of prior years	**(20)**	(16)
Unrecognized tax benefits, end of year	**78**	77

As at December 31, 2017, OPG's unrecognized tax benefits were $78 million (2016 – $77 million), excluding interest and penalties, all of which, if recognized, would affect OPG's effective tax rate. Changes in unrecognized tax benefits over the next 12 months cannot be predicted with certainty.

OPG recognizes interest and penalties related to unrecognized tax benefits as income tax expense. As at December 31, 2017, OPG had recorded interest on unrecognized tax benefits of $8 million (2016 – $8 million). OPG considers its significant tax jurisdiction to be Canada. OPG remains subject to income tax examination for years after 2013.

OPG paid $195 million in income taxes (net of tax refunds) during 2017 (2016 – $98 million).

10. ACCUMULATED OTHER COMPREHENSIVE LOSS

The changes in the balance of each component of accumulated other comprehensive loss (AOCL), net of income taxes, are as follows:

	2017			
(millions of dollars)	**Unrealized Gains and Losses on Cash Flow Hedges [1]**	**Pension and OPEB [1]**	**Available-for-sale Securities [1]**	**Total [1]**
AOCL, beginning of year	**(87)**	**(207)**	**(1)**	**(295)**
Actuarial loss on re-measurement of liabilities for pension and OPEB	**-**	**(23)**	**-**	**(23)**
Unrealized loss on available-for-sale securities	**-**	**-**	**(8)**	**(8)**
Amounts reclassified from AOCL	**18**	**10**	**-**	**28**
Other comprehensive income (loss) for the year	**18**	**(13)**	**(8)**	**(3)**
Reclassification of non-controlling interest on change in ownership interest *(Note 22)*	**3**	**-**	**-**	**3**
AOCL, end of year	**(66)**	**(220)**	**(9)**	**(295)**

[1] All amounts are net of income taxes.

	2016			
(millions of dollars)	**Unrealized Gains and Losses on Cash Flow Hedges [1]**	**Pension and OPEB [1]**	**Available-for-sale Securities [1]**	**Total [1]**
AOCL, beginning of year	(106)	(213)	-	(319)
Actuarial loss on re-measurement of liabilities for pension and OPEB	-	(6)	-	(6)
Unrealized loss on available-for-sale securities	-	-	(1)	(1)
Amounts reclassified from AOCL	19	12	-	31
Other comprehensive income (loss) for the year	19	6	(1)	24
AOCL, end of year	(87)	(207)	(1)	(295)

[1] All amounts are net of income taxes.

The significant amounts reclassified out of each component of AOCL, net of income taxes, during December 31, 2017 and 2016 are as follows:

	Amount Reclassified from AOCL		
(millions of dollars)	**2017**	**2016**	**Statement of Income Line Item**
Amortization of losses from cash flow hedges			
Losses	**20**	21	Net interest expense
Income tax recovery	**(2)**	(2)	Income tax expense
	18	19	
Amortization of amounts related to pension and OPEB			
Actuarial losses and past service costs	**13**	16	See (1) below
Income tax recovery	**(3)**	(4)	Income tax expense
	10	12	
Total reclassifications for the year	**28**	31	

[1] These AOCL components are included in the computation of pension and OPEB costs (see Note 11 for additional details).

11. PENSION AND OTHER POST-EMPLOYMENT BENEFITS

Fund Assets

The OPG registered pension fund investment guidelines are stated in an approved Statement of Investment Policies and Procedures (SIPP). The SIPP is reviewed and approved by the Audit and Risk Committee of OPG's Board of Directors at least annually and includes a discussion of investment objectives and expectations, asset mix and rebalancing, and the basis for measuring the performance of the pension fund assets.

In accordance with the SIPP, investment allocation decisions are made with a view to achieve OPG's objective of meeting obligations of the plan as they come due. The pension fund assets are invested in four categories of asset classes. The first category is liability hedging assets, which are intended to hedge the inflation and interest rate sensitivity of the plan liabilities. The second category is return enhancing assets, which are intended to obtain higher investment returns compared to the returns expected for liability hedging assets. The third category is real assets, which offer exposure to the combined characteristics of liability hedging and return enhancing assets. The fourth category is return diversifying strategies, which are intended to improve the overall return of the pension fund while mitigating the downside market risk.

To achieve the above objective, OPG has adopted the following target strategic asset allocation:

	Target
Asset Class	
Liability Hedging Assets	34%
Return Enhancing Assets	31%
Real Assets	20%
Return Diversifying Assets	15%

The plan may use derivatives for risk management or strategic purposes, where such activity is consistent with the plan's investment objectives.

Significant Concentrations of Risk in Fund Assets

The assets of the pension fund are diversified to limit the impact of any individual investment. The pension fund is diversified across multiple asset classes. Fixed income securities are diversified among Canadian government bonds, government agency bonds, real return bonds, and corporate bonds. Equity securities are diversified across

Canadian, US, and Global stocks. There are also real estate, infrastructure, and agriculture portfolios that represent approximately 12 percent of the total pension fund assets as at December 31, 2017. Investments in the above asset classes are further diversified across funds, investment managers, strategies, vintages, sectors and geographies, depending on the specific characteristics of each asset class.

Credit risk with respect to the pension fund's fixed income securities is managed by risk tolerance guidelines, which requires that fixed income securities comply with various investment constraints that ensure prudent diversification and prescribed minimum required credit rating quality. Credit risk, as it relates to the pension fund's derivatives, is managed through the use of International Swap and Derivatives Association documentation and counterparty management performed by the fund's investment managers.

Risk Management

Risk management oversight with respect to the pension fund includes, but is not limited to, the following activities:

- Periodic asset/liability management and strategic asset allocation studies
- Monitoring of funding levels and funding ratios
- Monitoring compliance with asset allocation guidelines and investment management agreements
- Monitoring asset class performance against asset class benchmarks
- Monitoring investment manager performance against benchmarks
- Monitoring of risk tolerance guidelines

Expected Rate of Return on Plan Assets

The expected rate of return on plan assets is based on the fund's asset allocation, as well as the return expectations considering long-term risks and returns associated with each asset class within the plan portfolio. The asset management decisions consider the economic liabilities of the plan.

Fair Value Measurements

OPG is required to classify fair value measurements using a fair value hierarchy. This hierarchy groups financial instruments into three levels, based on the significance of inputs used in measuring the fair value of the assets and liabilities. Refer to Note 13 for a detailed discussion of fair value measurements and the fair value hierarchy.

The following tables present pension plan assets measured at fair value in accordance with the fair value hierarchy:

	December 31, 2017			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Cash and cash equivalents	**377**	**-**	**-**	**377**
Short-term investments	**-**	**9**	**-**	**9**
Fixed income				
Corporate debt securities	**-**	**521**	**-**	**521**
Government bonds	**-**	**3,476**	**-**	**3,476**
Equities				
Canadian	**1,441**	**329**	**-**	**1,770**
US	**1,551**	**-**	**-**	**1,551**
Global	**1,681**	**-**	**-**	**1,681**
Pooled funds	**459**	**105**	**-**	**564**
Other	**15**	**-**	**-**	**15**
	5,524	**4,440**	**-**	**9,964**
Investments measured at NAV [1]				**4,221**
				14,185 [2]

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to the total fair value of plan assets presented in tables following.

[2] The table above excludes pension fund receivables and payables.

	December 31, 2016			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Cash and cash equivalents	690	-	-	690
Fixed income				
Corporate debt securities	-	407	-	407
Government bonds	-	3,483	-	3,483
Equities				
Canadian	1,449	291	-	1,740
US	1,495	-	-	1,495
Global	1,643	-	-	1,643
Pooled funds	118	413	-	531
	5,395	4,594	-	9,989
Investments measured at NAV [1]				3,504
				13,493 [2]

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to the total fair value of plan assets presented in tables following.

[2] The table above excludes pension fund receivables and payables.

Plan Costs and Liabilities

Details of OPG's pension and OPEB obligations, pension fund assets and costs are presented in the following tables:

	Registered and Supplementary Pension Plans		Other Post-Employment Benefits	
	2017	**2016**	**2017**	**2016**
Weighted Average Assumptions – Benefit Obligations at Year-End				
Discount rate for projected benefit obligation	**3.57 %**	3.90 %	**3.60 %**	3.94 %
Salary schedule escalation rate - initial rate [1]	**1.90 %**	1.80 %	**1.90 %**	1.80 %
- thereafter	**2.50 %**	2.50 %	**2.50 %**	2.50 %
Rate of cost of living increase to pensions	**2.00 %**	2.00 %	**n/a**	n/a
Initial health care trend rate	**n/a**	n/a	**5.80 %**	5.90 %
Ultimate health care trend rate	**n/a**	n/a	**4.32 %**	4.32 %
Year ultimate health care trend rate reached	**n/a**	n/a	**2030**	2030
Rate of increase in disability benefits	**n/a**	n/a	**2.00 %**	2.00 %

[1] Per year to December 31, 2021.

	Registered and Supplementary Pension Plans		Other Post-Employment Benefits	
	2017	**2016**	**2017**	**2016**
Weighted Average Assumptions – Costs for the Year				
Expected return on plan assets, net of expenses	**6.00 %**	6.00 %	**n/a**	n/a
Discount rate for projected benefit obligation	**3.90 %**	4.10 %	**3.94 %**	4.13 %
Discount rate for current service cost	**4.15 %**	4.10 %	**4.03 %**	4.13 %
Discount rate for interest on projected benefit obligation	**3.37 %**	4.10 %	**3.53 %**	4.13 %
Discount rate for interest on current service cost	**3.95 %**	4.10 %	**3.85 %**	4.13 %
Salary schedule escalation rate - initial rate [1]	**1.80 %**	1.60 %	**1.80 %**	1.60 %
- thereafter	**2.50 %**	2.50 %	**2.50 %**	2.50 %
Rate of cost of living increase to pensions	**2.00 %**	2.00 %	**n/a**	n/a
Initial health care trend rate	**n/a**	n/a	**5.90 %**	6.00 %
Ultimate health care trend rate	**n/a**	n/a	**4.32 %**	4.33 %
Year ultimate health care trend rate reached	**n/a**	n/a	**2030**	2030
Rate of increase in disability benefits	**n/a**	n/a	**2.00 %**	2.00 %
Expected average remaining service life for employees (years)	**12**	12	**13**	13

[1] Per year to December 31, 2021.

(millions of dollars)	Registered Pension Plans 2017	2016	Supplementary Pension Plans 2017	2016	Other Post-Employment Benefits 2017	2016
Components of Cost Recognized for the year						
Current service costs	**274**	277	**7**	7	**67**	67
Interest on projected benefit obligation	**548**	634	**11**	12	**106**	133
Expected return on plan assets, net of expenses	**(766)**	(734)	**-**	-	**-**	-
Amortization of past service costs [1]	**-**	-	**-**	-	**1**	1
Amortization of net actuarial loss [1]	**183**	192	**6**	4	**-**	19
Recognition of LTD net actuarial loss (gain)	**-**	**-**	**-**	**-**	**11**	(52)
Costs recognized [2]	**239**	369	**24**	23	**185**	168

[1] The amortization of past service costs and net actuarial loss was recognized as an increase to OCI. This increase was partially offset by the impact of the Pension and OPEB Regulatory Asset discussed in Note 5.

[2] Excludes the impact of regulatory variance and deferral accounts discussed in Note 5.

Total benefit costs, including the impact of the Pension & OPEB Cash Payment Variance Account and the Pension & OPEB Cash Versus Accrual Differential Deferral Account, for the years ended December 31 are as follows:

(millions of dollars)	2017	2016
Registered pension plans	**239**	369
Supplementary pension plans	**24**	23
Other post-employment benefits	**185**	168
Pension & OPEB Cash Payment Variance Account *(Note 5)*	**81**	86
Pension & OPEB Cash Versus Accrual Differential Deferral Account *(Note 5)*	**(117)**	(182)
Pension and other post-employment benefit costs	**412**	464

The pension and OPEB obligations and the pension fund assets measured as at December 31 are as follows:

(millions of dollars)	Registered Pension Plans 2017	2016	Supplementary Pension Plans 2017	2016	Other Post-Employment Benefits 2017	2016
Change in Plan Assets						
Fair value of plan assets at beginning of year	**13,506**	13,160	**-**	-	**-**	-
Contributions by employer	**214**	255	**14**	15	**94**	93
Contributions by employees	**97**	85	**-**	-	**-**	-
Actual return on plan assets, net of expenses	**1,207**	714	**-**	-	**-**	-
Benefit payments	**(761)**	(708)	**(14)**	(15)	**(94)**	(93)
Fair value of plan assets at end of year	**14,263**	13,506	**-**	-	**-**	-
Change in Projected Benefit Obligations						
Projected benefit obligations at beginning of year	**16,199**	15,475	**336**	299	**2,992**	3,188
Employer current service costs	**274**	277	**7**	7	**67**	67
Contributions by employees	**97**	85	**-**	-	**-**	-
Interest on projected benefit obligation	**548**	634	**11**	12	**106**	133
Benefit payments	**(761)**	(708)	**(14)**	(15)	**(94)**	(93)
Net actuarial loss (gain)	**987**	436	**16**	33	**119**	(303)
Projected benefit obligations at end of year	**17,344**	16,199	**356**	336	**3,190**	2,992
Funded status – deficit at end of year	**(3,081)**	(2,693)	**(356)**	(336)	**(3,190)**	(2,992)

The following table provides the pension and OPEB liabilities and their classification on the consolidated balance sheets as at December 31:

(millions of dollars)	Registered Pension Plans 2017	2016	Supplementary Pension Plans 2017	2016	Other Post-Employment Benefits 2017	2016
Current liabilities	**-**	-	**(14)**	(17)	**(98)**	(95)
Non-current liabilities	**(3,081)**	(2,693)	**(342)**	(319)	**(3,092)**	(2,897)
Total liabilities	**(3,081)**	(2,693)	**(356)**	(336)	**(3,190)**	(2,992)

The accumulated benefit obligations for the registered pension plans and supplementary pension plans as at December 31, 2017 are $16,005 million and $333 million, respectively (2016 – $14,909 million and $293 million, respectively). The accumulated benefit obligation differs from the projected benefit obligation in that the accumulated benefit obligation includes no assumption about future compensation levels.

The following table provides the components of OPG's OCI related to pension and OPEB plans and the offsetting Pension and OPEB Regulatory Asset, discussed in Note 5, for the years ended December 31, on a pre-tax basis:

(millions of dollars)	Registered Pension Plans 2017	Registered Pension Plans 2016	Supplementary Pension Plans 2017	Supplementary Pension Plans 2016	Other Post-Employment Benefits 2017	Other Post-Employment Benefits 2016
Changes in plan assets and benefit obligations recognized in OCI						
Current year net actuarial loss (gain)	**546**	456	**16**	33	**108**	(251)
Amortization of net actuarial loss	**(183)**	(192)	**(6)**	(4)	**-**	(19)
Amortization of past service costs	**-**	-	**-**	-	**(1)**	(1)
Total decrease (increase) in OCI	**363**	264	**10**	29	**107**	(271)
Less: increase (decrease) in Pension and OPEB Regulatory Asset *(Note 5)*	**352**	253	**9**	27	**102**	(250)
Net decrease (increase) in OCI (pre-tax)	**11**	11	**1**	2	**5**	(21)

The following table provides the components of OPG's AOCL and the offsetting Pension and OPEB Regulatory Asset that have not yet been recognized as components of benefit costs as at December 31, on a pre-tax basis:

(millions of dollars)	Registered Pension Plans 2017	Registered Pension Plans 2016	Supplementary Pension Plans 2017	Supplementary Pension Plans 2016	Other Post-Employment Benefits 2017	Other Post-Employment Benefits 2016
Unamortized amounts recognized in AOCL						
Past service costs	**-**	-	**-**	-	**4**	5
Net actuarial loss	**3,650**	3,287	**116**	106	**378**	270
Total recognized in AOCL	**3,650**	3,287	**116**	106	**382**	275
Less: Pension and OPEB Regulatory Asset *(Note 5)*	**3,391**	3,039	**109**	100	**355**	253
Net recognized in AOCL (pre-tax)	**259**	248	**7**	6	**27**	22

The following table provides the components of OPG's AOCL and the offsetting Pension and OPEB Regulatory Asset as at December 31 (included in the table above) that are expected to be amortized as components of benefit costs and recognized as increases to OCI and reductions in the Pension and OPEB Regulatory Asset in 2018, on a pre-tax basis:

(millions of dollars)	Registered Pension Plans	Supplementary Pension Plans	Other Post-Employment Benefits
Past service costs	**-**	**-**	**1**
Net actuarial loss	**198**	**7**	**6**
Total increase in OCI	**198**	**7**	**7**
Less: estimated decrease in Pension and OPEB Regulatory Asset	**184**	**6**	**6**
Net increase in OCI (pre-tax)	**14**	**1**	**1**

The most recently filed actuarial valuation, for funding purposes, of the OPG registered pension plan, as at January 1, 2017, was filed with the FSCO in September 2017. The next filed funding valuation must have an effective date no later than January 1, 2020. For 2018, OPG's required contribution to its registered pension plan is expected to be $215 million. The amount of OPG's additional, voluntary contribution, if any, is revisited from time to time. OPG will continue to assess the requirements for contributions to the pension plan.

The supplementary pension plans are not funded, but are secured by Letters of Credit totalling $353 million as at December 31, 2017 (2016 – $349 million).

Estimated future benefit payments to participants in the pension and OPEB plans based on the assumptions used to measure the benefit obligations as at December 31, 2017 are as follows:

(millions of dollars)	Registered Pension Plans	Supplementary Pension Plans	Other Post-Employment Benefits
2018	676	15	98
2019	696	15	101
2020	722	15	105
2021	747	16	108
2022	764	16	111
2023 through 2027	4,397	86	633

A one percent increase or decrease in the health care trend rate would result in an increase in the current service and interest components of the 2017 OPEB costs of $40 million (2016 – $45 million) or a decrease in the service and interest components of the 2017 OPEB costs of $29 million (2016 – $33 million). A one percent increase or decrease in the health care trend rate would result in an increase in the projected OPEB obligation as at December 31, 2017 of $592 million (2016 – $560 million) or a decrease in the projected OPEB obligation as at December 31, 2017 of $451 million (2016 – $426 million).

12. RISK MANAGEMENT AND DERIVATIVES

OPG is exposed to risks related to changes in market interest rates on debt expected to be issued in the future and movements in foreign currency that affect the Company's assets, liabilities, and forecasted transactions. Select derivative instruments are used to manage such risks. Derivatives are used as hedging instruments, as well as for trading purposes.

Interest rate risk is the risk that the value of assets and liabilities can change due to movements in related interest rates. Interest rate risk for OPG arises with the need to refinance existing debt and/or undertake new financing. The management of these risks includes using derivatives to hedge the exposure in accordance with corporate risk management policies. OPG periodically uses interest rate swap agreements to mitigate elements of interest rate risk exposure associated with anticipated financing.

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are denominated in, or tied to, US dollars. OPG enters into foreign exchange derivatives and agreements with major financial institutions, when appropriate, in order to manage the Company's exposure to foreign currency movements.

The majority of OPG's revenues are derived from sales through the IESO administered spot market. Market participants in the IESO spot market provide collateral in accordance with the IESO prudential support requirements to cover funds that they might owe to the market. Although the credit exposure to the IESO represents a significant portion of OPG's accounts receivable, the Company's management accepts this risk due to the IESO's primary role in the Ontario electricity market. The remaining receivables exposure is to a diverse group of generally high quality counterparties. OPG's allowance for doubtful accounts as at December 31, 2017 was less than $1 million. OPG's fair value derivatives totalled a net liability of $20 million as at December 31, 2017 (December 31, 2016 − $24 million).

The following table shows the pre-tax amounts related to derivatives recorded in AOCL and net income for the years ended December 31:

(millions of dollars)	**2017**	**2016**
Cash flow hedges (recorded in AOCL)		
Reclassification of losses to net interest expense	**19**	21
Commodity derivatives (recorded in net income)		
Realized losses in revenue	**(9)**	(12)
Unrealized gains (losses) in revenue	**3**	(3)

Existing pre-tax net losses of $19 million deferred in AOCL as at December 31, 2017 are expected to be reclassified to net income within the next 12 months.

13. FAIR VALUE MEASUREMENTS

OPG is required to classify fair value measurements using a fair value hierarchy. This hierarchy groups financial assets and liabilities into three levels, based on the inputs used in measuring the fair value of the financial assets and liabilities. The fair value hierarchy has the following levels:

- Level 1: Valuation of inputs is based on unadjusted quoted market prices observed in active markets for identical assets or liabilities.
- Level 2: Valuation is based on inputs other than quoted prices under Level 1 that are observable for the asset or liability, either directly or indirectly.
- Level 3: Valuation is based on inputs for the asset or liability that are not based on observable market data.

The fair value of financial instruments traded in active markets is based on quoted market prices as at the consolidated balance sheet dates. A market is regarded as active if quoted prices are readily and regularly available from an exchange, dealer, broker, industry group, pricing service, or regulatory agency, and those prices represent actual and regularly occurring market transactions on an arm's length basis. The quoted market price used for financial assets held by OPG is the current bid price. These instruments are included in Level 1 and are comprised primarily of equity investments and fund investments.

For financial instruments for which quoted market prices are not directly available, fair values are estimated using forward price curves developed from observable market prices or rates. The estimation of fair value may include the use of valuation techniques or models, based wherever possible on assumptions supported by observable market prices or rates prevailing as at the consolidated balance sheet dates. This is the case for over-the-counter derivatives and securities, which include energy commodity derivatives, foreign exchange derivatives, interest rate swap derivatives, and fund investments. Pooled fund investments are valued at the unit values supplied by the pooled fund administrators. The unit values represent the underlying net assets at fair values, determined using closing market prices. Valuation models use general assumptions and market data and therefore do not reflect the specific risks and other factors that would affect a particular instrument's fair value. The methodologies used for calculating the fair value adjustments are reviewed on an ongoing basis to ensure that they remain appropriate. If all significant inputs required to fair value an instrument are observable, the instrument is included in Level 2.

The following is a summary of OPG's financial instruments and their fair value as at December 31, 2017 and December 31, 2016:

	Fair Value		Carrying Value [1]		
(millions of dollars)	**2017**	**2016**	**2017**	**2016**	**Balance Sheet Line Item**
Nuclear Segregated Funds (includes current portion) [2]	**16,724**	15,984	**16,724**	15,984	Nuclear fixed asset removal and nuclear waste management funds
Financing receivables	**1,179**	-	**1,179**	-	Financing receivables
Investment in Hydro One shares	**188**	212	**188**	212	Available-for-sale securities
Payable related to cash flow hedges	**(40)**	(48)	**(40)**	(48)	Long-term accounts payable and accrued charges
Long-term debt (includes current portion and medium) term notes)	**(6,835)**	(6,033)	**(5,735)**	(5,520)	Long-term debt
Long-term debt – Fair Hydro Trust	**(601)**	-	**(601)**	-	Long-term debt
Other financial instruments	**(16)**	(18)	**(16)**	(18)	Various

[1] The carrying values of other financial instruments included in cash and cash equivalents, receivables from related parties, other current assets, short-term debt, and accounts payable and accrued charges approximate their fair values due to the immediate or short-term maturity of these financial instruments.

[2] The Nuclear Segregated Funds are comprised of the Decommissioning Segregated Fund and the Used Fuel Segregated Fund.

The fair value of long-term debt instruments is determined based on a conventional pricing model, which is a function of future cash flows, the current market yield curve and term to maturity. These inputs are considered Level 2 inputs.

The fair value of the Trust debt and Medium Term Note Program debt (included in the Long-term debt line above) are based on unadjusted quoted active market prices, which are considered Level 1 inputs. All other long-term debt instruments is determined based on a conventional pricing model, which is a function of future cash flows, the current market yield curve and term to maturity. These inputs are considered Level 2 inputs. For the financing receivables related to the Investment Interest acquired from the IESO, fair value is estimated to equal the fair value of the underlying debt due to the direct relationship of the asset, and the debt instruments that financed the acquisition. The financing receivables are funded by both the senior and subordinated debt issued by the Trust. The long-term debt ranks as senior notes and has inputs that are based on unadjusted quoted active market prices, which are considered Level 1 inputs, while the portion funded by the subordinated debt has inputs that are based on indicative pricing from the market, which are considered Level 2 inputs.

If one or more of the significant inputs is not based on observable market data, the instrument is included in Level 3. Specific valuation techniques are used to value these instruments. Significant Level 3 inputs include: recent comparable transactions, comparable benchmark information, bid/ask spread of similar transactions, and other relevant factors.

Transfers into, out of, or between levels are deemed to have occurred on the date of the event or change in circumstances that caused the transfer to occur.

The following tables present financial assets and financial liabilities measured at fair value in accordance with the fair value hierarchy as at December 31, 2017 and December 31, 2016:

	December 31, 2017			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Used Fuel Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	**6,090**	**4,705**	**-**	**10,795**
Investments measured at NAV [1]				**1,292**
				12,087
Due to Province				**(2,529)**
Used Fuel Segregated Fund, net				**9,558**
Decommissioning Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	**4,547**	**3,487**	**-**	**8,034**
Investments measured at NAV [1]				**1,065**
				9,099
Due to Province				**(1,933)**
Decommissioning Segregated Fund, net				**7,166**
Investment in available-for-sale securities	**188**	**-**	**-**	**188**
Other financial assets	**5**	**3**	**6**	**14**
Liabilities				
Other financial liabilities	**(28)**	**(2)**	**-**	**(30)**

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to amounts presented on the consolidated balance sheets.

(millions of dollars)	December 31, 2016 Level 1	Level 2	Level 3	Total
Assets				
Used Fuel Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	5,602	4,394	-	9,996
Investments measured at NAV [1]				1,086
				11,082
Due to Province				(1,938)
Used Fuel Segregated Fund, net				9,144
Decommissioning Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	4,171	3,243	-	7,414
Investments measured at NAV [1]				903
				8,317
Due to Province				(1,477)
Decommissioning Segregated Fund, net				6,840
Investments in available-for-sale securities	212	-	-	212
Other financial assets	6	2	9	17
Liabilities				
Other financial liabilities	(29)	(6)	-	(35)

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to amounts presented on the consolidated balance sheets.

During the year ended December 31, 2017, there were no transfers between Level 1 and Level 2. In addition, there were no transfers into or out of Level 3.

The following table presents the changes in OPG's net assets measured at fair value that are classified as Level 3 financial instruments.

(millions of dollars)	Other financial instruments
Opening balance, January 1 2017	**9**
Unrealized losses included in revenue	**(3)**
Realized losses included in revenue	**(9)**
Purchases	**9**
Closing balance, December 31, 2017	**6**

Nuclear Segregated Funds

The fair value of the investments within the Nuclear Segregated Funds' alternative investment portfolio is determined using appropriate valuation techniques, such as recent arm's length market transactions, references to current fair values of other instruments that are substantially the same, discounted cash flow analyses, third-party independent appraisals, valuation multiples, or other valuation methods. Any control, size, liquidity or other discount premiums on the investments are considered in the determination of fair value. Alternative investments are measured at fair value using NAV as a practical expedient.

The process of valuing investments for which no published market price exists is based on inherent uncertainties and the resulting values may differ from values that would have been used had a ready market existed for these investments. The values may also differ from the prices at which the investments may be sold.

The following are the classes of investments within the Nuclear Segregated Funds that are reported on the basis of NAV as at December 31, 2017:

(millions of dollars except where noted)	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice
Alternative Investments				
Infrastructure	**1,330**	**798**	**n/a**	**n/a**
Real Estate	**936**	**440**	**n/a**	**n/a**
Agriculture	**90**	**97**	**n/a**	**n/a**
Pooled Funds				
Short-term Investments	**32**	**n/a**	**Daily**	**1 - 5 Days**
Fixed Income	**729**	**n/a**	**Daily**	**1 - 5 Days**
Equity	**952**	**n/a**	**Daily**	**1 - 5 Days**
Total	**4,069**	**1,335**		

The fair value of the pooled funds is classified as Level 2. Infrastructure, real estate and agriculture investments are measured using NAV as a practical expedient for determining their fair value.

Infrastructure

This asset class includes investments in funds and assets with an objective to generate a combination of long-term capital appreciation and current income, generally through private investments in sectors such as energy, transportation, communication and utilities. The fair values of investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in these investments. The investments in its respective funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests/shares to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Distributions from each infrastructure fund will be received based on the operations of the underlying investments and/or as the underlying investments of the infrastructure funds are liquidated. It is not possible to estimate when the underlying assets in this asset class will be liquidated.

Real Estate

This asset class includes investments in funds and assets with an objective is to generate a combination of long-term capital appreciation and current income, generally through investments in institutional-grade real estate property. The fair values of the investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in these investments. The investments in its respective funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Distributions from each real estate fund will be received based on the operations of the underlying investments and/or as the underlying investments of the real estate funds are liquidated. For investments in private real estate corporations, shares may be redeemed through a pre-established redemption process. It is not possible to estimate when the underlying assets in this asset class will be liquidated.

Agriculture

This asset class includes investments in funds and assets with an objective to provide a differentiated return source, income yield, and inflation protection, generally through private investments inglobal farmland and timberland. The fair values of the investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in these investments. The investments in its respective funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests/shares to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Distributions from each fund will be received based on the operations of the underlying investments and/or as the underlying investments of the funds are liquidated. It is not possible to estimate when the underlying assets in this asset class will be liquidated.

Pooled Funds

This asset class represents investments in pooled funds, which primarily include a diversified portfolio of fixed income securities, issued mainly by Canadian corporations, and diversified portfolios of Emerging Market listed equity. The investment objective of the pooled funds is to achieve capital appreciation and income through professionally managed portfolios. The fair value of the investments in this class has been estimated using NAV per share of the investments. There are no significant restrictions on the ability to sell the investments in this class.

14. SHARE CAPITAL

Common Shares

As at December 31, 2017 and 2016, OPG had 256,300,010 common shares issued and outstanding at a stated value of $5,126 million. OPG is authorized to issue an unlimited number of common shares without nominal or par value. Any issue of new shares is subject to the consent of OPG's shareholder.

Class A Shares

The Company's Articles of Amalgamation were amended effective December 1, 2017 to allow for the creation and issuance of non-voting Class A shares to the Province in exchange for its equity injections in OPG to be used solely for its investment in the Trust. All of the outstanding shares are owned directly by the Province and OPG is authorized to issue an unlimited number of Class A shares without nominal or par value. The Class A and common shares rank equally as to dividends on a share for share basis, and all dividends declared by OPG shall be declared in equal amounts per share on all outstanding shares without preference or distinction. Upon the liquidation, dissolution or wind-up of OPG, whether voluntary or involuntary, the holders of Class A shares and common shares are entitled to share equally, on a share for share basis, in all distributions of property and assets without preference or distinction. Any issue of new shares is subject to the consent of the Province. OPG is entitled to redeem outstanding shares in connection with the repayment of the Trust's debt or other purposes as may be approved by OPG's Board of Directors.

In December 2017, OPG issued 12,217,616 Class A shares at a price of $42.46 per share to the Province for its equity injection in OPG, generating proceeds of $519 million, which was used to fund 44 percent of the total funding requirement of the Trust's acquisition of Investment Interest from the IESO.

15. EARNINGS PER COMMON SHARE

Basic and diluted earnings per common share is calculated by dividing net income attributable to the Shareholder of OPG by the weighted average number of common shares outstanding.

Class A shares are included in the weighted average number of common shares outstanding. The weighted average number of shares outstanding as at December 31, 2017 was 256.7 million (2016 – 256.3 million). There were no dilutive securities during the years ended December 31, 2017 and 2016.

16. COMMITMENTS AND CONTINGENCIES

Litigation

On August 9, 2006, a Notice of Action and Statement of Claim filed with the Ontario Superior Court of Justice in the amount of $500 million was served against OPG and Bruce Power by British Energy Limited and British Energy International Holdings Limited (together British Energy). The action is for contribution and indemnity of any amounts British Energy was liable for in an arbitration against it by some of the owners of Bruce Power regarding an alleged breach of British Energy's representations and warranties to the claimants when they purchased British Energy's interest in Bruce Power (the Arbitration). Both the action and the Arbitration relate to corrosion to a steam generator unit discovered after OPG leased the Bruce nuclear generating stations to Bruce Power.

In 2012, the arbitrator found that British Energy was liable to the claimants for some of the damages they claimed. The final settlement amount was valued by British Energy at $71 million. In September 2014, British Energy amended its Statement of Claim (Amended Claim) to reduce the claim amount to $100 million to reflect that the purchasers of British Energy's interest in Bruce Power did not receive the full damages they originally claimed in the Arbitration. British Energy also added an allegation to its Amended Claim that OPG breached a covenant to maintain the steam generator between the time of the initial agreement to lease and the effective date of the lease in accordance with "Good Utility Practices".

In November 2016, British Energy obtained consent from Ontario Superior Court of Justice to a timetable for the remaining steps in the litigation, pursuant to which the matter must be set down for trial by December 31, 2018. OPG has delivered a statement of defence in accordance with an extension of the original June 30, 2017 delivery deadline set up in the timetable. [**MONITOR**]

Various other legal proceedings are pending against OPG or its subsidiaries covering a wide range of matters that arise in the ordinary course of business activities.

Each of these matters is subject to various uncertainties. Some of these matters may be resolved unfavourably. While it is not possible to determine the ultimate outcome of the various pending actions, it is the Company's belief that their resolution is not likely to have a material adverse impact on its financial position.

Guarantees

The Company and its joint venture partners have jointly guaranteed the financial performance of jointly owned entities related primarily to the payment of liabilities. As at December 31, 2017, the total amount of guarantees OPG provided to these entities was $82 million (December 31, 2016 − $83 million). OPG may terminate some of these guarantees within a short time frame by providing written notice to the counterparties at any time. Other guarantees have terms ending between 2019 and 2029. As at December 31, 2017, the potential impact of the fair value of these guarantees to income has been estimated to be negligible and OPG does not expect to make any payments associated with these guarantees.

Contractual Obligations

OPG's contractual obligations as at December 31, 2017, are as follows:

(millions of dollars)	2018	2019	2020	2021	2022	Thereafter	Total
Fuel supply agreements	158	125	115	88	67	67	620
Contributions to the OPG registered pension plan [1]	215	219	-	-	-	-	434
OPG long-term debt repayment	398	368	663	413	172	3,721	5,735
Interest on OPG long-term debt	244	226	204	175	161	3,006	4,016
Fair Hydro Trust senior debt repayment [2]	-	601	-	-	-	-	601
Interest on Fair Hydro Trust senior debt	15	15	-	-	-	-	30
Commitments related to Darlington Refurbishment project [3]	473	-	-	-	-	-	473
Commitments related to Ranney Falls GS project	29	5	-	-	-	-	34
Operating licences	40	41	24	28	28	87	248
Operating lease obligations	28	24	24	22	22	79	199
Unconditional purchase obligations	59	58	56	5	-	-	178
Accounts payable and accrued charges	957	8	-	-	-	16	981
Other	57	30	2	1	1	64	155
Total	2,673	1,720	1,088	732	451	7,040	13,704

[1] The pension contributions include ongoing funding requirements and additional funding requirements towards the deficit, in accordance with the actuarial valuation of the OPG registered pension plan as at January 1, 2017. The next actuarial valuation of the OPG registered pension plan must have an effective date no later than January 1, 2020. The pension contributions are affected by various factors including market performance, changes in actuarial assumptions, plan experience, changes in the pension regulatory environment, and the timing of funding valuations. Funding requirements after 2019 are excluded due to significant variability in the assumptions required to project the timing of future cash flows. The amount of OPG's additional, voluntary contribution, if any, is revisited from time to time.

[2] The notes were issued by the Fair Hydro Trust under an $800 million two-year revolving warehouse facility in December 2017. In February 2018, the Trust issued $500 million of senior notes payable to repay the majority of the outstanding balance of the revolving warehouse facility.

[3] Represents estimated currently committed costs to close the project, including accruals for completed work, demobilization of project staff and cancellation of existing contracts and material orders.

Other Commitments

Collective Agreements

As of December 31, 2017, OPG had approximately 9,212 regular employees. Most of OPG's regular employees are represented by two unions:

- **The PWU** – This union represents approximately 4,849 OPG employees or approximately 53 percent of OPG's regular workforce as at December 31, 2017. Union membership includes operators, technicians, skilled trades, clerical, and security personnel. The current collective agreement between OPG and the PWU has a three-year term, expiring on March 31, 2018.
- **The Society** – This union represents approximately 3,259 OPG employees or approximately 35 percent of OPG's regular workforce as at December 31, 2017. Union membership includes supervisors, professional engineers, scientists, and other professionals. The current collective agreement between OPG and The Society has a three-year term, expiring on December 31, 2018.

In addition to the regular workforce, construction work is performed through 19 craft unions with established bargaining rights at OPG facilities. These bargaining rights are established either through the Electrical Power Systems Construction Association or directly with OPG. Collective agreements between the Company and its construction unions are negotiated either directly or through EPSCA. All of these collective agreements currently have multi-year terms, expiring on April 30, 2020.

17. BUSINESS SEGMENTS

Effective in the fourth quarter of 2017, OPG has the following six reportable business segments:

- Regulated – Nuclear Generation
- Regulated – Nuclear Waste Management
- Regulated – Hydroelectric
- Contracted Generation Portfolio
- Services, Trading, and Other Non-Generation
- Fair Hydro Trust

Regulated – Nuclear Generation Segment

The Regulated – Nuclear Generation business segment operates in Ontario, generating and selling electricity from the Pickering GS and the Darlington GS, both owned and operated by OPG. The business segment also includes revenue under the terms of a long-term lease arrangement and related agreements with Bruce Power related to the Bruce nuclear generating stations. This revenue includes lease revenue, fees for nuclear waste management, and revenue from heavy water sales and detritiation services. The segment also earns revenue from isotope sales and ancillary services supplied by OPG-operated nuclear stations. Ancillary revenues are earned through voltage control and reactive support. Revenues under the agreements with Bruce Power, including a portion of heavy water sales, and from isotope sales and ancillary services are included by the OEB as a credit to customers in the determination of the regulated prices for production from OPG's nuclear facilities, which has had the effect of reducing these prices.

Regulated – Nuclear Waste Management Segment

OPG's Regulated – Nuclear Waste Management segment reports the results of the Company's operations associated with the management of nuclear used fuel and L&ILW, the decommissioning of OPG's nuclear generating stations including the stations on lease to Bruce Power and other waste management facilities, the management of the Nuclear Segregated Funds, and related activities including the inspection and maintenance of the waste storage facilities. Accordingly, accretion expense, which is the increase in the Nuclear Liabilities carried on the consolidated balance sheets in present value terms due to passage of time, and earnings from the Nuclear Segregated Funds are reported under this segment.

As the nuclear generating stations operate over time, OPG incurs incremental costs related to used nuclear fuel and low and intermediate level wastes, which increase the Nuclear Liabilities. OPG charges these incremental costs to current operations in the Regulated – Nuclear Generation segment to reflect the cost of producing energy from the Pickering and Darlington nuclear generating stations and earning revenue under the Bruce Lease and related agreements. Since the incremental costs increase the Nuclear Liabilities in the Regulated – Nuclear Waste Management segment, OPG records an inter-segment charge between the Regulated – Nuclear Generation and the Regulated – Nuclear Waste Management segments. The impact of the inter-segment charge is eliminated in the consolidated statements of income and balance sheets.

The Regulated – Nuclear Waste Management segment is considered rate regulated because OPG's costs associated with the Nuclear Liabilities have been included in the determination of regulated prices for production from the Pickering and Darlington nuclear generating stations, in accordance with the methodology applied by the OEB since its 2008 decision on OPG's first application for regulated prices.

Regulated – Hydroelectric Segment

OPG's Regulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from most of the Company's hydroelectric generating stations. The business segment includes the results of the Sir Adam Beck 1, 2 and Pump generating stations, the DeCew Falls 1 and 2 generating stations, and the R.H. Saunders GS

that were prescribed for rate regulation prior to 2014, and the 48 hydroelectric stations prescribed for rate regulation effective in 2014.

In addition, the business segment includes ancillary and other revenues from OPG's regulated hydroelectric stations. Ancillary revenues are earned through offering available generating capacity as operating reserve and through the supply of other ancillary services including voltage control and reactive support, certified black start facilities, regulation service, and other services. These ancillary revenues and other revenues are included by the OEB as a credit to ratepayers in the determination of the regulated prices for production from OPG's prescribed hydroelectric facilities, which has had the effect of reducing these prices.

Contracted Generation Portfolio Segment

The Contracted Generation Portfolio business segment operates in Ontario, generating and selling electricity from the Company's generating stations that are not prescribed for rate regulation. The segment primarily includes generating facilities that are under an ESA with the IESO or other long-term contracts.

The Contracted Generation Portfolio segment also includes OPG's share of equity income from its 50 percent ownership interests in the PEC and Brighton Beach stations.

The business segment also includes ancillary revenues and other revenues from the stations included in the segment, which are earned through offering available generating capacity as operating reserve, and the supply of other ancillary services including voltage control and reactive support, certified black start facilities, regulation service, and other services.

Services, Trading, and Other Non-Generation Segment

The Services, Trading, and Other Non-Generation segment is a non-generation segment that is not subject to rate regulation. It includes the revenue and expenses related to OPG's trading and other non-hedging activities. As part of these activities, OPG transacts with counterparties in Ontario and neighbouring energy markets in predominantly short-term trading activities of typically one year or less in duration. These activities relate to electricity that is purchased and sold at the Ontario border, financial energy trades, financial risk management energy product revenues, and sales of energy-related products. In addition, OPG has a wholly owned trading subsidiary that transacts solely in the US market. The results of this subsidiary are reported in this segment. All contracts that are not designated as hedges are recorded as assets or liabilities at fair value on the consolidated balance sheets with changes in fair value recorded in the revenue of this segment. In addition, the segment includes revenue from real estate rentals and non-regulated services, non-regulated business development activities, and, prior to OPG's decision to decommission the stations, preservation costs related to the former coal-fired Lambton GS and the Nanticoke GS sites.

OM&A expenses of the generation business segments include an inter-segment service fee for the use of certain PP&E and intangible assets held within Service, Trading, and Other Non-Generation segment. The total service fee is recorded as a reduction to the segment's OM&A expenses.

The service fee included in OM&A expenses by segment in 2017 and 2016 was as follows:

(millions of dollars)	**2017**	**2016**
Regulated – Nuclear Generation	**36**	34
Regulated – Hydroelectric	**7**	7
Contracted Generation Portfolio	**4**	4
Reduction to Services, Trading, and Other Non-Generation	**47**	45

Fair Hydro Trust Segment

The Trust was established on December 20, 2017 and was established as a non-generation segment that is not subject to rate regulation. It includes OPG's earnings from the Trust, which includes the financial results of the Trust, as well as revenues and expenses related to OPG's role as Financial Services Manager of the Fair Hydro Trust and holder of subordinated debt issued by the Trust. Revenues include recovery of related to third-party costs and fees for financial management and ongoing administration services. OM&A expenses include incurred third-party and other recoverable incurred costs related to the management and administration of the Trust. Net interest expense (income) include interest income from OPG's investment in subordinated debt of the Trust of up to 49 percent of the Trust's total outstanding debt, partially offset by interest costs on debt issued by OPG to fund five percent of the subordinated investment in the Trust.

The earnings from the Trust is comprised of the following:

For the year ended December 31 *(millions of dollars)*	**2017**
Revenues	**(8)**
OM&A expenses	**8**
Net interest expense (income)	**(1)**
Earnings from Fair Hydro Trust	**(1)**

Segment Income (Loss) for the Year Ended December 31, 2017 *(millions of dollars)*	Nuclear Generation	Regulated Nuclear Waste Management	Hydro-Electric	Unregulated Contracted Generation Portfolio	Unregulated Services, Trading, and Other Non-Generation	Fair Hydro Trust	Elimination	Total
Revenue	**3,095**	**121**	**1,436**	**579**	**43**	**-**	**(116)**	**5,158**
Fuel expense	**284**	**-**	**351**	**53**	**1**	**-**	**-**	**689**
Gross margin	**2,811**	**121**	**1,085**	**526**	**42**	**-**	**(116)**	**4,469**
Operations, maintenance and administration	**2,293**	**129**	**330**	**169**	**18**	**1**	**(116)**	**2,824**
Depreciation and amortization	**431**	**-**	**139**	**79**	**30**	**-**	**-**	**679**
Accretion on fixed asset removal and nuclear waste management liabilities	**-**	**943**	**-**	**9**	**8**	**-**	**-**	**960**
Earnings on nuclear fixed asset removal and nuclear waste management funds	**-**	**(801)**	**-**	**-**	**-**	**-**	**-**	**(801)**
Earnings from Fair Hydro Trust						**(1)**		**(1)**
Income from investments subject to significant influence	**-**	**-**	**-**	**(38)**	**-**	**-**	**-**	**(38)**
Property taxes	**26**	**-**	**1**	**7**	**6**	**-**	**-**	**40**
Other (gains) losses	**4**	**-**	**1**	**-**	**(384)**	**-**	**-**	**(379)**
Income (loss) before interest and income taxes	**57**	**(150)**	**614**	**300**	**364**	**-**	**-**	**1,185**
Net interest expense								**95**
Income before income taxes								**1,090**
Income tax expense								**209**
Net income								**881**

Segment Income (Loss) for the Year Ended December 31, 2016 *(millions of dollars)*	Nuclear Generation	Regulated Nuclear Waste Management	Hydroelectric	Unregulated Contracted Generation Portfolio	Unregulated Services, Trading, and Other Non-Generation	Elimination	Total
Revenue	3,481	138	1,527	573	68	(134)	5,653
Fuel expense	315	-	353	58	1	-	727
Gross margin	3,166	138	1,174	515	67	(134)	4,926
Operations, maintenance and administration	2,210	146	325	178	22	(134)	2,747
Depreciation and amortization	925	-	225	75	32	-	1,257
Accretion on fixed asset removal and nuclear waste management liabilities	-	912	-	9	8	-	929
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(746)	-	-	-	-	(746)
Income from investments to significant influence	-	-	-	(37)	-	-	(37)
Property taxes	26	-	1	7	12	-	46
Restructuring	-	-	-	-	6	-	6
Other (gains) losses	1	-	(19)	1	-	-	(17)
Income (loss) before interest and taxes	4	(174)	642	282	(13)	-	741
Net interest expense							120
Income before income taxes							621
Income tax expense							168
Net income							453

Selected Consolidated Balance Sheet information as at December 31, 2017 *(millions of dollars)*	Nuclear Gener-ation	Regulated Nuclear Waste Manage-ment	Hydro-electric	Unregulated Contracted Generation Portfolio	Unregulated Services, Trading, and Other Non-Generation	Fair Hydro Trust	Total
Segment property, plant and equipment in-service, net	**6,167**	**-**	**7,359**	**3,480**	**224**	**-**	**17,230**
Segment construction in progress	**3,839**	**-**	**157**	**78**	**18**	**-**	**4,092**
Segment property, plant and equipment, net	**10,006**	**-**	**7,516**	**3,558**	**242**	**-**	**21,322**
Segment intangible assets in-service, net	**4**	**-**	**1**	**5**	**84**	**-**	**94**
Segment development in progress	**16**	**-**	**-**	**-**	**23**	**-**	**39**
Segment intangible assets, net	**20**	**-**	**1**	**5**	**107**	**-**	**133**
Segment fuel inventory	**265**	**-**	**-**	**44**	**-**	**-**	**309**
Segment materials and supplies inventory, net:							
Current	**102**	**-**	**-**	**1**	**-**	**-**	**103**
Long-term	**351**	**-**	**-**	**4**	**-**	**-**	**355**
Nuclear fixed asset removal and nuclear waste management funds (current and non-current portions)	**-**	**16,724**	**-**	**-**	**-**	**-**	**16,724**
Financing receivables Fair Hydro Trust	**-**	**-**	**-**	**-**	**-**	**1,179**	**1,179**
Fixed asset removal and nuclear waste liabilities	**-**	**(20,077)**	**-**	**(151)**	**(193)**	**-**	**(20,421)**

Selected Consolidated Balance Sheet Information as at December 31, 2016 *(millions of dollars)*	Nuclear Generation	Regulated Nuclear Waste Management	Hydro-electric	Unregulated Contracted Generation Portfolio	Unregulated Services, Trading, and Other Non-Generation	Total
Segment property, plant and equipment in-service, net	5,653	-	7,355	3,282	226	16,516
Segment construction in progress	2,988	-	166	301	27	3,482
Segment property, plant and equipment, net	8,641	-	7,521	3,583	253	19,998
Segment intangible assets in-service, net	7	-	2	4	66	79
Segment development in progress	3	-	-	1	16	20
Segment intangible assets, net	10	-	2	5	82	99
Segment fuel inventory	276	-	-	34	-	310
Segment materials and supplies inventory, net:						
Current	99	-	-	1	-	100
Long-term	340	-	1	4	-	345
Nuclear fixed asset removal and nuclear waste management funds (current and non-current portions)	-	15,984	-	-	-	15,984
Fixed asset removal and nuclear waste management liabilities	-	(19,103)	-	(160)	(221)	(19,484)

Selected Capital Expenditure Information	Regulated		Unregulated				
(millions of dollars)	**Nuclear Generation**	**Nuclear Waste Manage-ment**	**Hydro-electric**	**Contracted Generation Portfolio**	**Services, Trading, and Other Non-Generation**	**Fair Hydro Trust**	**Total**
Year ended December 31, 2017							
Investment in property, plant and equipment, and intangible assets	**1,631**	**-**	**148**	**73**	**74**	**-**	**1,926**
Year ended December 31, 2016							
Investment in property, plant and equipment, and intangible assets	1,338	-	132	198	36	-	1,704

Shareholder Declarations and Shareholder Resolutions to Sell Certain Non-Core Real Estate Properties

In December 2015, OPG received a Shareholder Declaration and a Shareholder Resolution requiring the Company to sell its head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street in Toronto, Ontario. The sale was completed in April 2017 with a gain on sale of $283 million, which is net of tax effects of $95 million, recognized in net income during the year ended December 31, 2017. The pre-tax gain on sale was recorded as an item of Other gains in the consolidated statement of income in the Services, Trading and Other Non-Generation segment. Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. The amount of designated proceeds transferred into the Consolidated Revenue Fund ~~will~~ are expected to approximate ~~be equal to~~ the after-tax gain on sale. [**MONITOR**] The transfer is expected to take place ~~as early as~~ in the first quarter of 2018, through a special dividend authorized by OPG's Board of Directors in March 2018. **[MONITOR]**

In June 2016, OPG received a Shareholder Declaration and a Shareholder Resolution that requires the Company to sell its former Lakeview GS site located in Mississauga, Ontario. The Lakeview GS site assets were fully depreciated prior to June 2017. OPG entered into a purchase and sale agreement with a purchaser with the sale scheduled to close in March 2018. An estimated after-tax gain on sale of approximately $200 million will be recognized in net income upon completion of the transaction in the first quarter of 2018. **[MONITOR]** Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. In accordance with the Shareholder Resolution, approximately one-third of the site is to be transferred to the City of Mississauga, by the purchaser, for parkland, institutional, and cultural uses. **[MONITOR]**

Commented [MR-4]: Accepted this change.

Commented [DS5]: The amount of designated proceeds will be determined by regulation and therefore uncertain until the regulation is filed and made public.

Commented [MR-6]: Did not take this change.

18. NET CHANGES IN NON-CASH WORKING CAPITAL BALANCES

(millions of dollars)	December 31 2017	2016
Receivables from related parties	**60**	116
Prepaid expenses	**(14)**	(6)
Other current assets [1]	**(28)**	(32)
Fuel inventory	**1**	34
Materials and supplies	**(3)**	(4)
Income taxes payable	**2**	57
Accounts payable and accrued charges	**36**	15
	54	180

[1] Represents other accounts receivable.

19. RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One, the IESO and the OEFC. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly-owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions for the years ended December 31 are summarized below:

(millions of dollars)	2017 Revenue	2017 Expense	2016 Revenue	2016 Expense
Hydro One				
Electricity sales	**8**	**-**	6	-
Services	**1**	**10**	1	5
Dividends	**7**	**-**	6	-
Province of Ontario				
Change in Decommissioning Segregated Fund amount due to Province [1]	**-**	**456**	-	192
Change in Used Fuel Segregated Fund amount due to Province [1]	**-**	**591**	-	235
Hydroelectric gross revenue charge	**-**	**110**	-	120
ONFA guarantee fee	**-**	**8**	-	8
Other	**-**	**2**	-	-
OEFC				
Hydroelectric gross revenue charge	**-**	**216**	-	203
Interest expense on long-term notes	**-**	**158**	-	169
Income taxes, net of investment tax credits	**-**	**246**	-	104
IESO				
Electricity related revenue	**4,802**	**-**	5,082	-
Fair Hydro Trust	**4**	**3**	-	-
	4,822	**1,800**	5,095	1,036

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at December 31, 2017 and December 31, 2016, the Nuclear Segregated Funds were reported net of amounts due to the Province of $4,462 million and $3,415 million, respectively.

The receivable, AFS securities, payable and long-term debt balances between OPG and its related parties are summarized below:

(millions of dollars)	**December 31 2017**	**December 31 2016**
Receivables from related parties		
Hydro One	**1**	1
IESO − Electricity related receivables	**354**	421
IESO − Fair Hydro Trust [1]	**7**	-
OEFC	**-**	1
PEC	**4**	4
Province of Ontario	**3**	2
Financing receivables		
IESO − Fair Hydro Trust	**1,179**	-
Available-for-sale securities		
Hydro One shares	**188**	212
Accounts payable and accrued charges		
Hydro One	**1**	-
OEFC	**52**	61
Province of Ontario	**9**	2
IESO − Electricity-related payables	**5**	2
IESO − Fair Hydro Trust	**3**	-
Long-term debt (including current portion)		
Notes payable to OEFC	**3,195**	3,295

[1] Balance consists of unbilled revenue.

OPG holds interest-bearing Province of Ontario bonds in the Nuclear Segregated Funds and the OPG registered pension fund. As at December 31, 2017, the Nuclear Segregated Funds held $1,503 million of interest-bearing Province of Ontario bonds. As at December 31, 2016, the Nuclear Segregated Funds and the registered pension fund held $1,652 million and $284 million of interest-bearing Province of Ontario bonds, respectively. These bonds are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

In December 2017, the Trust purchased its first tranche of Investment Interest from the IESO for an exchange amount of $1.18 billion, which has been classified as a financing receivable on OPG's consolidated balance sheet. The transaction was settled in cash using proceeds from the Trust's issuance of senior and subordinated debt. Pursuant to the general regulation of the Act, the IESO is required to pay and remit carrying costs of the Trust, excluding repayment of principal on any debt obligations, up to July 31, 2021. Commencing May 1, 2021, Specified Consumers will be invoiced by their local distribution company for the Clean Energy Adjustment to pay financing and other costs of the Trust. These funds will be remitted to the Trust through the IESO and will be used to settle all funding and other related expenses of the Trust that underlie the financing receivable.

As at December 31, 2017, OPG's consolidated balance sheet included approximately $7 million of unbilled revenue from the IESO primarily for OPG's general fee for 2017 as Financial Services Manager relating to incurred third-party and certain direct labour costs. In February 2018, OPG submitted to the OEB its proposed general fee for 2017 in the amount of approximately $6 million for review pursuant to the requirements of the general regulation of the Fair Hydro Act. Once approved, the fees will be remitted to the Trust by the IESO and the Trust will pay OPG's fees as Financial Services Manager.

20. INVESTMENTS SUBJECT TO SIGNIFICANT INFLUENCE

Investments subject to significant influence consist of OPG's 50 percent ownership interest in the jointly controlled entities of the PEC gas-fired combined cycle generating station and the Brighton Beach, which are accounted for using the equity method. Details of the balances as at December 31, 2017 and December 31, 2016 are as follows:

(millions of dollars)	**2017**	**2016**
PEC		
Current assets	**20**	18
Long-term assets	**240**	256
Current liabilities	**(10)**	(8)
Long-term liabilities	**(6)**	(5)
Brighton Beach		
Current assets	**5**	5
Long-term assets	**160**	168
Current liabilities	**(17)**	(16)
Long-term liabilities	**(9)**	(7)
Long-term debt	**(74)**	(90)
Investments subject to significant influence	**309**	321

21. RESEARCH AND DEVELOPMENT

For the year ended December 31, 2017, research and development expenses of $106 million (2016 – $95 million) were charged to operations.

22. NON-CONTROLLING INTEREST

PSS Generating Station LP

PSS is a limited partnership between OPG, Coral Rapids Power Corporation (CRP) and PSS Generating Station Inc. (PSS GS Inc.). The principal business of the partnership is the development, construction, ownership, operation and maintenance of the 28 Megawatt (MW) Peter Sutherland Sr. hydroelectric GS on the New Post Creek. OPG and PSS GS Inc. are general partners and CRP is a limited partner in the partnership. CRP is a wholly owned subsidiary of the Taykwa Tagamou Nation.

The Peter Sutherland Sr. GS was placed in-service in March 2017 and, in April 2017, CRP increased its interest in PSS to 33 percent under the partnership agreement, by making contributions of $21 million, reducing OPG's interest to 67 percent. CRP's 33 percent interest in PSS is reported as non-controlling interest. As a result of CRP increasing its interest in the partnership, PSS's AOCL and partner's deficit were proportionately allocated to CRP as a reduction to its non-controlling interest.

Nanticoke Solar LP

In March 2016, Nanticoke Solar LP (NSLP), a partnership between OPG, SunEdison Canadian Construction LP (SECCLP) and a subsidiary of the Six Nations of the Grand River Development Corporation, was selected through IESO's Large Renewal Procurement program to construct a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands. In the first quarter of 2017, OPG acquired all of SECCLP's interests in NSLP, which represented 25 percent of the equity interest in NSLP. Subsequent to the acquisition, OPG owns 90 percent of the equity interest in NSLP, with an approximate value of $2 million. OPG consolidates the results of the NSLP in its consolidated financial statements and reports the equity interest of the other partner as non-controlling interest.

ONTARIO POWER GENERATION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

DECEMBER 31, 2017

[DRAFT]

RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One, the IESO and the OEFC. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly-owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions for the years ended December 31 are summarized below:

	2017		2016	
(millions of dollars)	**Income**	**Expense**	**Income**	**Expense**
Hydro One				
Electricity sales	**8**	**-**	6	-
Services	**1**	**10**	1	5
Dividends	**7**	**-**	6	-
Province of Ontario				
Change in Decommissioning Segregated Fund amount due to Province [1]	**-**	**456**	-	192
Change in Used Fuel Segregated Fund amount due to Province [1]	**-**	**591**	-	235
Hydroelectric gross revenue charge	**-**	**110**	-	120
ONFA guarantee fee	**-**	**8**	-	8
Other	**-**	**2**	-	-
OEFC				
Hydroelectric gross revenue charge	**-**	**216**	-	203
Interest expense on long-term notes	**-**	**158**	-	169
Income taxes, net of investment tax credits	**-**	**246**	-	104
IESO				
Electricity related revenue	**4,802**	**-**	5,082	-
Earnings from Fair Hydro Trust	**1**	**-**	-	-
	4,819	**1,797**	5,095	1,036

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at December 31, 2017 and December 31, 2016, the Nuclear Segregated Funds were reported net of amounts due to the Province of $4,462 million and $3,415 million, respectively.

The receivable, AFS securities, payable and long-term debt balances between OPG and its related parties are summarized below:

(millions of dollars)	**December 31 2017**	**December 31 2016**
Receivables from related parties		
Hydro One	**1**	1
IESO – Electricity related receivables	**354**	421
IESO – Fair Hydro Trust [1]	**7**	-
OEFC	**-**	1
PEC	**4**	4
Province of Ontario	**3**	2
Financing receivables		
IESO – Fair Hydro Trust	**1,179**	-
Available-for-sale securities		
Hydro One shares	**188**	212
Accounts payable and accrued charges		
Hydro One	**1**	-
OEFC	**52**	61
Province of Ontario	**9**	2
IESO – Electricity-related payables	**5**	2
IESO – Fair Hydro Trust	**3**	-
Long-term debt (including current portion)		
Notes payable to OEFC	**3,195**	3,295

[1] Balance consists of unbilled revenue.

OPG holds interest-bearing Province of Ontario bonds in the Nuclear Segregated Funds and the OPG registered pension fund. As at December 31, 2017, the Nuclear Segregated Funds held $1,503 million of interest-bearing Province of Ontario bonds, while the registered pension fund had no such holdings. As at December 31, 2016, the Nuclear Segregated Funds and the registered pension fund held $1,652 million and $284 million of interest-bearing Province of Ontario bonds, respectively. These bonds are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

In December 2017, the Fair Hydro Trust purchased its first tranche of Investment Interest from the IESO for an exchange amount of $1.18 billion, which has been classified as a financing receivable on OPG's consolidated balance sheet. The transaction was settled in cash using proceeds from the Trust's issuance of senior and subordinated debt. Pursuant to the general regulation of the Fair Hydro Act, the IESO is required to pay and remit carrying costs of the Trust, excluding repayment of principal on any debt obligations, up to July 31, 2021. Commencing May 1, 2021, Specified Consumers will be invoiced by their local distribution company for the Clean Energy Adjustment to pay the carrying costs of the Trust. These funds will be remitted to the Trust through the IESO and will be used to settle all funding and other related expenses of the Trust that underlie the financing receivable.

As at December 31, 2017, OPG's consolidated balance sheet included approximately $7 million of unbilled revenue from the IESO, primarily for OPG's general fee for 2017 as the Financial Services Manager under the Act relating to incurred third-party and certain direct labour costs.

~~Under one of the Trust's program agreements, The~~the Province has provided a limited guarantee to specified creditors of the Fair Hydro Trust. The limited guarantee would be triggered in the event that the Trust's ability to receive amounts in respect of its Investment Interest to pay for certain funding obligations is adversely affected due to the occurrence of any one of the following: the Province changes the Fair Hydro Act or any other legislation or

regulation; Ontario's electricity market significantly changes due to actions undertaken by the Province; or a court declares that the Act is ~~declared~~ invalid or unconstitutional.

Commented [MR-1]: Accepted this change.

From: Ronald Kwan
To: "HO Philip -FIN & C CTRL"; John Kim
Cc: GORE Michael -FIN & C CTRL; DYKXHOORN Sandra -STAKEREL
Subject: RE: EXTERNAL – RE: OPG Q4 2017 Submission to Province
Date: Thursday, March 08, 2018 2:39:15 PM

Thanks Philip.

I do recognise that the use of the subjunctive in English, spoken and written, has declined dramatically, so much so that its use draws raised eyebrows, as opposed to its non-use.

Ron

From: HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
Sent: March-08-18 14:36
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>
Cc: GORE Michael -FIN & C CTRL <michael.gore@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>
Subject: RE: EXTERNAL – RE: OPG Q4 2017 Submission to Province

Hi Ron,

Point taken. I did a bit of research. It seems both is widely used. 'Were' is past subjunctive whereas 'Was' is the simple past. Using the simple past in lieu of the past subjunctive is acceptable in spoken English. In formal English, using the past subjunctive may be better. That being said, we've used 'was' in the previous quarters so we will stick with the current wording and take it into consideration for first quarter of 2018. Thank you for the clarification.

Philip

From: Ronald Kwan [mailto:Ronald.Kwan@ofina.on.ca]
Sent: Thursday, March 08, 2018 2:18 PM
To: HO Philip -FIN & C CTRL <philip.ho@opg.com>; John Kim <John.Kim@ofina.on.ca>
Cc: GORE Michael -FIN & C CTRL <michael.gore@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>
Subject: RE: EXTERNAL – RE: OPG Q4 2017 Submission to Province

Hi Phillip,

A small grammatical note on the suggestion in the NR:

> If Unit 2 at the Darlington GS were not currently undergoing refurbishment …

The issue is not singular vs plural. The suggestion to use "were" is in the context of this being a hypothetical counterfactual, which would reasonably lead to the use of the subjunctive verb form – "were" in this case.

Ron

From: HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
Sent: March-08-18 14:07
To: John Kim <John.Kim@ofina.on.ca>
Cc: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>
Subject: RE: EXTERNAL – RE: OPG Q4 2017 Submission to Province

Hi John,

Please find attached our responses to your comments on the Press Release, Financial Statements, Management, Discussion & Analysis, and Annual Information Form. Thank you!

Philip

From: John Kim [mailto:John.Kim@ofina.on.ca]
Sent: Monday, February 26, 2018 6:26 PM
To: HO Philip -FIN & C CTRL <philip.ho@opg.com>
Cc: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; PAN Rebecca -FIN & C CTRL <rebecca.pan@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; LAURETA LAPIRA May -TREASURY <may.lapira@opg.com>; LADAK Lubna -TREASURY <lubna.ladak@opg.com>; MAK Ricky -TREASURY <ricky.mak@opg.com>
Subject: EXTERNAL – RE: OPG Q4 2017 Submission to Province

*** Exercise caution. This is an EXTERNAL email. DO NOT open attachments or click links from unknown senders or unexpected email. ***

Hi Pilip,

Pls. see attached. Two separate files on your inquiry from Sunday are attached with comments from our Legal (the first two attachments). The draft documents with our comments are also attached (the next four).

Thanks,

John

From: HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
Sent: Sunday, February 25, 2018 3:09 PM
To: Shruti.Talwar@ontario.ca; Manu.Sud@ontario.ca; John Kim <John.Kim@ofina.on.ca>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: GORE Michael -FIN & C CTRL <michael.gore@opg.com>; PAN Rebecca -FIN & C CTRL <rebecca.pan@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; LAURETA LAPIRA May -TREASURY <may.lapira@opg.com>; LADAK Lubna -TREASURY <lubna.ladak@opg.com>; MAK Ricky -TREASURY <ricky.mak@opg.com>

Subject: RE: OPG Q4 2017 Submission to Province

Hi All,

We have added disclosure in the Financial Statements and the Management's Discussion and Analysis, specifically in the Related Party Transactions section (attached below), as it relates to the limited guarantee provided by the Province to the creditors of the Fair Hydro Trust, established as the financing entity contemplated by the *Ontario Fair Hydro Plan Act, 2017*, of which OPG is the Financial Services Manager.

This is broadly consistent with the wording used in the Financing Plan. Please let us know if you have comments.

Our external reporting timeline remains the same as previously communicated. Please let us know if you have any other comments.

Thank you.

Regards,

Philip

From: HO Philip -FIN & C CTRL
Sent: Friday, February 16, 2018 5:11 PM
To: 'Shruti.Talwar@ontario.ca' <Shruti.Talwar@ontario.ca>; 'Manu.Sud@ontario.ca' <Manu.Sud@ontario.ca>; 'John.Kim@ofina.on.ca' <John.Kim@ofina.on.ca>; 'Ronald.Kwan@ofina.on.ca' <Ronald.Kwan@ofina.on.ca>
Cc: GORE Michael -FIN & C CTRL <michael.gore@opg.com>; PAN Rebecca -FIN & C CTRL <rebecca.pan@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>
Subject: OPG Q4 2017 Submission to Province

Hi All,

Please find attached OPG's draft Q4 2017 Financial Results Press Release, Management's Discussion and Analysis (MD&A), Annual Information Form (AIF) and Financial Statements for the Province's review.

We would greatly appreciate comments on the above **no later than Thursday, Feb 22nd**.

These documents will be filed with the Ontario Securities Commission on **Thursday, March 8th** following OPG's Board of Directors meeting.

Kindly forward all comments directly to Philip Ho – philip.ho@opg.com.

To assist the review process, the following are the key items in the Q4 2017 MD&A:

Highlights	
Recent Developments	MD&A p.13-19
OEB's Decision on OPG's Application for New Regulated Prices	MD&A p.13-15
Darlington Refurbishment	MD&A p.16-17; 28-30
Ontario's Fair Hydro Plan	MD&A p.17-18

<< File: Q4 2017 Press Release - PROVINCE MAILING.docx >> << File: Q4 2017 MD&A - DRAFT - Feb 16 - PROVINCE MAILING.docx >> << File: 2017 AIF - DRAFT - Feb 16 - PROVINCE MAILING.docx >> << File: Q4 2017 OPG FS PROVINCE MAILING Feb 16.docx >>

Philip Ho, CPA, CA | Senior Manager, External Reporting & Accounting Policy | Ontario Power Generation

700 University Avenue, Toronto ON M5G 1X6 | Phone: (416) 592-3320| E-mail: philip.ho@opg.com

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From:	Bruno Amara
To:	Ronald Kwan
Cc:	John Kim
Subject:	RE: Electricity Outlook Update File
Date:	Friday, October 13, 2017 6:49:20 PM
Attachments:	Electricity Sector Outlook (2017 10 13)_v03.xlsm

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Hi Ron,

Attached is the Current Electricity Outlook File. We will set up a meeting to review with you.

The updated outlook reflects the following.

- OPG net income increase due to higher generation and lower expenses from labour savings and delay of Pickering planned outage.,
- Lower Hydro One net income largely reflects the impact of OEB transmission rate decisions on September 29, 2017. [Note Hydro One results are now directly through the model. The OEB decision impacts are very similar to those calculated outside the model.]
- Electricity PIL's update largely reflects impacts of OPG and Hydro One earnings updates.

Note:

1) the outlook update does not reflect the update to OPG's gain on sale of head office. This would add a further $82M to OPG EBT. We held off updating to avoid any confusion with current fiscal plan where gain on sale is still in Sales and Rentals. This update is flagged as a positive revenue risk in the Risk worksheet.
2) the Outlook is still based on a 70% Provincial Hydro One allocation rather than the roughly 50% going forward if we were to unpack. As we are now linking directly to Hydro One model, this means that our OEB decision impacts are implicitly calculated at 70% ownership rather than 50% - i.e., impact is a bit overstated. We can think of options to address this, e.g., add an adjustment to the Outlook or reflect an upside risk in the Risk table.

Some of the structural/format changes in the Electricity Outlook include

- A new Cover sheet to summarize, for TBS/OB/OEP, all expenses and revenues for electricity sector.
    - EFB met with OB, TBS and OEP earlier in the year to respond to a request that the required fiscal plan entries be made clear. (Mainly necessary due to turnover on TBS side and analysts unfamiliar with OEFC consolidation and MoF entries.
    - The Cover Sheet is just a summary of "Electricity Summary – Budget, Electricity Summary – On Deck, and Electricity Summary – Change" that have always been part of the Outlook.
- New Tracking worksheet (for EFB only) to track impact by expense/revenue line of each individual update to the outlook.
    - This is useful for variance analysis as you can trace all the updates made to a revenue/expense line during the year and reasons for the update.
    - Useful for quality control e.g. , a check that impacts of updates are as expected (both expected line, expected sign and expected magnitude) and a check that updates correspond to those shown on Electricity Summary – Change worksheet
- Documentation of data sources has been updated
- Hydro One worksheet is simplified with some calculations/information moved to separate worksheets. E.g. , Public Debt interest calculation on separate worksheet, Provincial share ownership on separate worksheet and current assumptions clarified.
- Formatting of each worksheet is standardized in terms of fiscal years shown, labelling etc.

There are a couple of updates to come Monday on Risk table, mostly around generic risks.

Bruno Amara
Sr. Manager, Financial and Regulatory Analysis
Electricity Finance Branch
Corporate and Electricity Finance Division
Ontario Financing Authority

Tel: 416-325-1489
Email: bruno.amara@ofina.on.ca

Electricity Sector Outlook
October 2017

Disclosure:

All information contained in this workbook is confidential and commercially sensitive

All projected numbers are estimates and subjected to change

This workbook and all information or analysis contained in it is property of the Ontario Financing Authority.
Please consult with OFA before sharing of information.

Commercially Sensitive and Confidential Advice to Cabinet for Consideration of Options for Discussion Purposes Only

Commercially Sensitive and Confidential Advice to Cabinet for Consideration of Options for Discussion Purposes Only

Electricity Sector Outlook
Including Line Items for Cor

Electricity Summary - On De

Type	Ministry Pickup	Line
Expense	MOF (OEFC)	38
Expense	MOF (OEFC)	40
Expense	MOF (OEFC)	41
Expense	MOF	17
Expense	MOF (OEFC)	42

Revenue	ENE	7
Revenue	ENE	8
Revenue	ENE	10
Revenue		11
Revenue	MOF (OEFC)	26
Revenue	MOF (OEFC)	29
Revenue	MOF (OEFC)	30
Revenue	MOF (OEFC)	31
Revenue	MOF (OEFC)	34

Electricity Summary - Budg

For Discussion

Type	Ministry Pickup	Line
Expense	MOF (OEFC)	38
Expense	MOF (OEFC)	40
Expense	MOF (OEFC)	41
Expense	MOF	17
Expense	MOF (OEFC)	42

Revenue	ENE	7
Revenue	ENE	8
Revenue	ENE	10

Revenue	MOF (OEFC)	25
Revenue	MOF (OEFC)	29
Revenue	MOF (OEFC)	30
Revenue	MOF (OEFC)	31
Revenue	MOF (OEFC)	34

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36

Electricity Summary - Chang

Type	Ministry Pickup	Line
Expense	MOF (OEFC)	69
Expense	MOF (OEFC)	71
Expense	MOF (OEFC)	72
Expense	MOF	48
Expense	MOF (OEFC)	73

Revenue	ENE	38
Revenue	ENE	39
Revenue	ENE	41
Revenue	MOF (OEFC)	25
Revenue	MOF (OEFC)	60
Revenue	MOF (OEFC)	61
Revenue	MOF (OEFC)	62
Revenue	MOF (OEFC)	65

17
36

FOR EFB USE ONLY

Type	Ministry Pickup	Line
Expense	MOF (OEFC)	69
Expense	MOF (OEFC)	71
Expense	MOF (OEFC)	72
Expense	MOF	48
Expense	MOF (OEFC)	73

Revenue	ENE	38
Revenue	ENE	39
Revenue	ENE	41
Revenue	MOF (OEFC)	25

Revenue	MOF (OEFC)	60
Revenue	MOF (OEFC)	61
Revenue	MOF (OEFC)	62
Revenue	MOF (OEFC)	65

	17
	36

Type	Ministry Pickup	Line
Expense	MOF (OEFC)	69
Expense	MOF (OEFC)	71
Expense	MOF (OEFC)	72
Expense	MOF	48
Expense	MOF (OEFC)	73

Revenue	ENE	38
Revenue	ENE	39
Revenue	ENE	41
Revenue	MOF (OEFC)	25
Revenue	MOF (OEFC)	60
Revenue	MOF (OEFC)	61
Revenue	MOF (OEFC)	62
Revenue	MOF (OEFC)	65

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MOF Expense Items (consolidated)	Current Outlook		
Item	**2017-18**	**2018-19**	**2019-20**
Power Supply Contract Costs	(292)	(325)	(301)
Demand Management Support Costs	(10)	-	-
Provision for Electricity Sector	129	-	-
Provision for Electricity Sector	(129)	-	-
Other (Finance)	(6)	(6)	(6)
Total MOF Expense	**(308)**	**(331)**	**(307)**
MOF Revenue Items (consolidated)			
OPG Income	152	732	625
OPG - ONFA and other Fair Value Adjustments	-	-	-
HOI Income	431	457	545
Brampton Income	-	-	-
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	381	479	531
Electricity Debt Retirement Charge	623	-	-
Power Supply Contract Recoveries	292	325	301
Net Reduction of Power Purchase Contracts	74	41	30
Miscellaneous	-	-	-
Total MOF Revenue	**1,953**	**2,034**	**2,032**
OFA IOD Expense			
Public Debt Interest - Electricity Sector	(454)	(454)	(454)
Interest on Debt	(475)	(438)	(411)
Total OFA IOD Expense	**(929)**	**(892)**	**(865)**
Impact on Surplus/Deficit	**716**	**811**	**860**
check	**-**	**-**	**-**

et17

MOF Expense Items (consolidated)	Plan		
Item	**2017-18**	**2018-19**	**2019-20**
Power Supply Contract Costs	(292)	(325)	(301)
Demand Management Support Costs	(10)	0	0
Provision for Electricity Sector	125	0	0
Provision for Electricity Sector	(125)	0	0
Other (Finance)	(6)	(6)	(6)
Total MOF Expense	**(308)**	**(331)**	**(307)**
MOF Revenue Items (consolidated)			
OPG Income	97	732	625
OPG - ONFA and other Fair Value Adjustments	0	0	0
HOI Income	520	562	603
Brampton Income			

Electricity Payments-in-Lieu of Taxes (PILs), including CIT	405	476	538
Electricity Debt Retirement Charge	623	0	0
Power Supply Contract Recoveries	292	325	301
Net Reduction of Power Purchase Contracts	74	41	30
Miscellaneous	0	0	0
Total MOF Revenue	**2,011**	**2,136**	**2,098**
OFA IOD Expense			
Public Debt Interest - Electricity Sector	(492)	(492)	(492)
Interest on Debt	(422)	(374)	(342)
Total OFA IOD Expense	**(914)**	**(866)**	**(834)**
Impact on Surplus/Deficit	**789**	**939**	**957**
	-	-	-

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MOF Expense Items (consolidated)

Item	2017-18	2018-19	2019-20
Power Supply Contract Costs	0	0	0
Demand Management Support Costs	0	0	0
Provision for Electricity Sector	4	0	0
Provision for Electricity Sector	(4)	0	0
Other (Finance)	0	0	0
Total MOF Expense	**0**	**0**	**0**
MOF Revenue Items (consolidated)			
OPG Income	55	0	0
OPG - ONFA and other Fair Value Adjustments	0	0	0
HOI Income	(89)	(105)	(58)
Brampton Income	0	0	0
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	(24)	3	(7)
Electricity Debt Retirement Charge	0	0	0
Power Supply Contract Recoveries	(0)	(0)	(0)
Net Reduction of Power Purchase Contracts	(0)	(0)	(0)
Miscellaneous	0	0	0
Total MOF Revenue	**(58)**	**(102)**	**(66)**
OFA IOD Expense			
Public Debt Interest - Electricity Sector	38	38	38
Interest on Debt	(53)	(64)	(69)
Total OFA IOD Expense	**(15)**	**(26)**	**(31)**
Impact on Surplus/Deficit	**(73)**	**(127)**	**(96)**
	-	*(0)*	*(0)*

MOF Expense Items (consolidated)

Item	2017-18	2018-19	2019-20
Power Supply Contract Costs	0	0	0
Demand Management Support Costs	0	0	0
Provision for Electricity Sector	28	0	0
Provision for Electricity Sector	(28)	0	0
Other (Finance)	0	0	0
Total MOF Expense	**0**	**0**	**0**

MOF Revenue Items (consolidated)

OPG Income	55	0	0
OPG - ONFA and other Fair Value Adjustments	0	0	0
HOI Income	(65)	(76)	(48)
Brampton Income	0	0	0
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	(24)	3	(7)

Electricity Debt Retirement Charge	0	0	0
Power Supply Contract Recoveries	(0)	(0)	(0)
Net Reduction of Power Purchase Contracts	(0)	(0)	(0)
Miscellaneous	0	0	0
Total MOF Revenue	**(34)**	**(73)**	**(55)**
OFA IOD Expense			
Public Debt Interest - Electricity Sector	38	38	38
Interest on Debt	(53)	(64)	(69)
Total OFA IOD Expense	**(15)**	**(26)**	**(31)**
Impact on Surplus/Deficit	**(49)**	**(99)**	**(86)**

MOF Expense Items (consolidated)

Item	**2017-18**	**2018-19**	**2019-20**
Power Supply Contract Costs	**-**	**-**	**-**
Demand Management Support Costs	**-**	**-**	**-**
Provision for Electricity Sector	**(24)**	**-**	**-**
Provision for Electricity Sector	**24**	**-**	**-**
Other (Finance)	**-**	**-**	**-**
Total MOF Expense	**-**	**-**	**-**
MOF Revenue Items (consolidated)			
OPG Income	**-**	**-**	**-**
OPG - ONFA and other Fair Value Adjustments	**-**	**-**	**-**
HOI Income	**(24)**	**(29)**	**(10)**
Brampton Income	**-**	**-**	**-**
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	**-**	**-**	**-**
Electricity Debt Retirement Charge	**-**	**-**	**-**
Power Supply Contract Recoveries	**-**	**-**	**-**
Net Reduction of Power Purchase Contracts	**-**	**-**	**-**
Miscellaneous	**-**	**-**	**-**
Total MOF Revenue	**(24)**	**(29)**	**(10)**
OFA IOD Expense	**-**	**-**	**-**
Public Debt Interest - Electricity Sector	**-**	**-**	**-**
Interest on Debt	**-**	**-**	**-**
Total OFA IOD Expense	**-**	**-**	**-**
Impact on Surplus/Deficit	**(24)**	**(29)**	**(10)**

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Date	Change ID#	Source in File	Tab
5/1/2017	20170501-1	Link	ONFA
5/1/2017	20170501-2	Link	Hydro One
5/1/2017	20170501-3	Link	Hydro One
5/1/2017	20170501-4	Link	Other Data
5/2/2017	20170502-1	Link	OPG
5/9/2017	20170509-1	Link	OPG
5/10/2017	20170510-1	Link	Hydro One
5/10/2017	20170510-2	Link	Other Data
5/12/2017	20170512-1	Link	Hydro One
5/15/2017	20170515-1	Link?	
5/15/2017	20170515-2	Link	OPG
5/17/2017	20170517-1	Link	Hydro One
5/17/2017	20170517-2	Link	ONFA
5/17/2017	20170517-3		
5/18/2017	20170518-1	Link	OPG
5/18/2017	20170518-2	Link	OPG
5/18/2017	20170518-3		
6/15/2017	20170615-1	Link	OPG
6/22/2017	20170622-1	Link	Hydro One
6/22/2017	20170622-2	Link	Hydro One
6/26/2017	20170626-1		
6/29/2017	20170629-1		

7/6/2017	20170706-1		
7/11/2017	20170711-1		
7/13/2017	20170713-1	Link	Provision
7/17/2017	20170717-1	Link	Revenue (Risks)
7/24/2017	20170724-1	Link	Revenue (Risks)
7/25/2017	20170725-1	Link	Revenue (Risks)
7/26/2017	20170726-1	Link	Revenue (Risks)
7/27/2017	20170727-1	Link	Revenue (Risks)
7/27/2017	20170727-2	Link	Revenue (Risks)
7/31/2017	20170731-1		
7/31/2017	20170731-2	Link	Hydro One
7/31/2017	20170731-3	Link	Other Data
8/11/2017	20170811-1	Link	OPG
8/15/2017	20170815-1		
8/15/2017	20170815-2		
8/15/2017	20170815-3		
8/15/2017	20170815-4		
8/15/2017	20170815-5		Other Data
8/15/2017	20170815-6		Other Data
8/15/2017	20170815-7		Other Data
8/15/2017	20170815-8		Other Data
8/15/2017	20170815-9		Other Data
8/15/2017	20170815-10		Other Data
8/17/2017	20170817-1	Link	Provision
8/17/2017	20170817-2	Link	Hydro One
8/18/2017	20170818-1	Link	Revenue (Risks)
8/22/2017	20170822-1	Link	OPG
8/25/2017	20170825-1		Hydro One
8/29/2017	20170829-1		Revenue (Risks)
8/31/2017	20170831-1		Revenue (Risks)
9/5/2017	20170905-1		Other Data
9/5/2017	20170905-2		Other Data
9/5/2017	20170905-3	Link	OPG

9/6/2017	20170906-1	Link	Other Data
9/6/2017	20170906-2	Link	Revenue (Risks)
9/8/2017	20170908-1	Link	Hydro One
9/8/2017	20170908-2	Link	OPG
9/11/2017			
9/12/2017			
9/13/2017			
9/21/2017			
9/22/2017			
10/2/2017			Hydro One
10/2/2017			
10/2/2017			
10/2/2017			
10/4/2017	20171004-1		OPG
10/4/2017	20171004-2		OPG
10/4/2017			
10/4/2017			
10/5/2017			
10/6/2017			
10/7/2017			
10/8/2017			
10/10/2017	20171010-1		Hydro One
10/10/2017			
10/10/2017			
10/11/2017	20171011-1		OPG
10/11/2017			
10/11/2017			
10/12/2017			OPG
10/12/2017			
10/12/2017			
10/12/2017			

Track Changes in Surplus/Deficit

FOR EFB USE ONLY

Budget 2017 Outlook
Current Outlook
Change Since Budget

Description of Update
ONFA Update as of March 31 2017
s. 50.3 Update for 2016-17
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Debt Interest
OPG IFRS Risk in 2019-20
Revised OPG 2016-17 Net Income
Revised OPG 2016-17 Net Income
Revised OPG 2016-17 Net Income
tech change: slight update to assumed Prov share 70.05% from 70%
tech change: slight update to assumed Prov share 70.05% from 70%
tech change: slight update to assumed Prov share 70.05% from 70%
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
Updating H1 2016-17 Net Income for ESDI
Updating H1 2016-17 Net Income for ESDI
Updating H1 2016-17 Net Income for ESDI
Power Purchase Supply
H1 Model Forecasts - No Fiscal Update Resaving Data
Update Budget 2017 Tabs to reflect fiscal plan
Update OPG forecasted PILS to reflect sources
Update H1 2016-17 CIT
Re-inputting ONFA updates
Updating H1 Net Income to include Pref Shares in 16-17
Updating OPG Income Tax Expense for 2016-17
Updating OPG non-income tax PILs
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2017
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2018
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2019
Updating with actual OPG IFRS Adjustment 2016-17
Updating with actual OPG IFRS Adjustment 2016-17
Updating with actual OPG IFRS Adjustment 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
[NOT APPLIED] Updating H1 Brampton (Interim Adjustments)
Shifted H1 Brampton 2016-17 NI to the 2017-18
Removed H1 Brampton for 2016-17 (pending finals)
Removed H1 Brampton for 2016-17 (pending finals)
Removed H1 Brampton for 2016-17 (pending finals)

add prior-year adjustment for 2016-17

add prior-year adjustment for 2016-18
Reconfigured calculation of ESDI and MOF ESDI Expense
Reconfigured calculation of OPG 2017-18 Net Income
Backup for the Provincial Interest cost
Linking source for Revenue Risks Tab
New source for Revenue Risks Tab
Revenue Risks Tab - ROE Risks
Updating OEB Risk for OPG
OEB Staff Report - H1 Tx - Revenue Risks
OPG Pensions - Cash vs Accrual Deferral Accounts
Updating Links in Electricity Summary Change and OEFC Change
Preliminary estimate for Hydro One Brampton
Preliminary estimate for Hydro One Brampton
Preliminary estimate for Hydro One Brampton

Updating DRC for Actuals 2016-17 (Based on draft FS)
Updating PILs for 2016-17 Baced on Actuals
OPG: Non-ONFA Fair Value Adjustment
Round all Hydro One ownership assumptions to two decimal places
H1 Equity Adjustment rounding.
Round all Hydro One ownership assumptions to two decimal places
Round all Hydro One ownership assumptions to two decimal places
Revising source of ESDI, Dedicated Electricity Earnings
2016-17 - Update Power Supply Recoveries to actuals
2016-17 - Update Power Supply Recoveries to actuals
2016-17 - Updating Miscellaneous OEFC Revenue to Actuals
Adj: Exclude Bramton $15m add prior year adjustment +$3M
Adj: Exclude Bramton $15m add prior year adjustment +$3M
Public Accts: Updated IESO debt interest Interest On Debt, 2016-17
Public Accts: 2016-17 - Demand Management Support Costs Update
2017-18 - Demand Management Support Costs (no change)
Public Accts: 2016-17 - Updating Operating Expense in OEFC
Sourcing Provision for Electricity Sector from Actual Public Accounts
Revised 2016-17 Brampton Amount for Public Accounts
OPG Pensions - Cash vs Accrual Deferral Accounts (Revenue Risks Tab)
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
Reclassification
Reclassification
Reverting H1 Ownership change (undoing 20170518-3)
Reverting H1 Ownership change (undoing 20170518-3)
Reverting H1 Ownership change (undoing 20170518-3)
Updating Risks based on Hydro One Q2 Results Model
Avista Acquisition Risks
NUG Amortization Liability (sourcing amortization schedule)
2016-17 Actuals - Debt Guarantee Fee
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results

Interest Revenue for IESO and "Other"	
OPG Revenue Risks from OEB Filings	
Net income corrected for Preferred Shares	
Net income corrected for Preferred Shares	
Net income corrected for Preferred Shares	
Made link edits to OPG sheet so that the "Net Income Before Tax" 2017-18 number is not a h	
Updated PILs to include OPCD public accounts adjustment	
Provision tab fix to pick up Hydro One preferred share net income	
Provision tab fix to pick up Hydro One preferred share net income	
FTD Update to OEFC Outlook (Sep 19, 2017) OPG Interest	
FTD Update to OEFC Outlook (Sep 19, 2017) Other Interest	
Update to Hydro One PILs from information in Tranmsission rate application material	
OEB September 28, 2017 Hydro One decision and order impact - incl. rebasing	
OEB September 28, 2017 Hydro One decision and order impact - incl. rebasing	
OEB September 28, 2017 Hydro One decision and order impact - incl. rebasing	
Remove update of gain on sale of head office(assume in Sales and Rentals)	
Remove update of gain on sale of head office(assume in Sales and Rentals)	
Remove update of gain on sale of head office(assume in Sales and Rentals)	
Remove update of gain on sale of head office(assume in Sales and Rentals)	
Remove update of gain on sale of head office(assume in Sales and Rentals)	
Remove update of gain on sale of head office(assume in Sales and Rentals)	
Remove update of gain on sale of head office(assume in Sales and Rentals)	
Remove update of gain on sale of head office(assume in Sales and Rentals)	
Debenture Interest Costs - Removing from Revenue (Risks) and adding it ot H1 Model	
Debenture Interest Costs - Removing from Revenue (Risks) and adding it ot H1 Model	
Debenture Interest Costs - Removing from Revenue (Risks) and adding it ot H1 Model	
Updated OPG Net Income and PILs based on monthly report (August 2017 results)	
Updated OPG Net Income and PILs based on monthly report (August 2017 results)	
Updated OPG Net Income and PILs based on monthly report (August 2017 results)	
Correction to PILs on OPG sheet	
Correction to PILs on OPG sheet	
Correction to PILs on OPG sheet	
Correction to PILs on OPG sheet	
Switch to Direct from Model	
This line show net impact of latest change. READ COMMENT	
	Expense
	Expense
	Expense
	Expense
	Expense
	Revenue

Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue

Expense
Expense
Expense
Expense
Expense

Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue

		$ Millions	
		2016-17	**2017-18**
		930	789
	File	915	716
		-15	-73
	check	***0***	***0***

Outlook line affected	**Expense / Rever**	**Impacts by FY →**	
ONFA and other Fair Value Adjustments	Revenue	41.0	0.0
N/A		0.0	0.0
?		0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		38.1
Provision for Electricity Sector (MOF)	Expense		(38.1)
Public Debt Interest - Electricity Sector	Expense	0.0	38.1
Interest on Debt	Expense	0.0	(69.1)
OPG Income	Expense	0.0	0.0
OPG Income	Revenue	(2.0)	0.0
Provision for Electricity Sector (OEFC)	Expense	**(2.0)**	
Provision for Electricity Sector (MOF)	Expense	2.0	
HOI Income	Revenue	0.4	
Provision for Electricity Sector (OEFC)	Expense	0.4	
Provision for Electricity Sector (MOF)	Expense	(0.4)	
Public Debt Interest - Electricity Sector	Expense	1.7	
Provision for Electricity Sector (OEFC)	Expense	(1.7)	
Provision for Electricity Sector (MOF)	Expense	1.7	
Interest on Debt	Expense	(1.7)	
HOI Income	Revenue	(39.8)	0.0
Provision for Electricity Sector (OEFC)	Expense	**(39.8)**	
Provision for Electricity Sector (MOF)	Expense	39.8	
	Revenue	-	-
	Revenue	-	-
	n/a	-	-
		-	-
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	4.7	0.0
	Revenue	0.0	0.0
HOI Income	Revenue	18.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	7.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	8.0	9.0
HOI Income	Revenue	0.0	(141.5)
Provision for Electricity Sector (OEFC)	Expense		(141.5)
Provision for Electricity Sector (MOF)	Expense		141.5
OPG Income	Revenue	(3.0)	0.0
Provision for Electricity Sector (OEFC)	Expense	**(3.0)**	
Provision for Electricity Sector (MOF)	Expense	3.0	
HOI Income	Revenue	7.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**7.0**	
Provision for Electricity Sector (MOF)	Expense	(7.0)	
	Revenue	-	-
	Revenue	0.0	0.0
Brampton Income	Revenue	(14.7)	0.0
Provision for Electricity Sector (OEFC)	Expense	**(14.7)**	
Provision for Electricity Sector (MOF)	Expense	14.7	

Provision for Electricity Sector (OEFC)	Expense	3.2	
Provision for Electricity Sector (MOF)	Expense	(3.2)	
	Revenue	-	-
		-	-
	n/a	0.0	0.0
	n/a	0.0	0.0
	n/a	0.0	0.0
	n/a	0.0	0.0
	n/a	0.0	0.0
	n/a	0.0	0.0
	n/a	0.0	0.0
	n/a	0.0	0.0
Brampton Income	Revenue	15.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**15.0**	
Provision for Electricity Sector (MOF)	Expense	(15.0)	
Provision for Electricity Sector (OEFC)	Expense	3.2	
Provision for Electricity Sector (MOF)	Expense	(3.2)	
Electricity Debt Retirement Charge	Revenue	(4.0)	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	(29.0)	0.0
OPG Income	Revenue	(6.0)	0.0
HOI Income	Revenue	(0.0)	(0.0)
HOI Income	Revenue	(1.7)	0.0
Provision for Electricity Sector (OEFC)	Expense		(0.0)
Provision for Electricity Sector (MOF)	Expense		0.0
	Revenue	0.0	0.0
Power Supply Contract Recoveries	Revenue	99.0	0.0
Power Supply Contract Costs	Expense	(99.0)	
Miscellaneous	Revenue	14.0	0.0
Provision for Electricity Sector (OEFC)	Expense	(12.0)	
Provision for Electricity Sector (MOF)	Expense	12.0	
Interest on Debt	Expense	(3.0)	0.0
Demand Management Support Costs	Expense	1.8	0.0
		0.0	0.0
Other (Finance)	Expense	(1.0)	0.0
	Revenue	-	-
Brampton Income	Revenue	3.0	0.0
		0.0	0.0
OPG Income	Revenue	0.0	85.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue		(6.0)
Provision for Electricity Sector (OEFC)	Expense		**85.0**
Provision for Electricity Sector (MOF)	Expense		(85.0)
OPG Income	Revenue	6.0	
ONFA and other Fair Value Adjustments	Revenue	(6.0)	
HOI Income	Revenue	0.0	141.9
Provision for Electricity Sector (OEFC)	Expense		141.9
Provision for Electricity Sector (MOF)	Expense		(141.9)
	n/a	0.0	0.0
		0.0	0.0
Net Reduction of Power Purchase Contracts	Revenue	0.1	(0.1)
	Revenue	0.0	0.0
OPG Income	Revenue	0.0	16.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue		(1.0)
Provision for Electricity Sector (OEFC)	Expense		**16.0**
Provision for Electricity Sector (MOF)	Expense		(16.0)

		0.0	0.0
	n/a	0.0	0.0
HOI Income	Revenue	0.0	5.3
Provision for Electricity Sector (OEFC)	Expense		(12.4)
Provision for Electricity Sector (MOF)	Expense		12.4
ardcoded formula in the cell	n/a	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	(30.4)	0.0
Provision for Electricity Sector (OEFC)	Expense		17.8
Provision for Electricity Sector (MOF)	Expense		(17.8)
Interest on Debt	Expense	(0.0)	1.0
Interest on Debt	Expense	0.0	15.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	0.0	(7.8)
HOI Income	Revenue	0.0	(47.4)
Provision for Electricity Sector (OEFC)	Expense	0.0	(47.4)
Provision for Electricity Sector (MOF)	Expense	0.0	47.4
OPG Income	Revenue	0.0	(61.0)
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	0.0	(21.0)
Provision for Electricity Sector (OEFC)	Expense	0.0	(61.0)
Provision for Electricity Sector (MOF)	Expense	0.0	61.0
OPG Income	Revenue	0.0	(21.0)
Provision for Electricity Sector (OEFC)	Expense	0.0	(21.0)
Provision for Electricity Sector (MOF)	Expense	0.0	21.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	0.0	21.0
HOI Income	Revenue	0.0	(23.6)
Provision for Electricity Sector (OEFC)	Expense	0.0	(23.6)
Provision for Electricity Sector (MOF)	Expense	0.0	23.6
OPG Income	Revenue	0.0	15.0
Provision for Electricity Sector (OEFC)	Expense	0.0	15.0
Provision for Electricity Sector (MOF)	Expense	0.0	(15.0)
OPG Income	Revenue	0.0	21.0
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	0.0	(18.0)
Provision for Electricity Sector (OEFC)	Expense	0.0	21.0
Provision for Electricity Sector (MOF)	Expense	0.0	(21.0)
HOI Income	Revenue	0.0	(23.8)
		0.0	***0.0***

Summary of Track Changes Above

Power Supply Contract Costs	(99.0)	0.0
Demand Management Support Costs	1.8	0.0
Provision for Electricity Sector OEFC)	(44.4)	27.8
Provision for Electricity Sector (MOF)	44.4	(27.8)
Other (Finance)	(1.0)	0.0
OPG Income	(5.0)	55.0

ONFA and other Fair Value Adjustments	35.0	0.0
HOI Income	(16.1)	(65.3)
Brampton Income	3.3	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	(39.7)	(23.8)
Electricity Debt Retirement Charge	(4.0)	0.0
Power Supply Contract Recoveries	99.0	0.0
Net Reduction of Power Purchase Contracts	0.1	(0.1)
Miscellaneous	14.0	0.0
Public Debt Interest - Electricity Sector	1.7	38.1
Interest on Debt	(4.7)	(53.1)
Impact on Surplus/Deficit	**(14.6)**	**(49.1)**
check	***0.0***	***23.8***

Check - Summary of Track Changes Above vs. Electricity Summary Change Worl

Power Supply Contract Costs	0.0	(0.4)
Demand Management Support Costs	(0.0)	0.0
Provision for Electricity Sector OEFC)	8.4	23.9
Provision for Electricity Sector (MOF)	(8.4)	(23.9)
Other (Finance)	0.0	0.0
OPG Income	0.0	0.0
ONFA and other Fair Value Adjustments	0.0	0.0
HOI Income	(0.0)	23.8
Brampton Income	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	(0.0)	0.0
Electricity Debt Retirement Charge	0.0	0.0
Power Supply Contract Recoveries	0.0	0.4
Net Reduction of Power Purchase Contracts	(0.0)	(0.0)
Miscellaneous	0.0	0.0
Public Debt Interest - Electricity Sector	23.4	0.1
Interest on Debt	(23.4)	(0.1)
Impact on Surplus/Deficit	**(0.0)**	**23.8**

2018-19	2019-20	2020-21
939	957	1,676
811	860	1,544
-127	-96	-131
0	***0***	***0***
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
38.1	38.1	38.1
(79.1)	(75.1)	(104.1)
0.0		0.0
0.0	0.0	0.0
0.0	(0.0)	0.0
-	-	-
-	-	-
-	-	-
-	-	-
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
12.0	3.5	1.8
(181.4)	(194.9)	(210.6)
0.0	0.0	0.0
0.0	0.0	0.0
-	-	-
0.0	0.0	0.0
0.0	0.0	0.0

-	-	-
-	-	-
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
-	-	-
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
181.8	195.4	211.1
0.0	0.0	0.0
0.0	0.0	0.0
(0.1)	(0.1)	(0.0)
0.0	0.0	0.0
0.0	0.0	0.0

0.0	0.0	0.0
0.0	0.0	0.0
5.3	5.3	5.3
0.0	0.0	0.0
0.0	0.0	0.0
(0.0)	1.0	1.3
15.0	5.0	5.0
(8.7)	(10.3)	(12.2)
(54.0)	(54.0)	(54.0)
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
(27.4)	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
(28.9)	(10.1)	(13.0)
0.0	***0.0***	***0.0***
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0

0.0	0.0	0.0
(75.7)	(48.2)	(48.2)
0.0	0.0	0.0
3.3	(6.8)	(10.5)
0.0	0.0	0.0
0.0	0.0	0.0
(0.1)	(0.1)	(0.0)
0.0	0.0	0.0
38.1	38.1	38.1
(64.1)	(69.1)	(97.8)
(98.5)	**(86.1)**	**(118.4)**
28.9	***10.1***	***13.0***

ksheet

(0.1)	(0.4)	0.2
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
28.9	10.1	13.0
0.0	0.0	0.0
0.0	0.0	(0.3)
0.0	0.0	0.0
0.1	0.4	(0.2)
(0.0)	(0.0)	0.0
0.0	0.0	0.0
0.1	0.1	0.1
(0.1)	(0.1)	0.1
28.9	**10.1**	**13.0**

Further Explanation of Change and source of data

Regular quarterly ONFA Update
Benefit to OEFC under s.50.3: $411M gain, SIFB
Change to OEFC payment for interest costs of Debt for Equity Swap

Revised Provincial Debt Interest related to Hydro One Equity
From FTD, revised Debt Interest (net of revisions to Provincial and OPG debt interest)
Revised numbers from OEP with 2019-20 Risk
Updated numbers from OPG Q1 2017 FS

Updating H1 Net Income for actuals. Note does not update Brampton Income at this point. Will update onc

No Change to numbers, just re-inputting data and saving sources
No Change to numbers, just re-inputting data and saving sources
No change to fiscal impact numbers. Deleting Budget 2016 and adding Budget 2017 fiscal impacts
No Change to numbers, just re-inputting data and saving sources
Updated with CIT Numbers received from H1 as part of s.91.2 MB20 allocation from MOF
No Change to numbers, just re-inputting data and saving sources
Only included H1 Net Income - Common Shareholders before. Added preferred shareholder impact as we
Updating OPG Income Tax Expense with info from OPG Monthly Presentation to Shareholder
Updating OPG GRC payable to OEFC and Proxy Property Tax from Answer back from OPG about the BP
Based on H1 final offering and expected First Nations Sale by the end of 2017 (CY), with a weighted avera

Based on EY analysis, and then applying fiscalization. Confirmation also received from OPCD.

Based on KPMG analysis, then fiscalization and other adjustments from OPCD.

[NOT APPLIED, CALCULATIONS AND DATA LEFT ON THE FILE] Used Brampton's Financial Stateme
Don't expect finalized 2016-17 data to become available in time for ESDI allocation. Will shift this to 2017-
make decision on shifting when we know 2016-17 status.

No change to numbers. Just re-organizing spreadsheet. No backup data.
No change to numbers. Just re-organizing spreadsheet. No backup data.
No change to numbers. Just provided actual backup/source.
No change to numbers. Just provided actual backup/source.
No change to numbers. Just provided another scenario backup/source
No change to numbers. Just provided actual backup/source.
No change to numbers. Just provided actual backup/source.
No change to numbers. Just provided actual backup/source.
No change to numbers. Just provided actual backup/source.
No change to numbers. Just updated the links to refer ot the delta between 2017 and On Deck (from 2016
Adjustment to ESDI to include Hydro One Brampton

Finalizing 2016-17 DRC Based on Draft OEFC AR
Received actual PILs amounts from FTD with breakdown of source. Updated 2016-17 numbers to reflect t
2016-17 - Non-ONFA Fair Value Adjustment
Round Hydro One ownership assumptions to 70.05% two decimal places to be consistent with OPCD.
Revising Hydro One Amount for consistency with OPCD. Equity Adjustments

Updated Provision tab. Made two separate Provision amounts for ESDI in OEFC AR and Dedicated Earnir
Updating Power Supply Recoveries to Public Accounts/OEFC AR actuals

Updating Miscellaneous to OEFC AR actuals

Updated 2016-17 Interest on Debt (IESO, OPG, Other (Net))

2017-18 - Demand Management Support Costs (no change) - Linking correctly
2016-17 - Updating Operating Expense in OEFC and corresponding changes elsewhere and sources.
No change to numbers. Just re-organized spreadsheet
Revised H1 Brampton Net Income (for GBE Line only)
Revising for OPG's Q3 Finances
Revising OPG's Net Income for latest monthly report

Reverting ownership back to 70.05% from change 20170518-3. Will coordinate with other areas to ensure

Updating Risks based on Hydro One Q2 Results Model
Updated two Risk components for the Avista Acquisition.
No significant changes, but used actual amortization liability schedule. Hence the rounding impacts/change
Updating Debt Guarantee for actuals based on OEFC AR
Revising OPG's Net Income for latest monthly report

Linking interest revenue data for 2017-18 to 2020-21
OPG Revenue Risks from: OEB Staff Submission and OPG Updated Filings
Corrected Net income for 100% ownership in preferred shares and 70.05% in Commons Shares

Updated the formula in the cell for 2017-18 Net Income Before Tax so that the numbers are not hardcodec
Updated PILs to include OPCD public accounts adjustment

increase built into net income was $82m between NI and PILs
Remove $21m from PILs
expense impacts
expense impacts
need to also remove the $21m PILs built into OPG net incme

We removed $21m from PILs above, before having added it in (check is that lines 123 to 130 add up to -$

varinaces include: 2017-18 preferred vs common share fix, 2018-19 largely ROE change from 9.09% to 8.

Data Validation:

Options
Revenue (Risks)
OPG
Hydro One
Provision

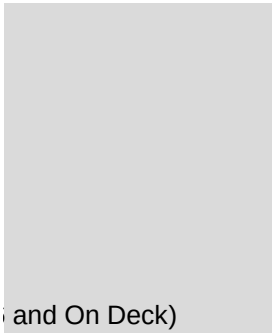
ONFA
Other Data

:e revised numbers are received.

ll.

ıge ownership for 2017-18. Also adjusted future net income attributed to the province.

nts to produce an estimate. May require additional calculations.
18.



and On Deck)

his.

gs in Public Accounts.

broadening change and reduction in net income happens concurrently in forecasts.

es.

ɪ directly

82m gain that we wanted to remove.

78% not previously captured.

Electricity Sector Outlook

$ Millions

	Actual 2015-16	Interim 2016-17	2017-18	2018-19 Pl
On Deck Outlook as of March 2017				
Income from Investment in Government Business Enterprises				
OPG Income[1]	291	304	97	732
OPG - ONFA and other Fair Value Adjustments[2]	172	8	-	-
Hydro One - Unrealized Gains Adjustment	-	-	-	-
HOI Income[3]	236	516	520	562
Brampton Income	20	15	-	-
Total OPG and HOI Income	**719**	**842**	**617**	**1,294**
Other Fees and Licences	**127**	**122**	**102**	**91**
Electricity Expenses of the Province				
Provision for Electricity Sector[4]	(3)	(342)	(125)	
Public Debt Interest - Electricity Sector	(520)	(492)	(492)	(492)
Subtotal	(523)	(834)	(617)	(492)
Public Debt Interest - Impact of ONFA				
Amortization of Deferred Revenue re profit on sale of H1 notes				
Total Electricity Expenses of the Province	**(523)**	**(834)**	**(617)**	**(492)**
OEFC Income				
Taxation Revenue				
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	3,228	373	405	476
Other Revenue				
Electricity Debt Retirement Charge[5]	859	625	623	-
Power Supply Contract Recoveries	875	739	292	325
Net Reduction of Power Purchase Contracts	172	129	74	41
Other Fees and Licences	(127)	(122)	(102)	(91)
Miscellaneous	9	-	-	-
Expenses				
Interest on Debt	(596)	(532)	(422)	(374)
Power Supply Contract Costs	(875)	(739)	(292)	(325)
Electricity Consumer Price Protection Fund	-	-	-	-
Demand Management Support Costs[6]	(8)	(10)	(10)	-
Provision for Electricity Sector	3	342	125	-
Other (Finance)	(7)	(6)	(6)	(6)
Total OEFC Income	**3,533**	**800**	**687**	**46**
Impact on Surplus/(Deficit)	**3,856**	**930**	**789**	**939**

Notes: The Hydro One net income outlook above (2016-17 to 2020-21) reflects the Province's current 70% ownership share, after the initial IPO in 2015 [and the secondary offering in April 2016]. Net estimated fiscal impacts from future Hydro One offerings are reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

Notes:

1.OPG's 2015-16 outlook reflected its reported earnings. 2016-17 outlook reflected OPG's November monthly update. Out-years reflect OPG's preliminary 2017-19 business plan and long-term outlook to 2019-20 (as fiscalized by OPG). 2020-21 estimates are based on OPG's calendar year-based business plan projections and as fiscalized by CEFD staff.

2. Provincial consolidation adjustments for unrealized earnings on the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds, as of the end of December 2016.

3. Hydro One 2015-16 income reflects its reported net income, adjusted for Hydro One IPO impacts. 2016-17 to 2020-21 projections are based on CEFD projections based on latest public information and modelling, including its 2015-17 distribution rate decision, adjustments to forecast ROEs based on current interest rate outlook and estimated Hydro One IPO and secondary share offering impacts.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial ONFA consolidation adjustments, minus the interest on debt payable ~~costs~~ to OEFC. The provision is currently assumed to end once the DRC ends on a legislated fixed end date of April 1, 2018.

5. Reflects April 23, 2014 announcement that DRC will be eliminated for residential users, after December 31, 2015. The end date of DRC for remaining users is legislated to be on April 1, 2018. Estimates are subject to change based on actual consumption.

6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Expenses	2015-16	2016-17	2017-18	2018-19
Power Supply Contract Costs	875	739	292	325
Demand Management Support Costs	8	10	10	-
Provision for Electricity Sector	(3)	(342)	(125)	-
Other (Finance)	7	6	6	6
SUBTOTAL - OEFC Consolidation	**887**	**412**	**183**	**331**

Provision for Electricity Sector (Dedicated Earnings)	**3**	**342**	**125**	**-**

Electricity Sector Outlook

$ Millions

	Actual 2015-16	Actual 2016-17	2017-18	Current 2018-19
On Deck Outlook as of October 2017				
Income from Investment in Government Business Enterprises				
OPG Income[1]	291	299	152	732
OPG - ONFA and other Fair Value Adjustments[2]	172	43	-	-
Hydro One - Unrealized Gains Adjustment	-	-	-	-
HOI Income[3]	236	500	431	457
Brampton Income	20	18	-	-
Total OPG and HOI Income	**719**	**860**	**583**	**1,189**
Other Fees and Licences (Debt Guarantee fee)	**127**	**122**	**102**	**91**
Electricity Expenses of the Province				
Provision for Electricity Sector[4]	-	(290)	(129)	
Public Debt Interest - Electricity Sector	(520)	(514)	(454)	(454)
Subtotal	(520)	(803)	(583)	(454)
Public Debt Interest - Impact of ONFA				
Amortization of Deferred Revenue re profit on sale of H1 notes				
Total Electricity Expenses of the Province	**(520)**	**(803)**	**(583)**	**(454)**
OEFC Income				
Taxation Revenue				
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	3,247	334	381	479
Other Revenue				
Electricity Debt Retirement Charge[5]	859	621	623	-
Power Supply Contract Recoveries	875	838	292	325
Net Reduction of Power Purchase Contracts	172	129	74	41
Other Fees and Licences	(127)	(122)	(102)	(91)
Miscellaneous	9	14	-	-
Expenses				
Interest on Debt	(596)	(513)	(475)	(438)
Power Supply Contract Costs	(875)	(838)	(292)	(325)
Electricity Consumer Price Protection Fund	-	-	-	-
Demand Management Support Costs[6]	(8)	(8)	(10)	-
Provision for Electricity Sector	-	290	129	-
Other (Finance)	(7)	(7)	(6)	(6)
Total OEFC Income	**3,549**	**737**	**614**	**(15)**
Impact on Surplus/(Deficit)	**3,876**	**915**	**716**	**811**
variance to OEFC check	*(156)*	*(454)*	-	-

Notes:

1.OPG's 2015-16 outlook reflected its reported earnings. 2016-17 outlook reflected OPG's November monthly update. Out-years reflect OPG's preliminary 2017-
outlook to 2019-20 (as fiscalized by OPG). 2020-21 estimates are based on OPG's calendar year-based business plan projections and as fiscalized by CEFD st

2. Provincial consolidation adjustments for unrealized earnings on the decommissioning and used fuel segregated funds net of Bruce variance account and char
decommissioning and used fuel segregated funds, as of the end of December 2016.

3. The Hydro One net income outlook above (2016-17 to 2020-21) reflects the Province's 70% ownership share, after the initial IPO in 2015 and the secondary c
estimated fiscal impacts of subsequent Hydro One offerings are currently reported along with other planned Asset Optimization proceeds under "Sales and Rent
outlook. Hydro One outlook based on CEFD projections based on latest public information.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial ONFA consolidation adjustments, minus the interest on
The provision is currently assumed to end once the DRC ends on a legislated fixed end date of April 1, 2018.

5. Reflects April 23, 2014 announcement that DRC will be eliminated for residential users, after December 31, 2015. The end date of DRC for remaining users i
2018. Estimates are subject to change based on actual consumption.

6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Expenses	2015-16	2016-17	2017-18	2018-19
Power Supply Contract Costs	875	838	292	325
Demand Management Support Costs	8	8	10	-
Provision for Electricity Sector	-	(290)	(129)	-
Other (Finance)	7	7	6	6
SUBTOTAL - OEFC Consolidation	**890**	**563**	**179**	**331**
Provision for Electricity Sector (Dedicated Earnings)	**-**	**290**	**129**	**-**

Electricity Sector Change Since Budget

$ Millions

($million)	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Changes from Budget 2017 as of October 2017							
Income from Investment in Government Business Enterprises							
OPG Income	-	(5)	55	-	-	-	2016-17 small decrease due to IFRS adjustment revision and OPG Net Income revision. 2017-18 increase mainly due to deferral of Pickering Unit 6 planned outage to jan 18, deferral of sale of land at Hearn site from Q1 2017 to later in 2017, partially offsdet by lower gropss margin.
ONFA and other Fair Value Adjustments	-	35	-	-	-	-	Largely revision to ONFA fair value as of March 31, 2017
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	-	
HOI Income	20	(16)	(89)	(105)	(58)	(61)	2016-17 slight decrease from Budget 2017 Interim projection. 2017-18 onwards reflects impacts of OEB decision on Hydro One rates, interest expense on Avitsa debentures (in 2017-18 and 2018-19) and update to Hydro One model update based on Hydro One Q2 results
Brampton Income		3.3					
Total OPG and HOI Income	**-**	**17**	**(34.1)**	**(105)**	**(58)**	**(61)**	
Other Fees and Licences	**-**	**-**	**-**	**-**	**-**	**-**	
Electricity Expenses of the Province							
Provision for Electricity Sector	3	53	(4)	-	-	-	Changes in the Proviision (ESDI) expense reflect net changes in the outlook for Public Debt Interest, and OPG and HOI net income (excludinging ONFA adjustments).
Public Debt Interest - Electricity Sector	-	(22)	38	38	38	38	2016-17 PDI at ($514m) was slightly larger than ($492m) projected at Interim. 2017-18 change reflects revised projections for Provincial debt interest related to Hydro equity.
Total Electricity Expenses of the Province	**3**	**31**	**34**	**38**	**38**	**38**	
OEFC Income							
Taxation Revenue							
Electricity Payments-in-Lieu of Taxes (PILs)	19	(40)	(24)	3	(7)	(10)	2016-17 decrease largely due to an OPCD Public Accounts PILs adjustment related to reconciling between OPCD and OEFC net opening assets. OPG PILs also slightly lower than projected.
Other Revenue							
Electricity Debt Retirement Charge	-	(4)	-	-	-	-	
Power Supply Contract Recoveries	-	99	(0)	(0)	(0)	0	Variance is largely due to retroactive payments that the OEFC made to certain non-utility-generators (NUGs) with former Ontario Hydro power purchase agreement contracts with OEFC. OEFC was required to make these payment following the dismissal by the Supreme Court of Canada of OEFC's application for leave to appeal a judgment of the Court of Appeal of Ontario on a 2015 court decision.
Net Reduction of Power Purchase Contracts	-	0.1	(0)	(0)	(0)	(0)	
Other Fees and Licences	-	-	-	-	-	-	
Revenue Pool Residual	-	-	-	-		-	
Miscellaneous	-	14	-	-	-	-	Higher than projected at Interim.
Expenses							
Interest on Debt	-	19	(53)	(64)	(69)	(98)	2016-17 higher than projected at Interim. 2017-18 reflects revised debt interest outlook net of revisions to OEFC interest revenue from OPG and Province.
Power Supply Contract Costs	-	(99)	0	0	0	(0)	Same as Power supply contract recoveries above. Power supply contract costs are fully recovered by power supply contract recoveries.
Electricity Consumer Price Protection Fund	-	-	-	-	-	-	
Demand Management Support Costs	-	1.8	-	-	-	-	
Provision for Electricity Sector	(3)	(53)	4	-	-	-	Changes in the Proviision (ESDI) expense (negative expense or revenue to OEFC) reflect net changes in the outlook for Public Debt Interest, and OPG and HOI net income (excludinging ONFA adjustments).
Other (Finance)	-	(1.0)	-	-	-	-	
Total OEFC Income	**16**	**(63)**	**(73)**	**(61)**	**(76)**	**(108)**	
Impact on Surplus/(Deficit)	**19**	(14.6)	(73)	(127)	(96)	(131)	
Total revenue Impact	**19**	**87**	**(58)**	**(102)**		**(71)**	
Total revenue Impact - less power supply contract recoverie	19	(12)	(58)	(101)		(71)	
Total Expenditure impact	**0**	**101**	**15**	**26**		**60**	

Electricity Sector Outlook (PSAB)

Negative Revenue Risks	$ Millions			
($ millions)	Plan			
	2017-18	2018-19	2019-20	2020-21
Generic				
OPG Generation Risk: Nuclear Reliability (-1.6 TWh)[1]	(120)	(120)	(120)	(120)
1% decrease in Hydro One actual load[2]	(15)	(15)	(15)	(15)
Lower OPG's Equity weighting & Return on Equity (ROE)[3]	(12)	(20)	(25)	(43)
Lower Hydro One Return on Equity (ROE)[4]	(10)	(39)	(41)	(43)
Regulatory				
Hydro One Distribution rate application[5]	(50)	(50)	(50)	(50)
OPG Switch from accrual based to cash based accounting for pension and OPEB[6]	(600)			
Regulatory Risk - Timing of Rate Decision[7]	(540)			
OEB Staff Recommendations wrt OPG rate application(May 2017)[8]	(175)	(143)	(151)	(175)
Nuclear Liabilities Cash vs. Accrual[9]	(450)	(450)	(450)	(450)
OEB decision on tax recapture write-down	(375)	10	15	20
Accounting				
Net OPG IFRS Consolidation Risks - Scenario 1b: 15 year historical, update discount rate each year.[10]	-	(475)	(500)	(750)
Other Risks				
Avista Acquisition - Termination fee		(103)		

Electricity Sector Outlook (PSAB)

Positive Revenue Risks				
($ millions)	Plan			
	2017-18	2018-19	2019-20	2020-21
Generic				
OPG Generation Risk: Nuclear Reliability (+1.1 TWh)[1]	85	85	85	85
1% increase in Hydro One actual load[2]	15	15	15	15
Higher Hydro One Return on Equity (ROE)[3]	15	60	65	65
Higher OPG Return on Equity (ROE)[4]	6	25	30	55
Regulatory				
Other Risks				
ONFA adjustment increase (as of June 2017 Q2)	165			
Projected gain from OPG head office sale (as of Budget 2017)[5]	296			
Adjustment to gain from OPG head office sale post-May17 Transaction[6]	82			

ONTARIO ELECTRICITY FINANCIAL CORPORATION
On Deck Outlook as of March 2017 **$ Millions**

	Actual 2015-16	Interim 2016-17	2017-18	2018-19	Pl
Revenue					
Revenue Pool Residual					
Debt Retirement Charge	859	625	623	-	
Payments-in-lieu of tax:					
OPG	268	302	315	366	
Legacy Hydro One (Including Brampton)	2,929	7	2	2	
Hydro One CIT dedicated to OEFC	3	20	20	22	
MEUs	27	44	68	86	
Total PILs & CIT dedicated to OEFC[1]	3,228	373	405	476	
Interest :					
OPG	173	179	168	153	
H1					
IESO	2	3	3	3	
Province	520	492	492	492	
Other	28	10	5	5	
Total Interest	723	684	668	653	
Power Supply Contract Recoveries	875	739	292	325	
Amortization of NUG liability	172	129	74	41	
Electricity sector dedicated income	3	342	125	-	
Gain to OEFC under s. 50.3	172	-	-	-	
Miscellaneous	9	-	-	-	
	6,041	2,893	2,187	1,495	
Expense					
Debt interest	1,319	1,216	1,090	1,027	
Interest on nuclear risk funding					
Demand Management Support Costs	8	10	10	-	
Amortization of deferred debt costs	-	-	-		
Power Supply Contract Costs	875	739	292	325	
Debt Guarantee fee	127	122	102	91	
Operating	7	6	6	6	
	2,336	2,093	1,500	1,449	
Excess (Deficiency) of Revenue over Expense	**3,705**	**800**	**687**	**46**	
Prior period adjustment	87				
Stranded Debt - Year End	**4,393**	**3,593**	**2,906**	**2,860**	

ONTARIO ELECTRICITY FINANCIAL CORPORATION

On Deck Outlook as of October 2017 **$ Millions**

	Actual 2015-16	Actual 2016-17	2017-18	Current 2018-19
Revenue				
Revenue Pool Residual				
Debt Retirement Charge	859	621	623	0
Payments-in-lieu of tax:				
OPG	268	224	299	378
Legacy Hydro One (Including Brampton)	2,929	4	2	2
Hydro One CIT dedicated to OEFC	3	25	12	13
MEUs	27	112	68	86
Total PILs & CIT dedicated to OEFC[1]	3,228	364	381	479
Interest :				
OPG	173	167	169	179
H1				
IESO	2	2	3	3
Province	520	514	454	454
Other	28	20	20	20
Total Interest	723	703	646	656
Power Supply Contract Recoveries	875	838	292	325
Amortization of NUG liability	172	129	74	41
Electricity sector dedicated income	3	302	129	0
Gain to OEFC under s. 50.3	172	411	0	0
Miscellaneous	9	14	0	0
	6,041	3,382	2,145	1,501
Expense				
Debt interest	1,319	1,216	1,121	1,094
Interest on nuclear risk funding				
Demand Management Support Costs	8	8	10	0
Amortization of deferred debt costs	0	0	0	
Power Supply Contract Costs	875	838	292	325
Debt Guarantee fee	127	122	102	91
Operating	7	7	6	6
	2,336	2,191	1,531	1,516
Excess (Deficiency) of Revenue over Expense	3,705	**1,191**	**614**	**(15)**
Prior period adjustment	87			
Stranded Debt - Year End	4,393	**3,202**	**2,588**	**2,603**

ONTARIO ELECTRICITY FINANCIAL CORPORATION

Changes from Budget 2017 as of October 2017 **$ Millions**

	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Revenue						
Debt Retirement Charge	(4)	-	-	-	-	
Payments-in-lieu of tax:						
OPG	(78)	(16)	12	4	2	2016-17 variance is largely due to method of reporting OPG PILs by OEFC and OPG.
Legacy Hydro One (Including Brampton)	(3)	-	-	-	-	
Hydro One CIT dedicated to OEFC	5	(8)	(9)	(10)	(12)	Adjustment based on updated information in Hydro One rate application
MEUs	68	-	-	-	-	Large increase in 2016-17 from $80M payment during transfer of H01 Brampton to new consolidated MEU Alectra.
Total PILs	(9)	(24)	3	(7)	(10)	
Interest :						
OPG	(12)	1	26	40	13	Update to OPG interest outlook (wrt interest on OEFC loan).
H1	-	-	-	-	-	
IESO	(1)	-	-	-	-	
Province	22	(38)	(38)	(38)	(38)	2016-17 PDI at ($514m) was slightly larger than ($492m) projected at Interim. 2017-18 change reflects revised projections for Provincial debt interest related to Hydro equity.
Other	10	15	15	5	5	
Total Interest	19	(22)	3	7	(20)	
Power Supply Contract Recoveries	99	(0)	(0)	(0)	0	Variance is largely due to retroactive payments that the OEFC made to certain non-utility-generators (NUGs) with former Ontario Hydro power purchase agreement contracts with OEFC. OEFC was required to make these payment following the dismissal by the Supreme Court of Canada of OEFC's application for leave to appeal a judgment of the Court of Appeal of Ontario on a 2015 court decision.
Amortization of NUG liability	0	(0)	(0)	(0)	(0)	
Electricity sector dedicated income	(41)	4	-	-	-	Changes to ESDI (offset ny MoF Provision expense) largely reflect combined revisions to OPG and Hydro One net income and revisions to public debt intetest.
Gain to OEFC under s. 50.3	411	-	-	-	-	
Miscellaneous	14	-	-	-	-	
	489	(42)	6	(0)	(30)	
Expense						
Debt interest	-	31	67	76	78	Revised outlook for OEFC debt interest outlook
Interest on nuclear risk funding	-	-	-	-	-	
Demand Management Support Costs	(2)	-	-	-	-	
Amortization of deferred debt costs	-	-	-	-	-	
Power Supply Contract Costs	99	(0)	(0)	(0)	0	Same as Power supply contract recoveries above. Power supply contract costs are fully recovered by power supply contract recoveries.
Debt Guarantee fee	-	-	-	-	-	
Operating	1	-	-	-	-	
	98	31	67	76	78	
Excess (Deficiency) of Revenue over Expense	**391**	**(73)**	**(61)**			
Stranded Debt - Year End	**3,202**	**2,588**	**2,603**	**2,547**	**2,285**	

Provision for Electricity Sector (Dedicated Electricity Earnings/Electricity Sector Dedicated Earnings)

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Income from Investment in Government Business Enterprises						
OPG Income	291	299	152	732	625	1,066
Hydro One Income	232	501	431	457	545	591
Hydro One Brampton (if applied separately)		15				
Total Income	**523**	**815**	**583**	**1,189**	**1,170**	**1,656**
Public Debt Interest - Electricity Sector						
OPG			(300)	(300)	(300)	(300)
Hydro One			(154)	(154)	(154)	(154)
Public Debt Interest - Electricity Sector (OEFC Interest revenue)	**(520)**	**(514)**	**(454)**	**(454)**	**(454)**	**(454)**
MOF Provision Expense (before adjustments)	**3**	**302**	**129**	**735**	**716**	**1,202**
Other Adjustments						
Prior-year Adjustment[1]		3				
Exclude Brampton[2]		(15)				
MOF Provision Expense (after other adjustments)	**0**	**290**	**129**	**735**	**716**	**1,202**
Cumulative Shortfall Adjustment						
Opening Balance	0	0	0	0	0	0
Deduction / (Addition)	0	0	0	0	0	0
Ending Balance	0	0	0	0	0	0
Dedicated Electricity Earnings (all adjustments) (Public Accounts)	**0**	**290**	**129**	**735**	**716**	**1,202**
Electricity Sector Dedicated Income (OEFC Annual Report)	**3**	**302**	**129**			

Notes:

1. 2016-17 Adjustment was due to the discrepancy between the numbers in MOF expense in PA 2015-16 and OEFC Financials in 2015-16. $3M Serves to the rectify this discrepancy
2. Brampton was excluded from the Ministry of Finance's ESDI allocation.

Source Details	Source (Link)
OEFC 1999-2000 FS, pg 24	
OEFC 1999-2000 FS, pg 26	
Monthly Balances Shee	S:\Users\CEF\Hydro 2017\OEFC\RbP\Outlook\07. July\Backup\20170713-1\interest from Province.pdf
2015-16 Public Accoun	S:\Users\CEF\Hydro 2017\OEFC\RbP\Outlook\08. August\Backup\20170817-1 - Provision for Electricity Sector\PA 2015-16 - Vol 1.pdf

Ontario Power Generation

OPG Income - Budget 2017

$ Millions

	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
OPG Net Income After Tax (Adjusted)	291	304	97	732	625	1,066
OPG Net Income After Tax	*291*	*379*	*480*	*678*	*726*	*913*
Extraordinary Gains	-	-	-	-	-	-
GA - OPG Trust Interest Revenue			*17.2*	*54.4*	*99.4*	*152.5*
OPG IFRS consolidation risk picked up in Fiscal Plan		(75)	(400)		(200)	
ONFA and other Fair Value Adjustments	(75)	8				
ONFA Adjustments	-	8				
Other Fair Value Adjustments	(75)					

OPG PIL - Budget 2017

$ Millions

	Actual	Interim		Pl
	2015-16	2016-17	2017-18	2018-19
Net Income Before Tax	383	396	572	867
Net Income After Tax (Adjusted)	291	304	97	732
Income Taxes	92	92	92	135
GRC: Payable to OEFC	198	196	205	212
Proxy Property Tax	16	14	18	19
Ontario Capital Tax	0	0	0	0
Total	**306**	**302**	**315**	**366**

OPG Income - October 2017

$ Millions

	Actual	Actual	Current Outlook			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
OPG Net Income	291	377	818	678	726	913
Adjustment for OPG HQ gain on sale[1]			(283)			
Extraordinary Gains	0	0	0	0	0	0
GA Financing - OPG Trust Interest Revenue[2]			17	54	99	153
OPG IFRS consolidation risk reflected in Fiscal Plan[3]		(78.00)	(400)		(200)	
OPG Net Income (Adjusted before ONFA)	**291**	**299**	**152**	**732**	**625**	**1,066**
ONFA Adjustments	247	49				
Other Fair Value Adjustments	(75)	(6)				
ONFA and other Fair Value Adjustments	**172**	**43**				
OPG Net Income	**463**	**342**	**152**	**732**	**625**	**1,066**

OPG PIL - August 2017

$ Millions

	Actual	Actual		Current
	2015-16	2016-17	2017-18	2018-19
Income Before Tax	383	308	684	867
OPG Net Income (Adjusted before ONFA)	291	299	152	732
OPG Income Tax (PILs)	92	9	162	135
Tax adjustment for OPG HQ gain on sale[1]			(95)	
GRC: Payable to OEFC	198	201	214	224
Proxy Property Tax to OEFC	16	14	18	19
Ontario Capital Tax	0	0	0	0
Total OPG PILs	**306**	**224**	**299**	**378**

1. As part of Asset Optimization Plan the projected proceeds are currently reported in OEP/MoF Sales and Rentals line. To be re-categorized after the transaction is completed and in coordination with OEP and SIFB.
2. This reflects interest earnings on GA financing costs which are consolidated back to Province
3. See Risks tab for IFRS impacts that were not reflected in Fiscal Plan, and table below.

	#REF!	#REF!	#REF!	#REF!
#REF!	#REF!	#REF!	#REF!	#REF!

Hydro One Net Income and PILs

Hydro One Income - Budget 2017
($ millions)

	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Hydro One Net Income After Tax	685	737	742	802	862	931
Hydro One - Unrealized Gains Adjustment						

2016-17 to 2020-21 from CEFD Hydro One 2016 model.

Hydro One PIL - Budget 2017
($ millions)

	2015-16	2016-17	2017-18	2018-19
Net Income After Tax	685	737	742	802
Income Taxes PILs	132	160	181	205
Proxy Property Tax	2	2	2	2
Ontario Capital Tax	0	0	0	0
Total	**134**	**162**	**183**	**207**

Hydro One Income - October 2017
($ millions) **$ Millions**

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Hydro One Net Income After Tax			623	666	753	818
Debenture Costs Impacts (After Tax)			(34)	(39)		
Hydro One Net Income After Tax - Including Adjustments	670	680	589	627	753	818
Hydro One - Net Income Attributable to Preferred Shareholders	15	18				
Hydro One - Unrealized Gains Adjustment						

Hydro One (100% Ownership)
($ millions) **$ Millions**

	Actual 2015-16	Actual 2016-17	Current 2017-18	2018-19
Net Income After Tax - Common Shares	670	680	589	627
Net Income After Tax - Preferred Shares	15	18		
Income Taxes PILs	132	160	181	205
Proxy Property Tax	2	2	2	2
Ontario Capital Tax	0	0	0	0

Hydro One Ownership Calculation:		SOURCE:
Total number of shares outstanding[1]	595,000,000	1. Hydro One Ltd Annual Report 2015, pg 94 of PDF, pg 92 of the Report.
IPO November 2015		
Initial Public Offering(2015)[2]	81,100,000	2. From news release: http://hydroone.mediaroom.com/2015-11-05-Hydro-One-Limited-Announces-Closing-of-IPO
Over allotment option (2015)[3]	8,150,000	3. From news release: http://hydroone.mediaroom.com/2015-11-12-Hydro-One-Limited-Announces-Closing-of-IPO-Over-Allotment-Option
Sales to PWU/SEP Trusts	5,646,340	
Total	94,896,340	
Province's remaining ownership, Nov 2015 (# Shares)	**500,103,660**	
Province's remaining ownership, Nov 2015 (%)	**84.05%**	
Secondary Offering April 2016		
Secondary Offering (2016)	72,434,800	4. Hydro One Ltd. Q2 Report, pg 1 http://www.hydroone.com/InvestorRelations/FinancialReporting/Documents/Hydro%20One%20Ltd%20Second%20Qu
Over allotment option (2016)	10,865,200	
Total	83,300,000	
Province's remaining ownership, Apr 2016 (# Shares)	**416,803,660**	
Province's remaining ownership, Apr 2016 (%)	**70.05%**	
Final Offering May 2017		
Final Offering (2017)	120,000,000	Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by
Over allotment option (2017)	-	Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by
Total	120,000,000	
Province's remaining ownership, May 8, 2017 (# Shares)	296,803,660	Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by
Province's remaining ownership, May 8, 2017 (%)	**49.88%**	
First Nations Sale, Assumed closing for December 31, 2017	14,875,000	
	2.5%	Source: https://news.ontario.ca/mei/en/2017/05/ontario-raises-28-billion-from-final-hydro-one-share-offering.html
Province's remaining onwership - post First Nations Sale (#Shares)	281,928,660	
Province's remaining onwership - post First Nations Sale (%)	**47.38%**	
Avista Impact (projected closing date 2nd half of 2018)		
Contingent Convertible Debenture	$1,540,000,000	
Conversion Price	$21	
Potential Dilution (# Shares)	71,962,617	
Revised Total number of shares outstanding	**666,962,617**	
Province's remaining onwership - post Avista Acquisition (#Shares)	281,928,660	
Province's remaining onwership - post Avista Aquisition (%)	**42.27%**	

Ownership Percentage in 2017-18 Fiscal Year	Number of Months	Percentage of Year
70.05%	1	8.3%
49.88%	8	66.7%
47.38%	3	25.0%
	12	
Average 2017-18 FY Ownership:	**50.9%**	

Ownership Percentage in 2018-19 Fiscal Year (assume Avista closing end of September 2018)	Number of Months	Percentage of Year
47.38%	6	50.0%
42.27%	6	50.0%
	12	
Average 2018-19 FY Ownership:	**44.8%**	

Ownership Percentage in 2019-20 Fiscal Year Onwards
42.27%

Accretive to earnings per share and cash flow for Hydro One in the first full year post closing
above is from Hydro One transaction overview. Check what this means for timing of additional shares and /or earnings.

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-the-Province-of-Ontario

Public Debt Interest and Section 50.3 payments

$ Millions	Actual 2015-16	Actual 2016-17	2017-18
Hydro One Public Debt Interest and Section 50.3 payments			
Government Annual Interest Costs - Hydro One	220	220	220
Reduction in Interest Costs due to Broadening		(29)	(66)
Province Annual Interest Costs - Hydro One Debt	**220**	**191**	**154**
Province Annual Interest Cost - OPG Debt	300	300	300
Total Public Debt Interest	**520**	**514**	**454**

$ Millions	Actual 2015-16	Actual 2016-17	2017-18
Gain to OEFC under s. 50.3	172	411	0

Current Outlook		
2018-19	2019-20	2020-21
220	220	220
(66)	(66)	(66)
154	**154**	**154**
300	300	300
454	**454**	**454**

ID# (Track Cha	Fiscal Year	alue (Hardcode
20170501-2	2016-17	411,152,733
20170501-3	2016-17	29
20170501-3	2017-18	66
20170501-3	n/a	220

Current Outlook		
2018-19	2019-20	2020-21
0	0	0

ID# (Track Cha	Fiscal Year	alue (Hardcode
n/a	n/a	5126
n/a	n/a	5.85%
		299.871

OPG's Annual Interest Costs:

20170713-1	2016-17	-513,768,361

Value (Linked)	Description	Source Details	Source (Link)
411,152,733	s 50.3 Gain for	Calculation provided by SIFB	
29	Reduction in Int	Internal Calculation	
66	Reduction in Int	Internal Calculation	
220	Annual Interest	Internal Calculation	

Value (Linked)	Description	Source Details	Source (Link)
	($M) Provinces	OEFC 1999-2000 FS, pg 24	
	Annual Interest	OEFC 1999-2000 FS, pg 26	

300

Provincial interest cost for equity investment in OPG, H1 in 2016-17
Monthly Balances Sheet (from FTD)
S:\Users\CEF\Hydro 2017\OEFC\RbP\Outlook\07. July\Backup\20170713-1\interest from Province.pdf

PROVINCIAL CONSOLIDATION ADJUSTMENTS
Ontario Nuclear Funds Agreement

Adjustment for Change in OPG Reported Net Income

Adjustment for DSF Unrealized Earnings

Unrealized Earnings as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Bruce Variance Account Adjustment
OPG Net Income Adjustment

Adjustment for UFSF Unrealized Earnings

Unrealized Earnings as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Bruce Variance Account Adjustment
OPG Net Income Adjustment

Unrealized Earnings -- Fiscal YTD

Adjustment for Change in Due to Province

Adjustment for DSF Due to Province
Due to Province (cost basis) as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Change in Due to Province -- Fiscal YTD

Adjustment for UFSF Due to Province

Due to Province (cost basis) as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Change in Due to Province -- Fiscal YTD

Provincial Consolidation Adjustment

Other Data

	Actual 2016-17	2017-18
Debt Retirement Charge	621	0

	2016-17	2017-18
Power Supply Contract Recoveries	838	292

	2016-17	2017-18
Interest		
OPG	167	169
IESO	2	3
Other (Net)	20	20
Expense		
Debt interest	1216	1121

	Actual 2016-17	2017-18
MEU - PIL Income Tax	109.8	
MEU - PIL Property Tax	0.6	
MEU - GRC	1.2	
TOTAL MEU PILs	111.6	

	Actual 2016-17	2017-18
Miscellaneous/Other (OEFC FS)	14	
Demand Management Support Costs (IEI)	8	10
Operating [Expense]	7	6
Interest on nuclear risk funding	-	-
Amortization of deferred debt costs	-	-
Amortization of NUG liability	129	74
Debt Guarantee Fee	122	

Expense (Electrictiy Summary Tab)		
Other (Finance)	-7	-6
Demand Management Support Costs (IEI)	-8	-10
Debt Guarantee Fee	(122)	

Plan		
2018-19	2019-20	2020-21
0	0	0

Plan		
2018-19	2019-20	2020-21
325	301	273

Plan		
2018-19	2019-20	2020-21
179	175	148
3	3	3
20	10	10
1094	1053	963

Plan		
2018-19	2019-20	2020-21

Plan		
2018-19	2019-20	2020-21
6	6	6
-	-	-
-	-	-
41	30	28
-6	-6	-6

ID# (Track Changes	Fiscal Year	Value (Hardcoded)	Value (Linked)
20170510-2	2016-17	$ 739,216,115	
20170510-2	2017-18	$ 291,629,707	
20170510-2	2018-19	$ 324,906,017	
20170510-2	2019-20	$ 300,648,570	
20170510-2	2020-21	$ 273,240,858	
20170501-4	2016-17	179	179
20170501-4	2017-18	169	169
20170501-4	2018-19	179	179
20170501-4	2019-20	175	175
20170501-4	2020-21	148	148
20170501-5	2016-17	1216	1,216
20170501-5	2017-18	1121	1,121
20170501-5	2018-19	1094	1,094
20170501-5	2019-20	1053	1,053
20170501-5	2020-21	963	963
20170731-3	2016-17	621	
20170811-1	2016-17	109.8	
20170811-1	2016-17	0.6	
20170811-1	2016-17	1.2	
20170815-5	2016-17	$ 838,000,000	
20170815-6	2016-17	$ 14,000,000	
20170815-8	2016-17	8	
20170815-9	2017-18	10	
20170815-10	2016-17	7	
20170815-10	2017-18	6	
20170815-10	2018-19	6	
20170815-10	2019-20	6	
20170815-10	2020-21	6	
20170815-7	2016-17	167	
20170815-7	2016-17	2	
20170815-7	2016-17	20	
20170815-7			

ID# (Track Changes	Fiscal Year	Value (Hardcoded)	Value (Linked)
20170905-1	2016-17	129	129
20170905-1	2017-18	74	74

20170905-1	2018-19	41	41
20170905-1	2019-20	30	30
20170905-1	2020-21	28	28
20170905-2	2016-17	122	
20170906-1	2017-18	3	3
20170906-1	2018-19	3	3
20170906-1	2019-20	3	3
20170906-1	2020-21	3	3
20170906-1	2017-18	20	5
20170906-1	2018-19	20	5
20170906-1	2019-20	10	5
20170906-1	2020-21	10	5

Description	Source Details	Source (Link)
The table below contains an updated preliminary N	SPFB Estimates, Email	
• The tables below provides both last year's submission for NUG costs by CEFD and this year's estimates (both of which exclude HST) based on the most recent NUG model.	SPFB Estimates, BN SPFB Estimates, BN SPFB Estimates, BN SPFB Estimates, BN	
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
Updating DRC from OEFC AR (Drafts)	2017 OEFC DRAFT FS	S:\Users\CEF\Hydro 2017\OEFC'
MEU - PIL Income Tax	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
MEU - PIL Property Tax	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
MEU - GRC	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
Updating to actuals	2017 OEFC AR	2017 OEFC Annual Report - Eng
Updating to actuals	2017 OEFC AR	2017 OEFC Annual Report - Eng
Updating to Actuals	2017 OEFC AR	S:\Users\CEF\Hydro 2017\OEFC'
OEFC 2017-18 IEI/Demand Management Suppor	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Operating Expense - Updating to Actuals	2017 OEFC AR	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Operating Expense - No source available. Just brought the information to this tab.		
OPG Interest Revenue - Actuals 2016-17	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
IESO Interest Revenue - Actuals 2016-17		
Other (Net) Interest Revenue - Actuals 2016-17		

Description	Source Details	Source (Link)
		S:\Users\CEF\Hydro 2017\OEFC'
	Amortization Schedule.	S:\Users\CEF\Hydro 2017\OEFC'

Sourcing the NUG liability amortization schedule.	Tab: Summary Fiscal Impact	S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Gurantee Fee - Updating to Actuals	2017 OEFC AR (pg 13 (	\\ofina.on.ca\ofadfs\Users\CEF\H
IESO Interest Revenue Plan	OEFC Revenue Forecast for Board - April 2017	\\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H
Other Interest Revenue Plan		\\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H

\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
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\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board

\RbP\Outlook\07. July\Backup\20170731-3 - DRC Update\2017 OEFC Annual Report - English - DRAFT.PDF

\RbP\Outlook\08. August\Backup\20170811-1 - Updating PILs for 2016-17\OEFC 2016-17 Pils summary.pdf
\RbP\Outlook\08. August\Backup\20170811-1 - Updating PILs for 2016-17\OEFC 2016-17 Pils summary.pdf
\RbP\Outlook\08. August\Backup\20170811-1 - Updating PILs for 2016-17\OEFC 2016-17 Pils summary.pdf

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\RbP\Outlook\08. August\Backup\20170815-8 - 2016-17 Demand Management Support Costs (IEI)\2017 OEFC
\RbP\Outlook\08. August\Backup\20170815-9 - 2017-18 Demand Management Support Costs (IEI)\OEFC rever
\RbP\Outlook\08. August\Backup\20170815-10 - 2016-17 Operating (Expense)\2017 OEFC Annual Report - Enc

\RbP\Outlook\08. August\Backup\20170815-7 - 2016-17 Updated Interest on Debt Revenue\RE Revised OEFC

\RbP\Outlook\09. September\Backup\20170905-1 - Amortization of NUG Liability\NUG liability_estimated draw c
\RbP\Outlook\09. September\Backup\20170905-1 - Amortization of NUG Liability\NUG liability_estimated draw c

\RbP\Outlook\09. September\Backup\20170905-1 - Amortization of NUG Liability\NUG liability_estimated draw c
\RbP\Outlook\09. September\Backup\20170905-1 - Amortization of NUG Liability\NUG liability_estimated draw c
\RbP\Outlook\09. September\Backup\20170905-1 - Amortization of NUG Liability\NUG liability_estimated draw c

ydro 2017\OEFC\RbP\Outlook\09. September\Backup\20170905-2 - 2016-17 Debt Guarantee Fee\2017 OEFC
ydro 2017\OEFC\RbP\Outlook\09. September\Backup\20170906-1 - OEFC Revenue Forecast for Board
ydro 2017\OEFC\RbP\Outlook\09. September\Backup\20170906-1 - OEFC Revenue Forecast for Board
ydro 2017\OEFC\RbP\Outlook\09. September\Backup\20170906-1 - OEFC Revenue Forecast for Board
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ydro 2017\OEFC\RbP\Outlook\09. September\Backup\20170906-1 - OEFC Revenue Forecast for Board
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ydro 2017\OEFC\RbP\Outlook\09. September\Backup\20170906-1 - OEFC Revenue Forecast for Board

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Annual Report - English.pdf
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glish.pdf

Debt Interest Cost.msg

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down_Mar15_if apply Jan1_Apr21.xls

down_Mar15_if apply Jan1_Apr21.xls
down_Mar15_if apply Jan1_Apr21.xls
down_Mar15_if apply Jan1_Apr21.xls

Annual Report - English.pdf

Colour Codes

Formulas are in black text

Hard coded numbers are in blue text

References elsewhere are in purple

Green bold text with or without highlights mean updates required

Policies to follow when making updates to the Outlook

*** To quickly jump to the source numbers for a link, press "**Ctrl + [**"

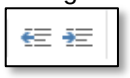
All new numbers must be fully sourced, and follow the colour codes above

Most numbers and text are Arial Size 10, unless it is a title

Add back up materials in a folder with the same numbers as in the 'Track Changes' tab

If there is a reason for italics, or other colours, or formatting make sure it is clear. Othe

Use indents to make things more clear to read



If numbers are taken from another tab they should ONLY be direct links, no calculation

Electricity Summary - (Budget17/On Deck) - Reflects Public Accounts/Financial Statem

OEFC - (Budget17/On Deck) - Reflects OEFC Annual Reports

*Due to slight discrepancies between Public Accounts reporting and OEFC Annual Rep

Outlook Updates Frequency

Frequency	Description	Tab
Monthly	OPG Net Income in-year forecast	OPG
Monthly	OPG PILs in-year forecast	OPG
Quarterly	ONFA Consolidation Adjustment	ONFA
Quarterly	OPG Cash vs Accrual Variance Account	Revenue (Risks)

ɔ.
rwise expect it to be cleared

ı, adjustment should be done. Even if its just making a negative to a positive. Perform all the calculations on the

ıents

ɔorts, the numbers may not be identical

source tab then bring the number into the next tab. (Eg. Formulas like this become hard to troubleshoot ='Hydro

One'!AR29+'Hydro One'!AR31+'Hydro One'!AR32), let's avoid them.

From: Bruno Amara
To: Ronald Kwan
Cc: John Kim; Francisco Chinchon
Subject: RE: Electricity Outlook Update
Date: Friday, February 16, 2018 12:02:32 PM

Hi Ron

Further on OPG 2019-20. 2020 earnings are likely weighted to the first part of the year as the drop in 2020 net income is due to larger planned Pickering outage including advancement of some outage from 2021. In that scenario, 2019-20 could indeed be higher than either of the calendar year amounts.

In addition, OPG also notes higher nuclear production in 2019 reflecting outage optimization initiatives, higher earnings from the Nanticoke solar facility upon completion in 2019 and lower OMA in 2019 due to fewer major planned outages at Pickering and cost efficiencies.

Bruno

From: Bruno Amara
Sent: Friday, February 16, 2018 11:37 AM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: John Kim <John.Kim@ofina.on.ca>; Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>
Subject: RE: Electricity Outlook Update

Hi Ron

We are getting ready to distribute. Fyi, see below the changes we have made per your comments.

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That is indirectly one our follow-up questions for OPG. OPG's calendar year net income for 2019 and 2020 are $968M and $764M respectively, but the Province's fiscal year amount for 2019-20 is $1,053. Not sure how fiscalizing gets to a higher number than each of those years.

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Thanks,
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Subject: RE: Electricity Outlook Update

File location

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Tel: 416-325-1489
Email: bruno.amara@ofina.on.ca

From:	Bruno Amara
To:	Ronald Kwan
Cc:	John Kim; Francisco Chinchon
Subject:	RE: Electricity Outlook Update
Date:	Friday, February 16, 2018 11:36:42 AM

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Tel: 416-325-1489
Email: bruno.amara@ofina.on.ca

From: Francisco Chinchon
To: John Kim; Bruno Amara
Cc: Darren Scanlan; Ronald Kwan
Subject: RE: Electricity Outlook Update
Date: Friday, February 16, 2018 9:37:23 AM

Hi,

Anything related to the Brampton sale (meaning net gains and one-time PILs) was accrued in 16/17. For 17/18 and forward it should only be MEU PILs.

Thanks,

Francisco

From: John Kim
Sent: Friday, February 16, 2018 9:34 AM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Bruno Amara <Bruno.Amara@ofina.on.ca>; Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>
Subject: Re: Electricity Outlook Update

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From:	Bruno Amara
To:	Ronald Kwan
Cc:	John Kim; Francisco Chinchon
Subject:	RE: Electricity Outlook Update
Date:	Friday, February 16, 2018 8:58:57 AM

Hi Ron

Thanks for edits and comments. Will address those and circulate today.

Bruno

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From: John Kim
To: Ronald Kwan; Bruno Amara
Cc: Francisco Chinchon
Subject: RE: Electricity Outlook Update
Date: Friday, February 16, 2018 7:42:18 AM

Hi Bruno, Francisco,

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From: Bruno Amara
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Subject: RE: Electricity Outlook Update
Date: Friday, February 16, 2018 12:33:11 PM

Hi Ron

Yes, Thanks, I have sent them the question and am waiting to hear back.

Bruno

From: Ronald Kwan
Sent: Friday, February 16, 2018 12:29 PM
To: Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>
Cc: Bruno Amara <Bruno.Amara@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>
Subject: Re: Electricity Outlook Update

Hi All,

FTD should be able to respond. Rob B.

Ron

On Feb 16, 2018, at 12:16 PM, Francisco Chinchon <Francisco.Chinchon@ofina.on.ca> wrote:

> Just in case is helpful, Ron's recollection with respect to when the cash was collected is correct.
>
> On Feb 16, 2018, at 12:02 PM, Ronald Kwan <Ronald.Kwan@ofina.on.ca> wrote:
>
> > Hi,
> >
> > I thought we had this discussion last year, and that the BSC tracks cash flow, and the Brampton PILs were paid in cash during 17-18, but accrued to 16-17. If so, backing that out, leaves MEU PILs way behind plan.
> >
> > Please check. I don't want to overstate PILs in this outlook run.
> >
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In the comments on the impact of Lakeview, it has +200 in both OPG income and PILs rows. Should it be 70 for the PILs comment row? And should I assume that SIFB has backed out Lakeview from Sales and rentals?

Why the big variance in 19-20 for OPG vs Budget 2017?

On the FHP impact on OPG, is there coordination with FTD on their IOD impact assumptions?

We should alert CQSD too on the ESDI projection update, to ensure

the MOF PRRT is updated (and for Estimates).

Risks:

I think we should add in general OPG and Hydro One risks on OM&A too.

Shouldn't there be an ONFA funds return risk too?

Let's relabel the "Nuclear Reliability" risk to "Nuclear Output".

Should we update the Hydro One deferred tax benefit risk, given the drop in ownership share? Or will it be based on a weighted average over the year basis? And how should we reflect that the risk could be in 18-19 instead? Add an asterix or footnote to that cell too?

It should refer to stranded debt being "retired" (not defeased – that timing would be earlier – when residual stranded debt is retired, if it were still in the Act and being calculated)

Isn't the PILs leakage risk too big. Property tax PILs are only about $20 million – isn't that the case?

Thanks,
Ron

From: Bruno Amara
Sent: February-15-18 6:41 PM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: John Kim

<John.Kim@ofina.on.ca>
Subject: RE: Electricity Outlook Update

File location

S:\Users\CEF\Hydro 2018\OEFC\RbP\Outlook\02. February

From: Bruno Amara
Sent: Thursday, February 15, 2018 6:39 PM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: John Kim <John.Kim@ofina.on.ca>
Subject: Electricity Outlook Update

Hi Ron

Please see attached our updated Electricity Sector Outlook.

This includes

- OPG 2018-2021 Business plan updates including the inclusion now of the proceeds in 2017-18 from Lakeview properties.
- Hydro One has also been updated to reflect year-end results for Hydro One. In particular 2017-18 is driven mainly by quarterly actual (the 2018 quarter is model projection. 2018-19 onward are also model projections.
- The outlook also incorporates the latest figures from SIFB wrt s. 50.3 and the debt OEF H1

debt paydown related to last May 2017 disposition.

- We also have updated IOD numbers from FTD today
- SPFB indicated they will updated power purchase/recovery outlook early next week.

We have added an additional year to the Outlook, 2021-22.

On risk table we added possible PILs transfer to municipalities. Note that this outlook has SD defeased as of 2021-22.

I have added a temporary worksheet showing the changes since the last Outlook distribution in January. The main changes related to OPG, particularly the 2017-18 increase only partly explained by inclusion of Lakeview. Note that the OPG business plan noted that 2017-18 included a $325 hit related to the later effective date. That is consistent with our estimate.

Thanks
Bruno

Bruno Amara
Sr. Manager, Financial and Regulatory Analysis
Electricity Finance Branch
Corporate and Electricity Finance Division
Ontario Financing Authority

Tel: 416-325-1489
Email: bruno.amara@ofina.on.ca

From: Ronald Kwan
To: John Kim
Cc: Gavin He; Francisco Chinchon
Subject: RE: Electricity Outlook
Date: Tuesday, March 07, 2017 6:12:27 PM

Hi,

I was talking to Gadi earlier today and he said that the IOD adjustment had not yet been provided for the fiscal roll-up, so the OPG net income numbers would be out of sync .

Was anything sent to OB, OEP and TBS today? I didn't see an email.

Was there a discussion with staff?

Thanks,
Ron

From: Ronald Kwan
Sent: March-07-17 09:09
To: Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>
Cc: John Kim <John.Kim@ofina.on.ca>
Subject: Re: Electricity Outlook

Hi Francisco, John,

Would it be helpful to send the two underlying spreadsheets together, noting the pivot to 70%, which is fiscally-neutral across the two products, but shown for interim actuals purposes to be closer to Public Accounts?

And note as well the OPG number adjustments to match the IOD adjustment (assuming those have gone up?).

Please bcc me.

Thanks,
Ron

On Mar 7, 2017, at 9:00 AM, Francisco Chinchon <Francisco.Chinchon@ofina.on.ca> wrote:

> Hi,
>
> We are good too. I did share the latest AO slides with OEP and OTB and staff have been communicating.
>
> What takes more time for staff to fully grasp is how the unpacking of the multiple sales affect each line although neutral on aggregate.

Thanks,

Francisco

On Mar 7, 2017, at 8:49 AM, Ronald Kwan <Ronald.Kwan@ofina.on.ca> wrote:

> Hi,
>
> For sure. Last Friday would have been better.
>
> Ron
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> On Mar 7, 2017, at 8:41 AM, John Kim <John.Kim@ofina.on.ca> wrote:
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> > Hi Ron,
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> > Brampton is in AO….and we're both at 70%.
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Thanks,
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Date:	Tuesday, March 07, 2017 7:00:18 AM
Importance:	High

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Subject:	RE: Electricity Outlook
Date:	Friday, March 03, 2017 6:00:30 PM
Attachments:	Copy of Electricity Sector Outlook- Feb 2017_70%_no IOD_v12_Markup.xlsx

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From: John Kim
Sent: March-03-17 17:16
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Subject: RE: Electricity Outlook

Yes, that is the case….that had been assumed for a long time. We've moved to coordinating on 70% for 2-3 weeks now.

John.

From: Ronald Kwan
Sent: Friday, March 03, 2017 5:13 PM
To: John Kim <John.Kim@ofina.on.ca>
Subject: RE: Electricity Outlook

Hi John,

But what has changed on the Hydro One side and SIFB`s AO numbers?

I was thinking the two branches had been coordinating on an on-going basis --- so if the EFB numbers were using 84% as the baseline, the AO numbers would be net of more forgone net income. And if the EFB file is at 70%, then the SIFB AO forgone revenue numbers would be net of less forgone revenue.

Is that the case as each branch has been sending up files, this month versus last?

Ron

From: John Kim
Sent: March-03-17 17:07
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Subject: RE: Electricity Outlook

Hi Ron,

Yes, we're now working on the 70% baseline. The numbers are generally the same.

NUG numbers changed somewhat.

The Bampton PILs is there.

Unpacked the PILs impact of the office sale.

So, generally the information has not changed significantly. I'd characterize as the 70% baseline and house-keeping.

John.

From: Ronald Kwan
Sent: Friday, March 03, 2017 5:04 PM
To: John Kim <John.Kim@ofina.on.ca>
Subject: RE: Electricity Outlook

Hi,

Are we now working on a 70% baseline, and coordinated with the AO numbers? What changed since the early February file and numbers coordination?

Ron

From: John Kim
Sent: March-03-17 16:03
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Gavin He <Gavin.He@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>
Subject: FW: Electricity Outlook

Pls. see attached.

Thanks,

John.

From: John Kim
Sent: Friday, March 03, 2017 3:56 PM
To: Bruno Amara <Bruno.Amara@ofina.on.ca>
Cc: Adam Prokop <Adam.Prokop@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>; Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Salman Qadir <Salman.Qadir@ofina.on.ca>
Subject: RE: Electricity Outlook

One more modification….I added the GA interest cost impact in the OPG tab. Also, highlighted in yellow. I'm sure there's a more elegant way of modelling due to my lack of skills at this.

I used FTD's forecast for 2017-18 to 2019-20 and then used our conservative interest income for 2020-21 of 135 (based on 3.5% interest) as a placeholder until FTD does their number.

John.

From: John Kim
Sent: Friday, March 03, 2017 3:31 PM
To: Bruno Amara <Bruno.Amara@ofina.on.ca>
Cc: Adam Prokop <Adam.Prokop@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>; Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Salman Qadir <Salman.Qadir@ofina.on.ca>
Subject: RE: Electricity Outlook

Thanks Bruno…..just changed the yellow highlighted part on the Revenue (Risk) tab. Let me know if what I did makes sense pls.

From: Bruno Amara
Sent: Friday, March 03, 2017 2:29 PM
To: John Kim <John.Kim@ofina.on.ca>
Cc: Adam Prokop <Adam.Prokop@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>; Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Salman Qadir <Salman.Qadir@ofina.on.ca>
Subject: RE: Electricity Outlook

I should attach file

From: Bruno Amara
Sent: Friday, March 03, 2017 2:28 PM
To: John Kim <John.Kim@ofina.on.ca>
Cc: Adam Prokop <Adam.Prokop@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>; Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Salman Qadir <Salman.Qadir@ofina.on.ca>
Subject: FW: Electricity Outlook

Hi John

See updated outlook attached. Never mind my earlier comments. As Adam notes the only change is that we have info now to split out the head office sale impact between NI and PILs.

Bruno

From: Adam Prokop
Sent: Friday, March 03, 2017 2:25 PM
To: Bruno Amara <Bruno.Amara@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>
Cc: Salman Qadir <Salman.Qadir@ofina.on.ca>
Subject: RE: Electricity Outlook

Hello Bruno,

Here is the updated outlook for your review. The only change was in how the head office sale was split between PILS and net income for OPG, so there are no changes in the total change from 2016 budget.

Kind regards,

Adam Prokop

From: Bruno Amara
Sent: Friday, March 03, 2017 11:08 AM
To: John Kim <John.Kim@ofina.on.ca>
Cc: Gavin He <Gavin.He@ofina.on.ca>; Adam Prokop <Adam.Prokop@ofina.on.ca>
Subject: Electricity Outlook

Hi John

Attached is the updated outlook reflecting Ron's comments on the risk page. Note that there is a new Cover Sheet per request from TBS/OB.

S:\Users\CEF\Hydro 2017\OEFC\RbP\Outlook\02. February

Bruno

Gavin, we picked up the revised DRC forecast.

Electricity Sector Outlook
March 2017

Disclosure:

All information contained in this workbook are confidential and commercially sensitive

All projected numbers are estimates and subjected to change, and the focus is on OPG and Hydro One projections

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Commercially Sensitive and Confidential Advice to Cabinet for Consideration of Options for Discussion Purposes Only

Electricity Sector Outlook*
Line Items for Consolidation

Electricity Summary - On Deck

Type
Expense
Expense
Expense
Expense
Expense
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue

Electricity Summary - Budget16

Type
Expense
Expense
Expense
Expense
Expense
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue

Electricity Summary - Change

Type
Expense
Expense
Expense
Expense
Expense
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue

* Outlook reflects revenues from OPG, Hydro One, OEFC and PILS f

For Discussion

Ministry Pickup	Line	Item
MOF (OEFC)	**38**	Power Supply Contract Costs
MOF (OEFC)	**40**	Demand Management Support Costs6
MOF (OEFC)	**41**	Provision for Electricity Sector
MOF	**17**	Provision for Electricity Sector4
MOF (OEFC)	**42**	Other (Finance)
ENE	**7**	OPG Income1
ENE	**8**	OPG - ONFA and other Fair Value Adjustments2
ENE	**10**	HOI Income3
	11	Brampton Income
MOF (OEFC)	**26**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT
MOF (OEFC)	**29**	Electricity Debt Retirement Charge5
MOF (OEFC)	**30**	Power Supply Contract Recoveries
MOF (OEFC)	**31**	Net Reduction of Power Purchase Contracts
MOF (OEFC)	**34**	Miscellaneous
		Sub-Total
		add IOD expense (picked up by OFA)
		Public Debt Interest - Electricity Sector
		Interest on Debt
		Impact on Surplus/Deficit
		check

For Discussion

Ministry Pickup	Line	Item
MOF (OEFC)	**38**	Power Supply Contract Costs
MOF (OEFC)	**40**	Demand Mangement Support Costs6
MOF (OEFC)	**41**	Provision for Electricity Sector
MOF	**17**	Provision for Electricity Sector
MOF (OEFC)	**42**	Other (Finance)
ENE	**7**	OPG Income1
ENE	**8**	OPG - ONFA and other Fair Value Adjustments2
ENE	**10**	HOI Income3
MOF (OEFC)	**25**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT
MOF (OEFC)	**29**	Electricity Debt Retirement Charge5
MOF (OEFC)	**30**	Power Supply Contract Recoveries
MOF (OEFC)	**31**	Net Reduction of Power Purchase Contracts
MOF (OEFC)	**34**	Miscellaneous
		Sub-Total
		add IOD expense (picked up by OFA)
	17	Public Debt Interest - Electricity Sector
	36	Interest on Debt

		Impact on Surplus/Deficit
		check

Ministry Pickup	Line	Item
MOF (OEFC)	**37**	Power Supply Contract Costs
MOF (OEFC)	**39**	Demand Management Support Costs
MOF (OEFC)	**40**	Provision for Electricity Sector
MOF	**16**	Provision for Electricity Sector
MOF (OEFC)	**41**	Other (Finance)
ENE	**7**	OPG Income
ENE	**8**	ONFA and other Fair Value Adjustments
ENE	**10**	HOI Income
MOF (OEFC)	**25**	Electricity Payments-in-Lieu of Taxes (PILs)
MOF (OEFC)	**28**	Electricity Debt Retirement Charge
MOF (OEFC)	**29**	Power Supply Contract Recoveries
MOF (OEFC)	**30**	Net Reduction of Power Purchase Contracts
MOF (OEFC)	**3**	Miscellaneous

		Sub-Total
		add IOD expense (picked up by OFA)
		Public Debt Interest - Electricity Sector
		Interest on Debt
		Impact on Surplus/Deficit
		check

from MEUs, and excludes OPA, IESO and OEB.

Plan ($ Millions)				
2016-17	**2017-18**	**2018-19**	**2019-20**	**2020-21**
(739)	(285)	(217)	(293)	(265)
(10)	(10)	-	-	-
393	525	-	-	-
(393)	(525)	-	-	-
(6)	(6)	(6)	(6)	(6)
355	497	733	828	1,048
8	-	-	-	-
516	520	562	603	652
15	-	-	-	-
457	405	476	538	679
638	629	-	-	-
739	285	217	293	265
129	74	41	30	28
-	-	-	-	-
2,102	**2,109**	**1,805**	**1,993**	**2,400**
(492)	(492)	(492)	(492)	(492)
(532)	(422)	(374)	(342)	(250)
1,078	**1,195**	**939**	**1,159**	**1,658**
-	**-**	**-**	**-**	**-**

Plan ($ Millions)				
2016-17	**2017-18**	**2018-19**	**2019-20**	**2020-21**
(643)	(463)	(396)	(276)	(248)
(10)	(10)	0	0	0
138	706	0	0	0
(138)	(706)	0	0	0
(6)	(6)	(6)	(6)	(6)
471	586	673	705	734
0	0	0	0	0
578	612	674	713	737
515	480	532	481	565
625	623	0	0	0
643	463	396	276	248
129	74	41	30	28
5	5	5	5	5
2,307	**2,364**	**1,919**	**1,928**	**2,063**
(492)	(492)	(492)	(492)	(492)
(635)	(657)	(617)	(633)	(627)

1,180	**1,215**	**810**	**803**	**944**
-	**-**	**-**	**-**	**-**

($ Millions)

2016-17	2017-18	2018-19	2019-20	2020-21
(96)	**178**	**179**	**(17)**	**(17)**
-	**-**	**-**	**-**	**-**
256	**(182)**	**-**	**-**	**-**
(256)	**182**	**-**	**-**	**-**
-	**-**	**-**	**-**	**-**
(116)	**(89)**	**60**	**124**	**315**
8	**-**	**-**	**-**	**-**
(48)	**(93)**	**(112)**	**(109)**	**(86)**
(57)	**(75)**	**(56)**	**57**	**114**
13	**6**	**-**	**-**	**-**
96	**(178)**	**(179)**	**17**	**17**
-	**-**	**-**	**-**	**-**
(5)	**(5)**	**(5)**	**(5)**	**(5)**
(205)	(255)	(114)	66	338
-	-	-	-	-
103	235	243	291	377
(102)	**(20)**	**129**	**357**	**715**
0	***0***	**-**	**-**	**-**

Outlook Tracking Log

Date	Previous File Name	New File Name
Nov 2016 v2		
Dec 2016 v3		
Dec 2016 v4 OPG BP-July		
Dec 2016 v4 OPG BP-Nov		
Dec 2016 v4 OPG BP-Nov v2		
28-Dec-16	Electricity Sector Outlook-December 2016_84%_no IOD v4 OPG BP-Nov_v2.xlsx	Electricity Sector Outlook-December 2016_84%_no IOD v4 OPG BP-Nov_v3.xlsx
3-Jan-17	Electricity Sector Outlook-December 2016_84%_no IOD v5 OPG BP-Nov v4.xlsx	Electricity Sector Outlook-December 2016_84%_no IOD v5 OPG BP-Nov v5.xlsx
4-Jan-17	Electricity Sector Outlook-December 2016_84%_no IOD v5 OPG BP-Nov v5_Markup.xlsx	Electricity Sector Outlook-December 2016_84%_no IOD v5 OPG BP-Nov v6.xlsx
16-Jan-17	Electricity Sector Outlook-December 2016_84%_no IOD v5 OPG BP-Nov_v9.xlsx	Electricity Sector Outlook-December 2016_84%_no IOD v5 OPG BP-Nov_v10.xlsx
17-Jan-17	Electricity Sector Outlook-December 2016_84%_no IOD v5 OPG BP-Nov_v10.xlsx	Electricity Sector Outlook-December 2016_84%_no IOD v5 OPG BP-Nov_v11.xlsx
20-Jan-17	Electricity Sector Outlook-December 2016_84%_no IOD v5 OPG BP-Nov_v12.xlsx	Electricity Sector Outlook-December 2016_84%_no IOD v5 OPG BP-Nov_v13.xlsx
20-Jan-17	Electricity Sector Outlook-December 2016_84%_no IOD v5 OPG BP-Nov_v13.xlsx	Electricity Sector Outlook-December 2016_84%_no IOD v5 OPG BP-Nov_v14.xlsx

	26-Jan-17	Electricity Sector Outlook- December 2016_84%_no IOD v5 OPG BP-Nov_v15.xlsx	Electricity Sector Outlook- December 2016_84%_no IOD v5 OPG BP-Nov_v16.xlsx
	6-Feb-17	Electricity Sector Outlook- December 2016_84%_no IOD v5 OPG BP-Nov v16_OPG_H1TxRisks_Markup2.xlsx	Electricity Sector Outlook- December 2016_84%_no IOD v5 OPG BP-Nov v16_OPG_H1TxRisks_Markup3.xlsx
	16-Feb-17	Electricity Sector Outlook- Feb 2017_84%_no IOD_v1.xlsx	Electricity Sector Outlook- Feb 2017_84%_no IOD_v2.xlsx
	16-Feb-17	Electricity Sector Outlook- Feb 2017_84%_no IOD_v2.xlsx	Electricity Sector Outlook - Feb 2017_70%_no IOD_V2
	17-Feb-17	Electricity Sector Outlook - Feb 2017_70%_no IOD_V2	Electricity Sector Outlook - Feb 2017_70%_no IOD_V3
	2-Mar-17	Electricity Sector Outlook - Feb 2017_70%_no IOD_v6 (002)	Electricity Sector Outlook - Feb 2017_70%_no IOD_v7 (002)
	2-Mar-17	Electricity Sector Outlook - Feb 2017_70%_no IOD_v8 (002)	Electricity Sector Outlook - Feb 2017_70%_no IOD_v9 (002)
	3-Mar-17	Electricity Sector Outlook - Feb 2017_70%_no IOD_v9 (002)	Electricity Sector Outlook - Feb 2017_70%_no IOD_v10 (002)
	3-Mar-17	Electricity Sector Outlook - Feb 2017_70%_no IOD_v10 (002)	Electricity Sector Outlook - Feb 2017_70%_no IOD_v11 (002)

Summary of Changes
1) Price Mitigation Net Impact Tab - Flat-lined the tax base measures
2) Hydro One Tab - IPO Impacts, changed ownership to 70.1% from 84%
3) OPG Tab: Added 2017BP November 2016 NI and PILs numbers
Reverted Nov 2016 v2, #3 changes. Next version will insert H1 numbers from new EFB model and then will be split into 4 versions, 2 of which will incorporate the OPG Tab changes from Nov 2016 #3 changes.
New hydro one numbers have been inserted from the CEFD internal model. The 2020-21 number is the same as before.
Added in new OPG numbers from OPG BP November into OPG Tab
In OPG Tab, updated Income Tax for 2017-18 to reflect sale of HQ
Reverse the GRC amounts for OPG Nov 2016 BP to the previous forecast, since the breakdown information for GRC to OEFC information is not available in the new BP.
1) Addressed John's comments on various tabs, explaining the variances, and changed OPG's PIL revenues to $166M for 2017-18. 2) Updated the "Revenue (On Deck)" tab row 32 to include CIT impact. 3) Updated the variance explanation in the "Electricity Summary - Change" tab.
1) John linked the ONFA numbers on the "OPG" tab from the "ONFA" tab. 2) Updated the variance explanation on the "Electricity Summary - Change" tab.
1) Updated the positive and negative risks in the "Revenue (Risks)" tab for OPG and Hydro One, including the explanations. 2) ONFA Funds Return Risk on "Revenue (Risks)" tab - changed from -115.665 to -90 in 2016-17 3) OPG 2020-2021 numbers updated with business plan net income and income tax fiscalized.
1) Updated OPG Variance details on Electricity Summary - Change Tab 2) Added Note #4 on MEU PILs, confirming no change required on Revenue (On Deck) tab.
1) Updated Power Supply Contract Costs and Recoveries in OEFC tab with preliminary SFIB estimates, and explanations in the Electric Summary Change.
1) Revised ONFA Consolidation number for Dec 2016 update in the ONFA tab. 2) 2016-17 NUG lawsuit retroactive payment reflected in Power Supply Contract Costs and Recoveries. 3) Update NUG Forecast with 206-17 new forecast including the lawsuit.

1) OPG Net Income updated with latest monthly updated for 2016-2017.
1) Hydro One 2020-21 numbers updated with CEFD projection.
Updated the "Demand Mangement Support Costs" formula in the "Electricity Summary - Change" tab.
- Hydro One ownership changed to 70% - Hydro One forecasted with 2016 annual report numbers added into CEFD model - Hydro One Brampton PILS and Net Income removed from 2017-18 onwards - MEU Forecast updated with $5M per year HO1 Brampton PILS
-$80M PILS added to MEU line for 2016-2017 (less the prior $5M addition)
-NUG Forecast updated
Cleaned up comments
- Updated Risks tab to reflect IFRS consolidation risk impacting 2017 onwards. - DRC updated to refelct new forecast.
-OPG updated with answers for the head office sale

Electricity Sector Outlook (PSAB)

($ millions)	Budget 2015-16	2016-17	2017-18	Plan 2018-19	2019-20	2020-21
Approved Revenue Outlook as of Budget 2016						
Electricity Revenues						
Income from Investment in Government Business Enterprises[1]	330	1,049	1,198	1,347	1,417	1,471
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes	3,232	515	480	532	481	565
Other Revenue						
Electricity Debt Retirement Charge	868	625	623	-	-	-
Power Supply Contract Recoveries	784	643	463	396	276	248
Net reduction of Power Purchase Contracts[2]	172	129	74	41	30	28
Miscellaneous	5	5	5	5	5	5
Total Electricity Revenue[3]	5,391	2,966	2,843	2,321	2,209	2,317

Notes:

1. Includes provincial consolidation adjustments for OPG's nuclear funds

2. Reflects the effective elimination of above-market NUG liability over a number of years starting January 1, 2005 (on a predetermined schedule).

3. Total reflects revenues from OPG, Hydro One, OEFC and PILS from MEUs, and excludes OPA and IESO and OEB.

Revenue Items On Deck - Changes Compared to Budget 2016

($ millions)	Budget 2015-16	2016-17	2017-18	Plan 2018-19	2019-20	2020-21
OPG March 2017 Financial Outlook[1]	21	(247)	(156)	12	188	436
ONFA and other Fair Value Accounting Adjustments[2]	(69)	8	0	0	0	0
Hydro One March 2017 Financial Outlook Update[3]	430	(55)	(106)	(126)	(123)	(98)
MEUs PILs	2	80	5	5	5	5
Other OEFC FS / Public Accounts Updates						
Electricity Debt Retirement Charge	(9)	13	6	0	0	0
Miscellaneous	4	(5)	(5)	(5)	(5)	(5)
Power Supply Contract Recoveries[5]	91	96	(178)	(179)	17	17
Total Revenue Items On Deck	471	(110)	(433)	(293)	83	354

Notes:

1. OPG's 2015-16 outlook reflected its reported earnings. Out-years reflect OPG's 2017-19 business plan, November monthly update, and long-term outlook to 2019-20 (as fiscalized by OPG). 2020-21 estimates are based on OPG's calendar year-based long-term projections from the November business plan and fiscalized by CEFD staff. OPG Business Plan projections are also adjusted to remove amounts related to asset optimisation amounts (for real estate sales, to avoid double-counting) that are reflected in the fiscal plan under sales and rentals.

1. OPG Net Income is also adjusted for assumed equity return on Provincial equity injection to partially finance the Global Adjustment deferral -- designed to match FTD estimated IOD to finance the equity injection. See OPG Worksheet for annual breakdown.

2. Reflects provincial adjustment as at December 31, 2016, for net unrealized earnings in the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated fund. Adjustment for 2014-15 also includes non-ONFA financial instruments.

3. Reflects CEFD forecasts based on latest available public information and modelling. Reflects an 70% Provincial share ownership, with impacts of future share sales incorporated into the asset optimisation projection in Other Non-Tax Revenues, Sales and Rentals

5. Reflects retroactive payment to applicant NUGs under the Global Adjustment lawsuit, based on payment in October 2016. Reflect updated forecast from 2016-17 to 2020-21, with the latest forecast from February 2017.

On Deck Revenue Outlook as of March 2017	Budget 2015-16	2016-17	2017-18	Plan 2018-19	2019-20	2020-21
Electricity Revenues						
Income from Investment in Government Business Enterprises	719	893	1,017	1,295	1,431	1,700
Taxation Revenue	3,228	457	405	476	538	679
Electricity Payments-in-Lieu of Taxes						
Other Revenue						
Electricity Debt Retirement Charge	859	638	629	-	-	-
Power Supply Contract Recoveries	875	739	285	217	293	265
Net reduction of Power Purchase Contracts	172	129	74	41	30	28
Miscellaneous	9	-	-	-	-	-
Total Electricity Revenue	5,862	2,857	2,410	2,028	2,292	2,671
Check Calculation:						
Revenue	5,862	2,856	2,410	2,028	2,292	2,671
Expense	2,006	1,779	1,215	1,089	1,133	1,013
Net	3,856	1,078	1,195	939	1,159	1,658
Electricity Summary - On Deck	3,856	1,078	1,195	939	1,159	1,658
	ok	ok	ok	ok	ok	ok

($ millions)	2016-17 Changes		
Revenue Items On Deck - Changes Compared to Budget 2	Net Income	PILs	Total
OPG March 2017 Financial Outlook	(116)	(131)	(247)
ONFA and other Fair Value Accounting Adjustments	8		8
Hydro One March2017 Financial Outlook	(48)	(6)	(55)
MEU PILs		80	80
	(156)	(57)	(214)

Electricity Sector Outlook (PSAB)

Expenditure Outlook as of Budget 2016						
($ millions)	Actual	Plan				
	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
Electricity Expenditures						
Finance - Own Account	7	6	6	6	6	6
Interest on Debt	1,248	1,178	1,159	1,127	1,149	1,109
Electricity Consumer Price Protection Fund	-	-	-	-	-	-
Power Supply Contract Costs	1,296	950	784	643	463	396
Total Electricity Expenditures	2,551	2,134	1,949	1,776	1,618	1,511

Details on Change in Expenditure Outlook						
($ millions)	Actual	Plan				
	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
Public Accounts						
Finance - Own Account	-	-	(43)	(103)	(235)	(243)
Interest on Debt	-	-	-	-	-	-
Power Supply Contract Costs	-	-	91	96	(178)	(179)
Total Updates:	-	-	48	(7)	(413)	(422)

On Deck Expenditure Outlook as of March 2017						
($ millions)	Actual	Plan				
	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
Electricity Expenditures						
Finance - Own Account	7	6	7	6	6	6
Interest on Debt	1,248	1,178	1,116	1,024	914	866
Power Supply Contract Costs	1,296	950	875	739	285	217
Total Electricity Expenditures	2,551	2,134	1,998	1,769	1,205	1,089

Expense Items On Deck						
($ millions)	Actual	Plan				
	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
Finance - Own Account*	-	-	-	-	-	-
Interest on Debt*	-	-	-	-	-	-
Power Supply Contract Costs*	-	-	-	-	-	-
Total Expense Items "On Deck":	-	-	-	-	-	-

* Updated based on OEFC audited financial statements.

On Deck Expenditure Outlook as of March 2017						
($ millions)	Actual	Plan				
	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
Electricity Expenditures						
Finance - Own Account	7	6	7	6	6	6
Interest on Debt	1,248	1,178	1,116	1,024	914	866
Power Supply Contract Costs	1,296	950	875	739	285	217
Demand Management Support Costs	-	9	8	10	10	-
Total Electricity Expenditures	2,551	2,143	2,006	1,779	1,215	1,089

Additional Expenditure Risks						
($ millions)	Actual	Plan				
	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
Finance - Own Account						
Interest on Debt						
Power Supply Contract Costs						
Total Additional Risks:	-	-	-	-	-	-

Risk Based Expenditure Outlook						
($ millions)	Actual	Plan				
	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
Electricity Expenditures						
Finance - Own Account	7	6	7	6	6	6
Interest on Debt	1,248	1,178	1,116	1,024	914	866
Power Supply Contract Costs	1,296	950	875	739	285	217
Total Electricity Expenditures	2,551	2,134	1,998	1,769	1,205	1,089

Electricity Sector Outlook (PSAB)

($million)	Interim 2015-16	2016-17	2017-18	Plan 2018-19
Budget 2016 Outlook as of January 2016				
Income from Investment in Government Business Enterprises				
OPG Income[1]	257	471	586	673
OPG - ONFA and other Fair Value Adjustments[2]	241	-	-	-
Hydro One - Unrealized Gains Adjustment	-	-	-	-
HOI Income[3]	(168)	578	612	674
Total OPG and HOI Income	**330**	**1,049**	**1,198**	**1,347**
Other Fees and Licences	**127**	**127**	**125**	**123**
Electricity Expenses of the Province				
Provision for Electricity Sector[4]	-	(138)	(706)	-
Public Debt Interest - Electricity Sector	(508)	(492)	(492)	(492)
Subtotal	(508)	(630)	(1,198)	(492)
Public Debt Interest - Impact of ONFA				
Amortization of Deferred Revenue re profit on sale of H1 notes				
Total Electricity Expenses of the Province	**(508)**	**(630)**	**(1,198)**	**(492)**
OEFC Income				
Taxation Revenue				
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	3,232	515	480	532
Other Revenue				
Electricity Debt Retirement Charge[5]	868	625	623	-
Power Supply Contract Recoveries	784	643	463	396
Net Reduction of Power Purchase Contracts	172	129	74	41
Other Fees and Licences	(127)	(127)	(125)	(123)
Miscellaneous	5	5	5	5
Expenses				
Interest on Debt	(651)	(635)	(657)	(617)
Power Supply Contract Costs	(784)	(643)	(463)	(396)
Electricity Consumer Price Protection Fund	-	-	-	-
Demand Mangement Support Costs[6]	(9)	(10)	(10)	-
Provision for Electricity Sector	-	138	706	-
Other (Finance)	(6)	(6)	(6)	(6)
Total OEFC Income	**3,485**	**634**	**1,090**	**(168)**
Impact on Surplus/(Deficit)	**3,433**	**1,180**	**1,215**	**810**

Notes: All the Hydro One ownership broadening impacts, other than the initial IPO in 2015, are in the asset optimisation line (Sales and Rental) and not in the current Outlook file.

Notes:

1.Reflects OPG October 2015 report for 2015-16. Out-years reflect OPG's 2015 business plan and long-term outlook to 2018-19 (as fiscalized by OPG, received February 11, 2015). 2019-20 and 2020-21 estimates are preliminary and based on OPG's long-term model provided in 2015 and fiscalized by CEFD staff, to be updated.

2. Provincial consolidation adjustments for unrealized earnings on the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds, as of the end of December 2015.

3. Hydro One 2015-16 to 2020-21 projections are based on its 2015 Business plan, adjusted for latest information, including its 2015-17 distribution rate decIsion, adjustments to forecast ROEs based on current interest rate outlook and estimated Hydro One IPO impacts.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial consolidation adjustments, minus the interest costs to OEFC. The provision is currently assumed to end once the DRC ends on a legislated fixed end date of April 1, 2018.

5. Reflects April 23, 2014 announcement announcement that DRC will be eliminated for residential users, after December 31, 2015. The end date of DRC for remaining users is legislated to be on April 1, 2018. Estimates are subject to change based on actual consumption.

6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Expenses	2015-16	2016-17	2017-18	2018-19
Power Supply Contract Costs	784	643	463	396
Demand Management Support Costs	9	10	10	-
Provision for Electricity Sector	-	(138)	(706)	-
Other (Finance)	6	6	6	6
SUBTOTAL - OEFC Consolidation	**799**	**521**	**(228)**	**402**
Provision for Electricity Sector (Dedicated Earnings)	**-**	**138**	**706**	**-**

2) DETAIL LINES

REVENUE	2015-16	2016-17	2017-18	2018-19
CONSOLIDATED OPG/HOI NET INCOME	**330**	**1,049**	**1,198**	**1,347**
Public Debt Interest - Electricity Sector exp	*508*	*492*	*492*	*492*
equals ampount above $520M (not incl ONFA)	*0*	*138*	*706*	*0*
*of which: ONFA Adjustments***	*241*	*0*	*0*	*0*
check total	*749*	*630*	*1,198*	*492*
CONSOLIDATED REVENUE - OEFC				
Other Fees and Licences				
Provision for Electricity Sector				
Electricity Payments-in-Lieu of Taxes (PILs)	3,232	515	480	532
Electricity Debt Retirement Charge	868	625	623	0
Power Supply Contract Recoveries	784	643	463	396
Net Reduction of Power Purchase Contracts	172	129	74	41
Other Fees and Licences				
Miscellaneous	5	5	5	5
SUBTOTAL	**5,391**	**2,966**	**2,843**	**2,321**
EXPENSE				
CONSOLIDATED OEFC EXPENSE				
Provision for Electricity Sector				
Power Supply Contract Costs	784	643	463	396
Demand Mangement Support Costs	9	10	10	0
less provision	0	(138)	(706)	0
Other OEFC Expenses	6	6	6	6
SUBTOTAL	**799**	**521**	**(228)**	**402**
FINANCE				
Provision for Electricity Sector	0	138	706	0
Public Debt Interest - Electricity Sector (Treasury Program)	508	492	492	492
SUBTOTAL	**508**	**630**	**1,198**	**492**
TREASURY PROGRAM - EXPENSE				
OEFC Debt interest	1,344	1,326	1,337	1,282
interest payments to OEFC from Other than Province	(185)	(199)	(188)	(173)
interest to OEFC from Province	(508)	(492)	(492)	(492)
SUBTOTAL	**651**	**635**	**657**	**617**
Impact on Surplus/(Deficit)	**3,433**	**1,180**	**1,215**	**810**

Electricity Sector Outlook (PSAB)

($million)	Actual 2014-15	Actual 2015-16	2016-17	2017-18	Plan 2018-19
On Deck Outlook as of March 2017					
Income from Investment in Government Business Enterprises					
OPG Income[1]	817	291	355	497	733
OPG - ONFA and other Fair Value Adjustments[2]	239	172	8	-	-
Hydro One - Unrealized Gains Adjustment	(8)	-	-	-	-
HOI Income[3]	741	236	516	520	562
Brampton Income		20	15	-	-
Total OPG and HOI Income	**1,789**	**719**	**893**	**1,017**	**1,295**
Other Fees and Licences	**131**	**127**	**122**	**102**	**91**
Electricity Expenses of the Province					
Provision for Electricity Sector[4]	(1,038)	(3)	(393)	(525)	
Public Debt Interest - Electricity Sector	(520)	(520)	(492)	(492)	(492)
Subtotal	(1,558)	(523)	(885)	(1,017)	(492)
Public Debt Interest - Impact of ONFA					
Amortization of Deferred Revenue re profit on sale of H1 notes					
Total Electricity Expenses of the Province	**(1,558)**	**(523)**	**(885)**	**(1,017)**	**(492)**
OEFC Income					
Taxation Revenue					
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	180	3,228	457	405	476
Other Revenue					
Electricity Debt Retirement Charge[5]	956	859	638	629	-
Power Supply Contract Recoveries	950	875	739	285	217
Net Reduction of Power Purchase Contracts	217	172	129	74	41
Other Fees and Licences	(131)	(127)	(122)	(102)	(91)
Miscellaneous	9	9	-	-	-
Expenses					
Interest on Debt	(658)	(596)	(532)	(422)	(374)
Power Supply Contract Costs	(950)	(875)	(739)	(285)	(217)
Electricity Consumer Price Protection Fund	-	-	-	-	-
Demand Management Support Costs[6]	(9)	(8)	(10)	(10)	-
Provision for Electricity Sector	1,038	3	393	525	-
Other (Finance)	(6)	(7)	(6)	(6)	(6)
Total OEFC Income	**1,596**	**3,533**	**948**	**1,093**	**46**
Impact on Surplus/(Deficit)	**1,958**	**3,856**	**1,078**	**1,195**	**939**

Notes: The Hydro One net income outlook above (2016-17 to 2020-21) reflects the Province's current 70% ownership share, after the initial IPO in 2015 [and the secondary offering in April 2016]. Net estimated fiscal impacts from future Hydro One offerings are reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

Notes:

1.OPG's 2015-16 outlook reflected its reported earnings. 2016-17 outlook reflected OPG's November monthly update. Out-years reflect OPG's preliminary 2017-19 business plan and long-term outlook to 2019-20 (as fiscalized by OPG). 2020-21 estimates are based on OPG's calendar year-based business plan projections and as fiscalized by CEFD staff.

2. Provincial consolidation adjustments for unrealized earnings on the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds, as of the end of December 2016.

3. Hydro One 2015-16 income reflects its reported net income, adjusted for Hydro One IPO impacts. 2016-17 to 2020-21 projections are based on CEFD projections based on latest public information and modelling, including its 2015-17 distribution rate decision, adjustments to forecast ROEs based on current interest rate outlook and estimated Hydro One IPO and secondary share offering impacts.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial ONFA consolidation adjustments, minus the interest on debt payable ~~costs~~ to OEFC. The provision is currently assumed to end once the DRC ends on a legislated fixed end date of April 1, 2018.

5. Reflects April 23, 2014 announcement that DRC will be eliminated for residential users, after December 31, 2015. The end date of DRC for remaining users is legislated to be on April 1, 2018. Estimates are subject to change based on actual consumption.

6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Expenses	2014-15	2015-16	2016-17	2017-18	2018-19
Power Supply Contract Costs	950	875	739	285	217
Demand Management Support Costs	9	8	10	10	-
Provision for Electricity Sector	(1,038)	(3)	(393)	(525)	-
Other (Finance)	6	7	6	6	6
SUBTOTAL - OEFC Consolidation	**(73)**	**887**	**361**	**(224)**	**223**
Provision for Electricity Sector (Dedicated Earnings)	**1,038**	**3**	**393**	**525**	**-**

2) DETAIL LINES

REVENUE	2014-15	2015-16	2016-17	2017-18	2018-19
CONSOLIDATED OPG/HOI NET INCOME	**1,789**	**719**	**893**	**1,017**	**1,295**
Public Debt Interest - Electricity Sector exp	*520*	*520*	*492*	*492*	*492*
equals amount above $520M (not incl ONFA)	*1,038*	*3*	*393*	*525*	*0*
*of which: ONFA Adjustments***	*239*	*172*	*8*	*0*	*0*
check total	*1,797*	*695*	*893*	*1,017*	*492*
CONSOLIDATED REVENUE - OEFC					
Other Fees and Licences					
Provision for Electricity Sector					
Electricity Payments-in-Lieu of Taxes (PILs)	180	3,228	457	405	476
Electricity Debt Retirement Charge	956	859	638	629	0
Power Supply Contract Recoveries	950	875	739	285	217
Net Reduction of Power Purchase Contracts	217	172	129	74	41
Other Fees and Licences					
Miscellaneous	9	9	0	0	0
SUBTOTAL	**4,101**	**5,862**	**2,857**	**2,410**	**2,028**
EXPENSE					
CONSOLIDATED OEFC EXPENSE					
Provision for Electricity Sector					
Power Supply Contract Costs	950	875	739	285	217
Demand Management Support Costs	9	8	10	10	0
less provision	(1,038)	(3)	(393)	(525)	0
Other OEFC Expenses	6	7	6	6	6
SUBTOTAL	**(73)**	**887**	**361**	**(224)**	**223**
FINANCE					
Provision for Electricity Sector	1,038	3	393	525	0
Public Debt Interest - Electricity Sector (Treasury Program)	520	520	492	492	492
SUBTOTAL	**1,558**	**523**	**885**	**1,017**	**492**
TREASURY PROGRAM - EXPENSE					
OEFC Debt interest	1,385	1,319	1,216	1,090	1,027
interest payments to OEFC from Other than Province	(207)	(203)	(192)	(176)	(161)
interest to OEFC from Province	(520)	(520)	(492)	(492)	(492)
SUBTOTAL	**658**	**596**	**532**	**422**	**374**
Impact on Surplus/(Deficit)	**1,958**	**3,856**	**1,078**	**1,195**	**939**

Electricity Sector Outlook (PSAB)

($million)	Actual 2014-15	Plan 2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Changes from Budget 2016 as of March 2017								
Income from Investment in Government Business Enterprises								
OPG Income	-	34	(116)	(89)	60	124	315	The explanation for the drop of OPG's Income are related to a number of OEB regulatory risks related to the pe application for the 5-year period starting in 2017. Budget 2016 figures were primarily based on OPG's 2015-17 Plan as its board-approved multi-year business plan had not yet been approved and provided when the 2016 Bu plan was locked. OPG's revenues are projected to improve over time as the regulated rate increases on the ba custom incentive regulation approach, and the first refurbished Darlington unit will return to service in February
ONFA and other Fair Value Adjustments	-	(69)	8	-	-	-	-	
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	-	-	
HOI Income	-	424	(48)	(93)	(112)	(109)	(86)	The variance primarily reflects impacts of new Hydro One net income and corporate income tax projections pro CEFD. Hydro One's net income increased due to the stronger than anticipated results for Q3 2016. Corporate i are also lower to reflect the corporate minimum cash taxes Hydro One will pay due to the benefit from the defe asset reducing cash taxes. Hydro One Brampton's net income is removed from 2017-18 onwards due to the m Alectra Inc.
Total OPG and HOI Income	**-**	**389**	(156)	(182)	(52)	14	229	
Other Fees and Licences	**-**	**-**	(5)	(23)	(32)	(34)	(41)	
Electricity Expenses of the Province								
Provision for Electricity Sector	-	(3)	(256)	182	-	-	-	The variance is primarily due to the updated revenue figures from OPG and Hydro One. As well, at the time of 2016, the forecast was for a significant negative provision, which would have then be kept at zero to have the n balance clawed back from the subsequent year (2016-17). As a result of larger than anticipated deferred tax b reported by Hydro One and proportionate share attributed to the Province based on its ownership interest, the p 2015-16 came out to be $3 million [and not the large negative provision previously anticipated]. The variance i primarily explained by the reversal in the actual amount for 2015-16 versus the Budget 2016 forecast. The fore provision after 2017-18 fiscal is zero since the ESDI payments are assumed to discontinue after DRC ends on [CEFD will consider policy options on the continuation of ESDI in 2017.]
Public Debt Interest - Electricity Sector	-	(12)	-	-	-	-	-	
Subtotal	-	(15)	(256)	182	-	-	-	
Public Debt Interest - Impact of ONFA	-	-	-	-	-		-	
Amortization of Deferred Revenue re profit on sale of H1 notes	-	-	-	-	-		-	
Total Electricity Expenses of the Province	**-**	**(15)**	(256)	182	-	-	-	
OEFC Income								
Taxation Revenue								
Electricity Payments-in-Lieu of Taxes (PILs)	-	(4)	(57)	(75)	(56)	57	114	The variance is primarily due to updated OPG revenue figures in OPG's 2017-19 Business Plan, including lowe 2016-17, which impact its PIL payments as well.
Other Revenue								
Electricity Debt Retirement Charge	-	(9)	13	6	-	-	-	Updated with December 2016 Ontario Planning Outlook forecast Scenario A
Power Supply Contract Recoveries	-	91	96	(178)	(179)	17	17	• The declines in volumes, payments and rates in 2017-18 and 2018-19 compared to the earlier forecast are du termination and suspension of several NUG PPAs for curtailments. - The NUG suspensions/terminations coincide with the assumptions used by the IESO for LTEP modelling. • The increase in volumes from 2019-2023 compared to the earlier forecast is from the correction of generatior Nagagami and The Power Limited Partnership, which lowered the forecasted rates. • The latest model from Navigant includes more detailed modelling for Kirkland Lake, which resulted in lower o payments, however this decline was balanced by a higher payments due to an increase in forecasted TMC/DC - The decline in payments in 2022-2023 is due to Iroquois Falls and Nipigon expiring, leaving Kirkland Lake as remaining gas facility.
Net Reduction of Power Purchase Contracts	-	-	-	-	-	-	-	
Other Fees and Licences	-	-	5	23	32	34	41	
Revenue Pool Residual	-	-	-	-	-		-	
Miscellaneous	-	4	(5)	(5)	(5)	(5)	(5)	
Expenses								
Interest on Debt	-	55	103	235	243	291	377	
Power Supply Contract Costs	-	(91)	(96)	178	179	(17)	(17)	
Electricity Consumer Price Protection Fund	-	-	-	-	-	-	-	
Demand Management Support Costs	-	1	-	-	-	-	-	
Provision for Electricity Sector	-	3	256	(182)	-	-	-	
Other (Finance)	-	(1)	-	-	-	-	-	
Total OEFC Income	**-**	**49**	314	3	214	377	527	
Impact on Surplus/(Deficit)	**-**	**423**	(102)	(20)	129	357	715	
Total revenue Impact	**-**	**471**	**(109)**	**(433)**	**(293)**		**355**	
Total revenue Impact - less power supply contract recoveries	-	380	(205)	(255)	(114)		338	
Total Expenditure impact	**-**	**48**	**(7)**	**(413)**	**(422)**		**(360)**	

2) DETAIL LINES

REVENUE	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
CONSOLIDATED OPG/HOI NET INCOME	**389**	**389**	**(156)**	**(182)**	**(52)**	**14**
Public Debt Interest - Electricity Sector exp	*12*	*12*	*0*	*0*	*0*	*0*
equals amount above $520M (not incl ONFA)	*3*	*3*	*256*	*(182)*	*0*	*0*
of which: ONFA Adjustments	*(69)*	*(69)*	*8*	*0*	*0*	*0*
check total	*(54)*	*(54)*	*264*	*(182)*	*0*	*0*
CONSOLIDATED REVENUE - OEFC						
Other Fees and Licences						
Provision for Electricity Sector						
Electricity Payments-in-Lieu of Taxes (PILs)	(4)	(4)	(57)	(75)	(56)	57
Electricity Debt Retirement Charge	(9)	(9)	13	6	0	0
Power Supply Contract Recoveries	91	91	96	(178)	(179)	17
Net Reduction of Power Purchase Contracts	0	0	0	0	0	0
Other Fees and Licences						
Miscellaneous	4	4	(5)	(5)	(5)	(5)
SUBTOTAL	**471**	**471**	**(109)**	**(433)**	**(293)**	**83**
EXPENSE						
CONSOLIDATED OEFC EXPENSE						
Provision for Electricity Sector						
Power Supply Contract Costs	91	91	96	(178)	(179)	17
Demand Management Support Costs	13	(1)	-	-	-	-
less provision	(3)	(3)	(256)	182	0	0
Other OEFC Expenses	1	1	0	0	0	0
SUBTOTAL	**102**	**88**	**(160)**	**4**	**(179)**	**17**
FINANCE						
Provision for Electricity Sector	3	3	256	(182)	0	0
Public Debt Interest - Electricity Sector (Treasury Program)	12	12	0	0	0	0
SUBTOTAL	**15**	**15**	**256**	**(182)**	**0**	**0**

TREASURY PROGRAM - EXPENSE						
OEFC Debt interest	(8)	(25)	(110)	(247)	(255)	(303)
interest payments to OEFC from Other than Province	(8)	(18)	7	12	12	12
interest to OEFC from Province		(12)	0	0	0	0
SUBTOTAL	**(16)**	**(55)**	**(103)**	**(235)**	**(243)**	**(291)**
Impact on Surplus/(Deficit)	**370**	**423**	**(102)**	**(20)**	**129**	**357**

ONTARIO ELECTRICITY FINANCIAL CORPORATION
Budget 2016 Outlook as of January 2016

	Actual 2014-15	Interim 2015-16	2016-17	2017-18	Plan 2018-19
Revenue					
Revenue Pool Residual					
Debt Retirement Charge	956	868	625	623	-
Payments-in-lieu of tax:					
OPG	53	281	437	382	414
Legacy Hydro One (Including Brampton)	95	2,913	7	7	7
Hydro One CIT dedicated to OEFC		13	26	28	30
MEUs	32	25	44	63	81
Total PILs & CIT dedicated to OEFC	180	3,232	515	480	532
Interest :					
OPG	191	177	191	180	165
H1					
IESO	3	3	3	3	3
Province	520	508	492	492	492
Other	13	5	5	5	5
Total Interest	727	693	691	680	665
Power Supply Contract Recoveries	950	784	643	463	396
Amortization of NUG liability	217	172	129	74	41
Electricity sector dedicated income	1,038	-	138	706	-
Gain to OEFC under s. 50.3	-	150	-	-	-
Miscellaneous	9	5	5	5	5
	4,077	5,904	2,746	3,031	1,639
Expense					
Debt interest	1,385	1,344	1,326	1,337	1,282
Interest on nuclear risk funding					
Demand Management Support Costs	9	9	10	10	-
Amortization of deferred debt costs	-	-	-	-	
Power Supply Contract Costs	950	784	643	463	396
Debt Guarantee fee	131	127	127	125	123
Operating	6	6	6	6	6
	2,481	2,270	2,112	1,941	1,807
Excess (Deficiency) of Revenue over Expense	**1,596**	**3,634**	**634**	**1,090**	**(168)**
Stranded Debt - Year End	**8,185**	**4,551**	**3,917**	**2,827**	**2,995**
	658	651	635	657	617

ONTARIO ELECTRICITY FINANCIAL CORPORATION
On Deck Outlook as of March 2017

	Actual 2014-15	Actual 2015-16	2016-17	2017-18	Plan 2018-19
Revenue					
Revenue Pool Residual					
Debt Retirement Charge	956	859	638	629	-
Payments-in-lieu of tax:					
OPG	53	268	306	315	366
Legacy Hydro One (Including Brampton)	95	2,929	7	2	2
Hydro One CIT dedicated to OEFC		3	20	20	22
MEUs	32	27	124	68	86
Total PILs & CIT dedicated to OEFC[1]	180	3,228	457	405	476
Interest :					
OPG	191	173	179	168	153
H1					
IESO	3	2	3	3	3
Province	520	520	492	492	492
Other	13	28	10	5	5
Total Interest	727	723	684	668	653
Power Supply Contract Recoveries	950	875	739	285	217
Amortization of NUG liability	217	172	129	74	41
Electricity sector dedicated income	1,038	3	393	525	-
Gain to OEFC under s. 50.3	-	172	-	-	-
Miscellaneous	9	9	-	-	-
	4,077	6,041	3,041	2,586	1,387
Expense					
Debt interest	1,385	1,319	1,216	1,090	1,027
Interest on nuclear risk funding					
Demand Management Support Costs	9	8	10	10	-
Amortization of deferred debt costs	-	-	-	-	
Power Supply Contract Costs	950	875	739	285	217
Debt Guarantee fee	131	127	122	102	91
Operating	6	7	6	6	6
	2,481	2,336	2,093	1,493	1,341
Excess (Deficiency) of Revenue over Expense	**1,596**	**3,705**	**948**	**1,093**	**46**
Prior period adjustment		87			
Stranded Debt - Year End	**8,185**	**4,393**	**3,445**	**2,352**	**2,306**
	658	596	532	422	374

ONTARIO ELECTRICITY FINANCIAL CORPORATION

Changes from Budget 2016 as of March 2017

	Plan						
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Revenue							
Debt Retirement Charge	(9)	13	6	-	-	-	Updatedwith December 2016 Ontario Planning Outlook forecast Scenario A
Payments-in-lieu of tax:							
OPG	(13)	(131)	(67)	(48)	65	121	
Legacy Hydro One (Including Brampton)	16	-	(5)	(5)	(5)	(5)	
Hydro One CIT dedicated to OEFC	(10)	(6)	(8)	(8)	(8)	(7)	
MEUs	2	80	5	5	5	5	Large increase in 2016-2017 from $80M payment during transfer of H01 Brampton to new consolidated MEU Alectra.
Total PILs	(4)	(57)	(75)	(56)	57	114	
Interest :							
OPG	(4)	(12)	(12)	(12)	(12)	(12)	
H1	-	-	-	-	-	-	
IESO	(1)	-	-	-	-	-	
Province	12	-	-	-	-	-	
Other	23	5	-	-	-	-	
Total Interest	30	(7)	(12)	(12)	(12)	(12)	
Power Supply Contract Recoveries	91	96	(178)	(179)	17	17	
Amortization of NUG liability	-	-	-	-	-	-	
Electricity sector dedicated income	3	256	(182)	-	-	-	
Gain to OEFC under s. 50.3	22	-	-	-	-	-	
Miscellaneous	4	(5)	(5)	(5)	(5)	(5)	
	137	295	(445)	(252)	57	114	
Expense							
Debt interest	(25)	(110)	(247)	(255)	(303)	(389)	
Interest on nuclear risk funding	-	-	-	-	-	-	
Demand Management Support Costs	(1)	-	-	-	-	-	
Amortization of deferred debt costs	-	-	-	-	-	-	
Power Supply Contract Costs	91	96	(178)	(179)	17	17	
Debt Guarantee fee	-	(5)	(23)	(32)	(34)	(41)	
Operating	1	-	-	-	-	-	
	66	(19)	(448)	(466)	(320)	(413)	
Excess (Deficiency) of Revenue over Expense	**71**	**314**	**3**	**214**			
Stranded Debt - Year End	**(158)**	**(472)**	**(475)**	**(689)**	**(1,065)**	**(1,592)**	

Electricity Sector Outlook (PSAB)

Negative Revenue Risks						
($ millions)	**Plan**					
	2015-16	**2016-17**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
OPG Global Adjustment Trust			**TBD**	**TBD**	**TBD**	**TBD**
OPG Generation Risk: Nuclear Reliability (-1.6 TWh)[1]	-	(120)	(120)	(120)	(120)	(120)
ONFA Funds Return Risk[2]	-	(90)	(95)	(100)	(105)	(110)
Lower OPG's Equity weighting & Return on Equity (ROE)[3]		(2)	(12)	(20)	(25)	(43)
Ministry of Energy's price mitigation initiative - OPG operational efficiencies[9]		(60)	(240)	(240)	(240)	(180)
Lower Hydro One Return on Equity (ROE)[4]			(10)	(39)	(41)	(43)
Hydro One Tx rate application - OEB staff report[8]		(13)	(50)	(50)	(50)	(50)
OPG Switch from accrual based to cash based accounting for pension and OPEB[5]			(475)			
OPG IFRS Consolidation Risks - Scenario 1: 15 year historical, update discount rate each year.[6]	-	(75)	(425)	(525)	(675)	TBD
OPG IFRS Consolidation Risk - Scenario 2: 15 year historical + 5 forward, update every 5 year.[6]		(1,000)	(375)	(400)	(400)	TBD
Additional regulatory risk - Timing, Darlington Refurb Project & Others[7]	-		(660)			
Total - Scenario 1	-	(360)	(1,661)	(568)	(581)	(547)
Total - Scenario 2	-	(1,285)	(1,611)	(443)	(306)	(547)

Notes: The cumulative downside risk is presented as additive, which may overstate off-setting risks.

1. OPG's market and generation risks related to nuclear reliability similar to the scenarios OPG developed for its sales margins to capture major market risk factors (e.g., natural gas prices, coal prices, foreign exchange, nuclear reliability) in its 2012 business plan. Currently, only the nuclear reliability risk is captured at the current regulated rate for OPG's nuclear generation.

2. Under the Ontario Nuclear Funds Agreement (ONFA), OPG has established two segregated funds, the Decommissioning Segregated Fund (DSF) and for the Used Fuel Segregated Fund (UFSF). The risk shown is based on 1% decline on a realized basis in the DSF and UFSF, less the portion in the DSF assumed to be attributable to OPG's Bruce assets that is recoverable from consumers through the Bruce Variance Account.

3. Risk range for OPG reflects potential risk of lower ROE by 0.5% vs assumed ROEs in OPG's 2016 business plan and corresponding rate application. Also reflects how the proposed deemed equity of 49% might actually revert to the prior approved 45% weighting.

4. Risk range for Hydro One transmission and distribution reflects potential risk of lower ROE by 0.5% vs assumed ROEs in CEFD Hydro One Forecast based on the most recent rate applications and forecasted ROE rates.

5. The OEB directed a switch to cash-based accounting for years 2014 and 2015. However, the OEB also directed OPG to track the difference between cash based and accrual based accounting in a deferral account, while a generic proceeding is underway for all OEB-regulated electric and gas utilities.

6. The Ontario Auditor General recommended in the 2016 AG Report that the Province of Ontario include Hydro One and OPG financial information in the consolidated financial statements using the IFRS reporting framework as required by PSAB standards potentially as soon as the 2016-17 fiscal year. Estimated impacts to the Province by OPG being consolidated on an IFRS basis with respect to its nuclear liabilities under two methodologies are summarized in Scenarios 1 and 2. (Following work on the next Reference Plan, the potential impact to the 2021-22 fiscal year and going forward would be known.) **NOTE: The scenario 1 risk for 2017-18 to 2019-20 is reflected in the current fiscal plan.**

7. Additional regulatory risks related to the-rate application in spring 2016, including risks related to effective date timing, and a portion of refurb. costs-to-date of about $700-800M.

8. On January 25, 2017, the Ontario Energy Board (OEB) staff released their review of the Hydro One Transmission rate application (EB-2016-0160), and proposed a number of changes for the Board to rule on including a reduction in allowed capital expenditure, which would reduce the rate base and related return on capital, and OM&A related primarily to the compensation levels beyond the benchmark.

Electricity Sector Outlook (PSAB)

Positive Revenue Risks						
($ millions)	**Plan**					
	2015-16	**2016-17**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
OPG Global Adjustment Trust						
OPG Generation Risk: Nuclear Reliability (+1.1 TWh)[1]	-	85	85	85	85	85
Positive OPG regulatory risk - Motion to Review[2]	-	-	-	-	-	-
1% increase in Hydro One actual load[3]	-	15	15	15	15	15
Higher Hydro One Return on Equity (ROE)[4]		-	15	60	65	65
Higher OPG Return on Equity (ROE)[5]		-	6	25	30	55
Revenue risk if Scenario 2 IFRS Consolidation risk.[6]			50	125	275	
	-	100	171	310	470	220

Notes: The cumulative upside risk is presented as additive, which may overstate off-setting risks.

1. OPG's market and generation risks related to nuclear reliability similar to the scenarios OPG developed for its sales margins to capture major market risk factors (e.g., natural gas prices, coal prices, foreign exchange, nuclear reliability) in its 2012 business plan. Currently, only the nuclear reliability risk is captured at the current regulated rate for OPG's nuclear generation.

2. Reflects OPG's Motion to Review application with the OEB for the Niagara Tunnel cost disallowance and the 2013 tax loss.

3. A 1% change in the forecast represents a change of approximately 206MW for Tx in peak demand based on 2015/2016revenue requirement.

4. Risk range for Hydro One transmission and distribution reflects potential risk of higher ROE by 1% vs assumed ROEs in the Hydro One CEFD Forecast. Rounded to the nearest $5M.

5. Risk range for OPG reflects potential risk of higher ROE by 1% (for nuclear base) vs assumed ROE in OPG's 2016 business plan and corresponding rate application. Rounded to the nearest $5M.

6. NOTE: The Scenario 1 risk for 2017-18 to 2019-20 is reflected in the current fiscal plan. This is the impact if Scenario 2 is realized.

Ontario Electricity Financial Corporation

On Deck Revenue & Expense Outlook
($ millions)

		2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Revenue		4,077	6,041	3,041	2,586	1,387	1,496	1,607
less: interest income (to IOD)	1	727	723	684	668	653	635	635
less: Electricity Sector Dedicated Income from Prov	2	1,038	3	393	525	-	-	-
Adjustment to CRF revenue		2,312	5,315	1,963	1,394	734	861	972
Expense		2,481	2,336	2,093	1,493	1,341	1,364	1,237
less: Interest expense - With Province (to IOD)		1,385	1,319	1,216	1,090	1,027	977	885
less: Debt Guarantee Fee paid to Province	3	131	127	122	102	91	88	81
Adjustment to CRF expense		965	890	755	301	223	299	271
Surplus/(Deficit) Impact - without IOD Adj.		689	3,829	677	671	137	220	451
Surplus/(Deficit) Impact		1,347	4,425	1,208	1,093	511	562	701
In 2008-09 RBP - Surplus/(Deficit)		-	-	-	-	-	-	-
Adjustment required		1,347	4,425	1,208	1,093	511	562	701
Operating expense split		965	890	755	301	223	299	271
Capital expense split		-	-	-	-	-	-	-
Total		965	890	755	301	223	299	271
IOD		658	596	532	422	374	342	250

Notes:

1. OEFC interest income includes $520 million, or less (after H1 ownership broadening), annual interest payment from Province related to the Province's investment in OPG and Hydro One.

2. OEFC receives Electricity Sector Dedicated Income from the Province for the combined net income of OPG and Hydro One in excess of the Province's annual interest cost for its investment in these companies.

3. OEFC pays a Debt Guarantee Fee to the Province that is eliminated upon consolidation.

Ontario Power Generation

OPG Income - Budget 2016
($ millions)

	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
OPG Net Income After Tax	199	689	257	471	586	673	705	734
ONFA and other Fair Value Adjustments	475	122	241					
ONFA Adjustments	*367*	*122*	*241*					
Other Fair Value Adjustments	*108*							

OPG PIL - Budget 2016
($ millions)

	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
Net Income Before Tax	231	539	546	324	695	745	855
Net Income After Tax	244	334	689	257	471	586	673
Income Taxes	(12)	205	(143)	67	224	159	182
GRC	189	186	198	198	196	205	212
Proxy Property Tax	16	16	15	16	17	18	20
Ontario Capital Tax	0	0	0	0	0	0	0
Total	**193**	**407**	**70**	**281**	**437**	**382**	**414**

OPG Income - 2017-19 BP March 2017
($ millions)

	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
OPG Net Income After Tax (Adjusted)	334	817	291	355	497	733	828	1,048
OPG Net Income After Tax	*334*	*574*	*291*	*355*	*480*	*678*	*726*	*913*
Extraordinary Gains	*-*	*243*	*-*	*-*	*-*	*-*	*-*	*-*
ONFA and other Fair Value Adjustments	475	239	172	8				
ONFA Adjustments	*367*	*180*	*247*	*8*				
Other Fair Value Adjustments	*108*	*59*	(75)					

($ millions)

	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
Net Income Before Tax	232	539	659	383	450	572	868
Net Income After Tax (Adjusted)	244	334	817	291	355	497	733
Income Taxes	(12)	205	(158)	92	95	92	135
GRC	189	186	198	198	196	205	212
Proxy Property Tax	16	16	13	16	15	18	19
Ontario Capital Tax	0	0	0	0	0	0	0
Total	**193**	**407**	**53**	**306**	**306**	**315**	**366**

21.11% 16.08% 15.55%

OPG 2016-17 Net Income Calculation (USGAAP) ($M)			
	Q1 2016[1]	2016	Q1 2017[1]
Net Income Attributable to Shareholder	123	438	34

Hydro One

Hydro One Income - Budget 2016
($ millions)

	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Hydro One Net Income After Tax	786	741	703	772	831	908	952	995
Hydro One - Unrealized Gains Adjustment	10	-8						

Hydro One PIL - Budget 2016
($ millions)

	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
Net Income After Tax	786	754	703	772	831	908
Income Taxes	101	101	132	160	181	205
Proxy Property Tax	(3)	2	2	2	2	2
Ontario Capital Tax	0	0	0	0	0	0
Total	**98**	**103**	**134**	**162**	**183**	**207**

Hydro One Income - March 2017
($ millions)

	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Hydro One Net Income After Tax	786	741	685	737	742	802	862	931
Hydro One - Unrealized Gains Adjustment	10	(8)						

2016-17 to 2020-21 from CEFD Hydro One 2016 model.

Hydro One (Before IPO Scenario - 100% Ownership)
($ millions)

	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
Net Income After Tax	786	741	685	737	742	802
Income Taxes PILs	101	92	132	160	181	205
Proxy Property Tax	(3)	3	2	2	2	2
Ontario Capital Tax	0	0	0	0	0	0
Total	**98**	**95**	**134**	**162**	**183**	**207**

Provision for Electricity Sector

	Actual	Plan						
	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Income from Investment in Government Business Enterprises								
OPG Income	334	817	291	355	497	733	828	1,048
Hydro One Income	786	741	232	530	520	562	603	652
Total Income	1,120	1,558	523	885	1,017	1,295	1,431	1,700
Public Debt Interest - Electricity Sector	(520)	(520)	(520)	(492)	(492)	(492)	(492)	(492)
Impact of OPG and Hydro One	600	1,038	3	393	525	802	939	1,208
Other Adjustments*								
Cumulative Shortfall								
Opening Balance	-	-	-	-	-	-	-	-
Deduction / (Addition)	-	-	-	-	-	-	-	-
Ending Balance	-	-	-	-	-	-	-	-
Provision for Electricity Sector (without adjusting for unrealized losses)	**599**	**1,038**	**3**	**393**	**525**	**802**	**939**	**1,208**

Notes:

1. Provision for the fiscal year 2018-19 is assumed 0 based on the expectation that stranded debt would be eliminated by then.

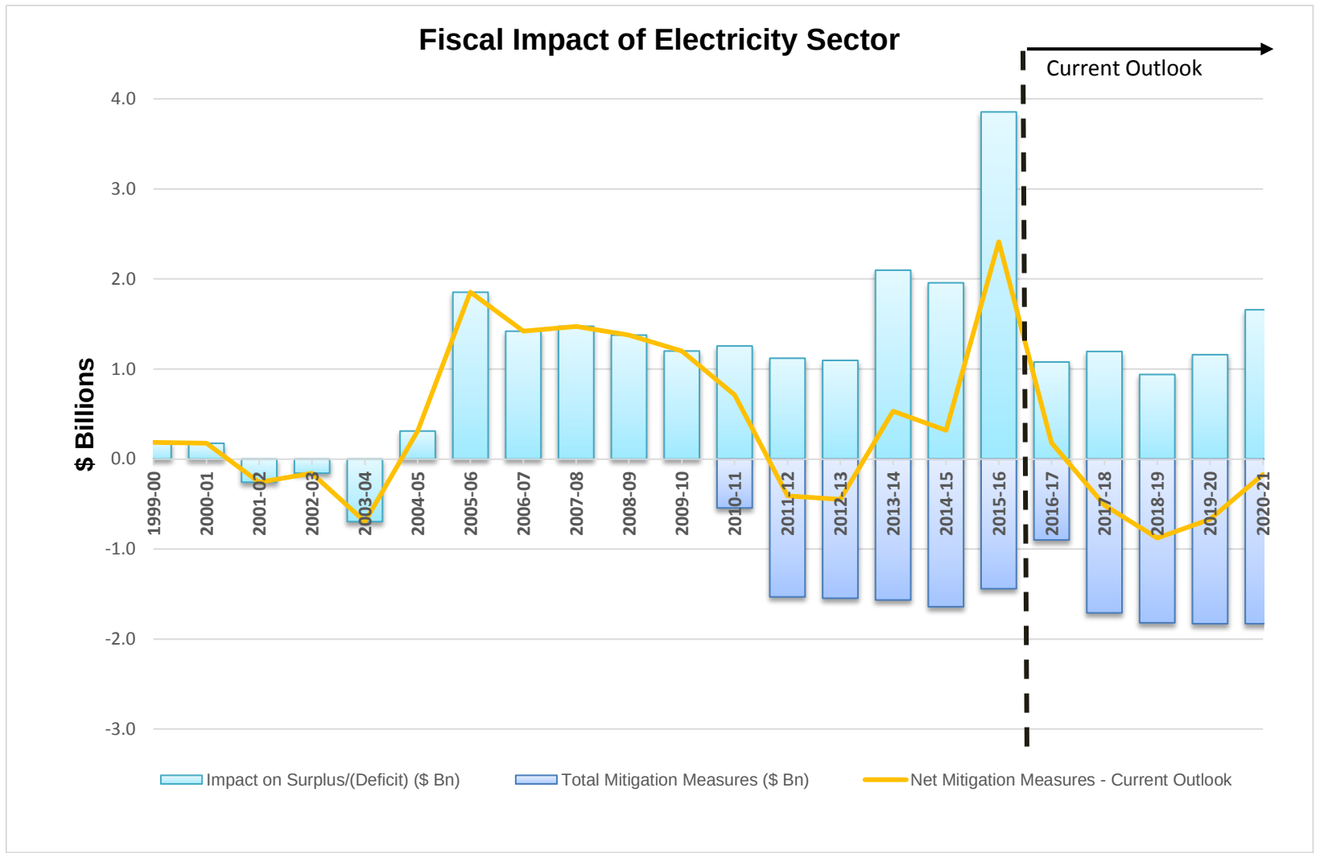
PROVINCIAL CONSOLIDATION ADJUSTMENTS
Ontario Nuclear Funds Agreement

	2011-12	2012-13	2013-14	2014-15
Adjustment for DSF Unrealized Earnings				
Unrealized Earnings as at beginning of year	0	0	0	0
Unrealized Earnings as at December 31, 2016	10	62	(244)	(21)
Bruce Variance Account Adjustment	5	29	(115)	(10)
Adjustment for UFSF Unrealized Earnings				
Unrealized Earnings as at beginning of year	0	0	0	0
Unrealized Earnings as at December 31, 2016	1	26	64	82
Bruce Variance Account Adjustment	1	14	34	43
Unrealized Earnings -- Fiscal YTD	**6**	**45**	**(99)**	**28**
Adjustment for UFSF Due to Province				
Due to Province (cost basis) as at beginning of year	(102)	(189)	(181)	87
Unrealized Earnings as at December 31, 2016	(189)	(181)	87	295
Change in Due to Province -- Fiscal YTD	**(87)**	**8**	**268**	**208**
Adjustment for DSF Due to Province				
Due to Province (cost basis) as at beginning of year				
Unrealized Earnings as at December 31, 2016				
Change in Due to Province -- Fiscal YTD				
Provincial Consolidation Adjustment	**(93)**	**(37)**	**367**	**180**

Fiscal Impact of Electricity Sector

Blue represents changed numbers from 2013
Maroon represents new information
Orange represents projections

	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	
Impact on Surplus/(Deficit)	1,256	1,120	1,096	2,098	1,958	3,856	1,078	1,195	939	1,159	1,658	
Impact on Surplus/(Deficit) ($ Bn)	*1.256*	*1.120*	*1.096*	*2.098*	*1.958*	*3.856*	*1.078*	*1.195*	*0.939*	*1.159*	*1.658*	
Electricity Price Mitigation Measures (Tax Base)												
Energy portion of the Ontario Energy and Property Tax Credit (OEPTC)**	113	354	406	418	429	444	450	460	470	480.5	480.5	OEP, Revenue Forecasting
Northern Ontario Energy Credit	24	23	24	25	24	26	27	27	27	27	27	Source for actuals
Ontario Emergency Energy Fund	2	2	2	2	2	2	2	2	2	2	2	
Northern Industrial Electricity Rate Program	105	120	120	115	108	108	120	120	120	120	120	Source for actuals
Ontario Clean Energy Benefit (OCEB)	300	1,033	994	1,006	1,078	860	-	-	-	-	-	
Ontario Rebate for Electricity Consumers							300	1100	1200	1200	1200	
Total Mitigation Measures ($ M)	**543**	**1,531**	**1,546**	**1,566**	**1,640**	**1,440**	**899**	**1,709**	**1,819**	**1,830**	**1,830**	
Total Mitigation Measures ($ Bn)	*(0.543)*	*(1.531)*	*(1.546)*	*(1.566)*	*(1.640)*	*(1.440)*	*(0.899)*	*(1.709)*	*(1.819)*	*(1.830)*	*(1.830)*	
Total Mitigation Measures excl. OCEB ($ M)	243	499	552	560	562	580	899	1,709	1,819	1,830	1,830	
Total Mitigation Measures excl. OCEB ($ Bn)	*0.243*	*0.499*	*0.552*	*0.560*	*0.562*	*0.580*	*0.899*	*1.709*	*1.819*	*1.830*	*1.830*	
Net Mitigation Measures - Current Outlook	0.71	(0.41)	(0.45)	0.53	0.32	2.42	0.18	(0.51)	(0.88)	(0.67)	(0.17)	



From: John Kim
To: Ronald Kwan
Cc: Gavin He; Francisco Chinchon; Bruno Amara
Subject: RE: Electricity Outlook
Date: Wednesday, March 08, 2017 9:10:49 AM

Hi Ron,

We will send the Outlook out indicating the IOD / NI component and without.

Thanks,

John.

From: Ronald Kwan
Sent: Tuesday, March 07, 2017 6:12 PM
To: John Kim <John.Kim@ofina.on.ca>
Cc: Gavin He <Gavin.He@ofina.on.ca>; Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>
Subject: RE: Electricity Outlook

Hi,

I was talking to Gadi earlier today and he said that the IOD adjustment had not yet been provided for the fiscal roll-up, so the OPG net income numbers would be out of sync .

Was anything sent to OB, OEP and TBS today? I didn't see an email.

Was there a discussion with staff?

Thanks,
Ron

From: Ronald Kwan
Sent: March-07-17 09:09
To: Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>
Cc: John Kim <John.Kim@ofina.on.ca>
Subject: Re: Electricity Outlook

Hi Francisco, John,

Would it be helpful to send the two underlying spreadsheets together, noting the pivot to 70%, which is fiscally-neutral across the two products, but shown for interim actuals purposes to be closer to Public Accounts?

And note as well the OPG number adjustments to match the IOD adjustment (assuming those have gone up?).

Please bcc me.

Thanks,
Ron

On Mar 7, 2017, at 9:00 AM, Francisco Chinchon <Francisco.Chinchon@ofina.on.ca> wrote:

> Hi,
>
> We are good too. I did share the latest AO slides with OEP and OTB and staff have been communicating.
>
> What takes more time for staff to fully grasp is how the unpacking of the multiple sales affect each line although neutral on aggregate.
>
> Thanks,
>
> Francisco
>
> On Mar 7, 2017, at 8:49 AM, Ronald Kwan <Ronald.Kwan@ofina.on.ca> wrote:
>
> > Hi,
> >
> > For sure. Last Friday would have been better.
> >
> > Ron
> >
> > On Mar 7, 2017, at 8:41 AM, John Kim <John.Kim@ofina.on.ca> wrote:
> >
> > > Hi Ron,
> > >
> > > Brampton is in AO….and we're both at 70%.
> > >
> > > We can coordinate the sending for sure, yes. We're planning to call a meeting of OB and OEP, as well as TBS to ensure we're all on the same page.
> > >
> > > The sooner the better would be my advice.
> > >
> > > John.
> > >
> > > ---
> > >
> > > **From:** Ronald Kwan
> > > **Sent:** Tuesday, March 07, 2017 8:29 AM
> > > **To:** John Kim <John.Kim@ofina.on.ca>

Cc: Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>
Subject: Re: Electricity Outlook

Hi John,

Miscommunication in what way? That Brampton should or should not be in the Electricity Outlook to be consistent with the AO outlook, and on Hydro One's 70%?

And is SIFB ready to go to send a new version in if they are rebasing to 70% too?.

Looping in Francisco.

Thanks,
Ron

On Mar 7, 2017, at 7:25 AM, John Kim <John.Kim@ofina.on.ca> wrote:

> Hi Ron,
>
> We are ready to go. Brampton was a miscommunication between staff.
>
> If okay with you we will start the outreach to ensure other divisions are incorporating properly.
>
> Thanks
>
> John
>
> On Mar 7, 2017, at 7:00 AM, Ronald Kwan <Ronald.Kwan@ofina.on.ca> wrote:
>
> > Hi John,
> >
> > What's the status of this?
> >
> > Thanks,
> > Ron
> >
> > ---
> >
> > **From:** Ronald Kwan
> > **Sent:** March-03-17 6:00 PM
> > **To:** John Kim <John.Kim@ofina.on.ca>
> > **Subject:** RE: Electricity Outlook

Hi John,

As discussed, please track down and confirm the coordination question with SIFB on H1 and Brampton/Alectra MEU PILs. On the latter, I wonder if they too will have a large tax shield, so we might not be getting the 5 in out years – and it might be a negative variance for a number of years.

Also, I started a footnote on the GA impact on OPG. Should have added too, for clarity, that all the offset impact is shown in net income, but likely would be split between net income and PILs.

We need to generate GA financing / equity returns risks on to the revenue risks tab.

Thanks,
Ron

From: John Kim
Sent: March-03-17 17:16
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Subject: RE: Electricity Outlook

Yes, that is the case….that had been assumed for a long time. We've moved to coordinating on 70% for 2-3 weeks now.

John.

From: Ronald Kwan
Sent: Friday, March 03, 2017 5:13 PM
To: John Kim <John.Kim@ofina.on.ca>

Subject: RE: Electricity Outlook

Hi John,

But what has changed on the Hydro One side and SIFB`s AO numbers?

I was thinking the two branches had been coordinating on an on-going basis --- so if the EFB numbers were using 84% as the baseline, the AO numbers would be net of more forgone net income. And if the EFB file is at 70%, then the SIFB AO forgone revenue numbers would be net of less forgone revenue.

Is that the case as each branch has been sending up files, this month versus last?

Ron

From: John Kim
Sent: March-03-17 17:07
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Subject: RE: Electricity Outlook

Hi Ron,

Yes, we're now working on the 70% baseline. The numbers are generally the same.

NUG numbers changed somewhat.

The Bampton PILs is there.

Unpacked the PILs impact of the office sale.

So, generally the information has not changed significantly. I'd characterize as the 70% baseline and house-keeping.

John.

From: Ronald Kwan
Sent: Friday, March 03, 2017 5:04 PM
To: John Kim <John.Kim@ofina.on.ca>
Subject: RE: Electricity Outlook

Hi,

Are we now working on a 70% baseline, and coordinated with the AO numbers? What changed since the early February file and numbers coordination?

Ron

From: John Kim
Sent: March-03-17 16:03
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Gavin He <Gavin.He@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>
Subject: FW: Electricity Outlook

Pls. see attached.

Thanks,

John.

From: John Kim
Sent: Friday, March 03, 2017 3:56 PM
To: Bruno Amara <Bruno.Amara@ofina.on.ca>

Cc: Adam Prokop <Adam.Prokop@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>; Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Salman Qadir <Salman.Qadir@ofina.on.ca>
Subject: RE: Electricity Outlook

One more modification….I added the GA interest cost impact in the OPG tab. Also, highlighted in yellow. I'm sure there's a more elegant way of modelling due to my lack of skills at this.

I used FTD's forecast for 2017-18 to 2019-20 and then used our conservative interest income for 2020-21 of 135 (based on 3.5% interest) as a placeholder until FTD does their number.

John.

From: John Kim
Sent: Friday, March 03, 2017 3:31 PM
To: Bruno Amara <Bruno.Amara@ofina.on.ca>
Cc: Adam Prokop <Adam.Prokop@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>; Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Salman Qadir <Salman.Qadir@ofina.on.ca>
Subject: RE: Electricity Outlook

Thanks Bruno…..just changed the yellow highlighted part on the Revenue (Risk) tab. Let me know if what I did makes sense pls.

From: Bruno Amara
Sent: Friday, March 03, 2017 2:29 PM
To: John Kim <John.Kim@ofina.on.ca>
Cc: Adam Prokop <Adam.Prokop@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>; Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Salman Qadir <Salman.Qadir@ofina.on.ca>
Subject: RE: Electricity Outlook

I should attach file

From: Bruno Amara
Sent: Friday, March 03, 2017 2:28 PM
To: John Kim <John.Kim@ofina.on.ca>
Cc: Adam Prokop <Adam.Prokop@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>; Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Salman Qadir <Salman.Qadir@ofina.on.ca>
Subject: FW: Electricity Outlook

Hi John

See updated outlook attached.
Never mind my earlier comments.
As Adam notes the only change is that we have info now to split out the head office sale impact between NI and PILs.

Bruno

From: Adam Prokop
Sent: Friday, March 03, 2017 2:25 PM
To: Bruno Amara <Bruno.Amara@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>
Cc: Salman Qadir <Salman.Qadir@ofina.on.ca>
Subject: RE: Electricity Outlook

Hello Bruno,

Here is the updated outlook for your review. The only change was in how the head office sale was split between PILS and net income for OPG, so there are no changes in the total change from 2016 budget.

Kind regards,

Adam Prokop

From: Bruno Amara
Sent: Friday, March 03, 2017 11:08 AM
To: John Kim <John.Kim@ofina.on.ca>
Cc: Gavin He <Gavin.He@ofina.on.ca>; Adam Prokop <Adam.Prokop@ofina.on.ca>
Subject: Electricity Outlook

Hi John

Attached is the updated outlook reflecting Ron's comments on the risk page. Note that there is a new Cover Sheet per request from TBS/OB.

S:\Users\CEF\Hydro

2017\OEFC\RbP\Outlook\02. February

Bruno

Gavin, we picked up the revised DRC forecast.

From:	Bruno Amara
To:	Ronald Kwan
Cc:	Usman Zahid; John Kim
Subject:	RE: Electricity Update
Date:	Wednesday, January 10, 2018 9:37:27 AM
Attachments:	Electricity Sector Outlook (2018 01 08)_unpacked_v05_with revsions.xlsm

Hi Ron

Thanks. I put through all your edits. For the last edit (line 45) of the "Electricity Summary – Change", I added a footnote and table showing the fiscally-neutral AO changes vs. non-AO changes. Let me know if this works. Otherwise I can just list the changes in the text explanation per your edit.

Thanks
Bruno

From: Ronald Kwan
Sent: Tuesday, January 09, 2018 7:09 PM
To: Bruno Amara <Bruno.Amara@ofina.on.ca>
Cc: Usman Zahid <Usman.Zahid@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>
Subject: RE: Electricity Update

Hi Bruno.

I made some suggested edits to the variance explanations on the "Electricity Summary – Change" tab. Please review.

Thanks,
Ron

From: Bruno Amara
Sent: January-09-18 17:19
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Usman Zahid <Usman.Zahid@ofina.on.ca>
Subject: RE: Electricity Update

Hi Ron

Please see attached with update footnotes and Pension risk revised per our discussion.

Bruno

From: Ronald Kwan
Sent: Tuesday, January 09, 2018 5:16 PM
To: Bruno Amara <Bruno.Amara@ofina.on.ca>
Cc: Usman Zahid <Usman.Zahid@ofina.on.ca>

Subject: RE: Electricity Update

Hi Bruno,

Please send me the revised version.

Thanks,
Ron

From: Bruno Amara
Sent: January-09-18 11:12
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Usman Zahid <Usman.Zahid@ofina.on.ca>
Subject: Electricity Update

Hi Ron

I realize we did not update various footnotes to reflect unpacking in the version I sent to you last night. We have now done this. I also revised the Risk table to shift the pension risk forward one-year, noting that while this risk may be mitigated by findings of the OEB report, OEB will make final decision with deferred decision. I haven't forwarded this for now to avoid any confusion with edits you may be making, but happy to do so.

Also we have coordinated with SIFB and FTD on the AO unpacking exercise to make sure we are all on same page before we share with Frost. We are just finalizing some summary tables on our unpacking exercise that we can send to you and/or walk you through.

I heard from CQSD late yesterday that wrap-up is on Monday. They would like to prepare ESDI update today for Helmut's review. I noted that we do have updates that we are finalizing and will send as soon as we can. We can check back to see if tomorrow will be OK as necessary.

I also let OPCD know that we are working on an update that will re-categorize AO impacts and will send them that version as it will be more accurate for Budget consolidation. But I will also offer them our Interim unpacked version if they want to use that for now.

Bruno

Bruno Amara
Sr. Manager, Financial and Regulatory Analysis
Electricity Finance Branch
Corporate and Electricity Finance Division
Ontario Financing Authority

Tel: 416-325-1489
Email: bruno.amara@ofina.on.ca

Electricity Sector Outlook
October 2017

Disclosure:

All information contained in this workbook is confidential and commercially sensitive

All projected numbers are estimates and subjected to change

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Commercially Sensitive and Confidential Advice to Cabinet for Consideration of Options for Discussion Purposes Only

Electricity Sector Outlook
Including Line Items for Consolidation

Electricity Summary - On Deck

			MOF Expense Items (consolidated)	Current Outlook			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**38**	Power Supply Contract Costs	(182)	(183)	(134)	(103)
Expense	**MOF (OEFC)**	**40**	Demand Management Support Costs	(10)	-	-	-
Expense	**MOF (OEFC)**	**41**	Provision for Electricity Sector	24	9	-	48
Expense	**MOF**	**17**	Provision for Electricity Sector	(24)	(9)	-	(48)
Expense	**MOF (OEFC)**	**42**	Other (Finance)	(6)	(7)	(7)	(7)
			Total MOF Expense	**(198)**	**(190)**	**(141)**	**(110)**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**7**	OPG Income	149	137	(7)	156
Revenue	**ENE**	**8**	OPG - ONFA and other Fair Value Adjustments	171	-	-	-
Revenue	**ENE**	**10**	HOI Income	329	327	388	419
Revenue		**11**	Brampton Income	-	-	-	-
Revenue	**MOF (OEFC)**	**26**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	377	452	503	635
Revenue	**MOF (OEFC)**	**29**	Electricity Debt Retirement Charge	623	-	-	-
Revenue	**MOF (OEFC)**	**30**	Power Supply Contract Recoveries	182	183	134	103
Revenue	**MOF (OEFC)**	**31**	Net Reduction of Power Purchase Contracts	74	41	30	28
Revenue	**MOF (OEFC)**	**34**	Miscellaneous	-	-	-	-
			Total MOF Revenue	**1,906**	**1,138**	**1,048**	**1,341**
			OFA IOD Expense				
			Public Debt Interest - Electricity Sector	(454)	(454)	(454)	(454)
			Interest on Debt	(475)	(438)	(411)	(348)
			Total OFA IOD Expense	**(929)**	**(892)**	**(865)**	**(802)**
			Impact on Surplus/Deficit	**779**	**57**	**42**	**429**
			check	*-*	*-*	*(0)*	*-*

Electricity Summary - Budget 17

For Discussion			MOF Expense Items (consolidated)	Plan			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**38**	Power Supply Contract Costs	(292)	(325)	(301)	(273)
Expense	**MOF (OEFC)**	**40**	Demand Management Support Costs	(10)	0	0	0
Expense	**MOF (OEFC)**	**41**	Provision for Electricity Sector	125	0	0	0
Expense	**MOF**	**17**	Provision for Electricity Sector	(125)	0	0	0
Expense	**MOF (OEFC)**	**42**	Other (Finance)	(6)	(6)	(6)	(6)
			Total MOF Expense	**(308)**	**(331)**	**(307)**	**(279)**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**7**	OPG Income	97	732	625	1,066
Revenue	**ENE**	**8**	OPG - ONFA and other Fair Value Adjustments	0	0	0	0
Revenue	**ENE**	**10**	HOI Income	520	562	603	652
			Brampton Income				
Revenue	**MOF (OEFC)**	**25**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	405	476	538	679
Revenue	**MOF (OEFC)**	**29**	Electricity Debt Retirement Charge	623	0	0	0
Revenue	**MOF (OEFC)**	**30**	Power Supply Contract Recoveries	292	325	301	273
Revenue	**MOF (OEFC)**	**31**	Net Reduction of Power Purchase Contracts	74	41	30	28
Revenue	**MOF (OEFC)**	**34**	Miscellaneous	0	0	0	0
			Total MOF Revenue	**2,011**	**2,136**	**2,098**	**2,697**
			OFA IOD Expense				
		17	Public Debt Interest - Electricity Sector	(492)	(492)	(492)	(492)
		36	Interest on Debt	(422)	(374)	(342)	(250)
			Total OFA IOD Expense	**(914)**	**(866)**	**(834)**	**(742)**
			Impact on Surplus/Deficit	**789**	**939**	**957**	**1,676**
			check	**-**	**-**	**-**	**-**

Electricity Summary - Change

			MOF Expense Items (consolidated)	Variance from Plan			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**69**	Power Supply Contract Costs	110	142	167	170
Expense	**MOF (OEFC)**	**71**	Demand Management Support Costs	0	0	0	0
Expense	**MOF (OEFC)**	**72**	Provision for Electricity Sector	(101)	9	0	48
Expense	**MOF**	**48**	Provision for Electricity Sector	101	(9)	0	(48)
Expense	**MOF (OEFC)**	**73**	Other (Finance)	0	(1)	(1)	(1)
			Total MOF Expense	**110**	**141**	**166**	**169**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**38**	OPG Income	52	(596)	(632)	(909)
Revenue	**ENE**	**39**	OPG - ONFA and other Fair Value Adjustments	171	0	0	0
Revenue	**ENE**	**41**	HOI Income	(190)	(235)	(216)	(233)
			Brampton Income	0	0	0	0
Revenue	**MOF (OEFC)**	**25**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	(28)	(24)	(35)	(43)
Revenue	**MOF (OEFC)**	**60**	Electricity Debt Retirement Charge	0	0	0	0
Revenue	**MOF (OEFC)**	**61**	Power Supply Contract Recoveries	(110)	(142)	(167)	(170)
Revenue	**MOF (OEFC)**	**62**	Net Reduction of Power Purchase Contracts	(0)	(0)	(0)	(0)
Revenue	**MOF (OEFC)**	**65**	Miscellaneous	0	0	0	0
			Total MOF Revenue	**(105)**	**(997)**	**(1,049)**	**(1,356)**
			OFA IOD Expense				
		17	Public Debt Interest - Electricity Sector	38	38	38	38
		36	Interest on Debt	(53)	(64)	(69)	(98)
			Total OFA IOD Expense	**(15)**	**(26)**	**(31)**	**(60)**
			Impact on Surplus/Deficit	**(10)**	**(882)**	**(914)**	**(1,247)**
			check	-	-	-	-

Track Changes in Surplus/Deficit

Date	Change ID#	Source	Tab
5/1/2017	20170501-1	Link	ONFA
5/1/2017	20170501-2	Link	Hydro One
5/1/2017	20170501-3	Link	Hydro One
5/1/2017	20170501-4	Link	Other Data
5/2/2017	20170502-1	Link	OPG
5/9/2017	20170509-1	Link	OPG
5/10/2017	20170510-1	Link	Hydro One
5/10/2017	20170510-2	Link	Other Data
5/12/2017	20170512-1	Link	Hydro One
5/15/2017	20170515-1	Link?	
5/15/2017	20170515-2	Link	OPG
5/17/2017	20170517-1	Link	Hydro One
5/17/2017	20170517-2	Link	ONFA
5/17/2017	20170517-3		
5/18/2017	20170518-1	Link	OPG
5/18/2017	20170518-2	Link	OPG
5/18/2017	20170518-3		
6/15/2017	20170615-1	Link	OPG
6/22/2017	20170622-1	Link	Hydro One
6/22/2017	20170622-2	Link	Hydro One
6/26/2017	20170626-1		
6/29/2017	20170629-1		

7/6/2017	20170706-1		
7/11/2017	20170711-1		
7/13/2017	20170713-1	Link	Provision
7/17/2017	20170717-1	Link	Revenue (Risks)
7/24/2017	20170724-1	Link	Revenue (Risks)
7/25/2017	20170725-1	Link	Revenue (Risks)
7/26/2017	20170726-1	Link	Revenue (Risks)
7/27/2017	20170727-1	Link	Revenue (Risks)
7/27/2017	20170727-2	Link	Revenue (Risks)
7/31/2017	20170731-1		
7/31/2017	20170731-2	Link	Hydro One
7/31/2017	20170731-3	Link	Other Data
8/11/2017	20170811-1	Link	OPG
8/15/2017	20170815-1		
8/15/2017	20170815-2		
8/15/2017	20170815-3		
8/15/2017	20170815-4		
8/15/2017	20170815-5		Other Data
8/15/2017	20170815-6		Other Data
8/15/2017	20170815-7		Other Data
8/15/2017	20170815-8		Other Data
8/15/2017	20170815-9		Other Data
8/15/2017	20170815-10		Other Data
8/17/2017	20170817-1	Link	Provision
8/17/2017	20170817-2	Link	Hydro One
8/18/2017	20170818-1	Link	Revenue (Risks)
8/22/2017	20170822-1	Link	OPG
8/25/2017	20170825-1		Hydro One
8/29/2017	20170829-1		Revenue (Risks)
8/31/2017	20170831-1		Revenue (Risks)
9/5/2017	20170905-1		Other Data
9/5/2017	20170905-2		Other Data
9/5/2017	20170905-3	Link	OPG

9/6/2017	20170906-1	Link	Other Data
9/6/2017	20170906-2	Link	Revenue (Risks)
9/8/2017	20170908-1	Link	Hydro One
9/8/2017	20170908-2	Link	OPG
9/11/2017			
9/12/2017			
9/13/2017			
9/21/2017			
9/22/2017			
10/2/2017			Hydro One
10/2/2017			
10/2/2017			
10/2/2017			
10/4/2017	20171004-1		OPG
10/4/2017	20171004-2		OPG
10/4/2017			
10/4/2017			
10/5/2017			
10/6/2017			
10/7/2017			
10/8/2017			
10/10/2017	20171010-1		Hydro One
10/10/2017			
10/10/2017			
10/11/2017	20171011-1		OPG
10/11/2017			
10/11/2017			
10/12/2017			OPG
10/12/2017			
10/12/2017			
10/12/2017			
10/18/2017	20171018-1		Hydro One
10/18/2017	20171018-1		Hydro One
10/18/2017	20171018-1		Hydro One
10/19/2017	20171019-1		Revenue (Risks)
10/19/2017	20171019-2		Revenue (Risks)
10/20/2017	20171020-1		Revenue (Risks)
10/20/2017	20171020-2		
10/20/2017	20171020-2		
10/20/2017	20171020-2		
10/20/2017	20171020-3		Revenue (Risks)
10/20/2017	20171020-4		OPG
10/20/2017	20171020-4		OPG
10/20/2017	20171020-4		OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017	20171114-1		Hydro One

11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017		Hydro One
11/14/2017		Hydro One
11/14/2017		Hydro One
11/30/2017	20171130-1	Revenue (Risks)
12/8/2017		Hydro One
12/11/2017	20171211-1	Other Data
12/11/2017	20171211-1	Other Data
12/22/2017	20171222-1	OPG
1/2/2018		Hydro One
1/2/2018		Hydro One
1/2/2018		Hydro One
1/2/2018	20180102-1	OPG
1/2/2018	20180102-1	OPG
1/2/2018	20180102-1	OPG
1/2/2018	20180102-2	OPG
1/2/2018	20180102-3	OPG
1/2/2018	20180102-3	Revenue (Risks)
1/2/2018	20180102-4	Revenue (Risks)
1/2/2018	20180102-5	Revenue (Risks)
1/2/2018	20180102-6	Revenue (Risks)
1/2/2018	20180102-7	Revenue (Risks)
1/2/2018	20180102-8	Revenue (Risks)
1/2/2018	20180102-9	OPG
1/2/2018	20180102-9	OPG
1/2/2018	20180102-9	OPG
1/2/2018	20180102-9	OPG
1/3/2018		OPG
1/3/2018		OPG
1/3/2018		OPG
1/3/2018		OPG
1/3/2018		Hydro One
1/3/2018		Hydro One
1/3/2018		Hydro One
1/4/2018	20180104-1	OPG
1/4/2018	20180104-1	OPG
1/4/2018	20180104-1	OPG
1/4/2018	20180104-1	OPG
1/4/2018	20180104-2	Other Data
1/4/2018	20180104-2	Other Data
1/5/2018		
1/5/2018		
1/5/2018		
1/5/2018		
1/5/2018		
1/5/2018		
1/5/2018		
1/8/2018		
1/8/2018		
1/8/2018		

FOR EFB USE ONLY

Budget 2017 Outlook
Current Outlook
Change Since Budget

Description of Update
ONFA Update as of March 31 2017
s. 50.3 Update for 2016-17
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Debt Interest
OPG IFRS Risk in 2019-20
Revised OPG 2016-17 Net Income
Revised OPG 2016-17 Net Income
Revised OPG 2016-17 Net Income
tech change: slight update to assumed Prov share 70.05% from 70%
tech change: slight update to assumed Prov share 70.05% from 70%
tech change: slight update to assumed Prov share 70.05% from 70%
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
Updating H1 2016-17 Net Income for ESDI
Updating H1 2016-17 Net Income for ESDI
Updating H1 2016-17 Net Income for ESDI
Power Purchase Supply
H1 Model Forecasts - No Fiscal Update Resaving Data
Update Budget 2017 Tabs to reflect fiscal plan
Update OPG forecasted PILS to reflect sources
Update H1 2016-17 CIT
Re-inputting ONFA updates
Updating H1 Net Income to include Pref Shares in 16-17
Updating OPG Income Tax Expense for 2016-17
Updating OPG non-income tax PILs
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2017
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2018
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2019
Updating with actual OPG IFRS Adjustment 2016-17
Updating with actual OPG IFRS Adjustment 2016-17
Updating with actual OPG IFRS Adjustment 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
[NOT APPLIED] Updating H1 Brampton (Interim Adjustments)
Shifted H1 Brampton 2016-17 NI to the 2017-18
Removed H1 Brampton for 2016-17 (pending finals)
Removed H1 Brampton for 2016-17 (pending finals)
Removed H1 Brampton for 2016-17 (pending finals)

add prior-year adjustment for 2016-17

add prior-year adjustment for 2016-18
Reconfigured calculation of ESDI and MOF ESDI Expense
Reconfigured calculation of OPG 2017-18 Net Income
Backup for the Provincial Interest cost
Linking source for Revenue Risks Tab
New source for Revenue Risks Tab
Revenue Risks Tab - ROE Risks
Updating OEB Risk for OPG
OEB Staff Report - H1 Tx - Revenue Risks
OPG Pensions - Cash vs Accrual Deferral Accounts
Updating Links in Electricity Summary Change and OEFC Change
Preliminary estimate for Hydro One Brampton
Preliminary estimate for Hydro One Brampton
Preliminary estimate for Hydro One Brampton

Updating DRC for Actuals 2016-17 (Based on draft FS)
Updating PILs for 2016-17 Baced on Actuals
OPG: Non-ONFA Fair Value Adjustment
Round all Hydro One ownership assumptions to two decimal places
H1 Equity Adjustment rounding.
Round all Hydro One ownership assumptions to two decimal places
Round all Hydro One ownership assumptions to two decimal places
Revising source of ESDI, Dedicated Electricity Earnings
2016-17 - Update Power Supply Recoveries to actuals
2016-17 - Update Power Supply Recoveries to actuals
2016-17 - Updating Miscellaneous OEFC Revenue to Actuals
Adj: Exclude Bramton $15m add prior year adjustment +$3M
Adj: Exclude Bramton $15m add prior year adjustment +$3M
Public Accts: Updated IESO debt interest Interest On Debt, 2016-17
Public Accts: 2016-17 - Demand Management Support Costs Update
2017-18 - Demand Management Support Costs (no change)
Public Accts: 2016-17 - Updating Operating Expense in OEFC
Sourcing Provision for Electricity Sector from Actual Public Accounts
Revised 2016-17 Brampton Amount for Public Accounts
OPG Pensions - Cash vs Accrual Deferral Accounts (Revenue Risks Tab)
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
Reclassification
Reclassification
Reverting H1 Ownership change (undoing 20170518-3)
Reverting H1 Ownership change (undoing 20170518-3)
Reverting H1 Ownership change (undoing 20170518-3)
Updating Risks based on Hydro One Q2 Results Model
Avista Acquisition Risks
NUG Amortization Liability (sourcing amortization schedule)
2016-17 Actuals - Debt Guarantee Fee
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results

Interest Revenue for IESO and "Other"
OPG Revenue Risks from OEB Filings
Net income corrected for Preferred Shares
Net income corrected for Preferred Shares
Net income corrected for Preferred Shares
Made link edits to OPG sheet so that the "Net Income Before Tax" 2017-18 number is not a hardc
Updated PILs to include OPCD public accounts adjustment
Provision tab fix to pick up Hydro One preferred share net income
Provision tab fix to pick up Hydro One preferred share net income
FTD Update to OEFC Outlook (Sep 19, 2017) OPG Interest
FTD Update to OEFC Outlook (Sep 19, 2017) Other Interest
Update to Hydro One PILs from information in Transmission rate application material
OEB September 28, 2017 Hydro One decision and order impact - incl. rebasing
OEB September 28, 2017 Hydro One decision and order impact - incl. rebasing
OEB September 28, 2017 Hydro One decision and order impact - incl. rebasing
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Debenture Interest Costs - Removing from Revenue (Risks) and adding it ot H1 Model
Debenture Interest Costs - Removing from Revenue (Risks) and adding it ot H1 Model
Debenture Interest Costs - Removing from Revenue (Risks) and adding it ot H1 Model
Updated OPG Net Income and PILs based on monthly report (August 2017 results)
Updated OPG Net Income and PILs based on monthly report (August 2017 results)
Updated OPG Net Income and PILs based on monthly report (August 2017 results)
Correction to PILs on OPG sheet
Correction to PILs on OPG sheet
Correction to PILs on OPG sheet
Correction to PILs on OPG sheet
Switch to Direct from Model
Switch to Direct from Model
Switch to Direct from Model
Updating ROE Risks
Updating H1 Load Risks based on model output
Updating ONFA Risks for September 2017
Adjust OEB decision/rebasing to ~50% provincial ownership
Adjust OEB decision/rebasing to ~50% provincial ownership
Adjust OEB decision/rebasing to ~50% provincial ownership
Updating OPG
OPG IOD impact from GA Financing, FHP
OPG IOD impact from GA Financing, FHP
OPG IOD impact from GA Financing, FHP
Unpacking updated OPG Gain on sale (net income)
Unpacking updated OPG Gain on sale (net income)
Unpacking updated OPG Gain on sale (net income)
Unpack PILs related to HQ gain on sale
Updating IFRS Risk
Adjustment for lower Provincial share (from 70.1% to 50.9 2017-18 & 47.4% after)
Adjustment for lower Provincial share (from 70.1% to 50.9 2017-18 & 47.4% after)
Adjustment for lower Provincial share (from 70.1% to 50.9 2017-18 & 47.4% after)
November 1 and November 7 Hydro One model updates

November 1 and November 7 Hydro One model updates
November 1 and November 7 Hydro One model updates
Revise Hydro Model to reverse OEB tax decision ongoing annual impact
Revise Hydro Model to reverse OEB tax decision ongoing annual impact
Revise Hydro Model to reverse OEB tax decision ongoing annual impact
Undo allocation adjustment in H1 tab (now that provincial shares are updated)
Undo allocation adjustment in H1 tab (now that provincial shares are updated)
Undo allocation adjustment in H1 tab (now that provincial shares are updated)
Updating OPG Revenue Risks from rate application
Update Hydro One PILs (reverses update on line 119 whuich did not account fro Dx side)
Updating Debt Guarantee Fee
Updating OEFC Operating Expense
small changes - linking the net income numbers

Updated number of shares sold for First Nations (Dec 2017) sale
Updated number of shares sold for First Nations (Dec 2017) sale
Updated number of shares sold for First Nations (Dec 2017) sale
Implemented OEB's Dec 2017 payment amounts decision for OPG (CEFD Analysis)
Implemented OEB's Dec 2017 payment amounts decision for OPG (CEFD Analysis)
Implemented OEB's Dec 2017 payment amounts decision for OPG (CEFD Analysis)
Updated OPG Net Income (based on their Q3 update, Sep 30, 2017)
Updated OPG ONFA adjustment (up to Sep 30, 2017) in OPG tab (removed it from Risks table)
Removal of OPG ONFA Sep 2017 adjustment in Risks table
Included possible range (-50M to 50M) of impact for future OPG ONFA adjustment in the negative
Removal of negative regulatory risk: "OPG Switch from accrual based to cash based accounting f
Removal of negative regulatory risk: "Timing of OPG Rate Decision" from Risks table
Removal of negative regulatory risk: "OEB Staff Recommendations wrt OPG rate application(May
Removal of negative regulatory risk: "Nuclear Liabilities Cash vs. Accrual" from Risks table
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month
Updated estimates of NUG costs.
Updated estimates of NUG costs.
Unpacking OPG (Head Office sale)
Unpacking OPG (Head Office sale)
Unpacking OPG (Head Office sale)
Unpacking OPG (Head Office sale)
Unpacking Hydro One for AO (from 70.1% ownership to as of January 2018)
Unpacking Hydro One for AO (from 70.1% ownership to as of January 2018)
Unpacking Hydro One for AO (from 70.1% ownership to as of January 2018)
Update H1 allocations for additional shares (SIFB edits)
Update H1 allocations for additional shares (SIFB edits)
Update H1 allocations for additional shares (SIFB edits)

This line show net impact of latest change. READ COMMENT

Expense
Expense
Expense
Expense
Expense
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue

Expense
Expense
Expense
Expense
Expense
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue

$ Millions

		2016-17	2017-18	2018-19	2019-20
		930	789	939	957
	File	915	779	57	42
		-15	-10	-882	-914
	check	*0*	*0*	*0*	*0*
		Impacts by FY →			
Outlook line affected	**Expense / Reve**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
ONFA and other Fair Value Adjustments	Revenue	41.0	0.0	0.0	0.0
N/A		0.0	0.0	0.0	0.0
?		0.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		38.1		
Provision for Electricity Sector (MOF)	Expense		(38.1)		
Public Debt Interest - Electricity Sector	Expense	0.0	38.1	38.1	38.1
Interest on Debt	Expense	0.0	(69.1)	(79.1)	(75.1)
OPG Income	Expense	0.0	0.0	0.0	
OPG Income	Revenue	(2.0)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**(2.0)**			
Provision for Electricity Sector (MOF)	Expense	2.0			
HOI Income	Revenue	0.4			
Provision for Electricity Sector (OEFC)	Expense	0.4			
Provision for Electricity Sector (MOF)	Expense	(0.4)			
Public Debt Interest - Electricity Sector	Expense	1.7			
Provision for Electricity Sector (OEFC)	Expense	(1.7)			
Provision for Electricity Sector (MOF)	Expense	1.7			
Interest on Debt	Expense	(1.7)			
HOI Income	Revenue	(39.8)	0.0	0.0	(0.0)
Provision for Electricity Sector (OEFC)	Expense	**(39.8)**			
Provision for Electricity Sector (MOF)	Expense	39.8			
	Revenue	-	-	-	-
	Revenue	-	-	-	-
	n/a	-	-	-	-
		-	-	-	-
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	4.7	0.0	0.0	0.0
	Revenue	0.0	0.0	0.0	0.0
HOI Income	Revenue	18.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	7.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	8.0	9.0	12.0	3.5
HOI Income	Revenue	0.0	(141.5)	(181.4)	(194.9)
Provision for Electricity Sector (OEFC)	Expense		(141.5)		
Provision for Electricity Sector (MOF)	Expense		141.5		
OPG Income	Revenue	(3.0)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**(3.0)**			
Provision for Electricity Sector (MOF)	Expense	3.0			
HOI Income	Revenue	7.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**7.0**			
Provision for Electricity Sector (MOF)	Expense	(7.0)			
	Revenue	-	-	-	-
	Revenue	0.0	0.0	0.0	0.0
Brampton Income	Revenue	(14.7)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**(14.7)**			
Provision for Electricity Sector (MOF)	Expense	14.7			

Provision for Electricity Sector (OEFC)	Expense		3.2			
Provision for Electricity Sector (MOF)	Expense		(3.2)			
	Revenue	-	-	-	-	
		-	-	-	-	
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
Brampton Income	Revenue		15.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		**15.0**			
Provision for Electricity Sector (MOF)	Expense		(15.0)			
Provision for Electricity Sector (OEFC)	Expense		3.2			
Provision for Electricity Sector (MOF)	Expense		(3.2)			
Electricity Debt Retirement Charge	Revenue		(4.0)	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue		(29.0)	0.0	0.0	0.0
OPG Income	Revenue		(6.0)	0.0	0.0	0.0
HOI Income	Revenue		(0.0)	(0.0)	0.0	0.0
HOI Income	Revenue		(1.7)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense			(0.0)		
Provision for Electricity Sector (MOF)	Expense			0.0		
	Revenue		0.0	0.0	0.0	0.0
Power Supply Contract Recoveries	Revenue		99.0	0.0	0.0	0.0
Power Supply Contract Costs	Expense		(99.0)			
Miscellaneous	Revenue		14.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		(12.0)			
Provision for Electricity Sector (MOF)	Expense		12.0			
Interest on Debt	Expense		(3.0)	0.0	0.0	0.0
Demand Management Support Costs	Expense		1.8	0.0	0.0	0.0
			0.0	0.0	0.0	0.0
Other (Finance)	Expense		(1.0)	0.0	0.0	0.0
	Revenue	-	-	-	-	
Brampton Income	Revenue		3.0	0.0	0.0	0.0
			0.0	0.0	0.0	0.0
OPG Income	Revenue		0.0	85.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue			(6.0)		
Provision for Electricity Sector (OEFC)	Expense			**85.0**		
Provision for Electricity Sector (MOF)	Expense			(85.0)		
OPG Income	Revenue		6.0			
ONFA and other Fair Value Adjustments	Revenue		(6.0)			
HOI Income	Revenue		0.0	141.9	181.8	195.4
Provision for Electricity Sector (OEFC)	Expense			141.9		
Provision for Electricity Sector (MOF)	Expense			(141.9)		
	n/a		0.0	0.0	0.0	0.0
			0.0	0.0	0.0	0.0
Net Reduction of Power Purchase Contracts	Revenue		0.1	(0.1)	(0.1)	(0.1)
	Revenue		0.0	0.0	0.0	0.0
OPG Income	Revenue		0.0	16.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue			(1.0)		
Provision for Electricity Sector (OEFC)	Expense			**16.0**		
Provision for Electricity Sector (MOF)	Expense			(16.0)		

		0.0	0.0	0.0	0.0
	n/a	0.0	0.0	0.0	0.0
HOI Income	Revenue	0.0	5.3	5.3	5.3
Provision for Electricity Sector (OEFC)	Expense		(12.4)		
Provision for Electricity Sector (MOF)	Expense		12.4		
oded formula in the cell	n/a	0.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	(30.4)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		17.8		
Provision for Electricity Sector (MOF)	Expense		(17.8)		
Interest on Debt	Expense	(0.0)	1.0	(0.0)	1.0
Interest on Debt	Expense	0.0	15.0	15.0	5.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	0.0	(7.8)	(8.7)	(10.3)
HOI Income	Revenue	0.0	(47.4)	(54.0)	(54.0)
Provision for Electricity Sector (OEFC)	Expense	0.0	(47.4)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	47.4	0.0	0.0
OPG Income	Revenue	0.0	(61.0)	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	0.0	(21.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	(61.0)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	61.0	0.0	0.0
OPG Income	Revenue	0.0	(21.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	(21.0)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	21.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	0.0	21.0	0.0	0.0
HOI Income	Revenue	0.0	(23.6)	(27.4)	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	(23.6)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	23.6	0.0	0.0
OPG Income	Revenue	0.0	15.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	15.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	(15.0)	0.0	0.0
OPG Income	Revenue	0.0	21.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	0.0	(18.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	21.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	(21.0)	0.0	0.0
HOI Income	Revenue	0.0	(23.8)	(28.9)	(10.1)
Provision for Electricity Sector (OEFC)	Expense	0.0	(23.8)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	23.8	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
HOI Income	Revenue		16.1	26.7	20.6
Provision for Electricity Sector (OEFC)	Expense		16.1		
Provision for Electricity Sector (MOF)	Expense		(16.1)		
n/a	n/a	0.0	0.0	0.0	0.0
OPG Income	Revenue		(4.9)	(11.9)	(17.1)
Provision for Electricity Sector (OEFC)	Expense		(4.9)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		4.9	0.0	0.0
OPG Income	Revenue		283.0		
Provision for Electricity Sector (OEFC)	Expense		283.0		
Provision for Electricity Sector (MOF)	Expense		(283.0)		
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue		95.0		
OPG Income	Revenue		0.0	(475.0)	(500.0)
HOI Income	Revenue		(112.6)	(142.1)	(170.6)
Provision for Electricity Sector (OEFC)	Expense		(112.6)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		112.6	0.0	0.0
HOI Income	Revenue		(3.3)	(3.0)	(0.1)

Provision for Electricity Sector (OEFC)	Expense		(3.3)		
Provision for Electricity Sector (MOF)	Expense		3.3		
HOI Income	Revenue		14.7	14.4	12.9
Provision for Electricity Sector (OEFC)	Expense		14.7	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		(14.7)	0.0	0.0
HOI Income	Revenue		(16.1)	(26.7)	(20.6)
Provision for Electricity Sector (OEFC)	Expense		(16.1)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		16.1	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)		0.0	7.8	8.7	10.3
n/a	n/a	0.0	0.0	0.0	0.0
Other (Finance)			0.0	(1.0)	(1.0)
OPG Income	Revenue		0.0	0.0	0.0
HOI Income	Revenue		0.1	0.5	0.6
Provision for Electricity Sector (OEFC)	Expense		0.1	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		(0.1)	0.0	0.0
OPG Income	Revenue		(477.1)	(145.2)	(153.1)
Provision for Electricity Sector (OEFC)	Expense		(305.7)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		305.7	0.0	0.0
OPG Income	Revenue		39.0	0.0	0.0
OPG - ONFA and other Fair Value Adjustments	Revenue		171.5	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
OPG Income	Revenue		119.3	36.3	38.3
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue		(119.3)	(36.3)	(38.3)
Provision for Electricity Sector (OEFC)	Expense		0.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		0.0	0.0	0.0
OPG Income	Revenue		(283.0)	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue		(95.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		0.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		0.0	0.0	0.0
HOI Income	Revenue		116.8	147.1	176.1
Provision for Electricity Sector (OEFC)	Expense		0.0	0.0	80.3
Provision for Electricity Sector (MOF)	Expense		0.0	0.0	(80.3)
OPG Income	Revenue		37.5	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue		12.5	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		0.0	14.4	23.1
Provision for Electricity Sector (MOF)	Expense		0.0	(14.4)	(23.1)
Power Supply Contract Recoveries	Revenue		(109.9)	(142.1)	(166.7)
Power Supply Contract Costs	Expense		109.9	142.1	166.7
OPG Income	Revenue		283.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue		95.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		141.1	141.9	0.0
Provision for Electricity Sector (MOF)	Expense		(141.1)	(141.9)	0.0
HOI Income	Revenue		(116.8)	(147.1)	(176.1)
Provision for Electricity Sector (OEFC)	Expense		(116.8)	(147.1)	(103.4)
Provision for Electricity Sector (MOF)	Expense		116.8	147.1	103.4
HOI Income	Revenue		(0.0)	(0.2)	(0.2)
Provision for Electricity Sector (OEFC)	Expense		(0.0)	(0.2)	0.0
Provision for Electricity Sector (MOF)	Expense		0.0	0.2	0.0

	0	*0*	*0*	*0*

Summary of Track Changes Above

Power Supply Contract Costs	(99.0)	0.0	0.0	0.0
Demand Management Support Costs	1.8	0.0	0.0	0.0
Provision for Electricity Sector OEFC)	(44.4)	180.9	0.0	0.0
Provision for Electricity Sector (MOF)	44.4	(180.9)	0.0	0.0
Other (Finance)	(1.0)	0.0	(1.0)	(1.0)
OPG Income	(5.0)	333.1	(486.9)	(517.1)
ONFA and other Fair Value Adjustments	35.0	0.0	0.0	0.0
HOI Income	(16.1)	(190.4)	(235.3)	(216.1)
Brampton Income	3.3	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	(39.7)	79.0	12.0	3.5
Electricity Debt Retirement Charge	(4.0)	0.0	0.0	0.0
Power Supply Contract Recoveries	99.0	0.0	0.0	0.0
Net Reduction of Power Purchase Contracts	0.1	(0.1)	(0.1)	(0.1)
Miscellaneous	14.0	0.0	0.0	0.0
Public Debt Interest - Electricity Sector	1.7	38.1	38.1	38.1
Interest on Debt	(4.7)	(53.1)	(64.1)	(69.1)
Impact on Surplus/Deficit	**(14.6)**	**206.7**	**(737.3)**	**(761.7)**
check	***0.0***	***216.5***	***144.9***	***152.7***

Check - Summary of Track Changes Above vs. Electricity Summary Change Worksheet

Power Supply Contract Costs	0.0	(110.2)	(142.2)	(167.0)
Demand Management Support Costs	(0.0)	0.0	0.0	0.0
Provision for Electricity Sector OEFC)	8.4	281.4	(9.0)	0.0
Provision for Electricity Sector (MOF)	(8.4)	(281.4)	9.0	0.0
Other (Finance)	0.0	0.0	0.0	0.0
OPG Income	0.0	281.3	108.9	114.8
ONFA and other Fair Value Adjustments	0.0	(171.5)	0.0	0.0
HOI Income	(0.0)	(0.1)	(0.3)	(0.4)
Brampton Income	0.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	(0.0)	106.8	36.3	38.3
Electricity Debt Retirement Charge	0.0	0.0	0.0	0.0
Power Supply Contract Recoveries	0.0	110.2	142.2	167.0
Net Reduction of Power Purchase Contracts	(0.0)	(0.0)	(0.0)	(0.0)
Miscellaneous	0.0	0.0	0.0	0.0
Public Debt Interest - Electricity Sector	23.4	0.1	0.1	0.1
Interest on Debt	(23.4)	(0.1)	(0.1)	(0.1)
Impact on Surplus/Deficit	**(0.0)**	**216.5**	**144.9**	**152.7**

2020-21
1,676
429
-1,247
0

2020-21	Further Explanation of Change and source of data
0.0	Regular quarterly ONFA Update
0.0	Benefit to OEFC under s.50.3: $411M gain, SIFB
0.0	Change to OEFC payment for interest costs of Debt for Equity Swap
38.1	Revised Provincial Debt Interest related to Hydro One Equity
(104.1)	From FTD, revised Debt Interest (net of revisions to Provincial and OPG debt interest)
0.0	Revised numbers from OEP with 2019-20 Risk
0.0	Updated numbers from OPG Q1 2017 FS
0.0	Updating H1 Net Income for actuals. Note does not update Brampton Income at this point. Will
-	No Change to numbers, just re-inputting data and saving sources
-	No Change to numbers, just re-inputting data and saving sources
-	No change to fiscal impact numbers. Deleting Budget 2016 and adding Budget 2017 fiscal imp
-	No Change to numbers, just re-inputting data and saving sources
0.0	Updated with CIT Numbers received from H1 as part of s.91.2 MB20 allocation from MOF
0.0	No Change to numbers, just re-inputting data and saving sources
0.0	Only included H1 Net Income - Common Shareholders before. Added preferred shareholder im
0.0	Updating OPG Income Tax Expense with info from OPG Monthly Presentation to Shareholder
1.8	Updating OPG GRC payable to OEFC and Proxy Property Tax from Answer back from OPG al
(210.6)	Based on H1 final offering and expected First Nations Sale by the end of 2017 (CY), with a wei
0.0	Based on EY analysis, and then applying fiscalization. Confirmation also received from OPCD.
0.0	Based on KPMG analysis, then fiscalization and other adjustments from OPCD.
-	**[NOT APPLIED, CALCULATIONS AND DATA LEFT ON THE FILE]** Used Brampton's Financ
0.0	Don't expect finalized 2016-17 data to become available in time for ESDI allocation. Will shift th
0.0	make decision on shifting when we know 2016-17 status.

-	No change to numbers. Just re-organizing spreadsheet. No backup data.
-	No change to numbers. Just re-organizing spreadsheet. No backup data.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided another scenario backup/source
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just updated the links to refer ot the delta between 2017 and On Deck
0.0	Adjustment to ESDI to include Hydro One Brampton
0.0	Finalizing 2016-17 DRC Based on Draft OEFC AR
0.0	Received actual PILs amounts from FTD with breakdown of source. Updated 2016-17 numbers
0.0	2016-17 - Non-ONFA Fair Value Adjustment
0.0	Round Hydro One ownership assumptions to 70.05% two decimal places to be consistent with
0.0	Revising Hydro One Amount for consistency with OPCD. Equity Adjustments
0.0	Updated Provision tab. Made two separate Provision amounts for ESDI in OEFC AR and Dedic
0.0	Updating Power Supply Recoveries to Public Accounts/OEFC AR actuals
0.0	Updating Miscellaneous to OEFC AR actuals
0.0	Updated 2016-17 Interest on Debt (IESO, OPG, Other (Net))
0.0	
0.0	2017-18 - Demand Management Support Costs (no change) - Linking correctly
0.0	2016-17 - Updating Operating Expense in OEFC and corresponding changes elsewhere and s
-	No change to numbers. Just re-organized spreadsheet
0.0	Revised H1 Brampton Net Income (for GBE Line only)
0.0	Revising for OPG's Q3 Finances
0.0	Revising OPG's Net Income for latest monthly report
211.1	Reverting ownership back to 70.05% from change 20170518-3. Will coordinate with other area
0.0	Updating Risks based on Hydro One Q2 Results Model
0.0	Updated two Risk components for the Avista Acquisition.
(0.0)	No significant changes, but used actual amortization liability schedule. Hence the rounding imp
0.0	Updating Debt Guarantee for actuals based on OEFC AR
0.0	Revising OPG's Net Income for latest monthly report

0.0	Linking interest revenue data for 2017-18 to 2020-21
0.0	OPG Revenue Risks from: OEB Staff Submission and OPG Updated Filings
5.3	Corrected Net income for 100% ownership in preferred shares and 70.05% in Commons Share
0.0	Updated the formula in the cell for 2017-18 Net Income Before Tax so that the numbers are no
0.0	Updated PILs to include OPCD public accounts adjustment
1.3	
5.0	
(12.2)	
(54.0)	
0.0	
0.0	
0.0	increase built into net income was $82m between NI and PILs
0.0	Remove $21m from PILs
0.0	expense impacts
0.0	expense impacts
0.0	need to also remove the $21m PILs built into OPG net incme
0.0	
0.0	
0.0	We removed $21m from PILs above, before having added it in (check is that lines 123 to 130 a
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
(13.0)	variances include: 2017-18 preferred vs common share fix, 2018-19 largely ROE change from
0.0	
0.0	
0.0	
0.0	
0.0	
21.6	
0.0	
(24.1)	
0.0	
0.0	**Distribution (October)**
(750.0)	
(185.3)	
0.0	
0.0	
(2.3)	

15.2	
0.0	
0.0	
(21.6)	
0.0	
0.0	
0.0	Updating OPG Rate application Revenue Risks based on revised calculations
12.2	
0.0	
(1.0)	Received Revised FTD Forecast
0.3	
0.7	
0.0	
0.0	
(180.7)	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	Removed based on Dec 2017 OEB decision
0.0	Removed based on Dec 2017 OEB decision
0.0	Removed based on Dec 2017 OEB decision
0.0	Removed based on Dec 2017 OEB decision
45.2	
(45.2)	
44.2	
(44.2)	
0.0	
0.0	
(44.2)	
44.2	
190.8	
311.7	
(311.7)	
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M
(170.7)	
170.7	
0.0	
0.0	
0.0	
0.0	
(190.8)	
(263.6)	
263.6	
(0.3)	
(0.5)	
0.5	

0

0.0
0.0
0.0
0.0
(1.0)
(774.1)
0.0
(233.7)
0.0
1.8
0.0
0.0
(0.0)
0.0
38.1
(97.8)
(1,067)
180.0

t

(170.4)
0.0
(47.6)
47.6
0.0
135.3
0.0
(0.4)
0.0
44.9
0.0
170.4
0.0
0.0
0.1
0.1
180.0

Data Validation:

Options
Revenue (F
OPG
Hydro One
Provision

ONFA
Other Data

update once revised numbers are received.

acts

ıpact as well.

bout the BP
ghted average ownership for 2017-18. Also adjusted future net income attributed to the province.

ial Statements to produce an estimate. May require additional calculations.
ıis to 2017-18.

(from 2016 and On Deck)

s to reflect this.

OPCD.

:ated Earnings in Public Accounts.

ources.

s to ensure broadening change and reduction in net income happens concurrently in forecasts.

acts/changes.

es

t hardcoded directly

dd up to -$82m gain that we wanted to remove.

9.09% to 8.78% not previously captured.

Risks)

Electricity Sector Outlook

$ Millions

	Actual 2015-16	Interim 2016-17	Plan 2017-18	2018-19	2019-20	2020-21
On Deck Outlook as of March 2017						
Income from Investment in Government Business Enterprises						
OPG Income[1]	291	304	97	732	625	1,066
OPG - ONFA and other Fair Value Adjustments[2]	172	8	-	-	-	-
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	-
HOI Income[3]	236	516	520	562	603	652
Brampton Income	20	15	-	-	-	-
Total OPG and HOI Income	**719**	**842**	**617**	**1,294**	**1,229**	**1,717**
Other Fees and Licences	**127**	**122**	**102**	**91**	**88**	**81**
Electricity Expenses of the Province						
Provision for Electricity Sector[4]	(3)	(342)	(125)		-	-
Public Debt Interest - Electricity Sector	(520)	(492)	(492)	(492)	(492)	(492)
Subtotal	(523)	(834)	(617)	(492)	(492)	(492)
Public Debt Interest - Impact of ONFA						
Amortization of Deferred Revenue re profit on sale of H1 notes						
Total Electricity Expenses of the Province	**(523)**	**(834)**	**(617)**	**(492)**	**(492)**	**(492)**
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	3,228	373	405	476	538	679
Other Revenue						
Electricity Debt Retirement Charge[5]	859	625	623	-	-	-
Power Supply Contract Recoveries	875	739	292	325	301	273
Net Reduction of Power Purchase Contracts	172	129	74	41	30	28
Other Fees and Licences	(127)	(122)	(102)	(91)	(88)	(81)
Miscellaneous	9	-	-	-	-	-
Expenses						
Interest on Debt	(596)	(532)	(422)	(374)	(342)	(250)
Power Supply Contract Costs	(875)	(739)	(292)	(325)	(301)	(273)
Electricity Consumer Price Protection Fund	-	-	-	-	-	-
Demand Management Support Costs[6]	(8)	(10)	(10)	-	-	-
Provision for Electricity Sector	3	342	125	-	-	-
Other (Finance)	(7)	(6)	(6)	(6)	(6)	(6)
Total OEFC Income	**3,533**	**800**	**687**	**46**	**132**	**370**
Impact on Surplus/(Deficit)	**3,856**	**930**	**789**	**939**	**957**	**1,676**

Notes: The Hydro One net income outlook above (2016-17 to 2020-21) reflects the Province's 70% ownership share after the initial IPO in 2015 and the secondary offering in April 2016. At the time of 2017 Budget, net estimated fiscal impacts from future Hydro One offerings are reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

Notes:

1.OPG's 2016-17 outlook reflected its reported earnings. 2017-18 to 2019-20 reflects OPG's preliminary 2017-2019 business plan (as fiscalized by OPG). 2020-21 estimates are based on OPG's calendar year-based business plan projections. OPG net income also reflects IFRS adjustments fiscal impact decisions that were made centrally.

2. Provincial consolidation adjustments for unrealized earnings on the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds, as of the end of December 2016.

3. Hydro One 2016-17 income reflects its reported net income, adjusted for Hydro One IPO impacts. 2017-18 to 2020-21 projections are based on CEFD projections using the latest public information. The Hydro One net income outlook above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering as of 2017 Budget were reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial ONFA consolidation adjustments, less the interest on the Province's OPG/Hydro One debt payable to OEFC. The provision is currently assumed to end once the DRC ends on a legislated fixed end date of April 1, 2018.

5. Reflects April 23, 2014 announcement that DRC will be eliminated for residential users, after December 31, 2015. The end date of DRC for remaining users is legislated to be on April 1, 2018. Estimates are subject to change based on actual consumption.

6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Electricity Sector Outlook

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
On Deck Outlook as of October 2017						
Income from Investment in Government Business Enterprises						
OPG Income[1]	291	299	149	137	(7)	156
OPG - ONFA and other Fair Value Adjustments[2]	172	43	171	-	-	-
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	-
HOI Income[3]	236	500	329	327	388	419
Brampton Income	20	18	-	-	-	-
Total OPG and HOI Income	**719**	**860**	**650**	**463**	**381**	**575**
Other Fees and Licences (Debt Guarantee fee)	**127**	**122**	**102**	**99**	**98**	**91**
Electricity Expenses of the Province						
Provision for Electricity Sector[4]	-	(290)	(24)	(9)	-	(48)
Public Debt Interest - Electricity Sector	(520)	(514)	(454)	(454)	(454)	(454)
Subtotal	(520)	(803)	(478)	(463)	(454)	(502)
Public Debt Interest - Impact of ONFA						
Amortization of Deferred Revenue re profit on sale of H1 notes						
Total Electricity Expenses of the Province	**(520)**	**(803)**	**(478)**	**(463)**	**(454)**	**(502)**
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	3,247	334	377	452	503	635
Other Revenue						
Electricity Debt Retirement Charge[5]	859	621	623	-	-	-
Power Supply Contract Recoveries	875	838	182	183	134	103
Net Reduction of Power Purchase Contracts	172	129	74	41	30	28
Other Fees and Licences	(127)	(122)	(102)	(99)	(98)	(91)
Miscellaneous	9	14	-	-	-	-
Expenses						
Interest on Debt	(596)	(513)	(475)	(438)	(411)	(348)
Power Supply Contract Costs	(875)	(838)	(182)	(183)	(134)	(103)
Electricity Consumer Price Protection Fund	-	-	-	-	-	-
Demand Management Support Costs[6]	(8)	(8)	(10)	-	-	-
Provision for Electricity Sector	-	290	24	9	-	48
Other (Finance)	(7)	(7)	(6)	(7)	(7)	(7)
Total OEFC Income	**3,549**	**737**	**506**	**(42)**	**17**	**265**
Impact on Surplus/(Deficit)	**3,876**	**915**	**779**	**57**	**42**	**429**
variance to OEFC check	*(156)*	*(454)*	*(550)*	*(0)*	*(0)*	*-*

Notes:

1.OPG's 2016-17 outlook reflected its reported earnings. 2017-18 reflects OPG's latest monthly update and now includes re-caztegorization from Sales and Rentals to OPG net income (and OPG PILs) of OPG head office properties sale. 2018 to 2019-20 reflects OPG's 2017-2019 business plan (as fiscalized by OPG). 2020-21 estimates are based on OPG's calendar year-based business plan projections. OPG net income also reflect projected IFRS adjustments as provided by OPCD at the time of the 2017 Budget and OEB Dec. 28 rate decision. Note rate decsion impact is alloacted to net income and PILs on a 75%/25% basis respectively.

2. Provincial consolidation adjustments for unrealized earnings on the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds, as of the end of September 2017.

3. Hydro One 2016-17 income reflects its projected net income adjusted for the Province's ownership share in Hydro One following the final offering in May 2017 and including the First Nations sale in December 2017. 2017-18 to 2020-21 projections are based on CEFD projections using the latest public information and now reflect the re-categorization from sales and Rentals to Hydro One net income of the full impact of Hydro One broadening.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial ONFA consolidation adjustments, minus the interest on debt payable to OEFC. The provision is now assumed to continue after 2017-18. There is currently a PRRT submission to continue ESDI payments to OEFC beyond 2017-18.

5. Reflects that DRC eliminated for residential users, after December 31, 2015. The end date of DRC for remaining users is legislated to be on April 1, 2018. Estimates are subject to change based on actual consumption.

6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Electricity Sector Change Since Budget	$ Millions					
($million)	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Changes from Budget 2017 as of October 2017						
Income from Investment in Government Business Enterprises						
OPG Income	(5)	52	(596)	(632)	(909)	2016-17 small decrease due to IFRS adjustment revision and OPG Net Income revision. 2017-18 increase is largely from re-categorization from Sales and Rentals to OPG net income (and OPG PILs) of the sale of OPG head office properties -- re-categorisation itself is fiscally-neutral, as Sales and Rentals will be lower than shown in Budget 2017, plus some in-year upside (about $95M), before the OEB rate decision for OPG. Recategorisation amount in net income (about $280 million) is largely offset by negative fiscal impact (about -$320M in net income, -$110M in PILs below) from OEB Dec. 28, 2017 rate decision for OPG, including effective date of new OPG rates of June 1, 2017 rather than Jan. 1, 2017 . Decrease in 2018-19 onward is due mainly to taking on projeceted IFRS adjustment impacts in those years as well as OEB Dec. 28, 2017 rate decision. The OEB Dec. 28, 2017 rate decision estimated impacts are allocated between OPG net income and PILs on a 75%/25% basis.
ONFA and other Fair Value Adjustments	35	171	-	-	-	Largely revision to ONFA fair value as of September 30, 2017
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	
HOI Income	(16)	(190)	(235)	(216)	(233)	2016-17 slight decrease from Budget 2017 Interim projection. 2017-18 onwards reflects i) re-categorization from Sales and Rentals to Hydro One net income of the impact of a lower Provincial share of Hydro One net income from Hydro One share sales ii) impact of OEB Sep. 2017 decision on Hydro One transmission rates and iii) interest expense on Avitsa debentures (in 2017-18 and 2018-19).
Brampton Income	3.3					
Total OPG and HOI Income	**17**	**33.0**	**(831)**	**(848)**	**(1,143)**	
Other Fees and Licences	**-**	**-**	**8**	**10**	**10**	
Electricity Expenses of the Province						
Provision for Electricity Sector	53	101	(9)	-	(48)	**[NOTE: A positive number on this line indicates a decrease in the provision, while a negative number means an increase in provision expense.] [CHECK]** Changes to the Provision (ESDI) expense in 2017-18 mainly reflect higher OPG net income due to recategorisation from Sales and Rentals (see above), offset by lower OPG net income due to OEB's Dec. 28, 2017 rate decision and lower Hydro One net income due to OEB's Sep. 2017 transmission rate decision. Note ESDI is also lowered as HYdro One net income now reflects the full impact of Hydro One share sales. Part of this impact was previously reflected in Sales and Rentals. The projected change in 2019-20 and 2020-21 is due to the continuation of ESDI beyond 2017-18 (approved in principle in the current PRRT). In the 2017 Budget outlook, ESDI was assumed to end after 2017-18. ESDI estimates for 2018-19 and 2018-19 are reduced due to negative balances in 2017-18 and 2018-19,
Public Debt Interest - Electricity Sector	(22)	38	38	38	38	2016-17 PDI at ($514m) was slightly larger than ($492m) projected at Interim. 2017-18 change reflects revised projections for Provincial debt interest related to HydroOne's April 2016 offering. Note the impact of the final offering will be refelected in PDI during 2018.
Total Electricity Expenses of the Province	**31**	**138**	**29**	**38**	**(10)**	

Electricity Sector Change Since Budget	$ Millions					
($million)	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs)	(40)	(28)	(24)	(35)	(43)	2016-17 decrease largely due to an OPCD Public Accounts PILs adjustment related to reconciling between OPCD and OEFC net opening assets. OPG PILs also slightly lower than projected.
Other Revenue						
Electricity Debt Retirement Charge	(4)	-	-	-	-	
Power Supply Contract Recoveries	99	(110)	(142)	(167)	(170)	Variance in 16-17 is largely due to retroactive payments that the OEFC made to certain non-utility generators (NUGs) with former Ontario Hydro power purchase agreement (PPA) contracts with OEFC. OEFC was required to make these payment following the dismissal by the Supreme Court of Canada of OEFC's application for leave to appeal a judgment of the Court of Appeal of Ontario on a 2015 court decision. Going-forward, variance is largely due to suspension or early termination of some NUG PPAs in response to the IESO's NUG curtailment initiative.
Net Reduction of Power Purchase Contracts	0.1	(0)	(0)	(0)	(0)	
Other Fees and Licences	-	-	(8)	(10)	(10)	
Revenue Pool Residual	-	-	-		-	
Miscellaneous	14	-	-	-	-	
Expenses						
Interest on Debt	19	(53)	(64)	(69)	(98)	2017-18 reflects revised debt interest outlook net of revisions to OEFC interest revenue from OPG and Province.
Power Supply Contract Costs	(99)	110	142	167	170	Same as Power supply contract recoveries above. Power supply contract costs are fully recovered by power supply contract recoveries.
Electricity Consumer Price Protection Fund	-	-	-	-	-	
Demand Management Support Costs	1.8	-	-	-	-	
Provision for Electricity Sector	(53)	(101)	9	-	48	see explanation above for "Provision for Electriocty Sector" (line 17)
Other (Finance)	(1.0)	-	(1)	(1)	(1)	
Total OEFC Income	**(63)**	**(181)**	**(88)**	**(115)**	**(105)**	
Impact on Surplus/(Deficit)[1]	**(14.6)**	**(10)**	**(882)**	**(914)**	**(1,247)**	Note: A significant component of the changes above affecting this net is from a fiscally-neutral recategorisation of revenue impacts from the Asset Optimisation (AO) initiative previously shown in Sales and Rentals in Budget 2017 for commercial confidentiality. The pure changes to non-AO electricity sector changes is significantly fiscally negative. See summary table below for breakdown of total change between these components.
Information: Breakdown of change between revenue and expense						
Total Revenue Impact	87	(105)	(997)	(1,049)	(1,356)	
Total Expenditure impact	101	(95)	(115)	(135)	(109)	

Electricity Sector Outlook (PSAB)

Negative Revenue Risks ($ Millions)	Plan			
($ millions)	2017-18	2018-19	2019-20	2020-21
Generic				
OPG Generation Risk: Nuclear Reliability (-1.6 TWh)[1]	(120)	(120)	(120)	(120)
1% decrease in Hydro One actual load[2]	(57)	(59)	(62)	(63)
Lower OPG's Equity weighting & Return on Equity (ROE)[3]	(12)	(20)	(26)	(45)
Lower Hydro One Return on Equity (ROE)[4]	(9)	(36)	(38)	(40)
Regulatory				
Hydro One Distribution rate application[5]	(50)	(50)	(50)	(50)
OPG Switch from accrual based to cash based accounting for pension and OPEB[6]	—	(600)		
Regulatory Risk - Timing of OPG Rate Decision[7]	—			
OEB Staff Recommendations wrt OPG rate application(May 2017)[8]	—			
Nuclear Liabilities Cash vs. Accrual[9]	—			
OEB decision on Hydro One tax recapture (if one-time write-down)[10]	(440)			
Accounting				
OPG IFRS Consolidation Risks[11]		—	—	—
Other Risks				
ONFA adjustment decrease[12]	(50)			
Avista Acquisition - Termination fee		(49)		

Note: These risks do not reflect the impacts on electricity sector revenue and expense of reclassification of the Asset Optimization

1. OPG's market and generation risks related to nuclear reliability similar to the scenarios OPG developed for its sales margins to capture major market risk factors (e.g., natural gas prices, coal prices, foreign exchange, nuclear reliability) in its 2012 business plan. Currently, only the nuclear reliability risk is captured at the current regulated rate for OPG's nuclear generation.

2. Estimated revenue impact if Hydro One load for Transmission and Distribution is 1% lower than projected for all years in CEFD Hydro One Forecast. Based on the assumption a 1% increase in load is directly proportional to a 1% change in revenue requirements.

3. Risk range for Hydro One transmission and distribution reflects potential risk of lower ROE by 0.5% vs assumed ROEs in business plan along with reduced deemed debt to equity weighting of 55%/45% from the current 51%/49%.

4. Risk range for Hydro One transmission and distribution reflects potential risk of lower ROE by 0.5% vs assumed ROEs in CEFD Hydro One Forecast based on the most recent rate applications and forecasted ROE rates.

5. OEB is expected to make a decision on Hydro One's Distibution rate application for 2018 during the first half of 2018.

6. Previous risk removed shifted from 2017-18 to 2018-19. OEB's September 2017 Report, established accrual accounting method as default rate setting method to recover Pension and Other Pension Benefits (OPEBs) costs and recommended continuance of variance account tracking the difference between cash vs. accrual basis reporting for Pension and OPEB. This finding mitigates this risk. However, OEB December 28, OPG rate decision instructs OPG to submit request to dispose of Pension and OPEB deferral and variance account balances during 2018 for its 2019 payment application. OEB's final decision will be made at that time. Note, the impact of a decision could fall in 2019-20 depending on timing of the OEB decision.

7. **Previous risk removed with timing impact now reflected in OPG outlook.**. OEB December 28, decision and order provides an effective date for new rates of June 1, 2017. OPG's business plan assumed OEB decision would be effective as of January 1, 2017. OPG estimated an impact of -$60M for each month for which OEB decsion is not retroactive. The resulting $300M estimated impact has been included in the OPG outlook.

8. **Previous risk removed .** Estimated impact of OEB December 28the decision and order with respect to OPG rates is now reflected on the OPG Outlook.

9. **Previous risk removed.** Risk is related to potential switch to cash-basis accounting for regulated recovery of nuclear payment anmounts. OEB December 28, 2017 Decision and Order has deferred this issue to next OPG rate application in 2021 for 2022 to 2027 period.

10. The OEB's Sep. 28, 2017 ruling on Hydro One's Transmission rate application included direction on sharing, with ratepayers, tax savings related to the Hydro One IPO. Hydro One filed a Motion to Review this decision with the OEB and has also filed a court appeal. Hydro One's 2017 Q3 financial report notes that if the Motion to Review and appeal are unsuccesful teh company would record a one-time write-down of $885 million reflecting the OEB decision. The risk above reflects this risk at teh Province's 49.9% average share allocation for 2017-18. Hydro One noted that timing for the Motion to Review and appeal is uncertain. It expects the OEB Review to start in Q1 but noted that it could run in to Q2.

11. **Previous risk removed.** OPCD provided IFRS impact estimates (largely related to OPG) at the time of Budget 2017. A portion of these were reflected in in OPG's and Hydro One's net income outlook at the time of the 2017. The current Electricity Outlook now reflects this additional IFRS risk. Table below outlines OPG IFRS Risks versus what is built into the 2017 Budget Fiscal Plan.

	2017-18	2018-19	2019-20	2020-21
OPG IFRS Risk	(400)	(475)	(700)	(750)
Risks Built into Fiscal Plan at 2017 Budget	(400)	0	(200)	0
Additional Risks now picked up in this Electricity Outlook	0	(475)	(500)	(750)

Electricity Sector Outlook (PSAB)

Positive Revenue Risks				
($ millions)	**Plan**			
	2017-18	**2018-19**	**2019-20**	**2020-21**
Generic				
OPG Generation Risk: Nuclear Reliability (+1.1 TWh)[1]	85	85	85	85
1% increase in Hydro One actual load[2]	57	59	61	63
Higher OPG Return on Equity (ROE)[3]	6	22	19	33
Higher Hydro One Return on Equity (ROE)[4]	19	69	50	50
Regulatory				
Accounting				
Other Risks				
ONFA adjustment increase[5]	50			

strategy or updates to AO strategy.

1. OPG's market and generation risks related to nuclear reliability similar to the scenarios OPG developed for its sales margins to capture major market risk factors (e.g., natural gas prices, coal prices, foreign exchange, nuclear reliability) in its 2012 business plan. Currently, only the nuclear reliability risk is captured at the current regulated rate for OPG's nuclear generation.

2. Estimated revenue impact if Hydro One load for Transmission and Distribution is 1% higher than projected for all years in CEFD Hydro One Forecast. Based on the assumption a 1% increase in load is directly proportional to a 1% change in revenue requirements.

3. Risk range for OPG reflects potential risk of higher ROE in 2018-2021 (for nuclear base) vs assumed ROE in OPG's 2016 business plan and corresponding rate application. Assumed ROE is 9.85%, respresenting recent in 2010.

4. Risk range for Hydro One transmission and distribution reflects potential risk of higher ROE vs assumed ROEs in the Hydro One CEFD Forecast for 2018-2021. Assumed ROE is 9.85%, representing recent high in 2010.

5. Reflects risk around the consolidation adjustment to OPG net income, whereby the realized portion of gains or losses of OPG's nuclear funds are added or subtracted from OPG net income. Currently $171M positive adjustment is included in the OPG outlook. The ONFA adjustment is expected to be finalized in February 2018.

ONTARIO ELECTRICITY FINANCIAL CORPORATION
On Deck Outlook as of March 2017

$ Millions

	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Revenue						
Revenue Pool Residual						
Debt Retirement Charge	859	625	623	-	-	-
Payments-in-lieu of tax:						
OPG	268	302	315	366	408	537
Legacy Hydro One (Including Brampton)	2,929	7	2	2	2	2
Hydro One CIT dedicated to OEFC	3	20	20	22	23	25
MEUs	27	44	68	86	105	114
Total PILs & CIT dedicated to OEFC[1]	3,228	373	405	476	538	679
Interest :						
OPG	173	179	168	153	135	135
H1						
IESO	2	3	3	3	3	3
Province	520	492	492	492	492	492
Other	28	10	5	5	5	5
Total Interest	723	684	668	653	635	635
Power Supply Contract Recoveries	875	739	292	325	301	273
Amortization of NUG liability	172	129	74	41	30	28
Electricity sector dedicated income	3	342	525	-	-	-
Gain to OEFC under s. 50.3	172	-	-	-	-	-
Miscellaneous	9	-	-	-	-	-
	6,041	2,893	2,587	1,495	1,504	1,615
Expense						
Debt interest	1,319	1,216	1,090	1,027	977	885
Interest on nuclear risk funding						
Demand Management Support Costs	8	10	10	-	-	-
Amortization of deferred debt costs	-	-	-			
Power Supply Contract Costs	875	739	292	325	301	273
Debt Guarantee fee	127	122	102	91	88	81
Operating	7	6	6	6	6	6
	2,336	2,093	1,500	1,449	1,372	1,245
Excess (Deficiency) of Revenue over Expense	**3,705**	**800**	**1,087**	**46**	**132**	**370**
Prior period adjustment	87					
Stranded Debt - Year End	**4,393**	**3,593**	**2,506**	**2,460**	**2,328**	**1,958**

Note: All the Hydro One ownership broadening impacts, other than the ownership change from the initial IPO in 2015 and the secondary offering in April 2016, were reflected in Sales and Rentals as of the 2017 Budget.

ONTARIO ELECTRICITY FINANCIAL CORPORATION
On Deck Outlook as of October 2017

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Revenue						
Revenue Pool Residual						
Debt Retirement Charge	859	621	623	0	0	0
Payments-in-lieu of tax:						
OPG	268	224	287	342	373	494
Legacy Hydro One (Including Brampton)	2,929	4	2	2	2	2
Hydro One CIT dedicated to OEFC	3	25	20	22	23	25
MEUs	27	112	68	86	105	114
Total PILs & CIT dedicated to OEFC[1]	3,228	364	377	452	503	635
Interest :						
OPG	173	167	169	179	175	148
H1						
IESO	2	2	3	3	3	3
Province	520	514	454	454	454	454
Other	28	20	20	20	10	10
Total Interest	723	703	646	656	642	615
Power Supply Contract Recoveries	875	838	182	183	134	103
Amortization of NUG liability	172	129	74	41	30	28
Electricity sector dedicated income	3	302	24	9	0	48
Gain to OEFC under s. 50.3[2]	172	411	550	0	0	0
Miscellaneous	9	14	0	0	0	0
	6,041	3,382	2,477	1,340	1,309	1,429
Expense						
Debt interest	1,319	1,216	1,121	1,094	1,053	963
Interest on nuclear risk funding						
Demand Management Support Costs	8	8	10	0	0	0
Amortization of deferred debt costs	0	0	0			
Power Supply Contract Costs	875	838	182	183	134	103
Debt Guarantee fee	127	122	102	99	98	91
Operating	7	7	6	7	7	7
	2,336	2,191	1,421	1,383	1,292	1,164
Excess (Deficiency) of Revenue over Expense	3,705	**1,191**	**1,056**	**(42)**	**17**	**265**
Prior period adjustment	87					
Stranded Debt - Year End	4,393	**3,202**	**2,146**	**2,189**	**2,172**	**1,906**

1

Payments-in-lieu of tax:	**2015-16 Public Accounts**
OPG	290
Legacy Hydro One (Including Brampton)	2,941
Hydro One CIT dedicated to OEFC	0
MEUs	15
	3,247

2 2017-18 value preliminary estimate, subject to change.

ONTARIO ELECTRICITY FINANCIAL CORPORATION

Changes from Budget 2017 as of October 2017 **$ Millions**

	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Revenue						
Debt Retirement Charge	(4)	-	-	-	-	
Payments-in-lieu of tax:						
OPG	(78)	(28)	(24)	(35)	(43)	2016-17 decrease largely due to reconciling between OPCD and OEFC net opening assets. OPG PILs also slightly lower than projected. 2017-18 and onward decrease is due to estimated impact of OEB Dec. 29=8, 2017 rate decision.
Legacy Hydro One (Including Brampton)	(3)	-	-	-	-	
Hydro One CIT dedicated to OEFC	5	-	-	-	-	Adjustment based on updated information in Hydro One rate application
MEUs	68	-	-	-	-	Large increase in 2016-17 from $80M payment during transfer of H01 Brampton to new consolidated MEU Alectra.
Total PILs	(9)	(28)	(24)	(35)	(43)	
Interest :						
OPG	(12)	1	26	40	13	Update to OPG interest outlook (wrt interest on OEFC loan).
H1	-	-	-	-	-	
IESO	(1)	-	-	-	-	
Province	22	(38)	(38)	(38)	(38)	2016-17 PDI at ($514m) was slightly larger than ($492m) projected at Interim. 2017-18 change reflects revised projections for Provincial debt interest related to Hydro equity.
Other	10	15	15	5	5	
Total Interest	19	(22)	3	7	(20)	
Power Supply Contract Recoveries	99	(110)	(142)	(167)	(170)	Variance is largely due to retroactive payments that the OEFC made to certain non-utility-generators (NUGs) with former Ontario Hydro power purchase agreement contracts with OEFC. OEFC was required to make these payment following the dismissal by the Supreme Court of Canada of OEFC's application for leave to appeal a judgment of the Court of Appeal of Ontario on a 2015 court decision.
Amortization of NUG liability	0	(0)	(0)	(0)	(0)	
Electricity sector dedicated income	(41)	(501)	9	-	48	The decrease in OEFC ESDI in 2017-18 reflects i) the IFRS adjustment of $400 million in 2017-18 that was not reflected in the OEFC ESDI projection at the time of the 2017 Budget (Note the IFRS adjustment was reflected in OPG net income for the 2017 Budget fiscal plan) and ii) the lower OPG and Hydro One net income due to OEB's 2017 rate decisions. ESDI is alo lowered as the full impact of Hydro One share dispositions is now refelected in lower Hydro One net income tothe Province. Part of this impact was previously reflected in Sales and Rentals. The projected change in 2019-20 and 2020-21 is due to the continuation of ESDI beyond 2017-18 (approved in principle in the current PRRT). In the 2017 Budget outlook, ESDI was assumed to end after 2017-18. ESDI estimates for 2018-19 and 2018-19 are reduced due to negative balances in 2017-18 and 2018-19,
Gain to OEFC under s. 50.3	411	550	-	-	-	
Miscellaneous	14	-	-	-	-	
	489	(111)	(155)	(195)	(186)	
Expense						
Debt interest	-	31	67	76	78	Revised outlook for OEFC debt interest outlook
Interest on nuclear risk funding	-	-	-	-	-	
Demand Management Support Costs	(2)	-	-	-	-	
Amortization of deferred debt costs	-	-	-	-	-	
Power Supply Contract Costs	99	(110)	(142)	(167)	(170)	Same as Power supply contract recoveries above. Power supply contract costs are fully recovered by power supply contract recoveries.
Debt Guarantee fee	-	-	8	10	10	
Operating	1	-	1	1	1	
	98	(79)	(66)	(80)	(81)	
Excess (Deficiency) of Revenue over Expense	**391**	**(31)**	**(88)**			
Stranded Debt - Year End	**3,202**	**2,146**	**2,189**	**2,172**	**1,906**	

Provision for Electricity Sector (Dedicated Electricity Earnings/Electricity Sector Dedicated Earnings)

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Income from Investment in Government Business Enterprises						
OPG Income	291	299	149	137	(7)	156
Hydro One Income[1]	232	501	329	327	388	419
Hydro One Brampton (if applied separately)		15				
Total Income	**523**	**815**	**478**	**463**	**381**	**575**
Public Debt Interest - Electricity Sector						
OPG			(300)	(300)	(300)	(300)
Hydro One[1]			(154)	(154)	(154)	(154)
Public Debt Interest - Electricity Sector (OEFC Interest revenue)	**(520)**	**(514)**	**(454)**	**(454)**	**(454)**	**(454)**
MOF Provision Expense (before adjustments)	**3**	**302**	**24**	**9**	**(73)**	**121**
Other Adjustments						
Prior-year Adjustment[2]		3				
Exclude Brampton[3]		(15)				
MOF Provision Expense (after other adjustments)	**0**	**290**	**24**	**9**	**(73)**	**121**
Cumulative Shortfall Adjustment						
Opening Balance	0	0	0	0	0	(73)
Deduction / (Addition)	0	0	0	0	(73)	73
Ending Balance	0	0	0	0	(73)	0
Dedicated Electricity Earnings (all adjustments) (Public Accounts)	**0**	**290**	**24**	**9**	**0**	**48**
Electricity Sector Dedicated Income (OEFC Annual Report)	**3**	**302**	**24**	**9**	**0**	**48**

Notes:

1. The Hydro One financials above now reflects the Provincial share allocation as of January 2018.

2. 2016-17 Adjustment was due to the discrepancy between the numbers in MOF expense in PA 2015-16 and OEFC Financials in 2015-16 due to timing issues. $3M adjustment rectifies this discrepancy

3. Brampton was excluded from the Ministry of Finance's ESDI allocation.

Ontario Power Generation

OPG Income - Budget 2017

$ Millions

	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
OPG Net Income After Tax (Adjusted)	291	304	97	732	625	1,066
OPG Net Income After Tax	*291*	*379*	*480*	*678*	*726*	*913*
Extraordinary Gains	-	-	-	-	-	-
GA - OPG Trust Interest Revenue			*17*	*54*	*99*	*153*
OPG IFRS consolidation risk picked up in Fiscal Plan		(75)	(400)		(200)	
ONFA and other Fair Value Adjustments	(75)	8				
ONFA Adjustments	-	8				
Other Fair Value Adjustments	(75)					

OPG PIL - Budget 2017

$ Millions

	Actual	Interim		Pl
	2015-16	2016-17	2017-18	2018-19
Net Income Before Tax	383	396	572	867
Net Income After Tax (Adjusted)	291	304	97	732
Income Taxes	92	92	92	135
GRC: Payable to OEFC	198	196	205	212
Proxy Property Tax	16	14	18	19
Ontario Capital Tax	0	0	0	0
Total	**306**	**302**	**315**	**366**

OPG Income - January 2018

$ Millions

	Actual	Actual	Current Outlook			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
OPG Net Income	291	377	857	678	726	913
Adjustment for OPG HQ gain on sale[1]			(283)			
Unpacking updated OPG Gain on sale (net income)			283.27			
OEB December 28, 2017 Rate Decision Impact[2]			(320)	(109)	(115)	(136)
Extraordinary Gains	0	0	0	0	0	0
GA Financing - OPG Trust Interest Revenue[3]			12	42	82	128
OPG IFRS consolidation risk reflected in Fiscal Plan[4]		(78.00)	(400)		(200)	
Update IFRS Risk			0	(475)	(500)	(750)
OPG Net Income (Adjusted before ONFA)	**291**	**299**	**149**	**137**	**(7)**	**156**
ONFA Adjustments	247	49	171			
Other Fair Value Adjustments	(75)	(6)				
ONFA and other Fair Value Adjustments	**172**	**43**	**171**			
OPG Net Income	**463**	**342**	**320**	**137**	**(7)**	**156**

OPG PIL - January 2018

$ Millions

	Actual	Actual		Current
	2015-16	2016-17	2017-18	2018-19
Income Before Tax	383	308	723	235
OPG Net Income (Adjusted before ONFA)	291	299	149	137
OPG Income Tax (PILs)	92	9	162	135
OEB December 28, 2017 Rate Decision Impact[2]			(107)	(36)
Tax adjustment for OPG HQ gain on sale[1]			(95)	
Unpack PILs related to HQ gain on sale			95	
GRC: Payable to OEFC	198	201	214	224
Proxy Property Tax to OEFC	16	14	18	19
Ontario Capital Tax	0	0	0	0
Total OPG PILs	**306**	**224**	**287**	**342**

1. OPG's May 2017 head office facilities sale impacts are re-categorized from Sales and Rentals to OPG net income and PILs in the current Electricity Outlook update.
2. OEB December 28, 2017 estimated rate decision impacts are split between net income and PILs and a 75%/25% basis.
3. This reflects interest earnings on GA financing costs which are consolidated back to Province
4. See Risks tab for IFRS impacts that were not reflected in Fiscal Plan, and table below.

	2017-18	2018-19	2019-20	2020-21
OPG IFRS Risk	(400)	(475)	(700)	(750)

Hydro One Ownership Calculation:		SOURCE:
Total number of shares outstanding[1]	595,000,000	1. Hydro One Ltd Annual Report 2015, pg 94 of PDF, pg 92 of the Report.
Additional Common Shares Issued since IPO	386,711	
IPO November 2015		
Initial Public Offering(2015)[2]	81,100,000	2. From news release: http://hydroone.mediaroom.com/2015-11-05-Hydro-One-Limited-Announces-Closing-of-IPO
Over allotment option (2015)[3]	8,150,000	3. From news release: http://hydroone.mediaroom.com/2015-11-12-Hydro-One-Limited-Announces-Closing-of-IPO-Over-Allotment-Option
Sales to PWU/SEP Trusts	5,646,340	
Total	94,896,340	
Province's remaining ownership, Nov 2015 (# Shares)	**500,103,660**	
Province's remaining ownership, Nov 2015 (%)	**84.05%**	
Secondary Offering April 2016		
Secondary Offering (2016)	72,434,800	4. Hydro One Ltd. Q2 Report, pg 1 http://www.hydroone.com/InvestorRelations/FinancialReporting/Documents/Hydro%20One%20Ltd%20Second%20Quarter%20
Over allotment option (2016)	10,865,200	
Total	83,300,000	
Province's remaining ownership, Apr 2016 (# Shares)	**416,803,660**	
Province's remaining ownership, Apr 2016 (%)	**70.05%**	
Final Offering May 2017		
Final Offering (2017)	120,000,000	Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by-the-Provin
Over allotment option (2017)	-	Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by-the-Provin
Total	120,000,000	
Province's remaining ownership, May 8, 2017 (# Shares)	296,803,660	Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by-the-Provin
Province's remaining ownership, May 8, 2017 (%)	**49.88%**	
First Nations Sale, closed on December 29, 2017	14,391,012	Source: http://www.S:\Users\CEF\Hydro 2018\OEFC\RbP\Outlook\01. January\Backup\20180103-0 - H1 First Nations Sales\
	2.4170865%	Source: https://news.ontario.ca/mei/en/2017/05/ontario-raises-28-billion-from-final-hydro-one-share-offering.html
Province's remaining onwership - post First Nations Sale (#Shares)	282,412,648	
Province's remaining onwership - post First Nations Sale (%)	**47.43%**	
Avista Impact (projected closing date 2nd half of 2018)		
Contingent Convertible Debenture	$1,540,000,000	
Conversion Price	$21	
Potential Dilution (# Shares)	71,962,617	
Revised Total number of shares outstanding	**666,962,617**	
Province's remaining onwership - post Avista Acquisition (#Shares)	282,412,648	
Province's remaining onwership - post Avista Aquisition (%)	**42.34%**	

Ownership Percentage in 2017-18 Fiscal Year	Number of Months	Percentage of Year
70.05%	1	8.3%
49.88%	8	66.7%
47.43%	3	25.0%
	12	
Average 2017-18 FY Ownership:	**51.0%**	

Ownership Percentage in 2018-19 Fiscal Year (assume Avista closing end of September 2018)	Number of Months	Percentage of Year
47.43%	6	50.0%
42.34%	6	50.0%
	12	
Average 2018-19 FY Ownership:	**44.9%**	

Ownership Percentage in 2019-20 Fiscal Year Onwards
42.34%

Accretive to earnings per share and cash flow for Hydro One in the first full year post closing
above is from Hydro One transaction overview. Check what this means for timing of additional shares and /or earnings.

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Hydro One Net Income and PILs

Hydro One Income - Budget 2017
($ millions)

	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Hydro One Net Income After Tax	685	737	742	802	862	931
Hydro One - Unrealized Gains Adjustment						

2016-17 to 2020-21 from CEFD Hydro One 2016 model.

Hydro One PIL - Budget 2017
($ millions)

	2015-16	2016-17	2017-18	2018-19
Net Income After Tax	685	737	742	802
Income Taxes PILs	132	160	181	205
Proxy Property Tax	2	2	2	2
Ontario Capital Tax	0	0	0	0
Total	**134**	**162**	**183**	**207**

Hydro One Income - December 2017
($ millions) **$ Millions**

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Hydro One Net Income After Tax			645	690	780	845
Debenture Costs Impacts (After Tax)			(34)	(39)		
Hydro One Net Income After Tax - Including Adjustments	670	680	612	651	780	845
Hydro One - Net Income Attributable to Preferred Shareholders	15	18				
Hydro One - Unrealized Gains Adjustment						

Hydro One (100% Ownership)
($ millions) **$ Millions**

	Actual 2015-16	Actual 2016-17	2017-18	Current 2018-19
Net Income After Tax - Common Shares	670	680	612	651
Net Income After Tax - Preferred Shares	15	18		
Income Taxes PILs	132	160	181	205
Proxy Property Tax	2	2	2	2
Ontario Capital Tax	0	0	0	0

Public Debt Interest and Section 50.3 payments

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Hydro One Public Debt Interest and Section 50.3 payments						
Government Annual Interest Costs - Hydro One	220	220	220	220	220	220
Reduction in Interest Costs due to Broadening[1]		(29)	(66)	(66)	(66)	(66)
Province Annual Interest Costs - Hydro One Debt	**220**	**191**	**154**	**154**	**154**	**154**
Province Annual Interest Cost - OPG Debt	300	300	300	300	300	300
Total Public Debt Interest	**520**	**514**	**454**	**454**	**454**	**454**

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Gain to OEFC under s. 50.3	172	411	550	0	0	0

1. The Hydro One reduction in interest costs above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering are currently reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

ID# (Track Cha	Fiscal Year	alue (Hardcode	Value (Linked)	Description	Source Details	Source (Link)
20170501-2	2016-17	411,152,733	411,152,733	s 50.3 Gain for	Calculation provided by SIFB	
20170501-3	2016-17	29	29	Reduction in Int	Internal Calculation	
20170501-3	2017-18	66	66	Reduction in Int	Internal Calculation	
20170501-3	n/a	220	220	Annual Interest	Internal Calculation	

ID# (Track Cha	Fiscal Year	alue (Hardcode	Value (Linked)	Description	Source Details	Source (Link)
n/a	n/a	5126		($M) Provinces	OEFC 1999-2000 FS, pg 24	
n/a	n/a	5.85%		Annual Interest	OEFC 1999-2000 FS, pg 26	
		299.871				

OPG's Annual Interest Costs: 300

20170713-1	2016-17	-513,768,361	Provincial interest cost for equity investment in OPG, H1 in 2016-17 Monthly Balances Sheet (from FTD) S:\Users\CEF\Hydro 2017\OEFC\RbP\Outlook\07. July\Backup\20170713-1\interest fr

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PROVINCIAL CONSOLIDATION ADJUSTMENTS
Ontario Nuclear Funds Agreement

Adjustment for Change in OPG Reported Net Income

Adjustment for DSF Unrealized Earnings

Unrealized Earnings as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Bruce Variance Account Adjustment
OPG Net Income Adjustment

Adjustment for UFSF Unrealized Earnings

Unrealized Earnings as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Bruce Variance Account Adjustment
OPG Net Income Adjustment

Unrealized Earnings -- Fiscal YTD

Adjustment for Change in Due to Province

Adjustment for DSF Due to Province
Due to Province (cost basis) as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Change in Due to Province -- Fiscal YTD

Adjustment for UFSF Due to Province

Due to Province (cost basis) as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Change in Due to Province -- Fiscal YTD

Provincial Consolidation Adjustment

Other Data

	Actual 2016-17	2017-18
Debt Retirement Charge	621	0

	2016-17	2017-18
Power Supply Contract Recoveries	838	182

	2016-17	2017-18
Interest		
OPG	167	169
IESO	2	3
Other (Net)	20	20
Expense		
Debt interest	1216	1121

	Actual 2016-17	2017-18
MEU - PIL Income Tax	109.8	
MEU - PIL Property Tax	0.6	
MEU - GRC	1.2	
TOTAL MEU PILs	111.6	

	Actual 2016-17	2017-18
Miscellaneous/Other (OEFC FS)	14	
Demand Management Support Costs (IEI)	8	10
Operating [Expense]	7	6
Interest on nuclear risk funding	-	-
Amortization of deferred debt costs	-	-
Amortization of NUG liability	129	74
Debt Guarantee Fee	122	102

Expense (Electrictiy Summary Tab)		
Other (Finance)	-7	-6
Demand Management Support Costs (IEI)	-8	-10
Debt Guarantee Fee	(122)	(102)

Plan		
2018-19	2019-20	2020-21
0	0	0

Plan		
2018-19	2019-20	2020-21
183	134	103

Plan		
2018-19	2019-20	2020-21
179	175	148
3	3	3
20	10	10
1094	1053	963

Plan		
2018-19	2019-20	2020-21

Plan		
2018-19	2019-20	2020-21
7	7	7
-	-	-
-	-	-
41	30	28
99	98	91
-7	-7	-7
(99)	(98)	(91)

ID# (Track Changes	Fiscal Year	Value (Hardcoded)	Value (Linked)
20170510-2	2016-17	$ 739,216,115	
20170510-2	2017-18	$ 291,629,707	
20170510-2	2018-19	$ 324,906,017	
20170510-2	2019-20	$ 300,648,570	
20170510-2	2020-21	$ 273,240,858	
20170501-4	2016-17	179	179
20170501-4	2017-18	169	169
20170501-4	2018-19	179	179
20170501-4	2019-20	175	175
20170501-4	2020-21	148	148
20170501-5	2016-17	1216	1,216
20170501-5	2017-18	1121	1,121
20170501-5	2018-19	1094	1,094
20170501-5	2019-20	1053	1,053
20170501-5	2020-21	963	963
20170731-3	2016-17	621	
20170811-1	2016-17	109.8	
20170811-1	2016-17	0.6	
20170811-1	2016-17	1.2	
20170815-5	2016-17	$ 838,000,000	
20170815-6	2016-17	$ 14,000,000	
20170815-8	2016-17	8	
20170815-9	2017-18	10	
20170815-10	2016-17	7	
20171211-2	2017-18	6	6
20171211-2	2018-19	7	7
20171211-2	2019-20	7	7
20171211-2	2020-21	7	7
20170815-7	2016-17	167	
20170815-7	2016-17	2	
20170815-7	2016-17	20	
20170815-7			

ID# (Track Changes	Fiscal Year	Value (Hardcoded)	Value (Linked)
20170905-1	2016-17	129	129
20170905-1	2017-18	74	74

20170905-1	2018-19	41	41
20170905-1	2019-20	30	30
20170905-1	2020-21	28	28
20170905-2	2016-17	122	
20170906-1	2017-18	3	3
20170906-1	2018-19	3	3
20170906-1	2019-20	3	3
20170906-1	2020-21	3	3
20170906-1	2017-18	20	5
20170906-1	2018-19	20	5
20170906-1	2019-20	10	5
20170906-1	2020-21	10	5
20171211-0	2017-18	1121	1,121
20171211-0	2018-19	1094	1,094
20171211-0	2019-20	1053	1,053
20171211-0	2020-21	963	963
20171211-1	2017-18	102	102
20171211-1	2018-19	99	99
20171211-1	2019-20	98	98
20171211-1	2020-21	91	91
20171211-1			
20171211-1			
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20171211-1			
20171211-1			
20171211-1			
20171211-1			

ID# (Track Changes	Fiscal Year	Value (Hardcoded)	Value (Linked)
20180104-2	2017-18	$ 181,776,685	
20180104-2	2018-19	$ 182,785,215	
20180104-2	2019-20	$ 133,962,519	
20180104-2	2020-21	$ 102,554,665	

Description	Source Details	Source (Link)
The table below contains an updated preliminary N	SPFB Estimates, Email	
• The tables below provides both last year's submission for NUG costs by CEFD and this year's estimates (both of which exclude HST) based on the most recent NUG model.	SPFB Estimates, BN SPFB Estimates, BN SPFB Estimates, BN SPFB Estimates, BN	
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
Updating DRC from OEFC AR (Drafts)	2017 OEFC DRAFT FS	S:\Users\CEF\Hydro 2017\OEFC'
MEU - PIL Income Tax	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
MEU - PIL Property Tax	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
MEU - GRC	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
Updating to actuals	2017 OEFC AR	2017 OEFC Annual Report - Eng
Updating to actuals	2017 OEFC AR	2017 OEFC Annual Report - Eng
Updating to Actuals	2017 OEFC AR	S:\Users\CEF\Hydro 2017\OEFC'
OEFC 2017-18 IEI/Demand Management Suppor	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Operating Expense - Updating to Actuals	2017 OEFC AR	S:\Users\CEF\Hydro 2017\OEFC'
Revised Operating Expense from FTD Forecast	FTD - October PRRT	
OPG Interest Revenue - Actuals 2016-17	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
IESO Interest Revenue - Actuals 2016-17		
Other (Net) Interest Revenue - Actuals 2016-17		

Description	Source Details	Source (Link)
		S:\Users\CEF\Hydro 2017\OEFC'
	Amortization Schedule.	S:\Users\CEF\Hydro 2017\OEFC'

Sourcing the NUG liability amortization schedule.	Tab: Summary Fiscal Impact	S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Gurantee Fee - Updating to Actuals	2017 OEFC AR (pg 13 (	\\ofina.on.ca\ofadfs\Users\CEF\H
IESO Interest Revenue Plan	OEFC Revenue Forecast for Board - April 2017	\\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H
Other Interest Revenue Plan		\\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H
OEFC Debt Interest Expense (no change, just re-linking)	FTD - October PRRT	S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Guarantee Fee	FTD - October PRRT	S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC'

Description	Source Details	Source (Link)
Updated FY 2017-18 estimates of NUG costs	SPFB Estimates, BN	Power Purchases and Sales Fore
Updated FY 2017-18 estimates of NUG costs	SPFB Estimates, BN	Power Purchases and Sales Fore
Updated FY 2017-18 estimates of NUG costs	SPFB Estimates, BN	Power Purchases and Sales Fore
Updated FY 2017-18 estimates of NUG costs	SPFB Estimates, BN	Power Purchases and Sales Fore

\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board

\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board

\RbP\Outlook\07. July\Backup\20170731-3 - DRC Update\2017 OEFC Annual Report - English - DRAFT.PDF

\RbP\Outlook\08. August\Backup\20170811-1 - Updating PILs for 2016-17\OEFC 2016-17 Pils summary.pdf
\RbP\Outlook\08. August\Backup\20170811-1 - Updating PILs for 2016-17\OEFC 2016-17 Pils summary.pdf
\RbP\Outlook\08. August\Backup\20170811-1 - Updating PILs for 2016-17\OEFC 2016-17 Pils summary.pdf

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\RbP\Outlook\08. August\Backup\20170815-8 - 2016-17 Demand Management Support Costs (IEI)\2017 OEFC
\RbP\Outlook\08. August\Backup\20170815-9 - 2017-18 Demand Management Support Costs (IEI)\OEFC rever
\RbP\Outlook\08. August\Backup\20170815-10 - 2016-17 Operating (Expense)\2017 OEFC Annual Report - Enc

\RbP\Outlook\08. August\Backup\20170815-7 - 2016-17 Updated Interest on Debt Revenue\RE Revised OEFC

\RbP\Outlook\09. September\Backup\20170905-1 - Amortization of NUG Liability\NUG liability_estimated draw c
\RbP\Outlook\09. September\Backup\20170905-1 - Amortization of NUG Liability\NUG liability_estimated draw c

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ydro 2017\OEFC\RbP\Outlook\09. September\Backup\20170905-2 - 2016-17 Debt Guarantee Fee\2017 OEFC
ydro 2017\OEFC\RbP\Outlook\09. September\Backup\20170906-1 - OEFC Revenue Forecast for Board
ydro 2017\OEFC\RbP\Outlook\09. September\Backup\20170906-1 - OEFC Revenue Forecast for Board
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ydro 2017\OEFC\RbP\Outlook\09. September\Backup\20170906-1 - OEFC Revenue Forecast for Board

\RbP\Outlook\12. December\Backup\20171211-1 - Interest Numbers from FTD\OEFC forecast PRRT planning_
\RbP\Outlook\12. December\Backup\20171211-1 - Interest Numbers from FTD\OEFC forecast PRRT planning_
\RbP\Outlook\12. December\Backup\20171211-1 - Interest Numbers from FTD\OEFC forecast PRRT planning_
\RbP\Outlook\12. December\Backup\20171211-1 - Interest Numbers from FTD\OEFC forecast PRRT planning_
\RbP\Outlook\12. December\Backup\20171211-1 - Interest Numbers from FTD\OEFC forecast PRRT planning_
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\RbP\Outlook\12. December\Backup\20171211-1 - Interest Numbers from FTD\OEFC forecast PRRT planning_
\RbP\Outlook\12. December\Backup\20171211-1 - Interest Numbers from FTD\OEFC forecast PRRT planning_

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-April 2017.xlsx
-April 2017.xlsx

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lown_Mar15_if apply Jan1_Apr21.xls

Annual Report - English.pdf

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Oct5.xlsx

Colour Codes

Formulas are in black text

Hard coded numbers are in blue text

References elsewhere are in purple

Green bold text with or without highlights mean updates required

Policies to follow when making updates to the Outlook

*** To quickly jump to the source numbers for a link, press "**Ctrl + [**"

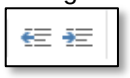
All new numbers must be fully sourced, and follow the colour codes above

Most numbers and text are Arial Size 10, unless it is a title

Add back up materials in a folder with the same numbers as in the 'Track Changes' tab

If there is a reason for italics, or other colours, or formatting make sure it is clear. Othe

Use indents to make things more clear to read



If numbers are taken from another tab they should ONLY be direct links, no calculation

Electricity Summary - (Budget17/On Deck) - Reflects Public Accounts/Financial Statem

OEFC - (Budget17/On Deck) - Reflects OEFC Annual Reports

*Due to slight discrepancies between Public Accounts reporting and OEFC Annual Rep

Outlook Updates Frequency

Frequency	Description	Tab
Monthly	OPG Net Income in-year forecast	OPG
Monthly	OPG PILs in-year forecast	OPG
Quarterly	ONFA Consolidation Adjustment	ONFA
Quarterly	OPG Cash vs Accrual Variance Account	Revenue (Risks)

ɔ.
rwise expect it to be cleared

ı, adjustment should be done. Even if its just making a negative to a positive. Perform all the calculations on the

ıents

ɔorts, the numbers may not be identical

source tab then bring the number into the next tab. (Eg. Formulas like this become hard to troubleshoot ='Hydro

One'!AR29+'Hydro One'!AR31+'Hydro One'!AR32), let's avoid them.

From:	Ronald Kwan
To:	Bruno Amara
Cc:	Usman Zahid; John Kim
Subject:	RE: Electricity Update
Date:	Tuesday, January 09, 2018 7:08:38 PM
Attachments:	Electricity Sector Outlook (2018 01 08)_unpacked_v05_Markup.xlsm

Hi Bruno.

I made some suggested edits to the variance explanations on the "Electricity Summary – Change" tab. Please review.

Thanks,
Ron

From: Bruno Amara
Sent: January-09-18 17:19
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Usman Zahid <Usman.Zahid@ofina.on.ca>
Subject: RE: Electricity Update

Hi Ron

Please see attached with update footnotes and Pension risk revised per our discussion.

Bruno

From: Ronald Kwan
Sent: Tuesday, January 09, 2018 5:16 PM
To: Bruno Amara <Bruno.Amara@ofina.on.ca>
Cc: Usman Zahid <Usman.Zahid@ofina.on.ca>
Subject: RE: Electricity Update

Hi Bruno,

Please send me the revised version.

Thanks,
Ron

From: Bruno Amara
Sent: January-09-18 11:12
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Usman Zahid <Usman.Zahid@ofina.on.ca>
Subject: Electricity Update

Hi Ron

I realize we did not update various footnotes to reflect unpacking in the version I sent to you last night. We have now done this. I also revised the Risk table to shift the pension risk forward one-year, noting that while this risk may be mitigated by findings of the OEB report, OEB will make final decision with deferred decision. I haven't forwarded this for now to avoid any confusion with edits you may be making, but happy to do so.

Also we have coordinated with SIFB and FTD on the AO unpacking exercise to make sure we are all on same page before we share with Frost. We are just finalizing some summary tables on our unpacking exercise that we can send to you and/or walk you through.

I heard from CQSD late yesterday that wrap-up is on Monday. They would like to prepare ESDI update today for Helmut's review. I noted that we do have updates that we are finalizing and will send as soon as we can. We can check back to see if tomorrow will be OK as necessary.

I also let OPCD know that we are working on an update that will re-categorize AO impacts and will send them that version as it will be more accurate for Budget consolidation. But I will also offer them our Interim unpacked version if they want to use that for now.

Bruno

Bruno Amara
Sr. Manager, Financial and Regulatory Analysis
Electricity Finance Branch
Corporate and Electricity Finance Division
Ontario Financing Authority

Tel: 416-325-1489
Email: bruno.amara@ofina.on.ca

Electricity Sector Outlook
October 2017

Disclosure:

All information contained in this workbook is confidential and commercially sensitive

All projected numbers are estimates and subjected to change

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Please consult with OFA before sharing of information.

Commercially Sensitive and Confidential Advice to Cabinet for Consideration of Options for Discussion Purposes Only

Commercially Sensitive and Confidential Advice to Cabinet for Consideration of Options for Discussion Purposes Only

Electricity Sector Outlook
Including Line Items for Consolidation

Electricity Summary - On Deck

			MOF Expense Items (consolidated)	Current Outlook			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**38**	Power Supply Contract Costs	(182)	(183)	(134)	(103)
Expense	**MOF (OEFC)**	**40**	Demand Management Support Costs	(10)	-	-	-
Expense	**MOF (OEFC)**	**41**	Provision for Electricity Sector	24	9	-	48
Expense	**MOF**	**17**	Provision for Electricity Sector	(24)	(9)	-	(48)
Expense	**MOF (OEFC)**	**42**	Other (Finance)	(6)	(7)	(7)	(7)
			Total MOF Expense	**(198)**	**(190)**	**(141)**	**(110)**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**7**	OPG Income	149	137	(7)	156
Revenue	**ENE**	**8**	OPG - ONFA and other Fair Value Adjustments	171	-	-	-
Revenue	**ENE**	**10**	HOI Income	329	327	388	419
Revenue		**11**	Brampton Income	-	-	-	-
Revenue	**MOF (OEFC)**	**26**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	377	452	503	635
Revenue	**MOF (OEFC)**	**29**	Electricity Debt Retirement Charge	623	-	-	-
Revenue	**MOF (OEFC)**	**30**	Power Supply Contract Recoveries	182	183	134	103
Revenue	**MOF (OEFC)**	**31**	Net Reduction of Power Purchase Contracts	74	41	30	28
Revenue	**MOF (OEFC)**	**34**	Miscellaneous	-	-	-	-
			Total MOF Revenue	**1,906**	**1,138**	**1,048**	**1,341**
			OFA IOD Expense				
			Public Debt Interest - Electricity Sector	(454)	(454)	(454)	(454)
			Interest on Debt	(475)	(438)	(411)	(348)
			Total OFA IOD Expense	**(929)**	**(892)**	**(865)**	**(802)**
			Impact on Surplus/Deficit	**779**	**57**	**42**	**429**
			check	*-*	*-*	*(0)*	*-*

Electricity Summary - Budget 17

For Discussion			MOF Expense Items (consolidated)	Plan			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**38**	Power Supply Contract Costs	(292)	(325)	(301)	(273)
Expense	**MOF (OEFC)**	**40**	Demand Management Support Costs	(10)	0	0	0
Expense	**MOF (OEFC)**	**41**	Provision for Electricity Sector	125	0	0	0
Expense	**MOF**	**17**	Provision for Electricity Sector	(125)	0	0	0
Expense	**MOF (OEFC)**	**42**	Other (Finance)	(6)	(6)	(6)	(6)
			Total MOF Expense	**(308)**	**(331)**	**(307)**	**(279)**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**7**	OPG Income	97	732	625	1,066
Revenue	**ENE**	**8**	OPG - ONFA and other Fair Value Adjustments	0	0	0	0
Revenue	**ENE**	**10**	HOI Income	520	562	603	652
			Brampton Income				
Revenue	**MOF (OEFC)**	**25**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	405	476	538	679
Revenue	**MOF (OEFC)**	**29**	Electricity Debt Retirement Charge	623	0	0	0
Revenue	**MOF (OEFC)**	**30**	Power Supply Contract Recoveries	292	325	301	273
Revenue	**MOF (OEFC)**	**31**	Net Reduction of Power Purchase Contracts	74	41	30	28
Revenue	**MOF (OEFC)**	**34**	Miscellaneous	0	0	0	0
			Total MOF Revenue	**2,011**	**2,136**	**2,098**	**2,697**
			OFA IOD Expense				
		17	Public Debt Interest - Electricity Sector	(492)	(492)	(492)	(492)
		36	Interest on Debt	(422)	(374)	(342)	(250)
			Total OFA IOD Expense	**(914)**	**(866)**	**(834)**	**(742)**
			Impact on Surplus/Deficit	**789**	**939**	**957**	**1,676**
			check	**-**	**-**	**-**	**-**

Electricity Summary - Change

			MOF Expense Items (consolidated)	Variance from Plan			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**69**	Power Supply Contract Costs	110	142	167	170
Expense	**MOF (OEFC)**	**71**	Demand Management Support Costs	0	0	0	0
Expense	**MOF (OEFC)**	**72**	Provision for Electricity Sector	(101)	9	0	48
Expense	**MOF**	**48**	Provision for Electricity Sector	101	(9)	0	(48)
Expense	**MOF (OEFC)**	**73**	Other (Finance)	0	(1)	(1)	(1)
			Total MOF Expense	**110**	**141**	**166**	**169**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**38**	OPG Income	52	(596)	(632)	(909)
Revenue	**ENE**	**39**	OPG - ONFA and other Fair Value Adjustments	171	0	0	0
Revenue	**ENE**	**41**	HOI Income	(190)	(235)	(216)	(233)
			Brampton Income	0	0	0	0
Revenue	**MOF (OEFC)**	**25**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	(28)	(24)	(35)	(43)
Revenue	**MOF (OEFC)**	**60**	Electricity Debt Retirement Charge	0	0	0	0
Revenue	**MOF (OEFC)**	**61**	Power Supply Contract Recoveries	(110)	(142)	(167)	(170)
Revenue	**MOF (OEFC)**	**62**	Net Reduction of Power Purchase Contracts	(0)	(0)	(0)	(0)
Revenue	**MOF (OEFC)**	**65**	Miscellaneous	0	0	0	0
			Total MOF Revenue	**(105)**	**(997)**	**(1,049)**	**(1,356)**
			OFA IOD Expense				
		17	Public Debt Interest - Electricity Sector	38	38	38	38
		36	Interest on Debt	(53)	(64)	(69)	(98)
			Total OFA IOD Expense	**(15)**	**(26)**	**(31)**	**(60)**
			Impact on Surplus/Deficit	**(10)**	**(882)**	**(914)**	**(1,247)**
			check	-	-	-	-

Track Changes in Surplus/Deficit

Date	Change ID#	Source	Tab
5/1/2017	20170501-1	Link	ONFA
5/1/2017	20170501-2	Link	Hydro One
5/1/2017	20170501-3	Link	Hydro One
5/1/2017	20170501-4	Link	Other Data
5/2/2017	20170502-1	Link	OPG
5/9/2017	20170509-1	Link	OPG
5/10/2017	20170510-1	Link	Hydro One
5/10/2017	20170510-2	Link	Other Data
5/12/2017	20170512-1	Link	Hydro One
5/15/2017	20170515-1	Link?	
5/15/2017	20170515-2	Link	OPG
5/17/2017	20170517-1	Link	Hydro One
5/17/2017	20170517-2	Link	ONFA
5/17/2017	20170517-3		
5/18/2017	20170518-1	Link	OPG
5/18/2017	20170518-2	Link	OPG
5/18/2017	20170518-3		
6/15/2017	20170615-1	Link	OPG
6/22/2017	20170622-1	Link	Hydro One
6/22/2017	20170622-2	Link	Hydro One
6/26/2017	20170626-1		
6/29/2017	20170629-1		

7/6/2017	20170706-1		
7/11/2017	20170711-1		
7/13/2017	20170713-1	Link	Provision
7/17/2017	20170717-1	Link	Revenue (Risks)
7/24/2017	20170724-1	Link	Revenue (Risks)
7/25/2017	20170725-1	Link	Revenue (Risks)
7/26/2017	20170726-1	Link	Revenue (Risks)
7/27/2017	20170727-1	Link	Revenue (Risks)
7/27/2017	20170727-2	Link	Revenue (Risks)
7/31/2017	20170731-1		
7/31/2017	20170731-2	Link	Hydro One
7/31/2017	20170731-3	Link	Other Data
8/11/2017	20170811-1	Link	OPG
8/15/2017	20170815-1		
8/15/2017	20170815-2		
8/15/2017	20170815-3		
8/15/2017	20170815-4		
8/15/2017	20170815-5		Other Data
8/15/2017	20170815-6		Other Data
8/15/2017	20170815-7		Other Data
8/15/2017	20170815-8		Other Data
8/15/2017	20170815-9		Other Data
8/15/2017	20170815-10		Other Data
8/17/2017	20170817-1	Link	Provision
8/17/2017	20170817-2	Link	Hydro One
8/18/2017	20170818-1	Link	Revenue (Risks)
8/22/2017	20170822-1	Link	OPG
8/25/2017	20170825-1		Hydro One
8/29/2017	20170829-1		Revenue (Risks)
8/31/2017	20170831-1		Revenue (Risks)
9/5/2017	20170905-1		Other Data
9/5/2017	20170905-2		Other Data
9/5/2017	20170905-3	Link	OPG

9/6/2017	20170906-1	Link	Other Data
9/6/2017	20170906-2	Link	Revenue (Risks)
9/8/2017	20170908-1	Link	Hydro One
9/8/2017	20170908-2	Link	OPG
9/11/2017			
9/12/2017			
9/13/2017			
9/21/2017			
9/22/2017			
10/2/2017			Hydro One
10/2/2017			
10/2/2017			
10/2/2017			
10/4/2017	20171004-1		OPG
10/4/2017	20171004-2		OPG
10/4/2017			
10/4/2017			
10/5/2017			
10/6/2017			
10/7/2017			
10/8/2017			
10/10/2017	20171010-1		Hydro One
10/10/2017			
10/10/2017			
10/11/2017	20171011-1		OPG
10/11/2017			
10/11/2017			
10/12/2017			OPG
10/12/2017			
10/12/2017			
10/12/2017			
10/18/2017	20171018-1		Hydro One
10/18/2017	20171018-1		Hydro One
10/18/2017	20171018-1		Hydro One
10/19/2017	20171019-1		Revenue (Risks)
10/19/2017	20171019-2		Revenue (Risks)
10/20/2017	20171020-1		Revenue (Risks)
10/20/2017	20171020-2		
10/20/2017	20171020-2		
10/20/2017	20171020-2		
10/20/2017	20171020-3		Revenue (Risks)
10/20/2017	20171020-4		OPG
10/20/2017	20171020-4		OPG
10/20/2017	20171020-4		OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017	20171114-1		Hydro One

11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017		Hydro One
11/14/2017		Hydro One
11/14/2017		Hydro One
11/30/2017	20171130-1	Revenue (Risks)
12/8/2017		Hydro One
12/11/2017	20171211-1	Other Data
12/11/2017	20171211-1	Other Data
12/22/2017	20171222-1	OPG
1/2/2018		Hydro One
1/2/2018		Hydro One
1/2/2018		Hydro One
1/2/2018	20180102-1	OPG
1/2/2018	20180102-1	OPG
1/2/2018	20180102-1	OPG
1/2/2018	20180102-2	OPG
1/2/2018	20180102-3	OPG
1/2/2018	20180102-3	Revenue (Risks)
1/2/2018	20180102-4	Revenue (Risks)
1/2/2018	20180102-5	Revenue (Risks)
1/2/2018	20180102-6	Revenue (Risks)
1/2/2018	20180102-7	Revenue (Risks)
1/2/2018	20180102-8	Revenue (Risks)
1/2/2018	20180102-9	OPG
1/2/2018	20180102-9	OPG
1/2/2018	20180102-9	OPG
1/2/2018	20180102-9	OPG
1/3/2018		OPG
1/3/2018		OPG
1/3/2018		OPG
1/3/2018		OPG
1/3/2018		Hydro One
1/3/2018		Hydro One
1/3/2018		Hydro One
1/4/2018	20180104-1	OPG
1/4/2018	20180104-1	OPG
1/4/2018	20180104-1	OPG
1/4/2018	20180104-1	OPG
1/4/2018	20180104-2	Other Data
1/4/2018	20180104-2	Other Data
1/5/2018		
1/5/2018		
1/5/2018		
1/5/2018		
1/5/2018		
1/5/2018		
1/5/2018		
1/8/2018		
1/8/2018		
1/8/2018		

FOR EFB USE ONLY

Budget 2017 Outlook
Current Outlook
Change Since Budget

Description of Update
ONFA Update as of March 31 2017
s. 50.3 Update for 2016-17
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Debt Interest
OPG IFRS Risk in 2019-20
Revised OPG 2016-17 Net Income
Revised OPG 2016-17 Net Income
Revised OPG 2016-17 Net Income
tech change: slight update to assumed Prov share 70.05% from 70%
tech change: slight update to assumed Prov share 70.05% from 70%
tech change: slight update to assumed Prov share 70.05% from 70%
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
Updating H1 2016-17 Net Income for ESDI
Updating H1 2016-17 Net Income for ESDI
Updating H1 2016-17 Net Income for ESDI
Power Purchase Supply
H1 Model Forecasts - No Fiscal Update Resaving Data
Update Budget 2017 Tabs to reflect fiscal plan
Update OPG forecasted PILS to reflect sources
Update H1 2016-17 CIT
Re-inputting ONFA updates
Updating H1 Net Income to include Pref Shares in 16-17
Updating OPG Income Tax Expense for 2016-17
Updating OPG non-income tax PILs
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2017
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2018
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2019
Updating with actual OPG IFRS Adjustment 2016-17
Updating with actual OPG IFRS Adjustment 2016-17
Updating with actual OPG IFRS Adjustment 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
[NOT APPLIED] Updating H1 Brampton (Interim Adjustments)
Shifted H1 Brampton 2016-17 NI to the 2017-18
Removed H1 Brampton for 2016-17 (pending finals)
Removed H1 Brampton for 2016-17 (pending finals)
Removed H1 Brampton for 2016-17 (pending finals)

add prior-year adjustment for 2016-17

add prior-year adjustment for 2016-18
Reconfigured calculation of ESDI and MOF ESDI Expense
Reconfigured calculation of OPG 2017-18 Net Income
Backup for the Provincial Interest cost
Linking source for Revenue Risks Tab
New source for Revenue Risks Tab
Revenue Risks Tab - ROE Risks
Updating OEB Risk for OPG
OEB Staff Report - H1 Tx - Revenue Risks
OPG Pensions - Cash vs Accrual Deferral Accounts
Updating Links in Electricity Summary Change and OEFC Change
Preliminary estimate for Hydro One Brampton
Preliminary estimate for Hydro One Brampton
Preliminary estimate for Hydro One Brampton

Updating DRC for Actuals 2016-17 (Based on draft FS)
Updating PILs for 2016-17 Baced on Actuals
OPG: Non-ONFA Fair Value Adjustment
Round all Hydro One ownership assumptions to two decimal places
H1 Equity Adjustment rounding.
Round all Hydro One ownership assumptions to two decimal places
Round all Hydro One ownership assumptions to two decimal places
Revising source of ESDI, Dedicated Electricity Earnings
2016-17 - Update Power Supply Recoveries to actuals
2016-17 - Update Power Supply Recoveries to actuals
2016-17 - Updating Miscellaneous OEFC Revenue to Actuals
Adj: Exclude Bramton $15m add prior year adjustment +$3M
Adj: Exclude Bramton $15m add prior year adjustment +$3M
Public Accts: Updated IESO debt interest Interest On Debt, 2016-17
Public Accts: 2016-17 - Demand Management Support Costs Update
2017-18 - Demand Management Support Costs (no change)
Public Accts: 2016-17 - Updating Operating Expense in OEFC
Sourcing Provision for Electricity Sector from Actual Public Accounts
Revised 2016-17 Brampton Amount for Public Accounts
OPG Pensions - Cash vs Accrual Deferral Accounts (Revenue Risks Tab)
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
Reclassification
Reclassification
Reverting H1 Ownership change (undoing 20170518-3)
Reverting H1 Ownership change (undoing 20170518-3)
Reverting H1 Ownership change (undoing 20170518-3)
Updating Risks based on Hydro One Q2 Results Model
Avista Acquisition Risks
NUG Amortization Liability (sourcing amortization schedule)
2016-17 Actuals - Debt Guarantee Fee
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results

Interest Revenue for IESO and "Other"
OPG Revenue Risks from OEB Filings
Net income corrected for Preferred Shares
Net income corrected for Preferred Shares
Net income corrected for Preferred Shares
Made link edits to OPG sheet so that the "Net Income Before Tax" 2017-18 number is not a hardc
Updated PILs to include OPCD public accounts adjustment
Provision tab fix to pick up Hydro One preferred share net income
Provision tab fix to pick up Hydro One preferred share net income
FTD Update to OEFC Outlook (Sep 19, 2017) OPG Interest
FTD Update to OEFC Outlook (Sep 19, 2017) Other Interest
Update to Hydro One PILs from information in Transmission rate application material
OEB September 28, 2017 Hydro One decision and order impact - incl. rebasing
OEB September 28, 2017 Hydro One decision and order impact - incl. rebasing
OEB September 28, 2017 Hydro One decision and order impact - incl. rebasing
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Debenture Interest Costs - Removing from Revenue (Risks) and adding it ot H1 Model
Debenture Interest Costs - Removing from Revenue (Risks) and adding it ot H1 Model
Debenture Interest Costs - Removing from Revenue (Risks) and adding it ot H1 Model
Updated OPG Net Income and PILs based on monthly report (August 2017 results)
Updated OPG Net Income and PILs based on monthly report (August 2017 results)
Updated OPG Net Income and PILs based on monthly report (August 2017 results)
Correction to PILs on OPG sheet
Correction to PILs on OPG sheet
Correction to PILs on OPG sheet
Correction to PILs on OPG sheet
Switch to Direct from Model
Switch to Direct from Model
Switch to Direct from Model
Updating ROE Risks
Updating H1 Load Risks based on model output
Updating ONFA Risks for September 2017
Adjust OEB decision/rebasing to ~50% provincial ownership
Adjust OEB decision/rebasing to ~50% provincial ownership
Adjust OEB decision/rebasing to ~50% provincial ownership
Updating OPG
OPG IOD impact from GA Financing, FHP
OPG IOD impact from GA Financing, FHP
OPG IOD impact from GA Financing, FHP
Unpacking updated OPG Gain on sale (net income)
Unpacking updated OPG Gain on sale (net income)
Unpacking updated OPG Gain on sale (net income)
Unpack PILs related to HQ gain on sale
Updating IFRS Risk
Adjustment for lower Provincial share (from 70.1% to 50.9 2017-18 & 47.4% after)
Adjustment for lower Provincial share (from 70.1% to 50.9 2017-18 & 47.4% after)
Adjustment for lower Provincial share (from 70.1% to 50.9 2017-18 & 47.4% after)
November 1 and November 7 Hydro One model updates

November 1 and November 7 Hydro One model updates
November 1 and November 7 Hydro One model updates
Revise Hydro Model to reverse OEB tax decision ongoing annual impact
Revise Hydro Model to reverse OEB tax decision ongoing annual impact
Revise Hydro Model to reverse OEB tax decision ongoing annual impact
Undo allocation adjustment in H1 tab (now that provincial shares are updated)
Undo allocation adjustment in H1 tab (now that provincial shares are updated)
Undo allocation adjustment in H1 tab (now that provincial shares are updated)
Updating OPG Revenue Risks from rate application
Update Hydro One PILs (reverses update on line 119 whuich did not account fro Dx side)
Updating Debt Guarantee Fee
Updating OEFC Operating Expense
small changes - linking the net income numbers

Updated number of shares sold for First Nations (Dec 2017) sale
Updated number of shares sold for First Nations (Dec 2017) sale
Updated number of shares sold for First Nations (Dec 2017) sale
Implemented OEB's Dec 2017 payment amounts decision for OPG (CEFD Analysis)
Implemented OEB's Dec 2017 payment amounts decision for OPG (CEFD Analysis)
Implemented OEB's Dec 2017 payment amounts decision for OPG (CEFD Analysis)
Updated OPG Net Income (based on their Q3 update, Sep 30, 2017)
Updated OPG ONFA adjustment (up to Sep 30, 2017) in OPG tab (removed it from Risks table)
Removal of OPG ONFA Sep 2017 adjustment in Risks table
Included possible range (-50M to 50M) of impact for future OPG ONFA adjustment in the negative
Removal of negative regulatory risk: "OPG Switch from accrual based to cash based accounting f
Removal of negative regulatory risk: "Timing of OPG Rate Decision" from Risks table
Removal of negative regulatory risk: "OEB Staff Recommendations wrt OPG rate application(May
Removal of negative regulatory risk: "Nuclear Liabilities Cash vs. Accrual" from Risks table
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month
Updated estimates of NUG costs.
Updated estimates of NUG costs.
Unpacking OPG (Head Office sale)
Unpacking OPG (Head Office sale)
Unpacking OPG (Head Office sale)
Unpacking OPG (Head Office sale)
Unpacking Hydro One for AO (from 70.1% ownership to as of January 2018)
Unpacking Hydro One for AO (from 70.1% ownership to as of January 2018)
Unpacking Hydro One for AO (from 70.1% ownership to as of January 2018)
Update H1 allocations for additional shares (SIFB edits)
Update H1 allocations for additional shares (SIFB edits)
Update H1 allocations for additional shares (SIFB edits)

This line show net impact of latest change. READ COMMENT

Expense
Expense
Expense
Expense
Expense
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue

Expense
Expense
Expense
Expense
Expense
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue

$ Millions

		2016-17	2017-18	2018-19	2019-20
		930	789	939	957
	File	915	779	57	42
		-15	-10	-882	-914
	check	*0*	*0*	*0*	*0*
		Impacts by FY →			
Outlook line affected	**Expense / Reve**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
ONFA and other Fair Value Adjustments	Revenue	41.0	0.0	0.0	0.0
N/A		0.0	0.0	0.0	0.0
?		0.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		38.1		
Provision for Electricity Sector (MOF)	Expense		(38.1)		
Public Debt Interest - Electricity Sector	Expense	0.0	38.1	38.1	38.1
Interest on Debt	Expense	0.0	(69.1)	(79.1)	(75.1)
OPG Income	Expense	0.0	0.0	0.0	
OPG Income	Revenue	(2.0)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**(2.0)**			
Provision for Electricity Sector (MOF)	Expense	2.0			
HOI Income	Revenue	0.4			
Provision for Electricity Sector (OEFC)	Expense	0.4			
Provision for Electricity Sector (MOF)	Expense	(0.4)			
Public Debt Interest - Electricity Sector	Expense	1.7			
Provision for Electricity Sector (OEFC)	Expense	(1.7)			
Provision for Electricity Sector (MOF)	Expense	1.7			
Interest on Debt	Expense	(1.7)			
HOI Income	Revenue	(39.8)	0.0	0.0	(0.0)
Provision for Electricity Sector (OEFC)	Expense	**(39.8)**			
Provision for Electricity Sector (MOF)	Expense	39.8			
	Revenue	-	-	-	-
	Revenue	-	-	-	-
	n/a	-	-	-	-
		-	-	-	-
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	4.7	0.0	0.0	0.0
	Revenue	0.0	0.0	0.0	0.0
HOI Income	Revenue	18.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	7.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	8.0	9.0	12.0	3.5
HOI Income	Revenue	0.0	(141.5)	(181.4)	(194.9)
Provision for Electricity Sector (OEFC)	Expense		(141.5)		
Provision for Electricity Sector (MOF)	Expense		141.5		
OPG Income	Revenue	(3.0)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**(3.0)**			
Provision for Electricity Sector (MOF)	Expense	3.0			
HOI Income	Revenue	7.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**7.0**			
Provision for Electricity Sector (MOF)	Expense	(7.0)			
	Revenue	-	-	-	-
	Revenue	0.0	0.0	0.0	0.0
Brampton Income	Revenue	(14.7)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**(14.7)**			
Provision for Electricity Sector (MOF)	Expense	14.7			

Provision for Electricity Sector (OEFC)	Expense		3.2			
Provision for Electricity Sector (MOF)	Expense		(3.2)			
	Revenue	-	-	-	-	
		-	-	-	-	
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
Brampton Income	Revenue		15.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		**15.0**			
Provision for Electricity Sector (MOF)	Expense		(15.0)			
Provision for Electricity Sector (OEFC)	Expense		3.2			
Provision for Electricity Sector (MOF)	Expense		(3.2)			
Electricity Debt Retirement Charge	Revenue		(4.0)	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue		(29.0)	0.0	0.0	0.0
OPG Income	Revenue		(6.0)	0.0	0.0	0.0
HOI Income	Revenue		(0.0)	(0.0)	0.0	0.0
HOI Income	Revenue		(1.7)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense			(0.0)		
Provision for Electricity Sector (MOF)	Expense			0.0		
	Revenue		0.0	0.0	0.0	0.0
Power Supply Contract Recoveries	Revenue		99.0	0.0	0.0	0.0
Power Supply Contract Costs	Expense		(99.0)			
Miscellaneous	Revenue		14.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		(12.0)			
Provision for Electricity Sector (MOF)	Expense		12.0			
Interest on Debt	Expense		(3.0)	0.0	0.0	0.0
Demand Management Support Costs	Expense		1.8	0.0	0.0	0.0
			0.0	0.0	0.0	0.0
Other (Finance)	Expense		(1.0)	0.0	0.0	0.0
	Revenue	-	-	-	-	
Brampton Income	Revenue		3.0	0.0	0.0	0.0
			0.0	0.0	0.0	0.0
OPG Income	Revenue		0.0	85.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue			(6.0)		
Provision for Electricity Sector (OEFC)	Expense			**85.0**		
Provision for Electricity Sector (MOF)	Expense			(85.0)		
OPG Income	Revenue		6.0			
ONFA and other Fair Value Adjustments	Revenue		(6.0)			
HOI Income	Revenue		0.0	141.9	181.8	195.4
Provision for Electricity Sector (OEFC)	Expense			141.9		
Provision for Electricity Sector (MOF)	Expense			(141.9)		
	n/a		0.0	0.0	0.0	0.0
			0.0	0.0	0.0	0.0
Net Reduction of Power Purchase Contracts	Revenue		0.1	(0.1)	(0.1)	(0.1)
	Revenue		0.0	0.0	0.0	0.0
OPG Income	Revenue		0.0	16.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue			(1.0)		
Provision for Electricity Sector (OEFC)	Expense			**16.0**		
Provision for Electricity Sector (MOF)	Expense			(16.0)		

		0.0	0.0	0.0	0.0
	n/a	0.0	0.0	0.0	0.0
HOI Income	Revenue	0.0	5.3	5.3	5.3
Provision for Electricity Sector (OEFC)	Expense		(12.4)		
Provision for Electricity Sector (MOF)	Expense		12.4		
oded formula in the cell	n/a	0.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	(30.4)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		17.8		
Provision for Electricity Sector (MOF)	Expense		(17.8)		
Interest on Debt	Expense	(0.0)	1.0	(0.0)	1.0
Interest on Debt	Expense	0.0	15.0	15.0	5.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	0.0	(7.8)	(8.7)	(10.3)
HOI Income	Revenue	0.0	(47.4)	(54.0)	(54.0)
Provision for Electricity Sector (OEFC)	Expense	0.0	(47.4)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	47.4	0.0	0.0
OPG Income	Revenue	0.0	(61.0)	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	0.0	(21.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	(61.0)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	61.0	0.0	0.0
OPG Income	Revenue	0.0	(21.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	(21.0)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	21.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	0.0	21.0	0.0	0.0
HOI Income	Revenue	0.0	(23.6)	(27.4)	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	(23.6)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	23.6	0.0	0.0
OPG Income	Revenue	0.0	15.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	15.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	(15.0)	0.0	0.0
OPG Income	Revenue	0.0	21.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	0.0	(18.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	21.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	(21.0)	0.0	0.0
HOI Income	Revenue	0.0	(23.8)	(28.9)	(10.1)
Provision for Electricity Sector (OEFC)	Expense	0.0	(23.8)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	23.8	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
HOI Income	Revenue		16.1	26.7	20.6
Provision for Electricity Sector (OEFC)	Expense		16.1		
Provision for Electricity Sector (MOF)	Expense		(16.1)		
n/a	n/a	0.0	0.0	0.0	0.0
OPG Income	Revenue		(4.9)	(11.9)	(17.1)
Provision for Electricity Sector (OEFC)	Expense		(4.9)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		4.9	0.0	0.0
OPG Income	Revenue		283.0		
Provision for Electricity Sector (OEFC)	Expense		283.0		
Provision for Electricity Sector (MOF)	Expense		(283.0)		
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue		95.0		
OPG Income	Revenue		0.0	(475.0)	(500.0)
HOI Income	Revenue		(112.6)	(142.1)	(170.6)
Provision for Electricity Sector (OEFC)	Expense		(112.6)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		112.6	0.0	0.0
HOI Income	Revenue		(3.3)	(3.0)	(0.1)

Provision for Electricity Sector (OEFC)	Expense		(3.3)		
Provision for Electricity Sector (MOF)	Expense		3.3		
HOI Income	Revenue		14.7	14.4	12.9
Provision for Electricity Sector (OEFC)	Expense		14.7	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		(14.7)	0.0	0.0
HOI Income	Revenue		(16.1)	(26.7)	(20.6)
Provision for Electricity Sector (OEFC)	Expense		(16.1)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		16.1	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)		0.0	7.8	8.7	10.3
n/a	n/a	0.0	0.0	0.0	0.0
Other (Finance)			0.0	(1.0)	(1.0)
OPG Income	Revenue		0.0	0.0	0.0
HOI Income	Revenue		0.1	0.5	0.6
Provision for Electricity Sector (OEFC)	Expense		0.1	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		(0.1)	0.0	0.0
OPG Income	Revenue		(477.1)	(145.2)	(153.1)
Provision for Electricity Sector (OEFC)	Expense		(305.7)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		305.7	0.0	0.0
OPG Income	Revenue		39.0	0.0	0.0
OPG - ONFA and other Fair Value Adjustments	Revenue		171.5	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
OPG Income	Revenue		119.3	36.3	38.3
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue		(119.3)	(36.3)	(38.3)
Provision for Electricity Sector (OEFC)	Expense		0.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		0.0	0.0	0.0
OPG Income	Revenue		(283.0)	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue		(95.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		0.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		0.0	0.0	0.0
HOI Income	Revenue		116.8	147.1	176.1
Provision for Electricity Sector (OEFC)	Expense		0.0	0.0	80.3
Provision for Electricity Sector (MOF)	Expense		0.0	0.0	(80.3)
OPG Income	Revenue		37.5	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue		12.5	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		0.0	14.4	23.1
Provision for Electricity Sector (MOF)	Expense		0.0	(14.4)	(23.1)
Power Supply Contract Recoveries	Revenue		(109.9)	(142.1)	(166.7)
Power Supply Contract Costs	Expense		109.9	142.1	166.7
OPG Income	Revenue		283.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue		95.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		141.1	141.9	0.0
Provision for Electricity Sector (MOF)	Expense		(141.1)	(141.9)	0.0
HOI Income	Revenue		(116.8)	(147.1)	(176.1)
Provision for Electricity Sector (OEFC)	Expense		(116.8)	(147.1)	(103.4)
Provision for Electricity Sector (MOF)	Expense		116.8	147.1	103.4
HOI Income	Revenue		(0.0)	(0.2)	(0.2)
Provision for Electricity Sector (OEFC)	Expense		(0.0)	(0.2)	0.0
Provision for Electricity Sector (MOF)	Expense		0.0	0.2	0.0

	0	*0*	*0*	*0*

Summary of Track Changes Above

Power Supply Contract Costs	(99.0)	0.0	0.0	0.0
Demand Management Support Costs	1.8	0.0	0.0	0.0
Provision for Electricity Sector OEFC)	(44.4)	180.9	0.0	0.0
Provision for Electricity Sector (MOF)	44.4	(180.9)	0.0	0.0
Other (Finance)	(1.0)	0.0	(1.0)	(1.0)
OPG Income	(5.0)	333.1	(486.9)	(517.1)
ONFA and other Fair Value Adjustments	35.0	0.0	0.0	0.0
HOI Income	(16.1)	(190.4)	(235.3)	(216.1)
Brampton Income	3.3	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	(39.7)	79.0	12.0	3.5
Electricity Debt Retirement Charge	(4.0)	0.0	0.0	0.0
Power Supply Contract Recoveries	99.0	0.0	0.0	0.0
Net Reduction of Power Purchase Contracts	0.1	(0.1)	(0.1)	(0.1)
Miscellaneous	14.0	0.0	0.0	0.0
Public Debt Interest - Electricity Sector	1.7	38.1	38.1	38.1
Interest on Debt	(4.7)	(53.1)	(64.1)	(69.1)
Impact on Surplus/Deficit	**(14.6)**	**206.7**	**(737.3)**	**(761.7)**
check	***0.0***	***216.5***	***144.9***	***152.7***

Check - Summary of Track Changes Above vs. Electricity Summary Change Worksheet

Power Supply Contract Costs	0.0	(110.2)	(142.2)	(167.0)
Demand Management Support Costs	(0.0)	0.0	0.0	0.0
Provision for Electricity Sector OEFC)	8.4	281.4	(9.0)	0.0
Provision for Electricity Sector (MOF)	(8.4)	(281.4)	9.0	0.0
Other (Finance)	0.0	0.0	0.0	0.0
OPG Income	0.0	281.3	108.9	114.8
ONFA and other Fair Value Adjustments	0.0	(171.5)	0.0	0.0
HOI Income	(0.0)	(0.1)	(0.3)	(0.4)
Brampton Income	0.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	(0.0)	106.8	36.3	38.3
Electricity Debt Retirement Charge	0.0	0.0	0.0	0.0
Power Supply Contract Recoveries	0.0	110.2	142.2	167.0
Net Reduction of Power Purchase Contracts	(0.0)	(0.0)	(0.0)	(0.0)
Miscellaneous	0.0	0.0	0.0	0.0
Public Debt Interest - Electricity Sector	23.4	0.1	0.1	0.1
Interest on Debt	(23.4)	(0.1)	(0.1)	(0.1)
Impact on Surplus/Deficit	**(0.0)**	**216.5**	**144.9**	**152.7**

2020-21
1,676
429
-1,247
0

2020-21	Further Explanation of Change and source of data
0.0	Regular quarterly ONFA Update
0.0	Benefit to OEFC under s.50.3: $411M gain, SIFB
0.0	Change to OEFC payment for interest costs of Debt for Equity Swap
38.1	Revised Provincial Debt Interest related to Hydro One Equity
(104.1)	From FTD, revised Debt Interest (net of revisions to Provincial and OPG debt interest)
0.0	Revised numbers from OEP with 2019-20 Risk
0.0	Updated numbers from OPG Q1 2017 FS
0.0	Updating H1 Net Income for actuals. Note does not update Brampton Income at this point. Will
-	No Change to numbers, just re-inputting data and saving sources
-	No Change to numbers, just re-inputting data and saving sources
-	No change to fiscal impact numbers. Deleting Budget 2016 and adding Budget 2017 fiscal imp
-	No Change to numbers, just re-inputting data and saving sources
0.0	Updated with CIT Numbers received from H1 as part of s.91.2 MB20 allocation from MOF
0.0	No Change to numbers, just re-inputting data and saving sources
0.0	Only included H1 Net Income - Common Shareholders before. Added preferred shareholder im
0.0	Updating OPG Income Tax Expense with info from OPG Monthly Presentation to Shareholder
1.8	Updating OPG GRC payable to OEFC and Proxy Property Tax from Answer back from OPG al
(210.6)	Based on H1 final offering and expected First Nations Sale by the end of 2017 (CY), with a wei
0.0	Based on EY analysis, and then applying fiscalization. Confirmation also received from OPCD.
0.0	Based on KPMG analysis, then fiscalization and other adjustments from OPCD.
-	**[NOT APPLIED, CALCULATIONS AND DATA LEFT ON THE FILE]** Used Brampton's Financ
0.0	Don't expect finalized 2016-17 data to become available in time for ESDI allocation. Will shift th
0.0	make decision on shifting when we know 2016-17 status.

-	No change to numbers. Just re-organizing spreadsheet. No backup data.
-	No change to numbers. Just re-organizing spreadsheet. No backup data.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided another scenario backup/source
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just updated the links to refer ot the delta between 2017 and On Deck
0.0	Adjustment to ESDI to include Hydro One Brampton
0.0	Finalizing 2016-17 DRC Based on Draft OEFC AR
0.0	Received actual PILs amounts from FTD with breakdown of source. Updated 2016-17 numbers
0.0	2016-17 - Non-ONFA Fair Value Adjustment
0.0	Round Hydro One ownership assumptions to 70.05% two decimal places to be consistent with
0.0	Revising Hydro One Amount for consistency with OPCD. Equity Adjustments
0.0	Updated Provision tab. Made two separate Provision amounts for ESDI in OEFC AR and Dedic
0.0	Updating Power Supply Recoveries to Public Accounts/OEFC AR actuals
0.0	Updating Miscellaneous to OEFC AR actuals
0.0	Updated 2016-17 Interest on Debt (IESO, OPG, Other (Net))
0.0	
0.0	2017-18 - Demand Management Support Costs (no change) - Linking correctly
0.0	2016-17 - Updating Operating Expense in OEFC and corresponding changes elsewhere and s
-	No change to numbers. Just re-organized spreadsheet
0.0	Revised H1 Brampton Net Income (for GBE Line only)
0.0	Revising for OPG's Q3 Finances
0.0	Revising OPG's Net Income for latest monthly report
211.1	Reverting ownership back to 70.05% from change 20170518-3. Will coordinate with other area
0.0	Updating Risks based on Hydro One Q2 Results Model
0.0	Updated two Risk components for the Avista Acquisition.
(0.0)	No significant changes, but used actual amortization liability schedule. Hence the rounding imp
0.0	Updating Debt Guarantee for actuals based on OEFC AR
0.0	Revising OPG's Net Income for latest monthly report

0.0	Linking interest revenue data for 2017-18 to 2020-21
0.0	OPG Revenue Risks from: OEB Staff Submission and OPG Updated Filings
5.3	Corrected Net income for 100% ownership in preferred shares and 70.05% in Commons Share
0.0	Updated the formula in the cell for 2017-18 Net Income Before Tax so that the numbers are no
0.0	Updated PILs to include OPCD public accounts adjustment
1.3	
5.0	
(12.2)	
(54.0)	
0.0	
0.0	
0.0	increase built into net income was $82m between NI and PILs
0.0	Remove $21m from PILs
0.0	expense impacts
0.0	expense impacts
0.0	need to also remove the $21m PILs built into OPG net incme
0.0	
0.0	
0.0	We removed $21m from PILs above, before having added it in (check is that lines 123 to 130 a
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
(13.0)	variances include: 2017-18 preferred vs common share fix, 2018-19 largely ROE change from
0.0	
0.0	
0.0	
0.0	
0.0	
21.6	
0.0	
(24.1)	
0.0	
0.0	**Distribution (October)**
(750.0)	
(185.3)	
0.0	
0.0	
(2.3)	

15.2	
0.0	
0.0	
(21.6)	
0.0	
0.0	
0.0	Updating OPG Rate application Revenue Risks based on revised calculations
12.2	
0.0	
(1.0)	Received Revised FTD Forecast
0.3	
0.7	
0.0	
0.0	
(180.7)	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	Removed based on Dec 2017 OEB decision
0.0	Removed based on Dec 2017 OEB decision
0.0	Removed based on Dec 2017 OEB decision
0.0	Removed based on Dec 2017 OEB decision
45.2	
(45.2)	
44.2	
(44.2)	
0.0	
0.0	
(44.2)	
44.2	
190.8	
311.7	
(311.7)	
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M
(170.7)	
170.7	
0.0	
0.0	
0.0	
0.0	
(190.8)	
(263.6)	
263.6	
(0.3)	
(0.5)	
0.5	

0

0.0
0.0
0.0
0.0
(1.0)
(774.1)
0.0
(233.7)
0.0
1.8
0.0
0.0
(0.0)
0.0
38.1
(97.8)
(1,067)
180.0

t

(170.4)
0.0
(47.6)
47.6
0.0
135.3
0.0
(0.4)
0.0
44.9
0.0
170.4
0.0
0.0
0.1
0.1
180.0

Data Validation:

Options
Revenue (F
OPG
Hydro One
Provision

ONFA
Other Data

update once revised numbers are received.

acts

ıpact as well.

bout the BP
ghted average ownership for 2017-18. Also adjusted future net income attributed to the province.

ial Statements to produce an estimate. May require additional calculations.
ıis to 2017-18.

(from 2016 and On Deck)

s to reflect this.

OPCD.

:ated Earnings in Public Accounts.

ources.

s to ensure broadening change and reduction in net income happens concurrently in forecasts.

acts/changes.

es

t hardcoded directly

dd up to -$82m gain that we wanted to remove.

9.09% to 8.78% not previously captured.

Risks)

Electricity Sector Outlook

$ Millions

	Actual 2015-16	Interim 2016-17	Plan 2017-18	2018-19	2019-20	2020-21
On Deck Outlook as of March 2017						
Income from Investment in Government Business Enterprises						
OPG Income[1]	291	304	97	732	625	1,066
OPG - ONFA and other Fair Value Adjustments[2]	172	8	-	-	-	-
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	-
HOI Income[3]	236	516	520	562	603	652
Brampton Income	20	15	-	-	-	-
Total OPG and HOI Income	**719**	**842**	**617**	**1,294**	**1,229**	**1,717**
Other Fees and Licences	**127**	**122**	**102**	**91**	**88**	**81**
Electricity Expenses of the Province						
Provision for Electricity Sector[4]	(3)	(342)	(125)		-	-
Public Debt Interest - Electricity Sector	(520)	(492)	(492)	(492)	(492)	(492)
Subtotal	(523)	(834)	(617)	(492)	(492)	(492)
Public Debt Interest - Impact of ONFA						
Amortization of Deferred Revenue re profit on sale of H1 notes						
Total Electricity Expenses of the Province	**(523)**	**(834)**	**(617)**	**(492)**	**(492)**	**(492)**
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	3,228	373	405	476	538	679
Other Revenue						
Electricity Debt Retirement Charge[5]	859	625	623	-	-	-
Power Supply Contract Recoveries	875	739	292	325	301	273
Net Reduction of Power Purchase Contracts	172	129	74	41	30	28
Other Fees and Licences	(127)	(122)	(102)	(91)	(88)	(81)
Miscellaneous	9	-	-	-	-	-
Expenses						
Interest on Debt	(596)	(532)	(422)	(374)	(342)	(250)
Power Supply Contract Costs	(875)	(739)	(292)	(325)	(301)	(273)
Electricity Consumer Price Protection Fund	-	-	-	-	-	-
Demand Management Support Costs[6]	(8)	(10)	(10)	-	-	-
Provision for Electricity Sector	3	342	125	-	-	-
Other (Finance)	(7)	(6)	(6)	(6)	(6)	(6)
Total OEFC Income	**3,533**	**800**	**687**	**46**	**132**	**370**
Impact on Surplus/(Deficit)	**3,856**	**930**	**789**	**939**	**957**	**1,676**

Notes: The Hydro One net income outlook above (2016-17 to 2020-21) reflects the Province's 70% ownership share after the initial IPO in 2015 and the secondary offering in April 2016. At the time of 2017 Budget, net estimated fiscal impacts from future Hydro One offerings are reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

Notes:

1.OPG's 2016-17 outlook reflected its reported earnings. 2017-18 to 2019-20 reflects OPG's preliminary 2017-2019 business plan (as fiscalized by OPG). 2020-21 estimates are based on OPG's calendar year-based business plan projections. OPG net income also reflects IFRS adjustments fiscal impact decisions that were made centrally.

2. Provincial consolidation adjustments for unrealized earnings on the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds, as of the end of December 2016.

3. Hydro One 2016-17 income reflects its reported net income, adjusted for Hydro One IPO impacts. 2017-18 to 2020-21 projections are based on CEFD projections using the latest public information. The Hydro One net income outlook above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering as of 2017 Budget were reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial ONFA consolidation adjustments, less the interest on the Province's OPG/Hydro One debt payable to OEFC. The provision is currently assumed to end once the DRC ends on a legislated fixed end date of April 1, 2018.

5. Reflects April 23, 2014 announcement that DRC will be eliminated for residential users, after December 31, 2015. The end date of DRC for remaining users is legislated to be on April 1, 2018. Estimates are subject to change based on actual consumption.

6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Electricity Sector Outlook

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
On Deck Outlook as of October 2017						
Income from Investment in Government Business Enterprises						
OPG Income[1]	291	299	149	137	(7)	156
OPG - ONFA and other Fair Value Adjustments[2]	172	43	171	-	-	-
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	-
HOI Income[3]	236	500	329	327	388	419
Brampton Income	20	18	-	-	-	-
Total OPG and HOI Income	**719**	**860**	**650**	**463**	**381**	**575**
Other Fees and Licences (Debt Guarantee fee)	**127**	**122**	**102**	**99**	**98**	**91**
Electricity Expenses of the Province						
Provision for Electricity Sector[4]	-	(290)	(24)	(9)	-	(48)
Public Debt Interest - Electricity Sector	(520)	(514)	(454)	(454)	(454)	(454)
Subtotal	(520)	(803)	(478)	(463)	(454)	(502)
Public Debt Interest - Impact of ONFA						
Amortization of Deferred Revenue re profit on sale of H1 notes						
Total Electricity Expenses of the Province	**(520)**	**(803)**	**(478)**	**(463)**	**(454)**	**(502)**
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	3,247	334	377	452	503	635
Other Revenue						
Electricity Debt Retirement Charge[5]	859	621	623	-	-	-
Power Supply Contract Recoveries	875	838	182	183	134	103
Net Reduction of Power Purchase Contracts	172	129	74	41	30	28
Other Fees and Licences	(127)	(122)	(102)	(99)	(98)	(91)
Miscellaneous	9	14	-	-	-	-
Expenses						
Interest on Debt	(596)	(513)	(475)	(438)	(411)	(348)
Power Supply Contract Costs	(875)	(838)	(182)	(183)	(134)	(103)
Electricity Consumer Price Protection Fund	-	-	-	-	-	-
Demand Management Support Costs[6]	(8)	(8)	(10)	-	-	-
Provision for Electricity Sector	-	290	24	9	-	48
Other (Finance)	(7)	(7)	(6)	(7)	(7)	(7)
Total OEFC Income	**3,549**	**737**	**506**	**(42)**	**17**	**265**
Impact on Surplus/(Deficit)	**3,876**	**915**	**779**	**57**	**42**	**429**
variance to OEFC check	*(156)*	*(454)*	*(550)*	*(0)*	*(0)*	*-*

Notes:

1.OPG's 2016-17 outlook reflected its reported earnings. 2017-18 reflects OPG's latest monthly update and now includes re-caztegorization from Sales and Rentals to OPG net income (and OPG PILs) of OPG head office properties sale. 2018 to 2019-20 reflects OPG's 2017-2019 business plan (as fiscalized by OPG). 2020-21 estimates are based on OPG's calendar year-based business plan projections. OPG net income also reflect projected IFRS adjustments as provided by OPCD at the time of the 2017 Budget and OEB Dec. 28 rate decision. Note rate decsion impact is alloacted to net income and PILs on a 75%/25% basis respectively.

2. Provincial consolidation adjustments for unrealized earnings on the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds, as of the end of September 2017.

3. Hydro One 2016-17 income reflects its projected net income adjusted for the Province's ownership share in Hydro One following the final offering in May 2017 and including the First Nations sale in December 2017. 2017-18 to 2020-21 projections are based on CEFD projections using the latest public information and now reflect the re-categorization from sales and Rentals to Hydro One net income of the full impact of Hydro One broadening.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial ONFA consolidation adjustments, minus the interest on debt payable to OEFC. The provision is now assumed to continue after 2017-18. There is currently a PRRT submission to continue ESDI payments to OEFC beyond 2017-18.

5. Reflects that DRC eliminated for residential users, after December 31, 2015. The end date of DRC for remaining users is legislated to be on April 1, 2018. Estimates are subject to change based on actual consumption.

6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Electricity Sector Change Since Budget	$ Millions					
($million)	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Changes from Budget 2017 as of October 2017						
Income from Investment in Government Business Enterprises						
OPG Income	(5)	52	(596)	(632)	(909)	2016-17 small decrease due to IFRS adjustment revision and OPG Net Income revision. 2017-18 increase is largely from re-categorization from Sales and Rentals to OPG net income (and OPG PILs) of the sale of OPG head office properties -- re-categorisation itself is fiscally-neutral, as Sales and Rentals will be lower than shown in Budget 2017, plus some in-year upside (about $90M), before the OEB rate decision for OPG. Recategorisation amount in net income (about $280 million) is largely offset by negative fiscal impact (about -$320M in net income, -$110M in PILs below) from OEB Dec. 28, 2017 rate decision for OPG, including effective date of new OPG rates of June 1, 2017 rather than Jan. 1, 2017 . Decrease in 2018-19 onward is due mainly to taking on projeceted IFRS adjustment impacts in those years as well as OEB Dec. 28, 2017 rate decision. The OEB Dec. 28, 2017 rate decision estimated impacts are allocated between OPG net income and PILs on a 75%/25% basis.
ONFA and other Fair Value Adjustments	35	171	-	-	-	Largely revision to ONFA fair value as of September 30, 2017
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	
HOI Income	(16)	(190)	(235)	(216)	(233)	2016-17 slight decrease from Budget 2017 Interim projection. 2017-18 onwards reflects i) re-categorization from Sales and Rentals to Hydro One net income of the impact of a lower Provincial share of Hydro One net income from Hydro One share sales ii) impact of OEB Sep. 2017 decision on Hydro One transmission rates and iii) interest expense on Avitsa debentures (in 2017-18 and 2018-19).
Brampton Income	3.3					
Total OPG and HOI Income	**17**	**33.0**	**(831)**	**(848)**	**(1,143)**	
Other Fees and Licences	**-**	**-**	**8**	**10**	**10**	
Electricity Expenses of the Province						
Provision for Electricity Sector	53	101	(9)	-	(48)	**[NOTE: A positive number on this line indicates a decrease in the provision, while a negative number means an increase in provision expense.] [CHECK]** Changes to the Provision (ESDI) expense in 2017-18 mainly reflect higher OPG net income due to recategorisation from Sales and Rentals (see above), offset by lower OPG net income due to OEB's Dec. 28, 2017 rate decision and lower Hydro One net income due to OEB's Sep. 2017 transmission rate decision. Note ESDI is also lowered as HYdro One net income now reflects the full impact of Hydro One share sales. Part of this impact was previously reflected in Sales and Rentals. The projected change in 2019-20 and 2020-21 is due to the continuation of ESDI beyond 2017-18 (approved in principle in the current PRRT). In the 2017 Budget outlook, ESDI was assumed to end after 2017-18. ESDI estimates for 2018-19 and 2018-19 are reduced due to negative balances in 2017-18 and 2018-19,
Public Debt Interest - Electricity Sector	(22)	38	38	38	38	2016-17 PDI at ($514m) was slightly larger than ($492m) projected at Interim. 2017-18 change reflects revised projections for Provincial debt interest related to HydroOne's April 2016 offering. Note the impact of the final offering will be refelected in PDI during 2018.
Total Electricity Expenses of the Province	**31**	**138**	**29**	**38**	**(10)**	

Electricity Sector Change Since Budget	$ Millions					
($million)	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs)	(40)	(28)	(24)	(35)	(43)	2016-17 decrease largely due to an OPCD Public Accounts PILs adjustment related to reconciling between OPCD and OEFC net opening assets. OPG PILs also slightly lower than projected.
Other Revenue						
Electricity Debt Retirement Charge	(4)	-	-	-	-	
Power Supply Contract Recoveries	99	(110)	(142)	(167)	(170)	Variance in 16-17 is largely due to retroactive payments that the OEFC made to certain non-utility generators (NUGs) with former Ontario Hydro power purchase agreement (PPA) contracts with OEFC. OEFC was required to make these payment following the dismissal by the Supreme Court of Canada of OEFC's application for leave to appeal a judgment of the Court of Appeal of Ontario on a 2015 court decision. Going-forward, variance is largely due to suspension or early termination of some NUG PPAs in response to the IESO's NUG curtailment initiative.
Net Reduction of Power Purchase Contracts	0.1	(0)	(0)	(0)	(0)	
Other Fees and Licences	-	-	(8)	(10)	(10)	
Revenue Pool Residual	-	-	-		-	
Miscellaneous	14	-	-	-	-	
Expenses						
Interest on Debt	19	(53)	(64)	(69)	(98)	2017-18 reflects revised debt interest outlook net of revisions to OEFC interest revenue from OPG and Province.
Power Supply Contract Costs	(99)	110	142	167	170	Same as Power supply contract recoveries above. Power supply contract costs are fully recovered by power supply contract recoveries.
Electricity Consumer Price Protection Fund	-	-	-	-	-	
Demand Management Support Costs	1.8	-	-	-	-	
Provision for Electricity Sector	(53)	(101)	9	-	48	see explanation above for "Provision for Electriocty Sector" (line 17)
Other (Finance)	(1.0)	-	(1)	(1)	(1)	
Total OEFC Income	**(63)**	**(181)**	**(88)**	**(115)**	**(105)**	
Impact on Surplus/(Deficit)	**(14.6)**	**(10)**	**(882)**	**(914)**	**(1,247)**	Note: A significant component of the changes above affecting this net is from a fiscally-neutral recategorisation of revenue impacts from the Asset Optimisation (AO) initiative previously shown in Sales and Rentals in Budget 2017 for commercial confidentiality. The pure changes to non-AO electricity sector changes is significantly fiscally negative -- approximately $xx M in 17-18 [and put in amounts by fiscal year]
Information: Breakdown of change between revenue and expense						
Total Revenue Impact	87	(105)	(997)	(1,049)	(1,356)	
Total Expenditure impact	101	(95)	(115)	(135)	(109)	

Electricity Sector Outlook (PSAB)

Negative Revenue Risks ($ Millions)	Plan			
($ millions)	2017-18	2018-19	2019-20	2020-21
Generic				
OPG Generation Risk: Nuclear Reliability (-1.6 TWh)[1]	(120)	(120)	(120)	(120)
1% decrease in Hydro One actual load[2]	(57)	(59)	(62)	(63)
Lower OPG's Equity weighting & Return on Equity (ROE)[3]	(12)	(20)	(26)	(45)
Lower Hydro One Return on Equity (ROE)[4]	(9)	(36)	(38)	(40)
Regulatory				
Hydro One Distribution rate application[5]	(50)	(50)	(50)	(50)
OPG Switch from accrual based to cash based accounting for pension and OPEB[6]	—	(600)		
Regulatory Risk - Timing of OPG Rate Decision[7]	—			
OEB Staff Recommendations wrt OPG rate application(May 2017)[8]	—			
Nuclear Liabilities Cash vs. Accrual[9]	—			
OEB decision on Hydro One tax recapture (if one-time write-down)[10]	(440)			
Accounting				
OPG IFRS Consolidation Risks[11]		—	—	—
Other Risks				
ONFA adjustment decrease[12]	(50)			
Avista Acquisition - Termination fee		(49)		

Note: These risks do not reflect the impacts on electricity sector revenue and expense of reclassification of the Asset Optimization

1. OPG's market and generation risks related to nuclear reliability similar to the scenarios OPG developed for its sales margins to capture major market risk factors (e.g., natural gas prices, coal prices, foreign exchange, nuclear reliability) in its 2012 business plan. Currently, only the nuclear reliability risk is captured at the current regulated rate for OPG's nuclear generation.

2. Estimated revenue impact if Hydro One load for Transmission and Distribution is 1% lower than projected for all years in CEFD Hydro One Forecast. Based on the assumption a 1% increase in load is directly proportional to a 1% change in revenue requirements.

3. Risk range for Hydro One transmission and distribution reflects potential risk of lower ROE by 0.5% vs assumed ROEs in business plan along with reduced deemed debt to equity weighting of 55%/45% from the current 51%/49%.

4. Risk range for Hydro One transmission and distribution reflects potential risk of lower ROE by 0.5% vs assumed ROEs in CEFD Hydro One Forecast based on the most recent rate applications and forecasted ROE rates.

5. OEB is expected to make a decision on Hydro One's Distibution rate application for 2018 during the first half of 2018.

6. Previous risk removed shifted from 2017-18 to 2018-19. OEB's September 2017 Report, established accrual accounting method as default rate setting method to recover Pension and Other Pension Benefits (OPEBs) costs and recommended continuance of variance account tracking the difference between cash vs. accrual basis reporting for Pension and OPEB. This finding mitigates this risk. However, OEB December 28, OPG rate decision instructs OPG to submit request to dispose of Pension and OPEB deferral and variance account balances during 2018 for its 2019 payment application. OEB's final decision will be made at that time. Note, the impact of a decision could fall in 2019-20 depending on timing of the OEB decision.

7. **Previous risk removed with timing impact now reflected in OPG outlook.**. OEB December 28, decision and order provides an effective date for new rates of June 1, 2017. OPG's business plan assumed OEB decision would be effective as of January 1, 2017. OPG estimated an impact of -$60M for each month for which OEB decsion is not retroactive. The resulting $300M estimated impact has been included in the OPG outlook.

8. **Previous risk removed .** Estimated impact of OEB December 28the decision and order with respect to OPG rates is now reflected on the OPG Outlook.

9. **Previous risk removed.** Risk is related to potential switch to cash-basis accounting for regulated recovery of nuclear payment anmounts. OEB December 28, 2017 Decision and Order has deferred this issue to next OPG rate application in 2021 for 2022 to 2027 period.

10. The OEB's Sep. 28, 2017 ruling on Hydro One's Transmission rate application included direction on sharing, with ratepayers, tax savings related to the Hydro One IPO. Hydro One filed a Motion to Review this decision with the OEB and has also filed a court appeal. Hydro One's 2017 Q3 financial report notes that if the Motion to Review and appeal are unsuccesful teh company would record a one-time write-down of $885 million reflecting the OEB decision. The risk above reflects this risk at teh Province's 49.9% average share allocation for 2017-18. Hydro One noted that timing for the Motion to Review and appeal is uncertain. It expects the OEB Review to start in Q1 but noted that it could run in to Q2.

11. **Previous risk removed.** OPCD provided IFRS impact estimates (largely related to OPG) at the time of Budget 2017. A portion of these were reflected in in OPG's and Hydro One's net income outlook at the time of the 2017. The current Electricity Outlook now reflects this additional IFRS risk. Table below outlines OPG IFRS Risks versus what is built into the 2017 Budget Fiscal Plan.

	2017-18	2018-19	2019-20	2020-21
OPG IFRS Risk	(400)	(475)	(700)	(750)
Risks Built into Fiscal Plan at 2017 Budget	(400)	0	(200)	0
Additional Risks now picked up in this Electricity Outlook	0	(475)	(500)	(750)

Electricity Sector Outlook (PSAB)

Positive Revenue Risks				
($ millions)	**Plan**			
	2017-18	**2018-19**	**2019-20**	**2020-21**
Generic				
OPG Generation Risk: Nuclear Reliability (+1.1 TWh)[1]	85	85	85	85
1% increase in Hydro One actual load[2]	57	59	61	63
Higher OPG Return on Equity (ROE)[3]	6	22	19	33
Higher Hydro One Return on Equity (ROE)[4]	19	69	50	50
Regulatory				
Accounting				
Other Risks				
ONFA adjustment increase[5]	50			

strategy or updates to AO strategy.

1. OPG's market and generation risks related to nuclear reliability similar to the scenarios OPG developed for its sales margins to capture major market risk factors (e.g., natural gas prices, coal prices, foreign exchange, nuclear reliability) in its 2012 business plan. Currently, only the nuclear reliability risk is captured at the current regulated rate for OPG's nuclear generation.

2. Estimated revenue impact if Hydro One load for Transmission and Distribution is 1% higher than projected for all years in CEFD Hydro One Forecast. Based on the assumption a 1% increase in load is directly proportional to a 1% change in revenue requirements.

3. Risk range for OPG reflects potential risk of higher ROE in 2018-2021 (for nuclear base) vs assumed ROE in OPG's 2016 business plan and corresponding rate application. Assumed ROE is 9.85%, respresenting recent in 2010.

4. Risk range for Hydro One transmission and distribution reflects potential risk of higher ROE vs assumed ROEs in the Hydro One CEFD Forecast for 2018-2021. Assumed ROE is 9.85%, representing recent high in 2010.

5. Reflects risk around the consolidation adjustment to OPG net income, whereby the realized portion of gains or losses of OPG's nuclear funds are added or subtracted from OPG net income. Currently $171M positive adjustment is included in the OPG outlook. The ONFA adjustment is expected to be finalized in February 2018.

ONTARIO ELECTRICITY FINANCIAL CORPORATION
On Deck Outlook as of March 2017

$ Millions

	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Revenue						
Revenue Pool Residual						
Debt Retirement Charge	859	625	623	-	-	-
Payments-in-lieu of tax:						
OPG	268	302	315	366	408	537
Legacy Hydro One (Including Brampton)	2,929	7	2	2	2	2
Hydro One CIT dedicated to OEFC	3	20	20	22	23	25
MEUs	27	44	68	86	105	114
Total PILs & CIT dedicated to OEFC[1]	3,228	373	405	476	538	679
Interest :						
OPG	173	179	168	153	135	135
H1						
IESO	2	3	3	3	3	3
Province	520	492	492	492	492	492
Other	28	10	5	5	5	5
Total Interest	723	684	668	653	635	635
Power Supply Contract Recoveries	875	739	292	325	301	273
Amortization of NUG liability	172	129	74	41	30	28
Electricity sector dedicated income	3	342	525	-	-	-
Gain to OEFC under s. 50.3	172	-	-	-	-	-
Miscellaneous	9	-	-	-	-	-
	6,041	2,893	2,587	1,495	1,504	1,615
Expense						
Debt interest	1,319	1,216	1,090	1,027	977	885
Interest on nuclear risk funding						
Demand Management Support Costs	8	10	10	-	-	-
Amortization of deferred debt costs	-	-	-			
Power Supply Contract Costs	875	739	292	325	301	273
Debt Guarantee fee	127	122	102	91	88	81
Operating	7	6	6	6	6	6
	2,336	2,093	1,500	1,449	1,372	1,245
Excess (Deficiency) of Revenue over Expense	**3,705**	**800**	**1,087**	**46**	**132**	**370**
Prior period adjustment	87					
Stranded Debt - Year End	**4,393**	**3,593**	**2,506**	**2,460**	**2,328**	**1,958**

Note: All the Hydro One ownership broadening impacts, other than the ownership change from the initial IPO in 2015 and the secondary offering in April 2016, were reflected in Sales and Rentals as of the 2017 Budget.

ONTARIO ELECTRICITY FINANCIAL CORPORATION
On Deck Outlook as of October 2017

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Revenue						
Revenue Pool Residual						
Debt Retirement Charge	859	621	623	0	0	0
Payments-in-lieu of tax:						
OPG	268	224	287	342	373	494
Legacy Hydro One (Including Brampton)	2,929	4	2	2	2	2
Hydro One CIT dedicated to OEFC	3	25	20	22	23	25
MEUs	27	112	68	86	105	114
Total PILs & CIT dedicated to OEFC[1]	3,228	364	377	452	503	635
Interest :						
OPG	173	167	169	179	175	148
H1						
IESO	2	2	3	3	3	3
Province	520	514	454	454	454	454
Other	28	20	20	20	10	10
Total Interest	723	703	646	656	642	615
Power Supply Contract Recoveries	875	838	182	183	134	103
Amortization of NUG liability	172	129	74	41	30	28
Electricity sector dedicated income	3	302	24	9	0	48
Gain to OEFC under s. 50.3[2]	172	411	550	0	0	0
Miscellaneous	9	14	0	0	0	0
	6,041	3,382	2,477	1,340	1,309	1,429
Expense						
Debt interest	1,319	1,216	1,121	1,094	1,053	963
Interest on nuclear risk funding						
Demand Management Support Costs	8	8	10	0	0	0
Amortization of deferred debt costs	0	0	0			
Power Supply Contract Costs	875	838	182	183	134	103
Debt Guarantee fee	127	122	102	99	98	91
Operating	7	7	6	7	7	7
	2,336	2,191	1,421	1,383	1,292	1,164
Excess (Deficiency) of Revenue over Expense	3,705	**1,191**	**1,056**	**(42)**	**17**	**265**
Prior period adjustment	87					
Stranded Debt - Year End	4,393	**3,202**	**2,146**	**2,189**	**2,172**	**1,906**

1

Payments-in-lieu of tax:	**2015-16 Public Accounts**
OPG	290
Legacy Hydro One (Including Brampton)	2,941
Hydro One CIT dedicated to OEFC	0
MEUs	15
	3,247

2 2017-18 value preliminary estimate, subject to change.

ONTARIO ELECTRICITY FINANCIAL CORPORATION

Changes from Budget 2017 as of October 2017 **$ Millions**

	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Revenue						
Debt Retirement Charge	(4)	-	-	-	-	
Payments-in-lieu of tax:						
OPG	(78)	(28)	(24)	(35)	(43)	2016-17 decrease largely due to reconciling between OPCD and OEFC net opening assets. OPG PILs also slightly lower than projected. 2017-18 and onward decrease is due to estimated impact of OEB Dec. 29=8, 2017 rate decision.
Legacy Hydro One (Including Brampton)	(3)	-	-	-	-	
Hydro One CIT dedicated to OEFC	5	-	-	-	-	Adjustment based on updated information in Hydro One rate application
MEUs	68	-	-	-	-	Large increase in 2016-17 from $80M payment during transfer of H01 Brampton to new consolidated MEU Alectra.
Total PILs	(9)	(28)	(24)	(35)	(43)	
Interest :						
OPG	(12)	1	26	40	13	Update to OPG interest outlook (wrt interest on OEFC loan).
H1	-	-	-	-	-	
IESO	(1)	-	-	-	-	
Province	22	(38)	(38)	(38)	(38)	2016-17 PDI at ($514m) was slightly larger than ($492m) projected at Interim. 2017-18 change reflects revised projections for Provincial debt interest related to Hydro equity.
Other	10	15	15	5	5	
Total Interest	19	(22)	3	7	(20)	
Power Supply Contract Recoveries	99	(110)	(142)	(167)	(170)	Variance is largely due to retroactive payments that the OEFC made to certain non-utility-generators (NUGs) with former Ontario Hydro power purchase agreement contracts with OEFC. OEFC was required to make these payment following the dismissal by the Supreme Court of Canada of OEFC's application for leave to appeal a judgment of the Court of Appeal of Ontario on a 2015 court decision.
Amortization of NUG liability	0	(0)	(0)	(0)	(0)	
Electricity sector dedicated income	(41)	(501)	9	-	48	The decrease in OEFC ESDI in 2017-18 reflects i) the IFRS adjustment of $400 million in 2017-18 that was not reflected in the OEFC ESDI projection at the time of the 2017 Budget (Note the IFRS adjustment was reflected in OPG net income for the 2017 Budget fiscal plan) and ii) the lower OPG and Hydro One net income due to OEB's 2017 rate decisions. ESDI is alo lowered as the full impact of Hydro One share dispositions is now refelected in lower Hydro One net income tothe Province. Part of this impact was previously reflected in Sales and Rentals. The projected change in 2019-20 and 2020-21 is due to the continuation of ESDI beyond 2017-18 (approved in principle in the current PRRT). In the 2017 Budget outlook, ESDI was assumed to end after 2017-18. ESDI estimates for 2018-19 and 2018-19 are reduced due to negative balances in 2017-18 and 2018-19,
Gain to OEFC under s. 50.3	411	550	-	-	-	
Miscellaneous	14	-	-	-	-	
	489	(111)	(155)	(195)	(186)	
Expense						
Debt interest	-	31	67	76	78	Revised outlook for OEFC debt interest outlook
Interest on nuclear risk funding	-	-	-	-	-	
Demand Management Support Costs	(2)	-	-	-	-	
Amortization of deferred debt costs	-	-	-	-	-	
Power Supply Contract Costs	99	(110)	(142)	(167)	(170)	Same as Power supply contract recoveries above. Power supply contract costs are fully recovered by power supply contract recoveries.
Debt Guarantee fee	-	-	8	10	10	
Operating	1	-	1	1	1	
	98	(79)	(66)	(80)	(81)	
Excess (Deficiency) of Revenue over Expense	**391**	**(31)**	**(88)**			
Stranded Debt - Year End	**3,202**	**2,146**	**2,189**	**2,172**	**1,906**	

Provision for Electricity Sector (Dedicated Electricity Earnings/Electricity Sector Dedicated Earnings)

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Income from Investment in Government Business Enterprises						
OPG Income	291	299	149	137	(7)	156
Hydro One Income[1]	232	501	329	327	388	419
Hydro One Brampton (if applied separately)		15				
Total Income	**523**	**815**	**478**	**463**	**381**	**575**
Public Debt Interest - Electricity Sector						
OPG			(300)	(300)	(300)	(300)
Hydro One[1]			(154)	(154)	(154)	(154)
Public Debt Interest - Electricity Sector (OEFC Interest revenue)	**(520)**	**(514)**	**(454)**	**(454)**	**(454)**	**(454)**
MOF Provision Expense (before adjustments)	**3**	**302**	**24**	**9**	**(73)**	**121**
Other Adjustments						
Prior-year Adjustment[2]		3				
Exclude Brampton[3]		(15)				
MOF Provision Expense (after other adjustments)	**0**	**290**	**24**	**9**	**(73)**	**121**
Cumulative Shortfall Adjustment						
Opening Balance	0	0	0	0	0	(73)
Deduction / (Addition)	0	0	0	0	(73)	73
Ending Balance	0	0	0	0	(73)	0
Dedicated Electricity Earnings (all adjustments) (Public Accounts)	**0**	**290**	**24**	**9**	**0**	**48**
Electricity Sector Dedicated Income (OEFC Annual Report)	**3**	**302**	**24**	**9**	**0**	**48**

Notes:

1. The Hydro One financials above now reflects the Provincial share allocation as of January 2018.

2. 2016-17 Adjustment was due to the discrepancy between the numbers in MOF expense in PA 2015-16 and OEFC Financials in 2015-16 due to timing issues. $3M adjustment rectifies this discrepancy

3. Brampton was excluded from the Ministry of Finance's ESDI allocation.

Ontario Power Generation

OPG Income - Budget 2017

$ Millions

	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
OPG Net Income After Tax (Adjusted)	291	304	97	732	625	1,066
OPG Net Income After Tax	*291*	*379*	*480*	*678*	*726*	*913*
Extraordinary Gains	-	-	-	-	-	-
GA - OPG Trust Interest Revenue			*17*	*54*	*99*	*153*
OPG IFRS consolidation risk picked up in Fiscal Plan		(75)	(400)		(200)	
ONFA and other Fair Value Adjustments	(75)	8				
ONFA Adjustments	-	8				
Other Fair Value Adjustments	(75)					

OPG PIL - Budget 2017

$ Millions

	Actual	Interim		Pl
	2015-16	2016-17	2017-18	2018-19
Net Income Before Tax	383	396	572	867
Net Income After Tax (Adjusted)	291	304	97	732
Income Taxes	92	92	92	135
GRC: Payable to OEFC	198	196	205	212
Proxy Property Tax	16	14	18	19
Ontario Capital Tax	0	0	0	0
Total	**306**	**302**	**315**	**366**

OPG Income - January 2018

$ Millions

	Actual	Actual	Current Outlook			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
OPG Net Income	291	377	857	678	726	913
Adjustment for OPG HQ gain on sale[1]			(283)			
Unpacking updated OPG Gain on sale (net income)			283.27			
OEB December 28, 2017 Rate Decision Impact[2]			(320)	(109)	(115)	(136)
Extraordinary Gains	0	0	0	0	0	0
GA Financing - OPG Trust Interest Revenue[3]			12	42	82	128
OPG IFRS consolidation risk reflected in Fiscal Plan[4]		(78.00)	(400)		(200)	
Update IFRS Risk			0	(475)	(500)	(750)
OPG Net Income (Adjusted before ONFA)	**291**	**299**	**149**	**137**	**(7)**	**156**
ONFA Adjustments	247	49	171			
Other Fair Value Adjustments	(75)	(6)				
ONFA and other Fair Value Adjustments	**172**	**43**	**171**			
OPG Net Income	**463**	**342**	**320**	**137**	**(7)**	**156**

OPG PIL - January 2018

$ Millions

	Actual	Actual		Current
	2015-16	2016-17	2017-18	2018-19
Income Before Tax	383	308	723	235
OPG Net Income (Adjusted before ONFA)	291	299	149	137
OPG Income Tax (PILs)	92	9	162	135
OEB December 28, 2017 Rate Decision Impact[2]			(107)	(36)
Tax adjustment for OPG HQ gain on sale[1]			(95)	
Unpack PILs related to HQ gain on sale			95	
GRC: Payable to OEFC	198	201	214	224
Proxy Property Tax to OEFC	16	14	18	19
Ontario Capital Tax	0	0	0	0
Total OPG PILs	**306**	**224**	**287**	**342**

1. OPG's May 2017 head office facilities sale impacts are re-categorized from Sales and Rentals to OPG net income and PILs in the current Electricity Outlook update.
2. OEB December 28, 2017 estimated rate decision impacts are split between net income and PILs and a 75%/25% basis.
3. This reflects interest earnings on GA financing costs which are consolidated back to Province
4. See Risks tab for IFRS impacts that were not reflected in Fiscal Plan, and table below.

	2017-18	2018-19	2019-20	2020-21
OPG IFRS Risk	(400)	(475)	(700)	(750)

Hydro One Ownership Calculation:		SOURCE:
Total number of shares outstanding[1]	595,000,000	1. Hydro One Ltd Annual Report 2015, pg 94 of PDF, pg 92 of the Report.
Additional Common Shares Issued since IPO	386,711	
IPO November 2015		
Initial Public Offering(2015)[2]	81,100,000	2. From news release: http://hydroone.mediaroom.com/2015-11-05-Hydro-One-Limited-Announces-Closing-of-IPO
Over allotment option (2015)[3]	8,150,000	3. From news release: http://hydroone.mediaroom.com/2015-11-12-Hydro-One-Limited-Announces-Closing-of-IPO-Over-Allotment-Option
Sales to PWU/SEP Trusts	5,646,340	
Total	94,896,340	
Province's remaining ownership, Nov 2015 (# Shares)	**500,103,660**	
Province's remaining ownership, Nov 2015 (%)	**84.05%**	
Secondary Offering April 2016		
Secondary Offering (2016)	72,434,800	4. Hydro One Ltd. Q2 Report, pg 1 http://www.hydroone.com/InvestorRelations/FinancialReporting/Documents/Hydro%20One%20Ltd%20Second%20Quarter%20
Over allotment option (2016)	10,865,200	
Total	83,300,000	
Province's remaining ownership, Apr 2016 (# Shares)	**416,803,660**	
Province's remaining ownership, Apr 2016 (%)	**70.05%**	
Final Offering May 2017		
Final Offering (2017)	120,000,000	Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by-the-Provin
Over allotment option (2017)	-	Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by-the-Provin
Total	120,000,000	
Province's remaining ownership, May 8, 2017 (# Shares)	296,803,660	Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by-the-Provin
Province's remaining ownership, May 8, 2017 (%)	**49.88%**	
First Nations Sale, closed on December 29, 2017	14,391,012	Source: http://www.S:\Users\CEF\Hydro 2018\OEFC\RbP\Outlook\01. January\Backup\20180103-0 - H1 First Nations Sales\
	2.4170865%	Source: https://news.ontario.ca/mei/en/2017/05/ontario-raises-28-billion-from-final-hydro-one-share-offering.html
Province's remaining onwership - post First Nations Sale (#Shares)	282,412,648	
Province's remaining onwership - post First Nations Sale (%)	**47.43%**	
Avista Impact (projected closing date 2nd half of 2018)		
Contingent Convertible Debenture	$1,540,000,000	
Conversion Price	$21	
Potential Dilution (# Shares)	71,962,617	
Revised Total number of shares outstanding	**666,962,617**	
Province's remaining onwership - post Avista Acquisition (#Shares)	282,412,648	
Province's remaining onwership - post Avista Aquisition (%)	**42.34%**	

Ownership Percentage in 2017-18 Fiscal Year	Number of Months	Percentage of Year
70.05%	1	8.3%
49.88%	8	66.7%
47.43%	3	25.0%
	12	
Average 2017-18 FY Ownership:	**51.0%**	

Ownership Percentage in 2018-19 Fiscal Year (assume Avista closing end of September 2018)	Number of Months	Percentage of Year
47.43%	6	50.0%
42.34%	6	50.0%
	12	
Average 2018-19 FY Ownership:	**44.9%**	

Ownership Percentage in 2019-20 Fiscal Year Onwards
42.34%

Accretive to earnings per share and cash flow for Hydro One in the first full year post closing
above is from Hydro One transaction overview. Check what this means for timing of additional shares and /or earnings.

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Hydro One Net Income and PILs

Hydro One Income - Budget 2017
($ millions)

	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Hydro One Net Income After Tax	685	737	742	802	862	931
Hydro One - Unrealized Gains Adjustment						

2016-17 to 2020-21 from CEFD Hydro One 2016 model.

Hydro One PIL - Budget 2017
($ millions)

	2015-16	2016-17	2017-18	2018-19
Net Income After Tax	685	737	742	802
Income Taxes PILs	132	160	181	205
Proxy Property Tax	2	2	2	2
Ontario Capital Tax	0	0	0	0
Total	**134**	**162**	**183**	**207**

Hydro One Income - December 2017
($ millions) **$ Millions**

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Hydro One Net Income After Tax			645	690	780	845
Debenture Costs Impacts (After Tax)			(34)	(39)		
Hydro One Net Income After Tax - Including Adjustments	670	680	612	651	780	845
Hydro One - Net Income Attributable to Preferred Shareholders	15	18				
Hydro One - Unrealized Gains Adjustment						

Hydro One (100% Ownership)
($ millions) **$ Millions**

	Actual 2015-16	Actual 2016-17	2017-18	Current 2018-19
Net Income After Tax - Common Shares	670	680	612	651
Net Income After Tax - Preferred Shares	15	18		
Income Taxes PILs	132	160	181	205
Proxy Property Tax	2	2	2	2
Ontario Capital Tax	0	0	0	0

Public Debt Interest and Section 50.3 payments

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Hydro One Public Debt Interest and Section 50.3 payments						
Government Annual Interest Costs - Hydro One	220	220	220	220	220	220
Reduction in Interest Costs due to Broadening[1]		(29)	(66)	(66)	(66)	(66)
Province Annual Interest Costs - Hydro One Debt	**220**	**191**	**154**	**154**	**154**	**154**
Province Annual Interest Cost - OPG Debt	300	300	300	300	300	300
Total Public Debt Interest	**520**	**514**	**454**	**454**	**454**	**454**

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Gain to OEFC under s. 50.3	172	411	550	0	0	0

1. The Hydro One reduction in interest costs above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering are currently reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

ID# (Track Cha	Fiscal Year	alue (Hardcode	Value (Linked)	Description	Source Details	Source (Link)
20170501-2	2016-17	411,152,733	411,152,733	s 50.3 Gain for	Calculation provided by SIFB	
20170501-3	2016-17	29	29	Reduction in Int	Internal Calculation	
20170501-3	2017-18	66	66	Reduction in Int	Internal Calculation	
20170501-3	n/a	220	220	Annual Interest	Internal Calculation	

ID# (Track Cha	Fiscal Year	alue (Hardcode	Value (Linked)	Description	Source Details	Source (Link)
n/a	n/a	5126		($M) Provinces	OEFC 1999-2000 FS, pg 24	
n/a	n/a	5.85%		Annual Interest	OEFC 1999-2000 FS, pg 26	
		299.871				

OPG's Annual Interest Costs: 300

20170713-1	2016-17	-513,768,361	Provincial interest cost for equity investment in OPG, H1 in 2016-17 Monthly Balances Sheet (from FTD) S:\Users\CEF\Hydro 2017\OEFC\RbP\Outlook\07. July\Backup\20170713-1\interest fr

om Province.pdf

PROVINCIAL CONSOLIDATION ADJUSTMENTS
Ontario Nuclear Funds Agreement

Adjustment for Change in OPG Reported Net Income

Adjustment for DSF Unrealized Earnings

Unrealized Earnings as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Bruce Variance Account Adjustment
OPG Net Income Adjustment

Adjustment for UFSF Unrealized Earnings

Unrealized Earnings as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Bruce Variance Account Adjustment
OPG Net Income Adjustment

Unrealized Earnings -- Fiscal YTD

Adjustment for Change in Due to Province

Adjustment for DSF Due to Province
Due to Province (cost basis) as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Change in Due to Province -- Fiscal YTD

Adjustment for UFSF Due to Province

Due to Province (cost basis) as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Change in Due to Province -- Fiscal YTD

Provincial Consolidation Adjustment

Other Data

	Actual 2016-17	2017-18
Debt Retirement Charge	621	0

	2016-17	2017-18
Power Supply Contract Recoveries	838	182

	2016-17	2017-18
Interest		
OPG	167	169
IESO	2	3
Other (Net)	20	20
Expense		
Debt interest	1216	1121

	Actual 2016-17	2017-18
MEU - PIL Income Tax	109.8	
MEU - PIL Property Tax	0.6	
MEU - GRC	1.2	
TOTAL MEU PILs	111.6	

	Actual 2016-17	2017-18
Miscellaneous/Other (OEFC FS)	14	
Demand Management Support Costs (IEI)	8	10
Operating [Expense]	7	6
Interest on nuclear risk funding	-	-
Amortization of deferred debt costs	-	-
Amortization of NUG liability	129	74
Debt Guarantee Fee	122	102

Expense (Electrictiy Summary Tab)		
Other (Finance)	-7	-6
Demand Management Support Costs (IEI)	-8	-10
Debt Guarantee Fee	(122)	(102)

Plan		
2018-19	2019-20	2020-21
0	0	0

Plan		
2018-19	2019-20	2020-21
183	134	103

Plan		
2018-19	2019-20	2020-21
179	175	148
3	3	3
20	10	10
1094	1053	963

Plan		
2018-19	2019-20	2020-21

Plan		
2018-19	2019-20	2020-21
7	7	7
-	-	-
-	-	-
41	30	28
99	98	91
-7	-7	-7
(99)	(98)	(91)

ID# (Track Changes	Fiscal Year	Value (Hardcoded)	Value (Linked)
20170510-2	2016-17	$ 739,216,115	
20170510-2	2017-18	$ 291,629,707	
20170510-2	2018-19	$ 324,906,017	
20170510-2	2019-20	$ 300,648,570	
20170510-2	2020-21	$ 273,240,858	
20170501-4	2016-17	179	179
20170501-4	2017-18	169	169
20170501-4	2018-19	179	179
20170501-4	2019-20	175	175
20170501-4	2020-21	148	148
20170501-5	2016-17	1216	1,216
20170501-5	2017-18	1121	1,121
20170501-5	2018-19	1094	1,094
20170501-5	2019-20	1053	1,053
20170501-5	2020-21	963	963
20170731-3	2016-17	621	
20170811-1	2016-17	109.8	
20170811-1	2016-17	0.6	
20170811-1	2016-17	1.2	
20170815-5	2016-17	$ 838,000,000	
20170815-6	2016-17	$ 14,000,000	
20170815-8	2016-17	8	
20170815-9	2017-18	10	
20170815-10	2016-17	7	
20171211-2	2017-18	6	6
20171211-2	2018-19	7	7
20171211-2	2019-20	7	7
20171211-2	2020-21	7	7
20170815-7	2016-17	167	
20170815-7	2016-17	2	
20170815-7	2016-17	20	
20170815-7			

ID# (Track Changes	Fiscal Year	Value (Hardcoded)	Value (Linked)
20170905-1	2016-17	129	129
20170905-1	2017-18	74	74

20170905-1	2018-19	41	41
20170905-1	2019-20	30	30
20170905-1	2020-21	28	28
20170905-2	2016-17	122	
20170906-1	2017-18	3	3
20170906-1	2018-19	3	3
20170906-1	2019-20	3	3
20170906-1	2020-21	3	3
20170906-1	2017-18	20	5
20170906-1	2018-19	20	5
20170906-1	2019-20	10	5
20170906-1	2020-21	10	5
20171211-0	2017-18	1121	1,121
20171211-0	2018-19	1094	1,094
20171211-0	2019-20	1053	1,053
20171211-0	2020-21	963	963
20171211-1	2017-18	102	102
20171211-1	2018-19	99	99
20171211-1	2019-20	98	98
20171211-1	2020-21	91	91
20171211-1			
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20171211-1			
20171211-1			
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20171211-1			

ID# (Track Changes	Fiscal Year	Value (Hardcoded)	Value (Linked)
20180104-2	2017-18	$ 181,776,685	
20180104-2	2018-19	$ 182,785,215	
20180104-2	2019-20	$ 133,962,519	
20180104-2	2020-21	$ 102,554,665	

Description	Source Details	Source (Link)
The table below contains an updated preliminary N	SPFB Estimates, Email	
• The tables below provides both last year's submission for NUG costs by CEFD and this year's estimates (both of which exclude HST) based on the most recent NUG model.	SPFB Estimates, BN SPFB Estimates, BN SPFB Estimates, BN SPFB Estimates, BN	
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
Updating DRC from OEFC AR (Drafts)	2017 OEFC DRAFT FS	S:\Users\CEF\Hydro 2017\OEFC'
MEU - PIL Income Tax	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
MEU - PIL Property Tax	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
MEU - GRC	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
Updating to actuals	2017 OEFC AR	2017 OEFC Annual Report - Eng
Updating to actuals	2017 OEFC AR	2017 OEFC Annual Report - Eng
Updating to Actuals	2017 OEFC AR	S:\Users\CEF\Hydro 2017\OEFC'
OEFC 2017-18 IEI/Demand Management Suppor	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Operating Expense - Updating to Actuals	2017 OEFC AR	S:\Users\CEF\Hydro 2017\OEFC'
Revised Operating Expense from FTD Forecast	FTD - October PRRT	
OPG Interest Revenue - Actuals 2016-17	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
IESO Interest Revenue - Actuals 2016-17		
Other (Net) Interest Revenue - Actuals 2016-17		

Description	Source Details	Source (Link)
		S:\Users\CEF\Hydro 2017\OEFC'
	Amortization Schedule.	S:\Users\CEF\Hydro 2017\OEFC'

Sourcing the NUG liability amortization schedule.	Tab: Summary Fiscal Impact	S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Gurantee Fee - Updating to Actuals	2017 OEFC AR (pg 13 (	\\ofina.on.ca\ofadfs\Users\CEF\H
IESO Interest Revenue Plan	OEFC Revenue Forecast for Board - April 2017	\\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H
Other Interest Revenue Plan		\\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H
OEFC Debt Interest Expense (no change, just re-linking)	FTD - October PRRT	S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Guarantee Fee	FTD - October PRRT	S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC'

Description	Source Details	Source (Link)
Updated FY 2017-18 estimates of NUG costs	SPFB Estimates, BN	Power Purchases and Sales Fore
Updated FY 2017-18 estimates of NUG costs	SPFB Estimates, BN	Power Purchases and Sales Fore
Updated FY 2017-18 estimates of NUG costs	SPFB Estimates, BN	Power Purchases and Sales Fore
Updated FY 2017-18 estimates of NUG costs	SPFB Estimates, BN	Power Purchases and Sales Fore

\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
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\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board

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\RbP\Outlook\08. August\Backup\20170811-1 - Updating PILs for 2016-17\OEFC 2016-17 Pils summary.pdf

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\RbP\Outlook\08. August\Backup\20170815-9 - 2017-18 Demand Management Support Costs (IEI)\OEFC rever
\RbP\Outlook\08. August\Backup\20170815-10 - 2016-17 Operating (Expense)\2017 OEFC Annual Report - Enc

\RbP\Outlook\08. August\Backup\20170815-7 - 2016-17 Updated Interest on Debt Revenue\RE Revised OEFC

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ydro 2017\OEFC\RbP\Outlook\09. September\Backup\20170906-1 - OEFC Revenue Forecast for Board
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\RbP\Outlook\12. December\Backup\20171211-1 - Interest Numbers from FTD\OEFC forecast PRRT planning_
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Colour Codes

Formulas are in black text

Hard coded numbers are in blue text

References elsewhere are in purple

Green bold text with or without highlights mean updates required

Policies to follow when making updates to the Outlook

*** To quickly jump to the source numbers for a link, press "**Ctrl + [**"

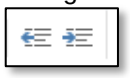
All new numbers must be fully sourced, and follow the colour codes above

Most numbers and text are Arial Size 10, unless it is a title

Add back up materials in a folder with the same numbers as in the 'Track Changes' tab

If there is a reason for italics, or other colours, or formatting make sure it is clear. Othe

Use indents to make things more clear to read



If numbers are taken from another tab they should ONLY be direct links, no calculation

Electricity Summary - (Budget17/On Deck) - Reflects Public Accounts/Financial Statem

OEFC - (Budget17/On Deck) - Reflects OEFC Annual Reports

*Due to slight discrepancies between Public Accounts reporting and OEFC Annual Rep

Outlook Updates Frequency

Frequency	Description	Tab
Monthly	OPG Net Income in-year forecast	OPG
Monthly	OPG PILs in-year forecast	OPG
Quarterly	ONFA Consolidation Adjustment	ONFA
Quarterly	OPG Cash vs Accrual Variance Account	Revenue (Risks)

ɔ.
rwise expect it to be cleared

ı, adjustment should be done. Even if its just making a negative to a positive. Perform all the calculations on the

ıents

ɔorts, the numbers may not be identical

source tab then bring the number into the next tab. (Eg. Formulas like this become hard to troubleshoot ='Hydro

One'!AR29+'Hydro One'!AR31+'Hydro One'!AR32), let's avoid them.

From:	Bruno Amara
To:	Ronald Kwan
Cc:	Usman Zahid
Subject:	RE: Electricity Update
Date:	Tuesday, January 09, 2018 5:18:41 PM
Attachments:	Electricity Sector Outlook (2018 01 08)_unpacked_v05.xlsm

Hi Ron

Please see attached with update footnotes and Pension risk revised per our discussion.

Bruno

From: Ronald Kwan
Sent: Tuesday, January 09, 2018 5:16 PM
To: Bruno Amara <Bruno.Amara@ofina.on.ca>
Cc: Usman Zahid <Usman.Zahid@ofina.on.ca>
Subject: RE: Electricity Update

Hi Bruno,

Please send me the revised version.

Thanks,
Ron

From: Bruno Amara
Sent: January-09-18 11:12
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Usman Zahid <Usman.Zahid@ofina.on.ca>
Subject: Electricity Update

Hi Ron

I realize we did not update various footnotes to reflect unpacking in the version I sent to you last night. We have now done this. I also revised the Risk table to shift the pension risk forward one-year, noting that while this risk may be mitigated by findings of the OEB report, OEB will make final decision with deferred decision. I haven't forwarded this for now to avoid any confusion with edits you may be making, but happy to do so.

Also we have coordinated with SIFB and FTD on the AO unpacking exercise to make sure we are all on same page before we share with Frost. We are just finalizing some summary tables on our unpacking exercise that we can send to you and/or walk you through.

I heard from CQSD late yesterday that wrap-up is on Monday. They would like to prepare ESDI update today for Helmut's review. I noted that we do have updates that we are finalizing and will

send as soon as we can. We can check back to see if tomorrow will be OK as necessary.

I also let OPCD know that we are working on an update that will re-categorize AO impacts and will send them that version as it will be more accurate for Budget consolidation. But I will also offer them our Interim unpacked version if they want to use that for now.

Bruno

Bruno Amara
Sr. Manager, Financial and Regulatory Analysis
Electricity Finance Branch
Corporate and Electricity Finance Division
Ontario Financing Authority

Tel: 416-325-1489
Email: bruno.amara@ofina.on.ca

Electricity Sector Outlook
October 2017

Disclosure:

All information contained in this workbook is confidential and commercially sensitive

All projected numbers are estimates and subjected to change

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Please consult with OFA before sharing of information.

Commercially Sensitive and Confidential Advice to Cabinet for Consideration of Options for Discussion Purposes Only

Commercially Sensitive and Confidential Advice to Cabinet for Consideration of Options for Discussion Purposes Only

Electricity Sector Outlook
Including Line Items for Consolidation

Electricity Summary - On Deck

			MOF Expense Items (consolidated)	Current Outlook			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**38**	Power Supply Contract Costs	(182)	(183)	(134)	(103)
Expense	**MOF (OEFC)**	**40**	Demand Management Support Costs	(10)	-	-	-
Expense	**MOF (OEFC)**	**41**	Provision for Electricity Sector	24	9	-	48
Expense	**MOF**	**17**	Provision for Electricity Sector	(24)	(9)	-	(48)
Expense	**MOF (OEFC)**	**42**	Other (Finance)	(6)	(7)	(7)	(7)
			Total MOF Expense	**(198)**	**(190)**	**(141)**	**(110)**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**7**	OPG Income	149	137	(7)	156
Revenue	**ENE**	**8**	OPG - ONFA and other Fair Value Adjustments	171	-	-	-
Revenue	**ENE**	**10**	HOI Income	329	327	388	419
Revenue		**11**	Brampton Income	-	-	-	-
Revenue	**MOF (OEFC)**	**26**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	377	452	503	635
Revenue	**MOF (OEFC)**	**29**	Electricity Debt Retirement Charge	623	-	-	-
Revenue	**MOF (OEFC)**	**30**	Power Supply Contract Recoveries	182	183	134	103
Revenue	**MOF (OEFC)**	**31**	Net Reduction of Power Purchase Contracts	74	41	30	28
Revenue	**MOF (OEFC)**	**34**	Miscellaneous	-	-	-	-
			Total MOF Revenue	**1,906**	**1,138**	**1,048**	**1,341**
			OFA IOD Expense				
			Public Debt Interest - Electricity Sector	(454)	(454)	(454)	(454)
			Interest on Debt	(475)	(438)	(411)	(348)
			Total OFA IOD Expense	**(929)**	**(892)**	**(865)**	**(802)**
			Impact on Surplus/Deficit	**779**	**57**	**42**	**429**
			check	*-*	*-*	*(0)*	*-*

Electricity Summary - Budget 17

For Discussion			MOF Expense Items (consolidated)	Plan			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**38**	Power Supply Contract Costs	(292)	(325)	(301)	(273)
Expense	**MOF (OEFC)**	**40**	Demand Management Support Costs	(10)	0	0	0
Expense	**MOF (OEFC)**	**41**	Provision for Electricity Sector	125	0	0	0
Expense	**MOF**	**17**	Provision for Electricity Sector	(125)	0	0	0
Expense	**MOF (OEFC)**	**42**	Other (Finance)	(6)	(6)	(6)	(6)
			Total MOF Expense	**(308)**	**(331)**	**(307)**	**(279)**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**7**	OPG Income	97	732	625	1,066
Revenue	**ENE**	**8**	OPG - ONFA and other Fair Value Adjustments	0	0	0	0
Revenue	**ENE**	**10**	HOI Income	520	562	603	652
			Brampton Income				
Revenue	**MOF (OEFC)**	**25**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	405	476	538	679
Revenue	**MOF (OEFC)**	**29**	Electricity Debt Retirement Charge	623	0	0	0
Revenue	**MOF (OEFC)**	**30**	Power Supply Contract Recoveries	292	325	301	273
Revenue	**MOF (OEFC)**	**31**	Net Reduction of Power Purchase Contracts	74	41	30	28
Revenue	**MOF (OEFC)**	**34**	Miscellaneous	0	0	0	0
			Total MOF Revenue	**2,011**	**2,136**	**2,098**	**2,697**
			OFA IOD Expense				
		17	Public Debt Interest - Electricity Sector	(492)	(492)	(492)	(492)
		36	Interest on Debt	(422)	(374)	(342)	(250)
			Total OFA IOD Expense	**(914)**	**(866)**	**(834)**	**(742)**
			Impact on Surplus/Deficit	**789**	**939**	**957**	**1,676**
			check	**-**	**-**	**-**	**-**

Electricity Summary - Change

			MOF Expense Items (consolidated)	Variance from Plan			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**69**	Power Supply Contract Costs	110	142	167	170
Expense	**MOF (OEFC)**	**71**	Demand Management Support Costs	0	0	0	0
Expense	**MOF (OEFC)**	**72**	Provision for Electricity Sector	(101)	9	0	48
Expense	**MOF**	**48**	Provision for Electricity Sector	101	(9)	0	(48)
Expense	**MOF (OEFC)**	**73**	Other (Finance)	0	(1)	(1)	(1)
			Total MOF Expense	**110**	**141**	**166**	**169**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**38**	OPG Income	52	(596)	(632)	(909)
Revenue	**ENE**	**39**	OPG - ONFA and other Fair Value Adjustments	171	0	0	0
Revenue	**ENE**	**41**	HOI Income	(190)	(235)	(216)	(233)
			Brampton Income	0	0	0	0
Revenue	**MOF (OEFC)**	**25**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	(28)	(24)	(35)	(43)
Revenue	**MOF (OEFC)**	**60**	Electricity Debt Retirement Charge	0	0	0	0
Revenue	**MOF (OEFC)**	**61**	Power Supply Contract Recoveries	(110)	(142)	(167)	(170)
Revenue	**MOF (OEFC)**	**62**	Net Reduction of Power Purchase Contracts	(0)	(0)	(0)	(0)
Revenue	**MOF (OEFC)**	**65**	Miscellaneous	0	0	0	0
			Total MOF Revenue	**(105)**	**(997)**	**(1,049)**	**(1,356)**
			OFA IOD Expense				
		17	Public Debt Interest - Electricity Sector	38	38	38	38
		36	Interest on Debt	(53)	(64)	(69)	(98)
			Total OFA IOD Expense	**(15)**	**(26)**	**(31)**	**(60)**
			Impact on Surplus/Deficit	**(10)**	**(882)**	**(914)**	**(1,247)**
			check	-	-	-	-

Track Changes in Surplus/Deficit

Date	Change ID#	Source	Tab
5/1/2017	20170501-1	Link	ONFA
5/1/2017	20170501-2	Link	Hydro One
5/1/2017	20170501-3	Link	Hydro One
5/1/2017	20170501-4	Link	Other Data
5/2/2017	20170502-1	Link	OPG
5/9/2017	20170509-1	Link	OPG
5/10/2017	20170510-1	Link	Hydro One
5/10/2017	20170510-2	Link	Other Data
5/12/2017	20170512-1	Link	Hydro One
5/15/2017	20170515-1	Link?	
5/15/2017	20170515-2	Link	OPG
5/17/2017	20170517-1	Link	Hydro One
5/17/2017	20170517-2	Link	ONFA
5/17/2017	20170517-3		
5/18/2017	20170518-1	Link	OPG
5/18/2017	20170518-2	Link	OPG
5/18/2017	20170518-3		
6/15/2017	20170615-1	Link	OPG
6/22/2017	20170622-1	Link	Hydro One
6/22/2017	20170622-2	Link	Hydro One
6/26/2017	20170626-1		
6/29/2017	20170629-1		

7/6/2017	20170706-1		
7/11/2017	20170711-1		
7/13/2017	20170713-1	Link	Provision
7/17/2017	20170717-1	Link	Revenue (Risks)
7/24/2017	20170724-1	Link	Revenue (Risks)
7/25/2017	20170725-1	Link	Revenue (Risks)
7/26/2017	20170726-1	Link	Revenue (Risks)
7/27/2017	20170727-1	Link	Revenue (Risks)
7/27/2017	20170727-2	Link	Revenue (Risks)
7/31/2017	20170731-1		
7/31/2017	20170731-2	Link	Hydro One
7/31/2017	20170731-3	Link	Other Data
8/11/2017	20170811-1	Link	OPG
8/15/2017	20170815-1		
8/15/2017	20170815-2		
8/15/2017	20170815-3		
8/15/2017	20170815-4		
8/15/2017	20170815-5		Other Data
8/15/2017	20170815-6		Other Data
8/15/2017	20170815-7		Other Data
8/15/2017	20170815-8		Other Data
8/15/2017	20170815-9		Other Data
8/15/2017	20170815-10		Other Data
8/17/2017	20170817-1	Link	Provision
8/17/2017	20170817-2	Link	Hydro One
8/18/2017	20170818-1	Link	Revenue (Risks)
8/22/2017	20170822-1	Link	OPG
8/25/2017	20170825-1		Hydro One
8/29/2017	20170829-1		Revenue (Risks)
8/31/2017	20170831-1		Revenue (Risks)
9/5/2017	20170905-1		Other Data
9/5/2017	20170905-2		Other Data
9/5/2017	20170905-3	Link	OPG

9/6/2017	20170906-1	Link	Other Data
9/6/2017	20170906-2	Link	Revenue (Risks)
9/8/2017	20170908-1	Link	Hydro One
9/8/2017	20170908-2	Link	OPG
9/11/2017			
9/12/2017			
9/13/2017			
9/21/2017			
9/22/2017			
10/2/2017			Hydro One
10/2/2017			
10/2/2017			
10/2/2017			
10/4/2017	20171004-1		OPG
10/4/2017	20171004-2		OPG
10/4/2017			
10/4/2017			
10/5/2017			
10/6/2017			
10/7/2017			
10/8/2017			
10/10/2017	20171010-1		Hydro One
10/10/2017			
10/10/2017			
10/11/2017	20171011-1		OPG
10/11/2017			
10/11/2017			
10/12/2017			OPG
10/12/2017			
10/12/2017			
10/12/2017			
10/18/2017	20171018-1		Hydro One
10/18/2017	20171018-1		Hydro One
10/18/2017	20171018-1		Hydro One
10/19/2017	20171019-1		Revenue (Risks)
10/19/2017	20171019-2		Revenue (Risks)
10/20/2017	20171020-1		Revenue (Risks)
10/20/2017	20171020-2		
10/20/2017	20171020-2		
10/20/2017	20171020-2		
10/20/2017	20171020-3		Revenue (Risks)
10/20/2017	20171020-4		OPG
10/20/2017	20171020-4		OPG
10/20/2017	20171020-4		OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017	20171114-1		Hydro One

11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017		Hydro One
11/14/2017		Hydro One
11/14/2017		Hydro One
11/30/2017	20171130-1	Revenue (Risks)
12/8/2017		Hydro One
12/11/2017	20171211-1	Other Data
12/11/2017	20171211-1	Other Data
12/22/2017	20171222-1	OPG
1/2/2018		Hydro One
1/2/2018		Hydro One
1/2/2018		Hydro One
1/2/2018	20180102-1	OPG
1/2/2018	20180102-1	OPG
1/2/2018	20180102-1	OPG
1/2/2018	20180102-2	OPG
1/2/2018	20180102-3	OPG
1/2/2018	20180102-3	Revenue (Risks)
1/2/2018	20180102-4	Revenue (Risks)
1/2/2018	20180102-5	Revenue (Risks)
1/2/2018	20180102-6	Revenue (Risks)
1/2/2018	20180102-7	Revenue (Risks)
1/2/2018	20180102-8	Revenue (Risks)
1/2/2018	20180102-9	OPG
1/2/2018	20180102-9	OPG
1/2/2018	20180102-9	OPG
1/2/2018	20180102-9	OPG
1/3/2018		OPG
1/3/2018		OPG
1/3/2018		OPG
1/3/2018		OPG
1/3/2018		Hydro One
1/3/2018		Hydro One
1/3/2018		Hydro One
1/4/2018	20180104-1	OPG
1/4/2018	20180104-1	OPG
1/4/2018	20180104-1	OPG
1/4/2018	20180104-1	OPG
1/4/2018	20180104-2	Other Data
1/4/2018	20180104-2	Other Data
1/5/2018		
1/5/2018		
1/5/2018		
1/5/2018		
1/5/2018		
1/5/2018		
1/5/2018		
1/8/2018		
1/8/2018		
1/8/2018		

FOR EFB USE ONLY

Budget 2017 Outlook
Current Outlook
Change Since Budget

Description of Update
ONFA Update as of March 31 2017
s. 50.3 Update for 2016-17
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Debt Interest
OPG IFRS Risk in 2019-20
Revised OPG 2016-17 Net Income
Revised OPG 2016-17 Net Income
Revised OPG 2016-17 Net Income
tech change: slight update to assumed Prov share 70.05% from 70%
tech change: slight update to assumed Prov share 70.05% from 70%
tech change: slight update to assumed Prov share 70.05% from 70%
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
Updating H1 2016-17 Net Income for ESDI
Updating H1 2016-17 Net Income for ESDI
Updating H1 2016-17 Net Income for ESDI
Power Purchase Supply
H1 Model Forecasts - No Fiscal Update Resaving Data
Update Budget 2017 Tabs to reflect fiscal plan
Update OPG forecasted PILS to reflect sources
Update H1 2016-17 CIT
Re-inputting ONFA updates
Updating H1 Net Income to include Pref Shares in 16-17
Updating OPG Income Tax Expense for 2016-17
Updating OPG non-income tax PILs
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2017
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2018
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2019
Updating with actual OPG IFRS Adjustment 2016-17
Updating with actual OPG IFRS Adjustment 2016-17
Updating with actual OPG IFRS Adjustment 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
[NOT APPLIED] Updating H1 Brampton (Interim Adjustments)
Shifted H1 Brampton 2016-17 NI to the 2017-18
Removed H1 Brampton for 2016-17 (pending finals)
Removed H1 Brampton for 2016-17 (pending finals)
Removed H1 Brampton for 2016-17 (pending finals)

add prior-year adjustment for 2016-17

add prior-year adjustment for 2016-18
Reconfigured calculation of ESDI and MOF ESDI Expense
Reconfigured calculation of OPG 2017-18 Net Income
Backup for the Provincial Interest cost
Linking source for Revenue Risks Tab
New source for Revenue Risks Tab
Revenue Risks Tab - ROE Risks
Updating OEB Risk for OPG
OEB Staff Report - H1 Tx - Revenue Risks
OPG Pensions - Cash vs Accrual Deferral Accounts
Updating Links in Electricity Summary Change and OEFC Change
Preliminary estimate for Hydro One Brampton
Preliminary estimate for Hydro One Brampton
Preliminary estimate for Hydro One Brampton

Updating DRC for Actuals 2016-17 (Based on draft FS)
Updating PILs for 2016-17 Baced on Actuals
OPG: Non-ONFA Fair Value Adjustment
Round all Hydro One ownership assumptions to two decimal places
H1 Equity Adjustment rounding.
Round all Hydro One ownership assumptions to two decimal places
Round all Hydro One ownership assumptions to two decimal places
Revising source of ESDI, Dedicated Electricity Earnings
2016-17 - Update Power Supply Recoveries to actuals
2016-17 - Update Power Supply Recoveries to actuals
2016-17 - Updating Miscellaneous OEFC Revenue to Actuals
Adj: Exclude Bramton $15m add prior year adjustment +$3M
Adj: Exclude Bramton $15m add prior year adjustment +$3M
Public Accts: Updated IESO debt interest Interest On Debt, 2016-17
Public Accts: 2016-17 - Demand Management Support Costs Update
2017-18 - Demand Management Support Costs (no change)
Public Accts: 2016-17 - Updating Operating Expense in OEFC
Sourcing Provision for Electricity Sector from Actual Public Accounts
Revised 2016-17 Brampton Amount for Public Accounts
OPG Pensions - Cash vs Accrual Deferral Accounts (Revenue Risks Tab)
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
Reclassification
Reclassification
Reverting H1 Ownership change (undoing 20170518-3)
Reverting H1 Ownership change (undoing 20170518-3)
Reverting H1 Ownership change (undoing 20170518-3)
Updating Risks based on Hydro One Q2 Results Model
Avista Acquisition Risks
NUG Amortization Liability (sourcing amortization schedule)
2016-17 Actuals - Debt Guarantee Fee
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results

Interest Revenue for IESO and "Other"
OPG Revenue Risks from OEB Filings
Net income corrected for Preferred Shares
Net income corrected for Preferred Shares
Net income corrected for Preferred Shares
Made link edits to OPG sheet so that the "Net Income Before Tax" 2017-18 number is not a hardc
Updated PILs to include OPCD public accounts adjustment
Provision tab fix to pick up Hydro One preferred share net income
Provision tab fix to pick up Hydro One preferred share net income
FTD Update to OEFC Outlook (Sep 19, 2017) OPG Interest
FTD Update to OEFC Outlook (Sep 19, 2017) Other Interest
Update to Hydro One PILs from information in Transmission rate application material
OEB September 28, 2017 Hydro One decision and order impact - incl. rebasing
OEB September 28, 2017 Hydro One decision and order impact - incl. rebasing
OEB September 28, 2017 Hydro One decision and order impact - incl. rebasing
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Debenture Interest Costs - Removing from Revenue (Risks) and adding it ot H1 Model
Debenture Interest Costs - Removing from Revenue (Risks) and adding it ot H1 Model
Debenture Interest Costs - Removing from Revenue (Risks) and adding it ot H1 Model
Updated OPG Net Income and PILs based on monthly report (August 2017 results)
Updated OPG Net Income and PILs based on monthly report (August 2017 results)
Updated OPG Net Income and PILs based on monthly report (August 2017 results)
Correction to PILs on OPG sheet
Correction to PILs on OPG sheet
Correction to PILs on OPG sheet
Correction to PILs on OPG sheet
Switch to Direct from Model
Switch to Direct from Model
Switch to Direct from Model
Updating ROE Risks
Updating H1 Load Risks based on model output
Updating ONFA Risks for September 2017
Adjust OEB decision/rebasing to ~50% provincial ownership
Adjust OEB decision/rebasing to ~50% provincial ownership
Adjust OEB decision/rebasing to ~50% provincial ownership
Updating OPG
OPG IOD impact from GA Financing, FHP
OPG IOD impact from GA Financing, FHP
OPG IOD impact from GA Financing, FHP
Unpacking updated OPG Gain on sale (net income)
Unpacking updated OPG Gain on sale (net income)
Unpacking updated OPG Gain on sale (net income)
Unpack PILs related to HQ gain on sale
Updating IFRS Risk
Adjustment for lower Provincial share (from 70.1% to 50.9 2017-18 & 47.4% after)
Adjustment for lower Provincial share (from 70.1% to 50.9 2017-18 & 47.4% after)
Adjustment for lower Provincial share (from 70.1% to 50.9 2017-18 & 47.4% after)
November 1 and November 7 Hydro One model updates

November 1 and November 7 Hydro One model updates
November 1 and November 7 Hydro One model updates
Revise Hydro Model to reverse OEB tax decision ongoing annual impact
Revise Hydro Model to reverse OEB tax decision ongoing annual impact
Revise Hydro Model to reverse OEB tax decision ongoing annual impact
Undo allocation adjustment in H1 tab (now that provincial shares are updated)
Undo allocation adjustment in H1 tab (now that provincial shares are updated)
Undo allocation adjustment in H1 tab (now that provincial shares are updated)
Updating OPG Revenue Risks from rate application
Update Hydro One PILs (reverses update on line 119 whuich did not account fro Dx side)
Updating Debt Guarantee Fee
Updating OEFC Operating Expense
small changes - linking the net income numbers

Updated number of shares sold for First Nations (Dec 2017) sale
Updated number of shares sold for First Nations (Dec 2017) sale
Updated number of shares sold for First Nations (Dec 2017) sale
Implemented OEB's Dec 2017 payment amounts decision for OPG (CEFD Analysis)
Implemented OEB's Dec 2017 payment amounts decision for OPG (CEFD Analysis)
Implemented OEB's Dec 2017 payment amounts decision for OPG (CEFD Analysis)
Updated OPG Net Income (based on their Q3 update, Sep 30, 2017)
Updated OPG ONFA adjustment (up to Sep 30, 2017) in OPG tab (removed it from Risks table)
Removal of OPG ONFA Sep 2017 adjustment in Risks table
Included possible range (-50M to 50M) of impact for future OPG ONFA adjustment in the negative
Removal of negative regulatory risk: "OPG Switch from accrual based to cash based accounting f
Removal of negative regulatory risk: "Timing of OPG Rate Decision" from Risks table
Removal of negative regulatory risk: "OEB Staff Recommendations wrt OPG rate application(May
Removal of negative regulatory risk: "Nuclear Liabilities Cash vs. Accrual" from Risks table
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month
Updated estimates of NUG costs.
Updated estimates of NUG costs.
Unpacking OPG (Head Office sale)
Unpacking OPG (Head Office sale)
Unpacking OPG (Head Office sale)
Unpacking OPG (Head Office sale)
Unpacking Hydro One for AO (from 70.1% ownership to as of January 2018)
Unpacking Hydro One for AO (from 70.1% ownership to as of January 2018)
Unpacking Hydro One for AO (from 70.1% ownership to as of January 2018)
Update H1 allocations for additional shares (SIFB edits)
Update H1 allocations for additional shares (SIFB edits)
Update H1 allocations for additional shares (SIFB edits)

This line show net impact of latest change. READ COMMENT

Expense
Expense
Expense
Expense
Expense
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue

Expense
Expense
Expense
Expense
Expense
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue

$ Millions

		2016-17	2017-18	2018-19	2019-20
		930	789	939	957
	File	915	779	57	42
		-15	-10	-882	-914
	check	*0*	*0*	*0*	*0*
		Impacts by FY →			
Outlook line affected	**Expense / Reve**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
ONFA and other Fair Value Adjustments	Revenue	41.0	0.0	0.0	0.0
N/A		0.0	0.0	0.0	0.0
?		0.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		38.1		
Provision for Electricity Sector (MOF)	Expense		(38.1)		
Public Debt Interest - Electricity Sector	Expense	0.0	38.1	38.1	38.1
Interest on Debt	Expense	0.0	(69.1)	(79.1)	(75.1)
OPG Income	Expense	0.0	0.0	0.0	
OPG Income	Revenue	(2.0)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**(2.0)**			
Provision for Electricity Sector (MOF)	Expense	2.0			
HOI Income	Revenue	0.4			
Provision for Electricity Sector (OEFC)	Expense	0.4			
Provision for Electricity Sector (MOF)	Expense	(0.4)			
Public Debt Interest - Electricity Sector	Expense	1.7			
Provision for Electricity Sector (OEFC)	Expense	(1.7)			
Provision for Electricity Sector (MOF)	Expense	1.7			
Interest on Debt	Expense	(1.7)			
HOI Income	Revenue	(39.8)	0.0	0.0	(0.0)
Provision for Electricity Sector (OEFC)	Expense	**(39.8)**			
Provision for Electricity Sector (MOF)	Expense	39.8			
	Revenue	-	-	-	-
	Revenue	-	-	-	-
	n/a	-	-	-	-
		-	-	-	-
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	4.7	0.0	0.0	0.0
	Revenue	0.0	0.0	0.0	0.0
HOI Income	Revenue	18.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	7.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	8.0	9.0	12.0	3.5
HOI Income	Revenue	0.0	(141.5)	(181.4)	(194.9)
Provision for Electricity Sector (OEFC)	Expense		(141.5)		
Provision for Electricity Sector (MOF)	Expense		141.5		
OPG Income	Revenue	(3.0)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**(3.0)**			
Provision for Electricity Sector (MOF)	Expense	3.0			
HOI Income	Revenue	7.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**7.0**			
Provision for Electricity Sector (MOF)	Expense	(7.0)			
	Revenue	-	-	-	-
	Revenue	0.0	0.0	0.0	0.0
Brampton Income	Revenue	(14.7)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**(14.7)**			
Provision for Electricity Sector (MOF)	Expense	14.7			

Provision for Electricity Sector (OEFC)	Expense		3.2			
Provision for Electricity Sector (MOF)	Expense		(3.2)			
	Revenue	-	-	-	-	
		-	-	-	-	
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
Brampton Income	Revenue		15.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		**15.0**			
Provision for Electricity Sector (MOF)	Expense		(15.0)			
Provision for Electricity Sector (OEFC)	Expense		3.2			
Provision for Electricity Sector (MOF)	Expense		(3.2)			
Electricity Debt Retirement Charge	Revenue		(4.0)	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue		(29.0)	0.0	0.0	0.0
OPG Income	Revenue		(6.0)	0.0	0.0	0.0
HOI Income	Revenue		(0.0)	(0.0)	0.0	0.0
HOI Income	Revenue		(1.7)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense			(0.0)		
Provision for Electricity Sector (MOF)	Expense			0.0		
	Revenue		0.0	0.0	0.0	0.0
Power Supply Contract Recoveries	Revenue		99.0	0.0	0.0	0.0
Power Supply Contract Costs	Expense		(99.0)			
Miscellaneous	Revenue		14.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		(12.0)			
Provision for Electricity Sector (MOF)	Expense		12.0			
Interest on Debt	Expense		(3.0)	0.0	0.0	0.0
Demand Management Support Costs	Expense		1.8	0.0	0.0	0.0
			0.0	0.0	0.0	0.0
Other (Finance)	Expense		(1.0)	0.0	0.0	0.0
	Revenue	-	-	-	-	
Brampton Income	Revenue		3.0	0.0	0.0	0.0
			0.0	0.0	0.0	0.0
OPG Income	Revenue		0.0	85.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue			(6.0)		
Provision for Electricity Sector (OEFC)	Expense			**85.0**		
Provision for Electricity Sector (MOF)	Expense			(85.0)		
OPG Income	Revenue		6.0			
ONFA and other Fair Value Adjustments	Revenue		(6.0)			
HOI Income	Revenue		0.0	141.9	181.8	195.4
Provision for Electricity Sector (OEFC)	Expense			141.9		
Provision for Electricity Sector (MOF)	Expense			(141.9)		
	n/a		0.0	0.0	0.0	0.0
			0.0	0.0	0.0	0.0
Net Reduction of Power Purchase Contracts	Revenue		0.1	(0.1)	(0.1)	(0.1)
	Revenue		0.0	0.0	0.0	0.0
OPG Income	Revenue		0.0	16.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue			(1.0)		
Provision for Electricity Sector (OEFC)	Expense			**16.0**		
Provision for Electricity Sector (MOF)	Expense			(16.0)		

		0.0	0.0	0.0	0.0
	n/a	0.0	0.0	0.0	0.0
HOI Income	Revenue	0.0	5.3	5.3	5.3
Provision for Electricity Sector (OEFC)	Expense		(12.4)		
Provision for Electricity Sector (MOF)	Expense		12.4		
oded formula in the cell	n/a	0.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	(30.4)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		17.8		
Provision for Electricity Sector (MOF)	Expense		(17.8)		
Interest on Debt	Expense	(0.0)	1.0	(0.0)	1.0
Interest on Debt	Expense	0.0	15.0	15.0	5.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	0.0	(7.8)	(8.7)	(10.3)
HOI Income	Revenue	0.0	(47.4)	(54.0)	(54.0)
Provision for Electricity Sector (OEFC)	Expense	0.0	(47.4)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	47.4	0.0	0.0
OPG Income	Revenue	0.0	(61.0)	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	0.0	(21.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	(61.0)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	61.0	0.0	0.0
OPG Income	Revenue	0.0	(21.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	(21.0)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	21.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	0.0	21.0	0.0	0.0
HOI Income	Revenue	0.0	(23.6)	(27.4)	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	(23.6)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	23.6	0.0	0.0
OPG Income	Revenue	0.0	15.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	15.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	(15.0)	0.0	0.0
OPG Income	Revenue	0.0	21.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	0.0	(18.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	21.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	(21.0)	0.0	0.0
HOI Income	Revenue	0.0	(23.8)	(28.9)	(10.1)
Provision for Electricity Sector (OEFC)	Expense	0.0	(23.8)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	23.8	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
HOI Income	Revenue		16.1	26.7	20.6
Provision for Electricity Sector (OEFC)	Expense		16.1		
Provision for Electricity Sector (MOF)	Expense		(16.1)		
n/a	n/a	0.0	0.0	0.0	0.0
OPG Income	Revenue		(4.9)	(11.9)	(17.1)
Provision for Electricity Sector (OEFC)	Expense		(4.9)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		4.9	0.0	0.0
OPG Income	Revenue		283.0		
Provision for Electricity Sector (OEFC)	Expense		283.0		
Provision for Electricity Sector (MOF)	Expense		(283.0)		
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue		95.0		
OPG Income	Revenue		0.0	(475.0)	(500.0)
HOI Income	Revenue		(112.6)	(142.1)	(170.6)
Provision for Electricity Sector (OEFC)	Expense		(112.6)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		112.6	0.0	0.0
HOI Income	Revenue		(3.3)	(3.0)	(0.1)

Provision for Electricity Sector (OEFC)	Expense		(3.3)		
Provision for Electricity Sector (MOF)	Expense		3.3		
HOI Income	Revenue		14.7	14.4	12.9
Provision for Electricity Sector (OEFC)	Expense		14.7	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		(14.7)	0.0	0.0
HOI Income	Revenue		(16.1)	(26.7)	(20.6)
Provision for Electricity Sector (OEFC)	Expense		(16.1)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		16.1	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)		0.0	7.8	8.7	10.3
n/a	n/a	0.0	0.0	0.0	0.0
Other (Finance)			0.0	(1.0)	(1.0)
OPG Income	Revenue		0.0	0.0	0.0
HOI Income	Revenue		0.1	0.5	0.6
Provision for Electricity Sector (OEFC)	Expense		0.1	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		(0.1)	0.0	0.0
OPG Income	Revenue		(477.1)	(145.2)	(153.1)
Provision for Electricity Sector (OEFC)	Expense		(305.7)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		305.7	0.0	0.0
OPG Income	Revenue		39.0	0.0	0.0
OPG - ONFA and other Fair Value Adjustments	Revenue		171.5	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
OPG Income	Revenue		119.3	36.3	38.3
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue		(119.3)	(36.3)	(38.3)
Provision for Electricity Sector (OEFC)	Expense		0.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		0.0	0.0	0.0
OPG Income	Revenue		(283.0)	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue		(95.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		0.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		0.0	0.0	0.0
HOI Income	Revenue		116.8	147.1	176.1
Provision for Electricity Sector (OEFC)	Expense		0.0	0.0	80.3
Provision for Electricity Sector (MOF)	Expense		0.0	0.0	(80.3)
OPG Income	Revenue		37.5	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue		12.5	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		0.0	14.4	23.1
Provision for Electricity Sector (MOF)	Expense		0.0	(14.4)	(23.1)
Power Supply Contract Recoveries	Revenue		(109.9)	(142.1)	(166.7)
Power Supply Contract Costs	Expense		109.9	142.1	166.7
OPG Income	Revenue		283.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue		95.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		141.1	141.9	0.0
Provision for Electricity Sector (MOF)	Expense		(141.1)	(141.9)	0.0
HOI Income	Revenue		(116.8)	(147.1)	(176.1)
Provision for Electricity Sector (OEFC)	Expense		(116.8)	(147.1)	(103.4)
Provision for Electricity Sector (MOF)	Expense		116.8	147.1	103.4
HOI Income	Revenue		(0.0)	(0.2)	(0.2)
Provision for Electricity Sector (OEFC)	Expense		(0.0)	(0.2)	0.0
Provision for Electricity Sector (MOF)	Expense		0.0	0.2	0.0

	0	*0*	*0*	*0*

Summary of Track Changes Above

Power Supply Contract Costs	(99.0)	0.0	0.0	0.0
Demand Management Support Costs	1.8	0.0	0.0	0.0
Provision for Electricity Sector OEFC)	(44.4)	180.9	0.0	0.0
Provision for Electricity Sector (MOF)	44.4	(180.9)	0.0	0.0
Other (Finance)	(1.0)	0.0	(1.0)	(1.0)
OPG Income	(5.0)	333.1	(486.9)	(517.1)
ONFA and other Fair Value Adjustments	35.0	0.0	0.0	0.0
HOI Income	(16.1)	(190.4)	(235.3)	(216.1)
Brampton Income	3.3	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	(39.7)	79.0	12.0	3.5
Electricity Debt Retirement Charge	(4.0)	0.0	0.0	0.0
Power Supply Contract Recoveries	99.0	0.0	0.0	0.0
Net Reduction of Power Purchase Contracts	0.1	(0.1)	(0.1)	(0.1)
Miscellaneous	14.0	0.0	0.0	0.0
Public Debt Interest - Electricity Sector	1.7	38.1	38.1	38.1
Interest on Debt	(4.7)	(53.1)	(64.1)	(69.1)
Impact on Surplus/Deficit	**(14.6)**	**206.7**	**(737.3)**	**(761.7)**
check	***0.0***	***216.5***	***144.9***	***152.7***

Check - Summary of Track Changes Above vs. Electricity Summary Change Worksheet

Power Supply Contract Costs	0.0	(110.2)	(142.2)	(167.0)
Demand Management Support Costs	(0.0)	0.0	0.0	0.0
Provision for Electricity Sector OEFC)	8.4	281.4	(9.0)	0.0
Provision for Electricity Sector (MOF)	(8.4)	(281.4)	9.0	0.0
Other (Finance)	0.0	0.0	0.0	0.0
OPG Income	0.0	281.3	108.9	114.8
ONFA and other Fair Value Adjustments	0.0	(171.5)	0.0	0.0
HOI Income	(0.0)	(0.1)	(0.3)	(0.4)
Brampton Income	0.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	(0.0)	106.8	36.3	38.3
Electricity Debt Retirement Charge	0.0	0.0	0.0	0.0
Power Supply Contract Recoveries	0.0	110.2	142.2	167.0
Net Reduction of Power Purchase Contracts	(0.0)	(0.0)	(0.0)	(0.0)
Miscellaneous	0.0	0.0	0.0	0.0
Public Debt Interest - Electricity Sector	23.4	0.1	0.1	0.1
Interest on Debt	(23.4)	(0.1)	(0.1)	(0.1)
Impact on Surplus/Deficit	**(0.0)**	**216.5**	**144.9**	**152.7**

2020-21
1,676
429
-1,247
0

2020-21	Further Explanation of Change and source of data
0.0	Regular quarterly ONFA Update
0.0	Benefit to OEFC under s.50.3: $411M gain, SIFB
0.0	Change to OEFC payment for interest costs of Debt for Equity Swap
38.1	Revised Provincial Debt Interest related to Hydro One Equity
(104.1)	From FTD, revised Debt Interest (net of revisions to Provincial and OPG debt interest)
0.0	Revised numbers from OEP with 2019-20 Risk
0.0	Updated numbers from OPG Q1 2017 FS
0.0	Updating H1 Net Income for actuals. Note does not update Brampton Income at this point. Will
-	No Change to numbers, just re-inputting data and saving sources
-	No Change to numbers, just re-inputting data and saving sources
-	No change to fiscal impact numbers. Deleting Budget 2016 and adding Budget 2017 fiscal imp
-	No Change to numbers, just re-inputting data and saving sources
0.0	Updated with CIT Numbers received from H1 as part of s.91.2 MB20 allocation from MOF
0.0	No Change to numbers, just re-inputting data and saving sources
0.0	Only included H1 Net Income - Common Shareholders before. Added preferred shareholder im
0.0	Updating OPG Income Tax Expense with info from OPG Monthly Presentation to Shareholder
1.8	Updating OPG GRC payable to OEFC and Proxy Property Tax from Answer back from OPG al
(210.6)	Based on H1 final offering and expected First Nations Sale by the end of 2017 (CY), with a wei
0.0	Based on EY analysis, and then applying fiscalization. Confirmation also received from OPCD.
0.0	Based on KPMG analysis, then fiscalization and other adjustments from OPCD.
-	**[NOT APPLIED, CALCULATIONS AND DATA LEFT ON THE FILE]** Used Brampton's Financ
0.0	Don't expect finalized 2016-17 data to become available in time for ESDI allocation. Will shift th
0.0	make decision on shifting when we know 2016-17 status.

-	No change to numbers. Just re-organizing spreadsheet. No backup data.
-	No change to numbers. Just re-organizing spreadsheet. No backup data.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided another scenario backup/source
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just updated the links to refer ot the delta between 2017 and On Deck
0.0	Adjustment to ESDI to include Hydro One Brampton
0.0	Finalizing 2016-17 DRC Based on Draft OEFC AR
0.0	Received actual PILs amounts from FTD with breakdown of source. Updated 2016-17 numbers
0.0	2016-17 - Non-ONFA Fair Value Adjustment
0.0	Round Hydro One ownership assumptions to 70.05% two decimal places to be consistent with
0.0	Revising Hydro One Amount for consistency with OPCD. Equity Adjustments
0.0	Updated Provision tab. Made two separate Provision amounts for ESDI in OEFC AR and Dedic
0.0	Updating Power Supply Recoveries to Public Accounts/OEFC AR actuals
0.0	Updating Miscellaneous to OEFC AR actuals
0.0	Updated 2016-17 Interest on Debt (IESO, OPG, Other (Net))
0.0	
0.0	2017-18 - Demand Management Support Costs (no change) - Linking correctly
0.0	2016-17 - Updating Operating Expense in OEFC and corresponding changes elsewhere and s
-	No change to numbers. Just re-organized spreadsheet
0.0	Revised H1 Brampton Net Income (for GBE Line only)
0.0	Revising for OPG's Q3 Finances
0.0	Revising OPG's Net Income for latest monthly report
211.1	Reverting ownership back to 70.05% from change 20170518-3. Will coordinate with other area
0.0	Updating Risks based on Hydro One Q2 Results Model
0.0	Updated two Risk components for the Avista Acquisition.
(0.0)	No significant changes, but used actual amortization liability schedule. Hence the rounding imp
0.0	Updating Debt Guarantee for actuals based on OEFC AR
0.0	Revising OPG's Net Income for latest monthly report

0.0	Linking interest revenue data for 2017-18 to 2020-21
0.0	OPG Revenue Risks from: OEB Staff Submission and OPG Updated Filings
5.3	Corrected Net income for 100% ownership in preferred shares and 70.05% in Commons Share
0.0	Updated the formula in the cell for 2017-18 Net Income Before Tax so that the numbers are no
0.0	Updated PILs to include OPCD public accounts adjustment
1.3	
5.0	
(12.2)	
(54.0)	
0.0	
0.0	
0.0	increase built into net income was $82m between NI and PILs
0.0	Remove $21m from PILs
0.0	expense impacts
0.0	expense impacts
0.0	need to also remove the $21m PILs built into OPG net incme
0.0	
0.0	
0.0	We removed $21m from PILs above, before having added it in (check is that lines 123 to 130 a
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
(13.0)	variances include: 2017-18 preferred vs common share fix, 2018-19 largely ROE change from
0.0	
0.0	
0.0	
0.0	
0.0	
21.6	
0.0	
(24.1)	
0.0	
0.0	**Distribution (October)**
(750.0)	
(185.3)	
0.0	
0.0	
(2.3)	

15.2	
0.0	
0.0	
(21.6)	
0.0	
0.0	
0.0	Updating OPG Rate application Revenue Risks based on revised calculations
12.2	
0.0	
(1.0)	Received Revised FTD Forecast
0.3	
0.7	
0.0	
0.0	
(180.7)	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	Removed based on Dec 2017 OEB decision
0.0	Removed based on Dec 2017 OEB decision
0.0	Removed based on Dec 2017 OEB decision
0.0	Removed based on Dec 2017 OEB decision
45.2	
(45.2)	
44.2	
(44.2)	
0.0	
0.0	
(44.2)	
44.2	
190.8	
311.7	
(311.7)	
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M
(170.7)	
170.7	
0.0	
0.0	
0.0	
0.0	
(190.8)	
(263.6)	
263.6	
(0.3)	
(0.5)	
0.5	

0

0.0
0.0
0.0
0.0
(1.0)
(774.1)
0.0
(233.7)
0.0
1.8
0.0
0.0
(0.0)
0.0
38.1
(97.8)
(1,067)
180.0

t

(170.4)
0.0
(47.6)
47.6
0.0
135.3
0.0
(0.4)
0.0
44.9
0.0
170.4
0.0
0.0
0.1
0.1
180.0

Data Validation:

Options
Revenue (F
OPG
Hydro One
Provision

ONFA
Other Data

update once revised numbers are received.

acts

ıpact as well.

bout the BP
ghted average ownership for 2017-18. Also adjusted future net income attributed to the province.

ial Statements to produce an estimate. May require additional calculations.
ıis to 2017-18.

(from 2016 and On Deck)

s to reflect this.

OPCD.

:ated Earnings in Public Accounts.

ources.

s to ensure broadening change and reduction in net income happens concurrently in forecasts.

acts/changes.

es

t hardcoded directly

dd up to -$82m gain that we wanted to remove.

9.09% to 8.78% not previously captured.

Risks)

Electricity Sector Outlook

$ Millions

	Actual 2015-16	Interim 2016-17	Plan 2017-18	2018-19	2019-20	2020-21
On Deck Outlook as of March 2017						
Income from Investment in Government Business Enterprises						
OPG Income[1]	291	304	97	732	625	1,066
OPG - ONFA and other Fair Value Adjustments[2]	172	8	-	-	-	-
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	-
HOI Income[3]	236	516	520	562	603	652
Brampton Income	20	15	-	-	-	-
Total OPG and HOI Income	**719**	**842**	**617**	**1,294**	**1,229**	**1,717**
Other Fees and Licences	**127**	**122**	**102**	**91**	**88**	**81**
Electricity Expenses of the Province						
Provision for Electricity Sector[4]	(3)	(342)	(125)		-	-
Public Debt Interest - Electricity Sector	(520)	(492)	(492)	(492)	(492)	(492)
Subtotal	(523)	(834)	(617)	(492)	(492)	(492)
Public Debt Interest - Impact of ONFA						
Amortization of Deferred Revenue re profit on sale of H1 notes						
Total Electricity Expenses of the Province	**(523)**	**(834)**	**(617)**	**(492)**	**(492)**	**(492)**
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	3,228	373	405	476	538	679
Other Revenue						
Electricity Debt Retirement Charge[5]	859	625	623	-	-	-
Power Supply Contract Recoveries	875	739	292	325	301	273
Net Reduction of Power Purchase Contracts	172	129	74	41	30	28
Other Fees and Licences	(127)	(122)	(102)	(91)	(88)	(81)
Miscellaneous	9	-	-	-	-	-
Expenses						
Interest on Debt	(596)	(532)	(422)	(374)	(342)	(250)
Power Supply Contract Costs	(875)	(739)	(292)	(325)	(301)	(273)
Electricity Consumer Price Protection Fund	-	-	-	-	-	-
Demand Management Support Costs[6]	(8)	(10)	(10)	-	-	-
Provision for Electricity Sector	3	342	125	-	-	-
Other (Finance)	(7)	(6)	(6)	(6)	(6)	(6)
Total OEFC Income	**3,533**	**800**	**687**	**46**	**132**	**370**
Impact on Surplus/(Deficit)	**3,856**	**930**	**789**	**939**	**957**	**1,676**

Notes: The Hydro One net income outlook above (2016-17 to 2020-21) reflects the Province's 70% ownership share after the initial IPO in 2015 and the secondary offering in April 2016. At the time of 2017 Budget, net estimated fiscal impacts from future Hydro One offerings are reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

Notes:

1.OPG's 2016-17 outlook reflected its reported earnings. 2017-18 to 2019-20 reflects OPG's preliminary 2017-2019 business plan (as fiscalized by OPG). 2020-21 estimates are based on OPG's calendar year-based business plan projections. OPG net income also reflects IFRS adjustments fiscal impact decisions that were made centrally.

2. Provincial consolidation adjustments for unrealized earnings on the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds, as of the end of December 2016.

3. Hydro One 2016-17 income reflects its reported net income, adjusted for Hydro One IPO impacts. 2017-18 to 2020-21 projections are based on CEFD projections using the latest public information. The Hydro One net income outlook above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering as of 2017 Budget were reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial ONFA consolidation adjustments, less the interest on the Province's OPG/Hydro One debt payable to OEFC. The provision is currently assumed to end once the DRC ends on a legislated fixed end date of April 1, 2018.

5. Reflects April 23, 2014 announcement that DRC will be eliminated for residential users, after December 31, 2015. The end date of DRC for remaining users is legislated to be on April 1, 2018. Estimates are subject to change based on actual consumption.

6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Electricity Sector Outlook

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
On Deck Outlook as of October 2017						
Income from Investment in Government Business Enterprises						
OPG Income[1]	291	299	149	137	(7)	156
OPG - ONFA and other Fair Value Adjustments[2]	172	43	171	-	-	-
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	-
HOI Income[3]	236	500	329	327	388	419
Brampton Income	20	18	-	-	-	-
Total OPG and HOI Income	**719**	**860**	**650**	**463**	**381**	**575**
Other Fees and Licences (Debt Guarantee fee)	**127**	**122**	**102**	**99**	**98**	**91**
Electricity Expenses of the Province						
Provision for Electricity Sector[4]	-	(290)	(24)	(9)	-	(48)
Public Debt Interest - Electricity Sector	(520)	(514)	(454)	(454)	(454)	(454)
Subtotal	(520)	(803)	(478)	(463)	(454)	(502)
Public Debt Interest - Impact of ONFA						
Amortization of Deferred Revenue re profit on sale of H1 notes						
Total Electricity Expenses of the Province	**(520)**	**(803)**	**(478)**	**(463)**	**(454)**	**(502)**
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	3,247	334	377	452	503	635
Other Revenue						
Electricity Debt Retirement Charge[5]	859	621	623	-	-	-
Power Supply Contract Recoveries	875	838	182	183	134	103
Net Reduction of Power Purchase Contracts	172	129	74	41	30	28
Other Fees and Licences	(127)	(122)	(102)	(99)	(98)	(91)
Miscellaneous	9	14	-	-	-	-
Expenses						
Interest on Debt	(596)	(513)	(475)	(438)	(411)	(348)
Power Supply Contract Costs	(875)	(838)	(182)	(183)	(134)	(103)
Electricity Consumer Price Protection Fund	-	-	-	-	-	-
Demand Management Support Costs[6]	(8)	(8)	(10)	-	-	-
Provision for Electricity Sector	-	290	24	9	-	48
Other (Finance)	(7)	(7)	(6)	(7)	(7)	(7)
Total OEFC Income	**3,549**	**737**	**506**	**(42)**	**17**	**265**
Impact on Surplus/(Deficit)	**3,876**	**915**	**779**	**57**	**42**	**429**
variance to OEFC check	*(156)*	*(454)*	*(550)*	*(0)*	*(0)*	*-*

Notes:

1.OPG's 2016-17 outlook reflected its reported earnings. 2017-18 reflects OPG's latest monthly update and now includes re-caztegorization from Sales and Rentals to OPG net income (and OPG PILs) of OPG head office properties sale. 2018 to 2019-20 reflects OPG's 2017-2019 business plan (as fiscalized by OPG). 2020-21 estimates are based on OPG's calendar year-based business plan projections. OPG net income also reflect projected IFRS adjustments as provided by OPCD at the time of the 2017 Budget and OEB Dec. 28 rate decision. Note rate decsion impact is alloacted to net income and PILs on a 75%/25% basis respectively.

2. Provincial consolidation adjustments for unrealized earnings on the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds, as of the end of September 2017.

3. Hydro One 2016-17 income reflects its projected net income adjusted for the Province's ownership share in Hydro One following the final offering in May 2017 and including the First Nations sale in December 2017. 2017-18 to 2020-21 projections are based on CEFD projections using the latest public information and now reflect the re-categorization from sales and Rentals to Hydro One net income of the full impact of Hydro One broadening.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial ONFA consolidation adjustments, minus the interest on debt payable to OEFC. The provision is now assumed to continue after 2017-18. There is currently a PRRT submission to continue ESDI payments to OEFC beyond 2017-18.

5. Reflects that DRC eliminated for residential users, after December 31, 2015. The end date of DRC for remaining users is legislated to be on April 1, 2018. Estimates are subject to change based on actual consumption.

6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Electricity Sector Change Since Budget	$ Millions					
($million)	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Changes from Budget 2017 as of October 2017						
Income from Investment in Government Business Enterprises						
OPG Income	(5)	52	(596)	(632)	(909)	2016-17 small decrease due to IFRS adjustment revision and OPG Net Income revision. 2017-18 due largely to OEB Dec. 28, 2017 rate decision including effective date of June 1, 2017 rather than jan. 1, 2017 largely offset by re-categorization from Sales and Rentals to OPG net income (and OPG PILs) of the slae of OPG head office properties. Decrease in 2018-19 onward is due mainly to taking on projeceted IFRS adjustment impacts in those years as well as OEB Dec. 28, 2017 rate decision. The OEB Dec. 28, 2017 rate decision estimated impacts are allocated between OPG net income and PILs on a 75%/25% basis.
ONFA and other Fair Value Adjustments	35	171	-	-	-	Largely revision to ONFA fair value as of September 30, 2017
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	
HOI Income	(16)	(190)	(235)	(216)	(233)	2016-17 slight decrease from Budget 2017 Interim projection. 2017-18 onwards reflects i) re-categorization from Sales and Rentals to Hydro One net income of the fll impact of Hydro One share sales ii) impact of OEB Sep. 2017 decision on Hydro One transmission rates and iii) interest expense on Avitsa debentures (in 2017-18 and 2018-19).
Brampton Income	3.3					
Total OPG and HOI Income	**17**	**33.0**	**(831)**	**(848)**	**(1,143)**	
Other Fees and Licences	**-**	**-**	**8**	**10**	**10**	
Electricity Expenses of the Province						
Provision for Electricity Sector	53	101	(9)	-	(48)	Changes to the Proviision (ESDI) expense in 2017-18 mainly reflect lower OPG net income due to OEB's Dec. 28, 2017 rate decision and lower Hydro One net income due to OEB's Sep. 2017 transmission rate decision. Note ESDI is also lowered as HYdro One net income now reflects the full impact of Hydro One share sales. Part of this impact was previously reflected in Sales and Rentals. The projected change in 2019-20 and 2020-21 is due to the continuation of ESDI beyond 2017-18 (approved in principle in the current PRRT). In the 2017 Budget outlook, ESDI was assumed to end after 2017-18. ESDI estimates for 2018-19 and 2018-19 are reduced due to negative balances in 2017-18 and 2018-19,
Public Debt Interest - Electricity Sector	(22)	38	38	38	38	2016-17 PDI at ($514m) was slightly larger than ($492m) projected at Interim. 2017-18 change reflects revised projections for Provincial debt interest related to HydroOne's April 2016 offering. Note the impact of the final offering will be refelected in PDI during 2018.
Total Electricity Expenses of the Province	**31**	**138**	**29**	**38**	**(10)**	

Electricity Sector Change Since Budget	$ Millions					
($million)	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs)	(40)	(28)	(24)	(35)	(43)	2016-17 decrease largely due to an OPCD Public Accounts PILs adjustment related to reconciling between OPCD and OEFC net opening assets. OPG PILs also slightly lower than projected.
Other Revenue						
Electricity Debt Retirement Charge	(4)	-	-	-	-	
Power Supply Contract Recoveries	99	(110)	(142)	(167)	(170)	Variance is largely due to retroactive payments that the OEFC made to certain non-utility-generators (NUGs) with former Ontario Hydro power purchase agreement contracts with OEFC. OEFC was required to make these payment following the dismissal by the Supreme Court of Canada of OEFC's application for leave to appeal a judgment of the Court of Appeal of Ontario on a 2015 court decision.
Net Reduction of Power Purchase Contracts	0.1	(0)	(0)	(0)	(0)	
Other Fees and Licences	-	-	(8)	(10)	(10)	
Revenue Pool Residual	-	-	-		-	
Miscellaneous	14	-	-	-	-	
Expenses						
Interest on Debt	19	(53)	(64)	(69)	(98)	2017-18 reflects revised debt interest outlook net of revisions to OEFC interest revenue from OPG and Province.
Power Supply Contract Costs	(99)	110	142	167	170	Same as Power supply contract recoveries above. Power supply contract costs are fully recovered by power supply contract recoveries.
Electricity Consumer Price Protection Fund	-	-	-	-	-	
Demand Management Support Costs	1.8	-	-	-	-	
Provision for Electricity Sector	(53)	(101)	9	-	48	see explanation above for "Provision for Electriocty Sector" (line 17)
Other (Finance)	(1.0)	-	(1)	(1)	(1)	
Total OEFC Income	**(63)**	**(181)**	**(88)**	**(115)**	**(105)**	
Impact on Surplus/(Deficit)	**(14.6)**	**(10)**	**(882)**	**(914)**	**(1,247)**	
Information: Breakdown of change between revenue and expense						
Total Revenue Impact	87	(105)	(997)	(1,049)	(1,356)	
Total Expenditure impact	101	(95)	(115)	(135)	(109)	

Electricity Sector Outlook (PSAB)

Negative Revenue Risks ($ Millions)	Plan			
($ millions)	2017-18	2018-19	2019-20	2020-21
Generic				
OPG Generation Risk: Nuclear Reliability (-1.6 TWh)[1]	(120)	(120)	(120)	(120)
1% decrease in Hydro One actual load[2]	(57)	(59)	(62)	(63)
Lower OPG's Equity weighting & Return on Equity (ROE)[3]	(12)	(20)	(26)	(45)
Lower Hydro One Return on Equity (ROE)[4]	(9)	(36)	(38)	(40)
Regulatory				
Hydro One Distribution rate application[5]	(50)	(50)	(50)	(50)
OPG Switch from accrual based to cash based accounting for pension and OPEB[6]	—	(600)		
Regulatory Risk - Timing of OPG Rate Decision[7]	—			
OEB Staff Recommendations wrt OPG rate application(May 2017)[8]	—			
Nuclear Liabilities Cash vs. Accrual[9]	—			
OEB decision on Hydro One tax recapture (if one-time write-down)[10]	(440)			
Accounting				
OPG IFRS Consolidation Risks[11]		—	—	—
Other Risks				
ONFA adjustment decrease[12]	(50)			
Avista Acquisition - Termination fee		(49)		

Note: These risks do not reflect the impacts on electricity sector revenue and expense of reclassification of the Asset Optimization

1. OPG's market and generation risks related to nuclear reliability similar to the scenarios OPG developed for its sales margins to capture major market risk factors (e.g., natural gas prices, coal prices, foreign exchange, nuclear reliability) in its 2012 business plan. Currently, only the nuclear reliability risk is captured at the current regulated rate for OPG's nuclear generation.

2. Estimated revenue impact if Hydro One load for Transmission and Distribution is 1% lower than projected for all years in CEFD Hydro One Forecast. Based on the assumption a 1% increase in load is directly proportional to a 1% change in revenue requirements.

3. Risk range for Hydro One transmission and distribution reflects potential risk of lower ROE by 0.5% vs assumed ROEs in business plan along with reduced deemed debt to equity weighting of 55%/45% from the current 51%/49%.

4. Risk range for Hydro One transmission and distribution reflects potential risk of lower ROE by 0.5% vs assumed ROEs in CEFD Hydro One Forecast based on the most recent rate applications and forecasted ROE rates.

5. OEB is expected to make a decision on Hydro One's Distibution rate application for 2018 during the first half of 2018.

6. Previous risk removed shifted from 2017-18 to 2018-19. OEB's September 2017 Report, established accrual accounting method as default rate setting method to recover Pension and Other Pension Benefits (OPEBs) costs and recommended continuance of variance account tracking the difference between cash vs. accrual basis reporting for Pension and OPEB. This finding mitigates this risk. Howver, OEB December 28, OPG rate decision instructs OPG to submit request to dispose of Pension and OPEB deferral and variance account balances during 2018 for its 2019 payment application. OEB's final decision will be made at that time.

7. **Previous risk removed with timing impact now reflected in OPG outlook.**. OEB December 28, decision and order provides an effective date for new rates of June 1, 2017. OPG's business plan assumed OEB decision would be effective as of January 1, 2017. OPG estimated an impact of -$60M for each month for which OEB decsion is not retroactive. The resulting $300M estimated impact has been included in the OPG outlook.

8. **Previous risk removed .** Estimated impact of OEB December 28the decision and order with respect to OPG rates is now reflected on the OPG Outlook.

9. **Previous risk removed.** Risk is related to potential switch to cash-basis accounting for regulated recovery of nuclear payment anmounts. OEB December 28, 2017 Decision and Order has deferred this issue to next OPG rate application in 2021 for 2022 to 2027 period.

10. The OEB's Sep. 28, 2017 ruling on Hydro One's Transmission rate application included direction on sharing, with ratepayers, tax savings related to the Hydro One IPO. Hydro One filed a Motion to Review this decision with the OEB and has also filed a court appeal. Hydro One's 2017 Q3 financial report notes that if the Motion to Review and appeal are unsuccesful teh company would record a one-time write-down of $885 million reflecting the OEB decision. The risk above reflects this risk at teh Province's 49.9% average share allocation for 2017-18. Hydro One noted that timing for the Motion to Review and appeal is uncertain. It expects the OEB Review to start in Q1 but noted that it could run in to Q2.

11. **Previous risk removed.** OPCD provided IFRS impact estimates (largely related to OPG) at the time of Budget 2017. A portion of these were reflected in in OPG's and Hydro One's net income outlook at the time of the 2017. The current Electricity Outlook now reflects this additional IFRS risk. Table below outlines OPG IFRS Risks versus what is built into the 2017 Budget Fiscal Plan.

	2017-18	2018-19	2019-20	2020-21
OPG IFRS Risk	(400)	(475)	(700)	(750)
Risks Built into Fiscal Plan at 2017 Budget	(400)	0	(200)	0
Additional Risks now picked up in this Electricity Outlook	0	(475)	(500)	(750)

Electricity Sector Outlook (PSAB)

Positive Revenue Risks				
($ millions)	**Plan**			
	2017-18	**2018-19**	**2019-20**	**2020-21**
Generic				
OPG Generation Risk: Nuclear Reliability (+1.1 TWh)[1]	85	85	85	85
1% increase in Hydro One actual load[2]	57	59	61	63
Higher OPG Return on Equity (ROE)[3]	6	22	19	33
Higher Hydro One Return on Equity (ROE)[4]	19	69	50	50
Regulatory				
Accounting				
Other Risks				
ONFA adjustment increase[5]	50			

strategy or updates to AO strategy.

1. OPG's market and generation risks related to nuclear reliability similar to the scenarios OPG developed for its sales margins to capture major market risk factors (e.g., natural gas prices, coal prices, foreign exchange, nuclear reliability) in its 2012 business plan. Currently, only the nuclear reliability risk is captured at the current regulated rate for OPG's nuclear generation.

2. Estimated revenue impact if Hydro One load for Transmission and Distribution is 1% higher than projected for all years in CEFD Hydro One Forecast. Based on the assumption a 1% increase in load is directly proportional to a 1% change in revenue requirements.

3. Risk range for OPG reflects potential risk of higher ROE in 2018-2021 (for nuclear base) vs assumed ROE in OPG's 2016 business plan and corresponding rate application. Assumed ROE is 9.85%, respresenting recent in 2010.

4. Risk range for Hydro One transmission and distribution reflects potential risk of higher ROE vs assumed ROEs in the Hydro One CEFD Forecast for 2018-2021. Assumed ROE is 9.85%, representing recent high in 2010.

5. Reflects risk around the consolidation adjustment to OPG net income, whereby the realized portion of gains or losses of OPG's nuclear funds are added or subtracted from OPG net income. Currently $171M positive adjustment is included in the OPG outlook. The ONFA adjustment is expected to be finalized in February 2018.

ONTARIO ELECTRICITY FINANCIAL CORPORATION
On Deck Outlook as of March 2017

$ Millions

	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Revenue						
Revenue Pool Residual						
Debt Retirement Charge	859	625	623	-	-	-
Payments-in-lieu of tax:						
OPG	268	302	315	366	408	537
Legacy Hydro One (Including Brampton)	2,929	7	2	2	2	2
Hydro One CIT dedicated to OEFC	3	20	20	22	23	25
MEUs	27	44	68	86	105	114
Total PILs & CIT dedicated to OEFC[1]	3,228	373	405	476	538	679
Interest :						
OPG	173	179	168	153	135	135
H1						
IESO	2	3	3	3	3	3
Province	520	492	492	492	492	492
Other	28	10	5	5	5	5
Total Interest	723	684	668	653	635	635
Power Supply Contract Recoveries	875	739	292	325	301	273
Amortization of NUG liability	172	129	74	41	30	28
Electricity sector dedicated income	3	342	525	-	-	-
Gain to OEFC under s. 50.3	172	-	-	-	-	-
Miscellaneous	9	-	-	-	-	-
	6,041	2,893	2,587	1,495	1,504	1,615
Expense						
Debt interest	1,319	1,216	1,090	1,027	977	885
Interest on nuclear risk funding						
Demand Management Support Costs	8	10	10	-	-	-
Amortization of deferred debt costs	-	-	-			
Power Supply Contract Costs	875	739	292	325	301	273
Debt Guarantee fee	127	122	102	91	88	81
Operating	7	6	6	6	6	6
	2,336	2,093	1,500	1,449	1,372	1,245
Excess (Deficiency) of Revenue over Expense	**3,705**	**800**	**1,087**	**46**	**132**	**370**
Prior period adjustment	87					
Stranded Debt - Year End	**4,393**	**3,593**	**2,506**	**2,460**	**2,328**	**1,958**

Note: All the Hydro One ownership broadening impacts, other than the ownership change from the initial IPO in 2015 and the secondary offering in April 2016, were reflected in Sales and Rentals as of the 2017 Budget.

ONTARIO ELECTRICITY FINANCIAL CORPORATION
On Deck Outlook as of October 2017

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Revenue						
Revenue Pool Residual						
Debt Retirement Charge	859	621	623	0	0	0
Payments-in-lieu of tax:						
OPG	268	224	287	342	373	494
Legacy Hydro One (Including Brampton)	2,929	4	2	2	2	2
Hydro One CIT dedicated to OEFC	3	25	20	22	23	25
MEUs	27	112	68	86	105	114
Total PILs & CIT dedicated to OEFC[1]	3,228	364	377	452	503	635
Interest :						
OPG	173	167	169	179	175	148
H1						
IESO	2	2	3	3	3	3
Province	520	514	454	454	454	454
Other	28	20	20	20	10	10
Total Interest	723	703	646	656	642	615
Power Supply Contract Recoveries	875	838	182	183	134	103
Amortization of NUG liability	172	129	74	41	30	28
Electricity sector dedicated income	3	302	24	9	0	48
Gain to OEFC under s. 50.3[2]	172	411	550	0	0	0
Miscellaneous	9	14	0	0	0	0
	6,041	3,382	2,477	1,340	1,309	1,429
Expense						
Debt interest	1,319	1,216	1,121	1,094	1,053	963
Interest on nuclear risk funding						
Demand Management Support Costs	8	8	10	0	0	0
Amortization of deferred debt costs	0	0	0			
Power Supply Contract Costs	875	838	182	183	134	103
Debt Guarantee fee	127	122	102	99	98	91
Operating	7	7	6	7	7	7
	2,336	2,191	1,421	1,383	1,292	1,164
Excess (Deficiency) of Revenue over Expense	3,705	**1,191**	**1,056**	**(42)**	**17**	**265**
Prior period adjustment	87					
Stranded Debt - Year End	4,393	**3,202**	**2,146**	**2,189**	**2,172**	**1,906**

1

Payments-in-lieu of tax:	**2015-16 Public Accounts**
OPG	290
Legacy Hydro One (Including Brampton)	2,941
Hydro One CIT dedicated to OEFC	0
MEUs	15
	3,247

2 2017-18 value preliminary estimate, subject to change.

ONTARIO ELECTRICITY FINANCIAL CORPORATION

Changes from Budget 2017 as of October 2017 **$ Millions**

	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Revenue						
Debt Retirement Charge	(4)	-	-	-	-	
Payments-in-lieu of tax:						
OPG	(78)	(28)	(24)	(35)	(43)	2016-17 decrease largely due to reconciling between OPCD and OEFC net opening assets. OPG PILs also slightly lower than projected. 2017-18 and onward decrease is due to estimated impact of OEB Dec. 29=8, 2017 rate decision.
Legacy Hydro One (Including Brampton)	(3)	-	-	-	-	
Hydro One CIT dedicated to OEFC	5	-	-	-	-	Adjustment based on updated information in Hydro One rate application
MEUs	68	-	-	-	-	Large increase in 2016-17 from $80M payment during transfer of H01 Brampton to new consolidated MEU Alectra.
Total PILs	(9)	(28)	(24)	(35)	(43)	
Interest :						
OPG	(12)	1	26	40	13	Update to OPG interest outlook (wrt interest on OEFC loan).
H1	-	-	-	-	-	
IESO	(1)	-	-	-	-	
Province	22	(38)	(38)	(38)	(38)	2016-17 PDI at ($514m) was slightly larger than ($492m) projected at Interim. 2017-18 change reflects revised projections for Provincial debt interest related to Hydro equity.
Other	10	15	15	5	5	
Total Interest	19	(22)	3	7	(20)	
Power Supply Contract Recoveries	99	(110)	(142)	(167)	(170)	Variance is largely due to retroactive payments that the OEFC made to certain non-utility-generators (NUGs) with former Ontario Hydro power purchase agreement contracts with OEFC. OEFC was required to make these payment following the dismissal by the Supreme Court of Canada of OEFC's application for leave to appeal a judgment of the Court of Appeal of Ontario on a 2015 court decision.
Amortization of NUG liability	0	(0)	(0)	(0)	(0)	
Electricity sector dedicated income	(41)	(501)	9	-	48	The decrease in OEFC ESDI in 2017-18 reflects i) the IFRS adjustment of $400 million in 2017-18 that was not reflected in the OEFC ESDI projection at the time of the 2017 Budget (Note the IFRS adjustment was reflected in OPG net income for the 2017 Budget fiscal plan) and ii) the lower OPG and Hydro One net income due to OEB's 2017 rate decisions. ESDI is alo lowered as the full impact of Hydro One share dispositions is now refelected in lower Hydro One net income tothe Province. Part of this impact was previously reflected in Sales and Rentals. The projected change in 2019-20 and 2020-21 is due to the continuation of ESDI beyond 2017-18 (approved in principle in the current PRRT). In the 2017 Budget outlook, ESDI was assumed to end after 2017-18. ESDI estimates for 2018-19 and 2018-19 are reduced due to negative balances in 2017-18 and 2018-19,
Gain to OEFC under s. 50.3	411	550	-	-	-	
Miscellaneous	14	-	-	-	-	
	489	(111)	(155)	(195)	(186)	
Expense						
Debt interest	-	31	67	76	78	Revised outlook for OEFC debt interest outlook
Interest on nuclear risk funding	-	-	-	-	-	
Demand Management Support Costs	(2)	-	-	-	-	
Amortization of deferred debt costs	-	-	-	-	-	
Power Supply Contract Costs	99	(110)	(142)	(167)	(170)	Same as Power supply contract recoveries above. Power supply contract costs are fully recovered by power supply contract recoveries.
Debt Guarantee fee	-	-	8	10	10	
Operating	1	-	1	1	1	
	98	(79)	(66)	(80)	(81)	
Excess (Deficiency) of Revenue over Expense	**391**	**(31)**	**(88)**			
Stranded Debt - Year End	**3,202**	**2,146**	**2,189**	**2,172**	**1,906**	

Provision for Electricity Sector (Dedicated Electricity Earnings/Electricity Sector Dedicated Earnings)

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Income from Investment in Government Business Enterprises						
OPG Income	291	299	149	137	(7)	156
Hydro One Income[1]	232	501	329	327	388	419
Hydro One Brampton (if applied separately)		15				
Total Income	**523**	**815**	**478**	**463**	**381**	**575**
Public Debt Interest - Electricity Sector						
OPG			(300)	(300)	(300)	(300)
Hydro One[1]			(154)	(154)	(154)	(154)
Public Debt Interest - Electricity Sector (OEFC Interest revenue)	**(520)**	**(514)**	**(454)**	**(454)**	**(454)**	**(454)**
MOF Provision Expense (before adjustments)	**3**	**302**	**24**	**9**	**(73)**	**121**
Other Adjustments						
Prior-year Adjustment[2]		3				
Exclude Brampton[3]		(15)				
MOF Provision Expense (after other adjustments)	**0**	**290**	**24**	**9**	**(73)**	**121**
Cumulative Shortfall Adjustment						
Opening Balance	0	0	0	0	0	(73)
Deduction / (Addition)	0	0	0	0	(73)	73
Ending Balance	0	0	0	0	(73)	0
Dedicated Electricity Earnings (all adjustments) (Public Accounts)	**0**	**290**	**24**	**9**	**0**	**48**
Electricity Sector Dedicated Income (OEFC Annual Report)	**3**	**302**	**24**	**9**	**0**	**48**

Notes:

1. The Hydro One financials above currently reflects the Provincial share allocation as the May 2017 final offering.

2. 2016-17 Adjustment was due to the discrepancy between the numbers in MOF expense in PA 2015-16 and OEFC Financials in 2015-16 due to timing issues. $3M adjustment rectifies this discrepancy

3. Brampton was excluded from the Ministry of Finance's ESDI allocation.

Ontario Power Generation

OPG Income - Budget 2017

$ Millions

	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
OPG Net Income After Tax (Adjusted)	291	304	97	732	625	1,066
OPG Net Income After Tax	*291*	*379*	*480*	*678*	*726*	*913*
Extraordinary Gains	-	-	-	-	-	-
GA - OPG Trust Interest Revenue			*17*	*54*	*99*	*153*
OPG IFRS consolidation risk picked up in Fiscal Plan		(75)	(400)		(200)	
ONFA and other Fair Value Adjustments	(75)	8				
ONFA Adjustments	-	8				
Other Fair Value Adjustments	(75)					

OPG PIL - Budget 2017

$ Millions

	Actual	Interim		Pl
	2015-16	2016-17	2017-18	2018-19
Net Income Before Tax	383	396	572	867
Net Income After Tax (Adjusted)	291	304	97	732
Income Taxes	92	92	92	135
GRC: Payable to OEFC	198	196	205	212
Proxy Property Tax	16	14	18	19
Ontario Capital Tax	0	0	0	0
Total	**306**	**302**	**315**	**366**

OPG Income - January 2018

$ Millions

	Actual	Actual	Current Outlook			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
OPG Net Income	291	377	857	678	726	913
Adjustment for OPG HQ gain on sale[1]			(283)			
Unpacking updated OPG Gain on sale (net income)			283.27			
OEB December 28, 2017 Rate Decision Impact[2]			(320)	(109)	(115)	(136)
Extraordinary Gains	0	0	0	0	0	0
GA Financing - OPG Trust Interest Revenue[3]			12	42	82	128
OPG IFRS consolidation risk reflected in Fiscal Plan[4]		(78.00)	(400)		(200)	
Update IFRS Risk			0	(475)	(500)	(750)
OPG Net Income (Adjusted before ONFA)	**291**	**299**	**149**	**137**	**(7)**	**156**
ONFA Adjustments	247	49	171			
Other Fair Value Adjustments	(75)	(6)				
ONFA and other Fair Value Adjustments	**172**	**43**	**171**			
OPG Net Income	**463**	**342**	**320**	**137**	**(7)**	**156**

OPG PIL - January 2018

$ Millions

	Actual	Actual		Current
	2015-16	2016-17	2017-18	2018-19
Income Before Tax	383	308	723	235
OPG Net Income (Adjusted before ONFA)	291	299	149	137
OPG Income Tax (PILs)	92	9	162	135
OEB December 28, 2017 Rate Decision Impact[2]			(107)	(36)
Tax adjustment for OPG HQ gain on sale[1]			(95)	
Unpack PILs related to HQ gain on sale			95	
GRC: Payable to OEFC	198	201	214	224
Proxy Property Tax to OEFC	16	14	18	19
Ontario Capital Tax	0	0	0	0
Total OPG PILs	**306**	**224**	**287**	**342**

1. OPG's May 2017 head office facilities sale impacts are re-categorized from Sales and Rentals to OPG net income and PILs in the current Electricity Outlook update.
2. OEB December 28, 2017 estimated rate decision impacts are split between net income and PILs and a 75%/25% basis.
3. This reflects interest earnings on GA financing costs which are consolidated back to Province
4. See Risks tab for IFRS impacts that were not reflected in Fiscal Plan, and table below.

	2017-18	2018-19	2019-20	2020-21
OPG IFRS Risk	(400)	(475)	(700)	(750)

Hydro One Ownership Calculation:		SOURCE:
Total number of shares outstanding[1]	595,000,000	1. Hydro One Ltd Annual Report 2015, pg 94 of PDF, pg 92 of the Report.
Additional Common Shares Issued since IPO	386,711	
IPO November 2015		
Initial Public Offering(2015)[2]	81,100,000	2. From news release: http://hydroone.mediaroom.com/2015-11-05-Hydro-One-Limited-Announces-Closing-of-IPO
Over allotment option (2015)[3]	8,150,000	3. From news release: http://hydroone.mediaroom.com/2015-11-12-Hydro-One-Limited-Announces-Closing-of-IPO-Over-Allotment-Option
Sales to PWU/SEP Trusts	5,646,340	
Total	94,896,340	
Province's remaining ownership, Nov 2015 (# Shares)	**500,103,660**	
Province's remaining ownership, Nov 2015 (%)	**84.05%**	
Secondary Offering April 2016		
Secondary Offering (2016)	72,434,800	4. Hydro One Ltd. Q2 Report, pg 1 http://www.hydroone.com/InvestorRelations/FinancialReporting/Documents/Hydro%20One%20Ltd%20Second%20Quarter%20
Over allotment option (2016)	10,865,200	
Total	83,300,000	
Province's remaining ownership, Apr 2016 (# Shares)	**416,803,660**	
Province's remaining ownership, Apr 2016 (%)	**70.05%**	
Final Offering May 2017		
Final Offering (2017)	120,000,000	Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by-the-Provin
Over allotment option (2017)	-	Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by-the-Provin
Total	120,000,000	
Province's remaining ownership, May 8, 2017 (# Shares)	296,803,660	Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by-the-Provin
Province's remaining ownership, May 8, 2017 (%)	**49.88%**	
First Nations Sale, closed on December 29, 2017	14,391,012	Source: http://www.S:\Users\CEF\Hydro 2018\OEFC\RbP\Outlook\01. January\Backup\20180103-0 - H1 First Nations Sales\
	2.4170865%	Source: https://news.ontario.ca/mei/en/2017/05/ontario-raises-28-billion-from-final-hydro-one-share-offering.html
Province's remaining onwership - post First Nations Sale (#Shares)	282,412,648	
Province's remaining onwership - post First Nations Sale (%)	**47.43%**	
Avista Impact (projected closing date 2nd half of 2018)		
Contingent Convertible Debenture	$1,540,000,000	
Conversion Price	$21	
Potential Dilution (# Shares)	71,962,617	
Revised Total number of shares outstanding	**666,962,617**	
Province's remaining onwership - post Avista Acquisition (#Shares)	282,412,648	
Province's remaining onwership - post Avista Aquisition (%)	**42.34%**	

Ownership Percentage in 2017-18 Fiscal Year	Number of Months	Percentage of Year
70.05%	1	8.3%
49.88%	8	66.7%
47.43%	3	25.0%
	12	
Average 2017-18 FY Ownership:	**51.0%**	

Ownership Percentage in 2018-19 Fiscal Year (assume Avista closing end of September 2018)	Number of Months	Percentage of Year
47.43%	6	50.0%
42.34%	6	50.0%
	12	
Average 2018-19 FY Ownership:	**44.9%**	

Ownership Percentage in 2019-20 Fiscal Year Onwards
42.34%

Accretive to earnings per share and cash flow for Hydro One in the first full year post closing
above is from Hydro One transaction overview. Check what this means for timing of additional shares and /or earnings.

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Hydro One Net Income and PILs

Hydro One Income - Budget 2017
($ millions)

	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Hydro One Net Income After Tax	685	737	742	802	862	931
Hydro One - Unrealized Gains Adjustment						

2016-17 to 2020-21 from CEFD Hydro One 2016 model.

Hydro One PIL - Budget 2017
($ millions)

	2015-16	2016-17	2017-18	2018-19
Net Income After Tax	685	737	742	802
Income Taxes PILs	132	160	181	205
Proxy Property Tax	2	2	2	2
Ontario Capital Tax	0	0	0	0
Total	**134**	**162**	**183**	**207**

Hydro One Income - December 2017
($ millions) **$ Millions**

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Hydro One Net Income After Tax			645	690	780	845
Debenture Costs Impacts (After Tax)			(34)	(39)		
Hydro One Net Income After Tax - Including Adjustments	670	680	612	651	780	845
Hydro One - Net Income Attributable to Preferred Shareholders	15	18				
Hydro One - Unrealized Gains Adjustment						

Hydro One (100% Ownership)
($ millions) **$ Millions**

	Actual 2015-16	Actual 2016-17	2017-18	Current 2018-19
Net Income After Tax - Common Shares	670	680	612	651
Net Income After Tax - Preferred Shares	15	18		
Income Taxes PILs	132	160	181	205
Proxy Property Tax	2	2	2	2
Ontario Capital Tax	0	0	0	0

Public Debt Interest and Section 50.3 payments

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Hydro One Public Debt Interest and Section 50.3 payments						
Government Annual Interest Costs - Hydro One	220	220	220	220	220	220
Reduction in Interest Costs due to Broadening[1]		(29)	(66)	(66)	(66)	(66)
Province Annual Interest Costs - Hydro One Debt	**220**	**191**	**154**	**154**	**154**	**154**
Province Annual Interest Cost - OPG Debt	300	300	300	300	300	300
Total Public Debt Interest	**520**	**514**	**454**	**454**	**454**	**454**

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Gain to OEFC under s. 50.3	172	411	550	0	0	0

1. The Hydro One reduction in interest costs above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering are currently reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

ID# (Track Cha	Fiscal Year	alue (Hardcode	Value (Linked)	Description	Source Details	Source (Link)
20170501-2	2016-17	411,152,733	411,152,733	s 50.3 Gain for	Calculation provided by SIFB	
20170501-3	2016-17	29	29	Reduction in Int	Internal Calculation	
20170501-3	2017-18	66	66	Reduction in Int	Internal Calculation	
20170501-3	n/a	220	220	Annual Interest	Internal Calculation	

ID# (Track Cha	Fiscal Year	alue (Hardcode	Value (Linked)	Description	Source Details	Source (Link)
n/a	n/a	5126		($M) Provinces	OEFC 1999-2000 FS, pg 24	
n/a	n/a	5.85%		Annual Interest	OEFC 1999-2000 FS, pg 26	
		299.871				

OPG's Annual Interest Costs: 300

20170713-1	2016-17	-513,768,361	Provincial interest cost for equity investment in OPG, H1 in 2016-17 Monthly Balances Sheet (from FTD) S:\Users\CEF\Hydro 2017\OEFC\RbP\Outlook\07. July\Backup\20170713-1\interest fr

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PROVINCIAL CONSOLIDATION ADJUSTMENTS
Ontario Nuclear Funds Agreement

Adjustment for Change in OPG Reported Net Income

Adjustment for DSF Unrealized Earnings

Unrealized Earnings as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Bruce Variance Account Adjustment
OPG Net Income Adjustment

Adjustment for UFSF Unrealized Earnings

Unrealized Earnings as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Bruce Variance Account Adjustment
OPG Net Income Adjustment

Unrealized Earnings -- Fiscal YTD

Adjustment for Change in Due to Province

Adjustment for DSF Due to Province
Due to Province (cost basis) as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Change in Due to Province -- Fiscal YTD

Adjustment for UFSF Due to Province

Due to Province (cost basis) as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Change in Due to Province -- Fiscal YTD

Provincial Consolidation Adjustment

Other Data

	Actual 2016-17	2017-18
Debt Retirement Charge	621	0

	2016-17	2017-18
Power Supply Contract Recoveries	838	182

	2016-17	2017-18
Interest		
OPG	167	169
IESO	2	3
Other (Net)	20	20
Expense		
Debt interest	1216	1121

	Actual 2016-17	2017-18
MEU - PIL Income Tax	109.8	
MEU - PIL Property Tax	0.6	
MEU - GRC	1.2	
TOTAL MEU PILs	111.6	

	Actual 2016-17	2017-18
Miscellaneous/Other (OEFC FS)	14	
Demand Management Support Costs (IEI)	8	10
Operating [Expense]	7	6
Interest on nuclear risk funding	-	-
Amortization of deferred debt costs	-	-
Amortization of NUG liability	129	74
Debt Guarantee Fee	122	102

Expense (Electrictiy Summary Tab)		
Other (Finance)	-7	-6
Demand Management Support Costs (IEI)	-8	-10
Debt Guarantee Fee	(122)	(102)

Plan		
2018-19	2019-20	2020-21
0	0	0

Plan		
2018-19	2019-20	2020-21
183	134	103

Plan		
2018-19	2019-20	2020-21
179	175	148
3	3	3
20	10	10
1094	1053	963

Plan		
2018-19	2019-20	2020-21

Plan		
2018-19	2019-20	2020-21
7	7	7
-	-	-
-	-	-
41	30	28
99	98	91
-7	-7	-7
(99)	(98)	(91)

ID# (Track Changes	Fiscal Year	Value (Hardcoded)	Value (Linked)
20170510-2	2016-17	$ 739,216,115	
20170510-2	2017-18	$ 291,629,707	
20170510-2	2018-19	$ 324,906,017	
20170510-2	2019-20	$ 300,648,570	
20170510-2	2020-21	$ 273,240,858	
20170501-4	2016-17	179	179
20170501-4	2017-18	169	169
20170501-4	2018-19	179	179
20170501-4	2019-20	175	175
20170501-4	2020-21	148	148
20170501-5	2016-17	1216	1,216
20170501-5	2017-18	1121	1,121
20170501-5	2018-19	1094	1,094
20170501-5	2019-20	1053	1,053
20170501-5	2020-21	963	963
20170731-3	2016-17	621	
20170811-1	2016-17	109.8	
20170811-1	2016-17	0.6	
20170811-1	2016-17	1.2	
20170815-5	2016-17	$ 838,000,000	
20170815-6	2016-17	$ 14,000,000	
20170815-8	2016-17	8	
20170815-9	2017-18	10	
20170815-10	2016-17	7	
20171211-2	2017-18	6	6
20171211-2	2018-19	7	7
20171211-2	2019-20	7	7
20171211-2	2020-21	7	7
20170815-7	2016-17	167	
20170815-7	2016-17	2	
20170815-7	2016-17	20	
20170815-7			

ID# (Track Changes	Fiscal Year	Value (Hardcoded)	Value (Linked)
20170905-1	2016-17	129	129
20170905-1	2017-18	74	74

20170905-1	2018-19	41	41
20170905-1	2019-20	30	30
20170905-1	2020-21	28	28
20170905-2	2016-17	122	
20170906-1	2017-18	3	3
20170906-1	2018-19	3	3
20170906-1	2019-20	3	3
20170906-1	2020-21	3	3
20170906-1	2017-18	20	5
20170906-1	2018-19	20	5
20170906-1	2019-20	10	5
20170906-1	2020-21	10	5
20171211-0	2017-18	1121	1,121
20171211-0	2018-19	1094	1,094
20171211-0	2019-20	1053	1,053
20171211-0	2020-21	963	963
20171211-1	2017-18	102	102
20171211-1	2018-19	99	99
20171211-1	2019-20	98	98
20171211-1	2020-21	91	91
20171211-1			
20171211-1			
20171211-1			
20171211-1			
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20171211-1			
20171211-1			
20171211-1			
20171211-1			

ID# (Track Changes	Fiscal Year	Value (Hardcoded)	Value (Linked)
20180104-2	2017-18	$ 181,776,685	
20180104-2	2018-19	$ 182,785,215	
20180104-2	2019-20	$ 133,962,519	
20180104-2	2020-21	$ 102,554,665	

Description	Source Details	Source (Link)
The table below contains an updated preliminary N	SPFB Estimates, Email	
• The tables below provides both last year's submission for NUG costs by CEFD and this year's estimates (both of which exclude HST) based on the most recent NUG model.	SPFB Estimates, BN SPFB Estimates, BN SPFB Estimates, BN SPFB Estimates, BN	
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
Updating DRC from OEFC AR (Drafts)	2017 OEFC DRAFT FS	S:\Users\CEF\Hydro 2017\OEFC'
MEU - PIL Income Tax	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
MEU - PIL Property Tax	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
MEU - GRC	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
Updating to actuals	2017 OEFC AR	2017 OEFC Annual Report - Eng
Updating to actuals	2017 OEFC AR	2017 OEFC Annual Report - Eng
Updating to Actuals	2017 OEFC AR	S:\Users\CEF\Hydro 2017\OEFC'
OEFC 2017-18 IEI/Demand Management Suppor	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Operating Expense - Updating to Actuals	2017 OEFC AR	S:\Users\CEF\Hydro 2017\OEFC'
Revised Operating Expense from FTD Forecast	FTD - October PRRT	
OPG Interest Revenue - Actuals 2016-17	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
IESO Interest Revenue - Actuals 2016-17		
Other (Net) Interest Revenue - Actuals 2016-17		

Description	Source Details	Source (Link)
		S:\Users\CEF\Hydro 2017\OEFC'
	Amortization Schedule.	S:\Users\CEF\Hydro 2017\OEFC'

Sourcing the NUG liability amortization schedule.	Tab: Summary Fiscal Impact	S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Gurantee Fee - Updating to Actuals	2017 OEFC AR (pg 13 (	\\ofina.on.ca\ofadfs\Users\CEF\H
IESO Interest Revenue Plan	OEFC Revenue Forecast for Board - April 2017	\\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H
Other Interest Revenue Plan		\\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H
OEFC Debt Interest Expense (no change, just re-linking)	FTD - October PRRT	S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Guarantee Fee	FTD - October PRRT	S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC'

Description	Source Details	Source (Link)
Updated FY 2017-18 estimates of NUG costs	SPFB Estimates, BN	Power Purchases and Sales Fore
Updated FY 2017-18 estimates of NUG costs	SPFB Estimates, BN	Power Purchases and Sales Fore
Updated FY 2017-18 estimates of NUG costs	SPFB Estimates, BN	Power Purchases and Sales Fore
Updated FY 2017-18 estimates of NUG costs	SPFB Estimates, BN	Power Purchases and Sales Fore

\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board

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\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board

\RbP\Outlook\07. July\Backup\20170731-3 - DRC Update\2017 OEFC Annual Report - English - DRAFT.PDF

\RbP\Outlook\08. August\Backup\20170811-1 - Updating PILs for 2016-17\OEFC 2016-17 Pils summary.pdf
\RbP\Outlook\08. August\Backup\20170811-1 - Updating PILs for 2016-17\OEFC 2016-17 Pils summary.pdf
\RbP\Outlook\08. August\Backup\20170811-1 - Updating PILs for 2016-17\OEFC 2016-17 Pils summary.pdf

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\RbP\Outlook\08. August\Backup\20170815-8 - 2016-17 Demand Management Support Costs (IEI)\2017 OEFC
\RbP\Outlook\08. August\Backup\20170815-9 - 2017-18 Demand Management Support Costs (IEI)\OEFC rever
\RbP\Outlook\08. August\Backup\20170815-10 - 2016-17 Operating (Expense)\2017 OEFC Annual Report - Enc

\RbP\Outlook\08. August\Backup\20170815-7 - 2016-17 Updated Interest on Debt Revenue\RE Revised OEFC

\RbP\Outlook\09. September\Backup\20170905-1 - Amortization of NUG Liability\NUG liability_estimated draw c
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ydro 2017\OEFC\RbP\Outlook\09. September\Backup\20170905-2 - 2016-17 Debt Guarantee Fee\2017 OEFC
ydro 2017\OEFC\RbP\Outlook\09. September\Backup\20170906-1 - OEFC Revenue Forecast for Board
ydro 2017\OEFC\RbP\Outlook\09. September\Backup\20170906-1 - OEFC Revenue Forecast for Board
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\RbP\Outlook\12. December\Backup\20171211-1 - Interest Numbers from FTD\OEFC forecast PRRT planning_
\RbP\Outlook\12. December\Backup\20171211-1 - Interest Numbers from FTD\OEFC forecast PRRT planning_
\RbP\Outlook\12. December\Backup\20171211-1 - Interest Numbers from FTD\OEFC forecast PRRT planning_
\RbP\Outlook\12. December\Backup\20171211-1 - Interest Numbers from FTD\OEFC forecast PRRT planning_
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ecast_Dec 2020

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-April 2017.xlsx
-April 2017.xlsx
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-April 2017.xlsx

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lown_Mar15_if apply Jan1_Apr21.xls

Annual Report - English.pdf

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Oct5.xlsx

Colour Codes

Formulas are in black text

Hard coded numbers are in blue text

References elsewhere are in purple

Green bold text with or without highlights mean updates required

Policies to follow when making updates to the Outlook

*** To quickly jump to the source numbers for a link, press "**Ctrl + [**"

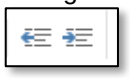
All new numbers must be fully sourced, and follow the colour codes above

Most numbers and text are Arial Size 10, unless it is a title

Add back up materials in a folder with the same numbers as in the 'Track Changes' tab

If there is a reason for italics, or other colours, or formatting make sure it is clear. Othe

Use indents to make things more clear to read



If numbers are taken from another tab they should ONLY be direct links, no calculation

Electricity Summary - (Budget17/On Deck) - Reflects Public Accounts/Financial Statem

OEFC - (Budget17/On Deck) - Reflects OEFC Annual Reports

*Due to slight discrepancies between Public Accounts reporting and OEFC Annual Rep

Outlook Updates Frequency

Frequency	Description	Tab
Monthly	OPG Net Income in-year forecast	OPG
Monthly	OPG PILs in-year forecast	OPG
Quarterly	ONFA Consolidation Adjustment	ONFA
Quarterly	OPG Cash vs Accrual Variance Account	Revenue (Risks)

ɔ.
rwise expect it to be cleared

ı, adjustment should be done. Even if its just making a negative to a positive. Perform all the calculations on the

ıents

ɔorts, the numbers may not be identical

source tab then bring the number into the next tab. (Eg. Formulas like this become hard to troubleshoot ='Hydro

One'!AR29+'Hydro One'!AR31+'Hydro One'!AR32), let's avoid them.

From:	Ronald Kwan
To:	Bruno Amara
Cc:	Usman Zahid; John Kim
Subject:	RE: Electricity Update
Date:	Wednesday, January 10, 2018 10:03:20 AM
Attachments:	Copy of Electricity Sector Outlook (2018 01 08)_unpacked_v05_with revsions2.xlsm

Thanks Bruno.

A few additional small suggestions.

Ron

From: Bruno Amara
Sent: January-10-18 09:39
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Usman Zahid <Usman.Zahid@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>
Subject: RE: Electricity Update

Ron, and Yes your note on provision signs is correct. I will remove the "CHECK"

From: Bruno Amara
Sent: Wednesday, January 10, 2018 9:37 AM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Usman Zahid <Usman.Zahid@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>
Subject: RE: Electricity Update

Hi Ron

Thanks. I put through all your edits. For the last edit (line 45) of the "Electricity Summary – Change", I added a footnote and table showing the fiscally-neutral AO changes vs. non-AO changes. Let me know if this works. Otherwise I can just list the changes in the text explanation per your edit.

Thanks
Bruno

From: Ronald Kwan
Sent: Tuesday, January 09, 2018 7:09 PM
To: Bruno Amara <Bruno.Amara@ofina.on.ca>
Cc: Usman Zahid <Usman.Zahid@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>
Subject: RE: Electricity Update

Hi Bruno.

I made some suggested edits to the variance explanations on the "Electricity Summary – Change"

tab. Please review.

Thanks,
Ron

From: Bruno Amara
Sent: January-09-18 17:19
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Usman Zahid <Usman.Zahid@ofina.on.ca>
Subject: RE: Electricity Update

Hi Ron

Please see attached with update footnotes and Pension risk revised per our discussion.

Bruno

From: Ronald Kwan
Sent: Tuesday, January 09, 2018 5:16 PM
To: Bruno Amara <Bruno.Amara@ofina.on.ca>
Cc: Usman Zahid <Usman.Zahid@ofina.on.ca>
Subject: RE: Electricity Update

Hi Bruno,

Please send me the revised version.

Thanks,
Ron

From: Bruno Amara
Sent: January-09-18 11:12
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Usman Zahid <Usman.Zahid@ofina.on.ca>
Subject: Electricity Update

Hi Ron

I realize we did not update various footnotes to reflect unpacking in the version I sent to you last night. We have now done this. I also revised the Risk table to shift the pension risk forward one-year, noting that while this risk may be mitigated by findings of the OEB report, OEB will make final decision with deferred decision. I haven't forwarded this for now to avoid any confusion with edits you may be making, but happy to do so.

Also we have coordinated with SIFB and FTD on the AO unpacking exercise to make sure we are all on same page before we share with Frost. We are just finalizing some summary tables on our unpacking exercise that we can send to you and/or walk you through.

I heard from CQSD late yesterday that wrap-up is on Monday. They would like to prepare ESDI update today for Helmut's review. I noted that we do have updates that we are finalizing and will send as soon as we can. We can check back to see if tomorrow will be OK as necessary.

I also let OPCD know that we are working on an update that will re-categorize AO impacts and will send them that version as it will be more accurate for Budget consolidation. But I will also offer them our Interim unpacked version if they want to use that for now.

Bruno

Bruno Amara
Sr. Manager, Financial and Regulatory Analysis
Electricity Finance Branch
Corporate and Electricity Finance Division
Ontario Financing Authority

Tel: 416-325-1489
Email: bruno.amara@ofina.on.ca

Electricity Sector Outlook
October 2017

Disclosure:

All information contained in this workbook is confidential and commercially sensitive

All projected numbers are estimates and subjected to change

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Please consult with OFA before sharing of information.

Commercially Sensitive and Confidential Advice to Cabinet for Consideration of Options for Discussion Purposes Only

Commercially Sensitive and Confidential Advice to Cabinet for Consideration of Options for Discussion Purposes Only

Electricity Sector Outlook
Including Line Items for Consolidation

Electricity Summary - On Deck

			MOF Expense Items (consolidated)	Current Outlook			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**38**	Power Supply Contract Costs	(182)	(183)	(134)	(103)
Expense	**MOF (OEFC)**	**40**	Demand Management Support Costs	(10)	-	-	-
Expense	**MOF (OEFC)**	**41**	Provision for Electricity Sector	24	9	-	48
Expense	**MOF**	**17**	Provision for Electricity Sector	(24)	(9)	-	(48)
Expense	**MOF (OEFC)**	**42**	Other (Finance)	(6)	(7)	(7)	(7)
			Total MOF Expense	**(198)**	**(190)**	**(141)**	**(110)**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**7**	OPG Income	149	137	(7)	156
Revenue	**ENE**	**8**	OPG - ONFA and other Fair Value Adjustments	171	-	-	-
Revenue	**ENE**	**10**	HOI Income	329	327	388	419
Revenue		**11**	Brampton Income	-	-	-	-
Revenue	**MOF (OEFC)**	**26**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	377	452	503	635
Revenue	**MOF (OEFC)**	**29**	Electricity Debt Retirement Charge	623	-	-	-
Revenue	**MOF (OEFC)**	**30**	Power Supply Contract Recoveries	182	183	134	103
Revenue	**MOF (OEFC)**	**31**	Net Reduction of Power Purchase Contracts	74	41	30	28
Revenue	**MOF (OEFC)**	**34**	Miscellaneous	-	-	-	-
			Total MOF Revenue	**1,906**	**1,138**	**1,048**	**1,341**
			OFA IOD Expense				
			Public Debt Interest - Electricity Sector	(454)	(454)	(454)	(454)
			Interest on Debt	(475)	(438)	(411)	(348)
			Total OFA IOD Expense	**(929)**	**(892)**	**(865)**	**(802)**
			Impact on Surplus/Deficit	**779**	**57**	**42**	**429**
			check	*-*	*-*	*(0)*	*-*

Electricity Summary - Budget 17

For Discussion			MOF Expense Items (consolidated)	Plan			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**38**	Power Supply Contract Costs	(292)	(325)	(301)	(273)
Expense	**MOF (OEFC)**	**40**	Demand Management Support Costs	(10)	0	0	0
Expense	**MOF (OEFC)**	**41**	Provision for Electricity Sector	125	0	0	0
Expense	**MOF**	**17**	Provision for Electricity Sector	(125)	0	0	0
Expense	**MOF (OEFC)**	**42**	Other (Finance)	(6)	(6)	(6)	(6)
			Total MOF Expense	**(308)**	**(331)**	**(307)**	**(279)**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**7**	OPG Income	97	732	625	1,066
Revenue	**ENE**	**8**	OPG - ONFA and other Fair Value Adjustments	0	0	0	0
Revenue	**ENE**	**10**	HOI Income	520	562	603	652
			Brampton Income				
Revenue	**MOF (OEFC)**	**25**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	405	476	538	679
Revenue	**MOF (OEFC)**	**29**	Electricity Debt Retirement Charge	623	0	0	0
Revenue	**MOF (OEFC)**	**30**	Power Supply Contract Recoveries	292	325	301	273
Revenue	**MOF (OEFC)**	**31**	Net Reduction of Power Purchase Contracts	74	41	30	28
Revenue	**MOF (OEFC)**	**34**	Miscellaneous	0	0	0	0
			Total MOF Revenue	**2,011**	**2,136**	**2,098**	**2,697**
			OFA IOD Expense				
		17	Public Debt Interest - Electricity Sector	(492)	(492)	(492)	(492)
		36	Interest on Debt	(422)	(374)	(342)	(250)
			Total OFA IOD Expense	**(914)**	**(866)**	**(834)**	**(742)**
			Impact on Surplus/Deficit	**789**	**939**	**957**	**1,676**
			check	**-**	**-**	**-**	**-**

Electricity Summary - Change

			MOF Expense Items (consolidated)	Variance from Plan			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**69**	Power Supply Contract Costs	110	142	167	170
Expense	**MOF (OEFC)**	**71**	Demand Management Support Costs	0	0	0	0
Expense	**MOF (OEFC)**	**72**	Provision for Electricity Sector	(101)	9	0	48
Expense	**MOF**	**48**	Provision for Electricity Sector	101	(9)	0	(48)
Expense	**MOF (OEFC)**	**73**	Other (Finance)	0	(1)	(1)	(1)
			Total MOF Expense	**110**	**141**	**166**	**169**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**38**	OPG Income	52	(596)	(632)	(909)
Revenue	**ENE**	**39**	OPG - ONFA and other Fair Value Adjustments	171	0	0	0
Revenue	**ENE**	**41**	HOI Income	(190)	(235)	(216)	(233)
			Brampton Income	0	0	0	0
Revenue	**MOF (OEFC)**	**25**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	(28)	(24)	(35)	(43)
Revenue	**MOF (OEFC)**	**60**	Electricity Debt Retirement Charge	0	0	0	0
Revenue	**MOF (OEFC)**	**61**	Power Supply Contract Recoveries	(110)	(142)	(167)	(170)
Revenue	**MOF (OEFC)**	**62**	Net Reduction of Power Purchase Contracts	(0)	(0)	(0)	(0)
Revenue	**MOF (OEFC)**	**65**	Miscellaneous	0	0	0	0
			Total MOF Revenue	**(105)**	**(997)**	**(1,049)**	**(1,356)**
			OFA IOD Expense				
		17	Public Debt Interest - Electricity Sector	38	38	38	38
		36	Interest on Debt	(53)	(64)	(69)	(98)
			Total OFA IOD Expense	**(15)**	**(26)**	**(31)**	**(60)**
			Impact on Surplus/Deficit	**(10)**	**(882)**	**(914)**	**(1,247)**
			check	-	-	-	-

Track Changes in Surplus/Deficit

Date	Change ID#	Source	Tab
5/1/2017	20170501-1	Link	ONFA
5/1/2017	20170501-2	Link	Hydro One
5/1/2017	20170501-3	Link	Hydro One
5/1/2017	20170501-4	Link	Other Data
5/2/2017	20170502-1	Link	OPG
5/9/2017	20170509-1	Link	OPG
5/10/2017	20170510-1	Link	Hydro One
5/10/2017	20170510-2	Link	Other Data
5/12/2017	20170512-1	Link	Hydro One
5/15/2017	20170515-1	Link?	
5/15/2017	20170515-2	Link	OPG
5/17/2017	20170517-1	Link	Hydro One
5/17/2017	20170517-2	Link	ONFA
5/17/2017	20170517-3		
5/18/2017	20170518-1	Link	OPG
5/18/2017	20170518-2	Link	OPG
5/18/2017	20170518-3		
6/15/2017	20170615-1	Link	OPG
6/22/2017	20170622-1	Link	Hydro One
6/22/2017	20170622-2	Link	Hydro One
6/26/2017	20170626-1		
6/29/2017	20170629-1		

7/6/2017	20170706-1		
7/11/2017	20170711-1		
7/13/2017	20170713-1	Link	Provision
7/17/2017	20170717-1	Link	Revenue (Risks)
7/24/2017	20170724-1	Link	Revenue (Risks)
7/25/2017	20170725-1	Link	Revenue (Risks)
7/26/2017	20170726-1	Link	Revenue (Risks)
7/27/2017	20170727-1	Link	Revenue (Risks)
7/27/2017	20170727-2	Link	Revenue (Risks)
7/31/2017	20170731-1		
7/31/2017	20170731-2	Link	Hydro One
7/31/2017	20170731-3	Link	Other Data
8/11/2017	20170811-1	Link	OPG
8/15/2017	20170815-1		
8/15/2017	20170815-2		
8/15/2017	20170815-3		
8/15/2017	20170815-4		
8/15/2017	20170815-5		Other Data
8/15/2017	20170815-6		Other Data
8/15/2017	20170815-7		Other Data
8/15/2017	20170815-8		Other Data
8/15/2017	20170815-9		Other Data
8/15/2017	20170815-10		Other Data
8/17/2017	20170817-1	Link	Provision
8/17/2017	20170817-2	Link	Hydro One
8/18/2017	20170818-1	Link	Revenue (Risks)
8/22/2017	20170822-1	Link	OPG
8/25/2017	20170825-1		Hydro One
8/29/2017	20170829-1		Revenue (Risks)
8/31/2017	20170831-1		Revenue (Risks)
9/5/2017	20170905-1		Other Data
9/5/2017	20170905-2		Other Data
9/5/2017	20170905-3	Link	OPG

9/6/2017	20170906-1	Link	Other Data
9/6/2017	20170906-2	Link	Revenue (Risks)
9/8/2017	20170908-1	Link	Hydro One
9/8/2017	20170908-2	Link	OPG
9/11/2017			
9/12/2017			
9/13/2017			
9/21/2017			
9/22/2017			
10/2/2017			Hydro One
10/2/2017			
10/2/2017			
10/2/2017			
10/4/2017	20171004-1		OPG
10/4/2017	20171004-2		OPG
10/4/2017			
10/4/2017			
10/5/2017			
10/6/2017			
10/7/2017			
10/8/2017			
10/10/2017	20171010-1		Hydro One
10/10/2017			
10/10/2017			
10/11/2017	20171011-1		OPG
10/11/2017			
10/11/2017			
10/12/2017			OPG
10/12/2017			
10/12/2017			
10/12/2017			
10/18/2017	20171018-1		Hydro One
10/18/2017	20171018-1		Hydro One
10/18/2017	20171018-1		Hydro One
10/19/2017	20171019-1		Revenue (Risks)
10/19/2017	20171019-2		Revenue (Risks)
10/20/2017	20171020-1		Revenue (Risks)
10/20/2017	20171020-2		
10/20/2017	20171020-2		
10/20/2017	20171020-2		
10/20/2017	20171020-3		Revenue (Risks)
10/20/2017	20171020-4		OPG
10/20/2017	20171020-4		OPG
10/20/2017	20171020-4		OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017	20171114-1		Hydro One

11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017		Hydro One
11/14/2017		Hydro One
11/14/2017		Hydro One
11/30/2017	20171130-1	Revenue (Risks)
12/8/2017		Hydro One
12/11/2017	20171211-1	Other Data
12/11/2017	20171211-1	Other Data
12/22/2017	20171222-1	OPG
1/2/2018		Hydro One
1/2/2018		Hydro One
1/2/2018		Hydro One
1/2/2018	20180102-1	OPG
1/2/2018	20180102-1	OPG
1/2/2018	20180102-1	OPG
1/2/2018	20180102-2	OPG
1/2/2018	20180102-3	OPG
1/2/2018	20180102-3	Revenue (Risks)
1/2/2018	20180102-4	Revenue (Risks)
1/2/2018	20180102-5	Revenue (Risks)
1/2/2018	20180102-6	Revenue (Risks)
1/2/2018	20180102-7	Revenue (Risks)
1/2/2018	20180102-8	Revenue (Risks)
1/2/2018	20180102-9	OPG
1/2/2018	20180102-9	OPG
1/2/2018	20180102-9	OPG
1/2/2018	20180102-9	OPG
1/3/2018		OPG
1/3/2018		OPG
1/3/2018		OPG
1/3/2018		OPG
1/3/2018		Hydro One
1/3/2018		Hydro One
1/3/2018		Hydro One
1/4/2018	20180104-1	OPG
1/4/2018	20180104-1	OPG
1/4/2018	20180104-1	OPG
1/4/2018	20180104-1	OPG
1/4/2018	20180104-2	Other Data
1/4/2018	20180104-2	Other Data
1/5/2018		
1/5/2018		
1/5/2018		
1/5/2018		
1/5/2018		
1/5/2018		
1/5/2018		
1/8/2018		
1/8/2018		
1/8/2018		

FOR EFB USE ONLY

Budget 2017 Outlook
Current Outlook
Change Since Budget

Description of Update
ONFA Update as of March 31 2017
s. 50.3 Update for 2016-17
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Debt Interest
OPG IFRS Risk in 2019-20
Revised OPG 2016-17 Net Income
Revised OPG 2016-17 Net Income
Revised OPG 2016-17 Net Income
tech change: slight update to assumed Prov share 70.05% from 70%
tech change: slight update to assumed Prov share 70.05% from 70%
tech change: slight update to assumed Prov share 70.05% from 70%
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
Updating H1 2016-17 Net Income for ESDI
Updating H1 2016-17 Net Income for ESDI
Updating H1 2016-17 Net Income for ESDI
Power Purchase Supply
H1 Model Forecasts - No Fiscal Update Resaving Data
Update Budget 2017 Tabs to reflect fiscal plan
Update OPG forecasted PILS to reflect sources
Update H1 2016-17 CIT
Re-inputting ONFA updates
Updating H1 Net Income to include Pref Shares in 16-17
Updating OPG Income Tax Expense for 2016-17
Updating OPG non-income tax PILs
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2017
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2018
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2019
Updating with actual OPG IFRS Adjustment 2016-17
Updating with actual OPG IFRS Adjustment 2016-17
Updating with actual OPG IFRS Adjustment 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
[NOT APPLIED] Updating H1 Brampton (Interim Adjustments)
Shifted H1 Brampton 2016-17 NI to the 2017-18
Removed H1 Brampton for 2016-17 (pending finals)
Removed H1 Brampton for 2016-17 (pending finals)
Removed H1 Brampton for 2016-17 (pending finals)

add prior-year adjustment for 2016-17

add prior-year adjustment for 2016-18
Reconfigured calculation of ESDI and MOF ESDI Expense
Reconfigured calculation of OPG 2017-18 Net Income
Backup for the Provincial Interest cost
Linking source for Revenue Risks Tab
New source for Revenue Risks Tab
Revenue Risks Tab - ROE Risks
Updating OEB Risk for OPG
OEB Staff Report - H1 Tx - Revenue Risks
OPG Pensions - Cash vs Accrual Deferral Accounts
Updating Links in Electricity Summary Change and OEFC Change
Preliminary estimate for Hydro One Brampton
Preliminary estimate for Hydro One Brampton
Preliminary estimate for Hydro One Brampton

Updating DRC for Actuals 2016-17 (Based on draft FS)
Updating PILs for 2016-17 Baced on Actuals
OPG: Non-ONFA Fair Value Adjustment
Round all Hydro One ownership assumptions to two decimal places
H1 Equity Adjustment rounding.
Round all Hydro One ownership assumptions to two decimal places
Round all Hydro One ownership assumptions to two decimal places
Revising source of ESDI, Dedicated Electricity Earnings
2016-17 - Update Power Supply Recoveries to actuals
2016-17 - Update Power Supply Recoveries to actuals
2016-17 - Updating Miscellaneous OEFC Revenue to Actuals
Adj: Exclude Bramton $15m add prior year adjustment +$3M
Adj: Exclude Bramton $15m add prior year adjustment +$3M
Public Accts: Updated IESO debt interest Interest On Debt, 2016-17
Public Accts: 2016-17 - Demand Management Support Costs Update
2017-18 - Demand Management Support Costs (no change)
Public Accts: 2016-17 - Updating Operating Expense in OEFC
Sourcing Provision for Electricity Sector from Actual Public Accounts
Revised 2016-17 Brampton Amount for Public Accounts
OPG Pensions - Cash vs Accrual Deferral Accounts (Revenue Risks Tab)
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
Reclassification
Reclassification
Reverting H1 Ownership change (undoing 20170518-3)
Reverting H1 Ownership change (undoing 20170518-3)
Reverting H1 Ownership change (undoing 20170518-3)
Updating Risks based on Hydro One Q2 Results Model
Avista Acquisition Risks
NUG Amortization Liability (sourcing amortization schedule)
2016-17 Actuals - Debt Guarantee Fee
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results

Interest Revenue for IESO and "Other"
OPG Revenue Risks from OEB Filings
Net income corrected for Preferred Shares
Net income corrected for Preferred Shares
Net income corrected for Preferred Shares
Made link edits to OPG sheet so that the "Net Income Before Tax" 2017-18 number is not a hardc
Updated PILs to include OPCD public accounts adjustment
Provision tab fix to pick up Hydro One preferred share net income
Provision tab fix to pick up Hydro One preferred share net income
FTD Update to OEFC Outlook (Sep 19, 2017) OPG Interest
FTD Update to OEFC Outlook (Sep 19, 2017) Other Interest
Update to Hydro One PILs from information in Transmission rate application material
OEB September 28, 2017 Hydro One decision and order impact - incl. rebasing
OEB September 28, 2017 Hydro One decision and order impact - incl. rebasing
OEB September 28, 2017 Hydro One decision and order impact - incl. rebasing
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Debenture Interest Costs - Removing from Revenue (Risks) and adding it ot H1 Model
Debenture Interest Costs - Removing from Revenue (Risks) and adding it ot H1 Model
Debenture Interest Costs - Removing from Revenue (Risks) and adding it ot H1 Model
Updated OPG Net Income and PILs based on monthly report (August 2017 results)
Updated OPG Net Income and PILs based on monthly report (August 2017 results)
Updated OPG Net Income and PILs based on monthly report (August 2017 results)
Correction to PILs on OPG sheet
Correction to PILs on OPG sheet
Correction to PILs on OPG sheet
Correction to PILs on OPG sheet
Switch to Direct from Model
Switch to Direct from Model
Switch to Direct from Model
Updating ROE Risks
Updating H1 Load Risks based on model output
Updating ONFA Risks for September 2017
Adjust OEB decision/rebasing to ~50% provincial ownership
Adjust OEB decision/rebasing to ~50% provincial ownership
Adjust OEB decision/rebasing to ~50% provincial ownership
Updating OPG
OPG IOD impact from GA Financing, FHP
OPG IOD impact from GA Financing, FHP
OPG IOD impact from GA Financing, FHP
Unpacking updated OPG Gain on sale (net income)
Unpacking updated OPG Gain on sale (net income)
Unpacking updated OPG Gain on sale (net income)
Unpack PILs related to HQ gain on sale
Updating IFRS Risk
Adjustment for lower Provincial share (from 70.1% to 50.9 2017-18 & 47.4% after)
Adjustment for lower Provincial share (from 70.1% to 50.9 2017-18 & 47.4% after)
Adjustment for lower Provincial share (from 70.1% to 50.9 2017-18 & 47.4% after)
November 1 and November 7 Hydro One model updates

November 1 and November 7 Hydro One model updates
November 1 and November 7 Hydro One model updates
Revise Hydro Model to reverse OEB tax decision ongoing annual impact
Revise Hydro Model to reverse OEB tax decision ongoing annual impact
Revise Hydro Model to reverse OEB tax decision ongoing annual impact
Undo allocation adjustment in H1 tab (now that provincial shares are updated)
Undo allocation adjustment in H1 tab (now that provincial shares are updated)
Undo allocation adjustment in H1 tab (now that provincial shares are updated)
Updating OPG Revenue Risks from rate application
Update Hydro One PILs (reverses update on line 119 whuich did not account fro Dx side)
Updating Debt Guarantee Fee
Updating OEFC Operating Expense
small changes - linking the net income numbers

Updated number of shares sold for First Nations (Dec 2017) sale
Updated number of shares sold for First Nations (Dec 2017) sale
Updated number of shares sold for First Nations (Dec 2017) sale
Implemented OEB's Dec 2017 payment amounts decision for OPG (CEFD Analysis)
Implemented OEB's Dec 2017 payment amounts decision for OPG (CEFD Analysis)
Implemented OEB's Dec 2017 payment amounts decision for OPG (CEFD Analysis)
Updated OPG Net Income (based on their Q3 update, Sep 30, 2017)
Updated OPG ONFA adjustment (up to Sep 30, 2017) in OPG tab (removed it from Risks table)
Removal of OPG ONFA Sep 2017 adjustment in Risks table
Included possible range (-50M to 50M) of impact for future OPG ONFA adjustment in the negative
Removal of negative regulatory risk: "OPG Switch from accrual based to cash based accounting f
Removal of negative regulatory risk: "Timing of OPG Rate Decision" from Risks table
Removal of negative regulatory risk: "OEB Staff Recommendations wrt OPG rate application(May
Removal of negative regulatory risk: "Nuclear Liabilities Cash vs. Accrual" from Risks table
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month
Updated estimates of NUG costs.
Updated estimates of NUG costs.
Unpacking OPG (Head Office sale)
Unpacking OPG (Head Office sale)
Unpacking OPG (Head Office sale)
Unpacking OPG (Head Office sale)
Unpacking Hydro One for AO (from 70.1% ownership to as of January 2018)
Unpacking Hydro One for AO (from 70.1% ownership to as of January 2018)
Unpacking Hydro One for AO (from 70.1% ownership to as of January 2018)
Update H1 allocations for additional shares (SIFB edits)
Update H1 allocations for additional shares (SIFB edits)
Update H1 allocations for additional shares (SIFB edits)

This line show net impact of latest change. READ COMMENT

Expense
Expense
Expense
Expense
Expense
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue

Expense
Expense
Expense
Expense
Expense
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue

$ Millions

		2016-17	2017-18	2018-19	2019-20
		930	789	939	957
	File	915	779	57	42
		-15	-10	-882	-914
	check	*0*	*0*	*0*	*0*
		Impacts by FY →			
Outlook line affected	**Expense / Reve**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
ONFA and other Fair Value Adjustments	Revenue	41.0	0.0	0.0	0.0
N/A		0.0	0.0	0.0	0.0
?		0.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		38.1		
Provision for Electricity Sector (MOF)	Expense		(38.1)		
Public Debt Interest - Electricity Sector	Expense	0.0	38.1	38.1	38.1
Interest on Debt	Expense	0.0	(69.1)	(79.1)	(75.1)
OPG Income	Expense	0.0	0.0	0.0	
OPG Income	Revenue	(2.0)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**(2.0)**			
Provision for Electricity Sector (MOF)	Expense	2.0			
HOI Income	Revenue	0.4			
Provision for Electricity Sector (OEFC)	Expense	0.4			
Provision for Electricity Sector (MOF)	Expense	(0.4)			
Public Debt Interest - Electricity Sector	Expense	1.7			
Provision for Electricity Sector (OEFC)	Expense	(1.7)			
Provision for Electricity Sector (MOF)	Expense	1.7			
Interest on Debt	Expense	(1.7)			
HOI Income	Revenue	(39.8)	0.0	0.0	(0.0)
Provision for Electricity Sector (OEFC)	Expense	**(39.8)**			
Provision for Electricity Sector (MOF)	Expense	39.8			
	Revenue	-	-	-	-
	Revenue	-	-	-	-
	n/a	-	-	-	-
		-	-	-	-
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	4.7	0.0	0.0	0.0
	Revenue	0.0	0.0	0.0	0.0
HOI Income	Revenue	18.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	7.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	8.0	9.0	12.0	3.5
HOI Income	Revenue	0.0	(141.5)	(181.4)	(194.9)
Provision for Electricity Sector (OEFC)	Expense		(141.5)		
Provision for Electricity Sector (MOF)	Expense		141.5		
OPG Income	Revenue	(3.0)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**(3.0)**			
Provision for Electricity Sector (MOF)	Expense	3.0			
HOI Income	Revenue	7.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**7.0**			
Provision for Electricity Sector (MOF)	Expense	(7.0)			
	Revenue	-	-	-	-
	Revenue	0.0	0.0	0.0	0.0
Brampton Income	Revenue	(14.7)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**(14.7)**			
Provision for Electricity Sector (MOF)	Expense	14.7			

Provision for Electricity Sector (OEFC)	Expense		3.2			
Provision for Electricity Sector (MOF)	Expense		(3.2)			
	Revenue	-	-	-	-	
		-	-	-	-	
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
Brampton Income	Revenue		15.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		**15.0**			
Provision for Electricity Sector (MOF)	Expense		(15.0)			
Provision for Electricity Sector (OEFC)	Expense		3.2			
Provision for Electricity Sector (MOF)	Expense		(3.2)			
Electricity Debt Retirement Charge	Revenue		(4.0)	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue		(29.0)	0.0	0.0	0.0
OPG Income	Revenue		(6.0)	0.0	0.0	0.0
HOI Income	Revenue		(0.0)	(0.0)	0.0	0.0
HOI Income	Revenue		(1.7)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense			(0.0)		
Provision for Electricity Sector (MOF)	Expense			0.0		
	Revenue		0.0	0.0	0.0	0.0
Power Supply Contract Recoveries	Revenue		99.0	0.0	0.0	0.0
Power Supply Contract Costs	Expense		(99.0)			
Miscellaneous	Revenue		14.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		(12.0)			
Provision for Electricity Sector (MOF)	Expense		12.0			
Interest on Debt	Expense		(3.0)	0.0	0.0	0.0
Demand Management Support Costs	Expense		1.8	0.0	0.0	0.0
			0.0	0.0	0.0	0.0
Other (Finance)	Expense		(1.0)	0.0	0.0	0.0
	Revenue	-	-	-	-	
Brampton Income	Revenue		3.0	0.0	0.0	0.0
			0.0	0.0	0.0	0.0
OPG Income	Revenue		0.0	85.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue			(6.0)		
Provision for Electricity Sector (OEFC)	Expense			**85.0**		
Provision for Electricity Sector (MOF)	Expense			(85.0)		
OPG Income	Revenue		6.0			
ONFA and other Fair Value Adjustments	Revenue		(6.0)			
HOI Income	Revenue		0.0	141.9	181.8	195.4
Provision for Electricity Sector (OEFC)	Expense			141.9		
Provision for Electricity Sector (MOF)	Expense			(141.9)		
	n/a		0.0	0.0	0.0	0.0
			0.0	0.0	0.0	0.0
Net Reduction of Power Purchase Contracts	Revenue		0.1	(0.1)	(0.1)	(0.1)
	Revenue		0.0	0.0	0.0	0.0
OPG Income	Revenue		0.0	16.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue			(1.0)		
Provision for Electricity Sector (OEFC)	Expense			**16.0**		
Provision for Electricity Sector (MOF)	Expense			(16.0)		

		0.0	0.0	0.0	0.0
	n/a	0.0	0.0	0.0	0.0
HOI Income	Revenue	0.0	5.3	5.3	5.3
Provision for Electricity Sector (OEFC)	Expense		(12.4)		
Provision for Electricity Sector (MOF)	Expense		12.4		
oded formula in the cell	n/a	0.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	(30.4)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		17.8		
Provision for Electricity Sector (MOF)	Expense		(17.8)		
Interest on Debt	Expense	(0.0)	1.0	(0.0)	1.0
Interest on Debt	Expense	0.0	15.0	15.0	5.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	0.0	(7.8)	(8.7)	(10.3)
HOI Income	Revenue	0.0	(47.4)	(54.0)	(54.0)
Provision for Electricity Sector (OEFC)	Expense	0.0	(47.4)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	47.4	0.0	0.0
OPG Income	Revenue	0.0	(61.0)	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	0.0	(21.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	(61.0)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	61.0	0.0	0.0
OPG Income	Revenue	0.0	(21.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	(21.0)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	21.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	0.0	21.0	0.0	0.0
HOI Income	Revenue	0.0	(23.6)	(27.4)	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	(23.6)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	23.6	0.0	0.0
OPG Income	Revenue	0.0	15.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	15.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	(15.0)	0.0	0.0
OPG Income	Revenue	0.0	21.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	0.0	(18.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	21.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	(21.0)	0.0	0.0
HOI Income	Revenue	0.0	(23.8)	(28.9)	(10.1)
Provision for Electricity Sector (OEFC)	Expense	0.0	(23.8)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	23.8	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
HOI Income	Revenue		16.1	26.7	20.6
Provision for Electricity Sector (OEFC)	Expense		16.1		
Provision for Electricity Sector (MOF)	Expense		(16.1)		
n/a	n/a	0.0	0.0	0.0	0.0
OPG Income	Revenue		(4.9)	(11.9)	(17.1)
Provision for Electricity Sector (OEFC)	Expense		(4.9)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		4.9	0.0	0.0
OPG Income	Revenue		283.0		
Provision for Electricity Sector (OEFC)	Expense		283.0		
Provision for Electricity Sector (MOF)	Expense		(283.0)		
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue		95.0		
OPG Income	Revenue		0.0	(475.0)	(500.0)
HOI Income	Revenue		(112.6)	(142.1)	(170.6)
Provision for Electricity Sector (OEFC)	Expense		(112.6)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		112.6	0.0	0.0
HOI Income	Revenue		(3.3)	(3.0)	(0.1)

Provision for Electricity Sector (OEFC)	Expense		(3.3)		
Provision for Electricity Sector (MOF)	Expense		3.3		
HOI Income	Revenue		14.7	14.4	12.9
Provision for Electricity Sector (OEFC)	Expense		14.7	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		(14.7)	0.0	0.0
HOI Income	Revenue		(16.1)	(26.7)	(20.6)
Provision for Electricity Sector (OEFC)	Expense		(16.1)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		16.1	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)		0.0	7.8	8.7	10.3
n/a	n/a	0.0	0.0	0.0	0.0
Other (Finance)			0.0	(1.0)	(1.0)
OPG Income	Revenue		0.0	0.0	0.0
HOI Income	Revenue		0.1	0.5	0.6
Provision for Electricity Sector (OEFC)	Expense		0.1	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		(0.1)	0.0	0.0
OPG Income	Revenue		(477.1)	(145.2)	(153.1)
Provision for Electricity Sector (OEFC)	Expense		(305.7)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		305.7	0.0	0.0
OPG Income	Revenue		39.0	0.0	0.0
OPG - ONFA and other Fair Value Adjustments	Revenue		171.5	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
OPG Income	Revenue		119.3	36.3	38.3
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue		(119.3)	(36.3)	(38.3)
Provision for Electricity Sector (OEFC)	Expense		0.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		0.0	0.0	0.0
OPG Income	Revenue		(283.0)	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue		(95.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		0.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		0.0	0.0	0.0
HOI Income	Revenue		116.8	147.1	176.1
Provision for Electricity Sector (OEFC)	Expense		0.0	0.0	80.3
Provision for Electricity Sector (MOF)	Expense		0.0	0.0	(80.3)
OPG Income	Revenue		37.5	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue		12.5	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		0.0	14.4	23.1
Provision for Electricity Sector (MOF)	Expense		0.0	(14.4)	(23.1)
Power Supply Contract Recoveries	Revenue		(109.9)	(142.1)	(166.7)
Power Supply Contract Costs	Expense		109.9	142.1	166.7
OPG Income	Revenue		283.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue		95.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		141.1	141.9	0.0
Provision for Electricity Sector (MOF)	Expense		(141.1)	(141.9)	0.0
HOI Income	Revenue		(116.8)	(147.1)	(176.1)
Provision for Electricity Sector (OEFC)	Expense		(116.8)	(147.1)	(103.4)
Provision for Electricity Sector (MOF)	Expense		116.8	147.1	103.4
HOI Income	Revenue		(0.0)	(0.2)	(0.2)
Provision for Electricity Sector (OEFC)	Expense		(0.0)	(0.2)	0.0
Provision for Electricity Sector (MOF)	Expense		0.0	0.2	0.0

	0	*0*	*0*	*0*

Summary of Track Changes Above

Power Supply Contract Costs	(99.0)	0.0	0.0	0.0
Demand Management Support Costs	1.8	0.0	0.0	0.0
Provision for Electricity Sector OEFC)	(44.4)	180.9	0.0	0.0
Provision for Electricity Sector (MOF)	44.4	(180.9)	0.0	0.0
Other (Finance)	(1.0)	0.0	(1.0)	(1.0)
OPG Income	(5.0)	333.1	(486.9)	(517.1)
ONFA and other Fair Value Adjustments	35.0	0.0	0.0	0.0
HOI Income	(16.1)	(190.4)	(235.3)	(216.1)
Brampton Income	3.3	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	(39.7)	79.0	12.0	3.5
Electricity Debt Retirement Charge	(4.0)	0.0	0.0	0.0
Power Supply Contract Recoveries	99.0	0.0	0.0	0.0
Net Reduction of Power Purchase Contracts	0.1	(0.1)	(0.1)	(0.1)
Miscellaneous	14.0	0.0	0.0	0.0
Public Debt Interest - Electricity Sector	1.7	38.1	38.1	38.1
Interest on Debt	(4.7)	(53.1)	(64.1)	(69.1)
Impact on Surplus/Deficit	**(14.6)**	**206.7**	**(737.3)**	**(761.7)**
check	***0.0***	***216.5***	***144.9***	***152.7***

Check - Summary of Track Changes Above vs. Electricity Summary Change Worksheet

Power Supply Contract Costs	0.0	(110.2)	(142.2)	(167.0)
Demand Management Support Costs	(0.0)	0.0	0.0	0.0
Provision for Electricity Sector OEFC)	8.4	281.4	(9.0)	0.0
Provision for Electricity Sector (MOF)	(8.4)	(281.4)	9.0	0.0
Other (Finance)	0.0	0.0	0.0	0.0
OPG Income	0.0	281.3	108.9	114.8
ONFA and other Fair Value Adjustments	0.0	(171.5)	0.0	0.0
HOI Income	(0.0)	(0.1)	(0.3)	(0.4)
Brampton Income	0.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	(0.0)	106.8	36.3	38.3
Electricity Debt Retirement Charge	0.0	0.0	0.0	0.0
Power Supply Contract Recoveries	0.0	110.2	142.2	167.0
Net Reduction of Power Purchase Contracts	(0.0)	(0.0)	(0.0)	(0.0)
Miscellaneous	0.0	0.0	0.0	0.0
Public Debt Interest - Electricity Sector	23.4	0.1	0.1	0.1
Interest on Debt	(23.4)	(0.1)	(0.1)	(0.1)
Impact on Surplus/Deficit	**(0.0)**	**216.5**	**144.9**	**152.7**

2020-21
1,676
429
-1,247
0

2020-21	Further Explanation of Change and source of data
0.0	Regular quarterly ONFA Update
0.0	Benefit to OEFC under s.50.3: $411M gain, SIFB
0.0	Change to OEFC payment for interest costs of Debt for Equity Swap
38.1	Revised Provincial Debt Interest related to Hydro One Equity
(104.1)	From FTD, revised Debt Interest (net of revisions to Provincial and OPG debt interest)
0.0	Revised numbers from OEP with 2019-20 Risk
0.0	Updated numbers from OPG Q1 2017 FS
0.0	Updating H1 Net Income for actuals. Note does not update Brampton Income at this point. Will
-	No Change to numbers, just re-inputting data and saving sources
-	No Change to numbers, just re-inputting data and saving sources
-	No change to fiscal impact numbers. Deleting Budget 2016 and adding Budget 2017 fiscal imp
-	No Change to numbers, just re-inputting data and saving sources
0.0	Updated with CIT Numbers received from H1 as part of s.91.2 MB20 allocation from MOF
0.0	No Change to numbers, just re-inputting data and saving sources
0.0	Only included H1 Net Income - Common Shareholders before. Added preferred shareholder im
0.0	Updating OPG Income Tax Expense with info from OPG Monthly Presentation to Shareholder
1.8	Updating OPG GRC payable to OEFC and Proxy Property Tax from Answer back from OPG al
(210.6)	Based on H1 final offering and expected First Nations Sale by the end of 2017 (CY), with a wei
0.0	Based on EY analysis, and then applying fiscalization. Confirmation also received from OPCD.
0.0	Based on KPMG analysis, then fiscalization and other adjustments from OPCD.
-	**[NOT APPLIED, CALCULATIONS AND DATA LEFT ON THE FILE]** Used Brampton's Financ
0.0	Don't expect finalized 2016-17 data to become available in time for ESDI allocation. Will shift th
0.0	make decision on shifting when we know 2016-17 status.

-	No change to numbers. Just re-organizing spreadsheet. No backup data.
-	No change to numbers. Just re-organizing spreadsheet. No backup data.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided another scenario backup/source
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just updated the links to refer ot the delta between 2017 and On Deck
0.0	Adjustment to ESDI to include Hydro One Brampton
0.0	Finalizing 2016-17 DRC Based on Draft OEFC AR
0.0	Received actual PILs amounts from FTD with breakdown of source. Updated 2016-17 numbers
0.0	2016-17 - Non-ONFA Fair Value Adjustment
0.0	Round Hydro One ownership assumptions to 70.05% two decimal places to be consistent with
0.0	Revising Hydro One Amount for consistency with OPCD. Equity Adjustments
0.0	Updated Provision tab. Made two separate Provision amounts for ESDI in OEFC AR and Dedic
0.0	Updating Power Supply Recoveries to Public Accounts/OEFC AR actuals
0.0	Updating Miscellaneous to OEFC AR actuals
0.0	Updated 2016-17 Interest on Debt (IESO, OPG, Other (Net))
0.0	
0.0	2017-18 - Demand Management Support Costs (no change) - Linking correctly
0.0	2016-17 - Updating Operating Expense in OEFC and corresponding changes elsewhere and s
-	No change to numbers. Just re-organized spreadsheet
0.0	Revised H1 Brampton Net Income (for GBE Line only)
0.0	Revising for OPG's Q3 Finances
0.0	Revising OPG's Net Income for latest monthly report
211.1	Reverting ownership back to 70.05% from change 20170518-3. Will coordinate with other area
0.0	Updating Risks based on Hydro One Q2 Results Model
0.0	Updated two Risk components for the Avista Acquisition.
(0.0)	No significant changes, but used actual amortization liability schedule. Hence the rounding imp
0.0	Updating Debt Guarantee for actuals based on OEFC AR
0.0	Revising OPG's Net Income for latest monthly report

0.0	Linking interest revenue data for 2017-18 to 2020-21
0.0	OPG Revenue Risks from: OEB Staff Submission and OPG Updated Filings
5.3	Corrected Net income for 100% ownership in preferred shares and 70.05% in Commons Share
0.0	Updated the formula in the cell for 2017-18 Net Income Before Tax so that the numbers are no
0.0	Updated PILs to include OPCD public accounts adjustment
1.3	
5.0	
(12.2)	
(54.0)	
0.0	
0.0	
0.0	increase built into net income was $82m between NI and PILs
0.0	Remove $21m from PILs
0.0	expense impacts
0.0	expense impacts
0.0	need to also remove the $21m PILs built into OPG net incme
0.0	
0.0	
0.0	We removed $21m from PILs above, before having added it in (check is that lines 123 to 130 a
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
(13.0)	variances include: 2017-18 preferred vs common share fix, 2018-19 largely ROE change from
0.0	
0.0	
0.0	
0.0	
0.0	
21.6	
0.0	
(24.1)	
0.0	
0.0	**Distribution (October)**
(750.0)	
(185.3)	
0.0	
0.0	
(2.3)	

15.2	
0.0	
0.0	
(21.6)	
0.0	
0.0	
0.0	Updating OPG Rate application Revenue Risks based on revised calculations
12.2	
0.0	
(1.0)	Received Revised FTD Forecast
0.3	
0.7	
0.0	
0.0	
(180.7)	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	Removed based on Dec 2017 OEB decision
0.0	Removed based on Dec 2017 OEB decision
0.0	Removed based on Dec 2017 OEB decision
0.0	Removed based on Dec 2017 OEB decision
45.2	
(45.2)	
44.2	
(44.2)	
0.0	
0.0	
(44.2)	
44.2	
190.8	
311.7	
(311.7)	
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M
(170.7)	
170.7	
0.0	
0.0	
0.0	
0.0	
(190.8)	
(263.6)	
263.6	
(0.3)	
(0.5)	
0.5	

0

0.0
0.0
0.0
0.0
(1.0)
(774.1)
0.0
(233.7)
0.0
1.8
0.0
0.0
(0.0)
0.0
38.1
(97.8)
(1,067)
180.0

t

(170.4)
0.0
(47.6)
47.6
0.0
135.3
0.0
(0.4)
0.0
44.9
0.0
170.4
0.0
0.0
0.1
0.1
180.0

Data Validation:

Options
Revenue (F
OPG
Hydro One
Provision

ONFA
Other Data

update once revised numbers are received.

acts

ıpact as well.

bout the BP
ghted average ownership for 2017-18. Also adjusted future net income attributed to the province.

ial Statements to produce an estimate. May require additional calculations.
ıis to 2017-18.

(from 2016 and On Deck)

s to reflect this.

OPCD.

:ated Earnings in Public Accounts.

ources.

s to ensure broadening change and reduction in net income happens concurrently in forecasts.

acts/changes.

es

t hardcoded directly

dd up to -$82m gain that we wanted to remove.

9.09% to 8.78% not previously captured.

Risks)

Electricity Sector Outlook

$ Millions

	Actual 2015-16	Interim 2016-17	Plan 2017-18	2018-19	2019-20	2020-21
On Deck Outlook as of March 2017						
Income from Investment in Government Business Enterprises						
OPG Income[1]	291	304	97	732	625	1,066
OPG - ONFA and other Fair Value Adjustments[2]	172	8	-	-	-	-
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	-
HOI Income[3]	236	516	520	562	603	652
Brampton Income	20	15	-	-	-	-
Total OPG and HOI Income	**719**	**842**	**617**	**1,294**	**1,229**	**1,717**
Other Fees and Licences	**127**	**122**	**102**	**91**	**88**	**81**
Electricity Expenses of the Province						
Provision for Electricity Sector[4]	(3)	(342)	(125)		-	-
Public Debt Interest - Electricity Sector	(520)	(492)	(492)	(492)	(492)	(492)
Subtotal	(523)	(834)	(617)	(492)	(492)	(492)
Public Debt Interest - Impact of ONFA						
Amortization of Deferred Revenue re profit on sale of H1 notes						
Total Electricity Expenses of the Province	**(523)**	**(834)**	**(617)**	**(492)**	**(492)**	**(492)**
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	3,228	373	405	476	538	679
Other Revenue						
Electricity Debt Retirement Charge[5]	859	625	623	-	-	-
Power Supply Contract Recoveries	875	739	292	325	301	273
Net Reduction of Power Purchase Contracts	172	129	74	41	30	28
Other Fees and Licences	(127)	(122)	(102)	(91)	(88)	(81)
Miscellaneous	9	-	-	-	-	-
Expenses						
Interest on Debt	(596)	(532)	(422)	(374)	(342)	(250)
Power Supply Contract Costs	(875)	(739)	(292)	(325)	(301)	(273)
Electricity Consumer Price Protection Fund	-	-	-	-	-	-
Demand Management Support Costs[6]	(8)	(10)	(10)	-	-	-
Provision for Electricity Sector	3	342	125	-	-	-
Other (Finance)	(7)	(6)	(6)	(6)	(6)	(6)
Total OEFC Income	**3,533**	**800**	**687**	**46**	**132**	**370**
Impact on Surplus/(Deficit)	**3,856**	**930**	**789**	**939**	**957**	**1,676**

Notes: The Hydro One net income outlook above (2016-17 to 2020-21) reflects the Province's 70% ownership share after the initial IPO in 2015 and the secondary offering in April 2016. At the time of 2017 Budget, net estimated fiscal impacts from future Hydro One offerings are reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

Notes:

1.OPG's 2016-17 outlook reflected its reported earnings. 2017-18 to 2019-20 reflects OPG's preliminary 2017-2019 business plan (as fiscalized by OPG). 2020-21 estimates are based on OPG's calendar year-based business plan projections. OPG net income also reflects IFRS adjustments fiscal impact decisions that were made centrally.

2. Provincial consolidation adjustments for unrealized earnings on the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds, as of the end of December 2016.

3. Hydro One 2016-17 income reflects its reported net income, adjusted for Hydro One IPO impacts. 2017-18 to 2020-21 projections are based on CEFD projections using the latest public information. The Hydro One net income outlook above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering as of 2017 Budget were reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial ONFA consolidation adjustments, less the interest on the Province's OPG/Hydro One debt payable to OEFC. The provision is currently assumed to end once the DRC ends on a legislated fixed end date of April 1, 2018.

5. Reflects April 23, 2014 announcement that DRC will be eliminated for residential users, after December 31, 2015. The end date of DRC for remaining users is legislated to be on April 1, 2018. Estimates are subject to change based on actual consumption.

6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Electricity Sector Outlook

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
On Deck Outlook as of October 2017						
Income from Investment in Government Business Enterprises						
OPG Income[1]	291	299	149	137	(7)	156
OPG - ONFA and other Fair Value Adjustments[2]	172	43	171	-	-	-
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	-
HOI Income[3]	236	500	329	327	388	419
Brampton Income	20	18	-	-	-	-
Total OPG and HOI Income	**719**	**860**	**650**	**463**	**381**	**575**
Other Fees and Licences (Debt Guarantee fee)	**127**	**122**	**102**	**99**	**98**	**91**
Electricity Expenses of the Province						
Provision for Electricity Sector[4]	-	(290)	(24)	(9)	-	(48)
Public Debt Interest - Electricity Sector	(520)	(514)	(454)	(454)	(454)	(454)
Subtotal	(520)	(803)	(478)	(463)	(454)	(502)
Public Debt Interest - Impact of ONFA						
Amortization of Deferred Revenue re profit on sale of H1 notes						
Total Electricity Expenses of the Province	**(520)**	**(803)**	**(478)**	**(463)**	**(454)**	**(502)**
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	3,247	334	377	452	503	635
Other Revenue						
Electricity Debt Retirement Charge[5]	859	621	623	-	-	-
Power Supply Contract Recoveries	875	838	182	183	134	103
Net Reduction of Power Purchase Contracts	172	129	74	41	30	28
Other Fees and Licences	(127)	(122)	(102)	(99)	(98)	(91)
Miscellaneous	9	14	-	-	-	-
Expenses						
Interest on Debt	(596)	(513)	(475)	(438)	(411)	(348)
Power Supply Contract Costs	(875)	(838)	(182)	(183)	(134)	(103)
Electricity Consumer Price Protection Fund	-	-	-	-	-	-
Demand Management Support Costs[6]	(8)	(8)	(10)	-	-	-
Provision for Electricity Sector	-	290	24	9	-	48
Other (Finance)	(7)	(7)	(6)	(7)	(7)	(7)
Total OEFC Income	**3,549**	**737**	**506**	**(42)**	**17**	**265**
Impact on Surplus/(Deficit)	**3,876**	**915**	**779**	**57**	**42**	**429**
variance to OEFC check	*(156)*	*(454)*	*(550)*	*(0)*	*(0)*	*-*

Notes:

1.OPG's 2016-17 outlook reflected its reported earnings. 2017-18 reflects OPG's latest monthly update and now includes re-caztegorization from Sales and Rentals to OPG net income (and OPG PILs) of OPG head office properties sale. 2018 to 2019-20 reflects OPG's 2017-2019 business plan (as fiscalized by OPG). 2020-21 estimates are based on OPG's calendar year-based business plan projections. OPG net income also reflect projected IFRS adjustments as provided by OPCD at the time of the 2017 Budget and OEB Dec. 28 rate decision. Note rate decsion impact is alloacted to net income and PILs on a 75%/25% basis respectively.

2. Provincial consolidation adjustments for unrealized earnings on the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds, as of the end of September 2017.

3. Hydro One 2016-17 income reflects its projected net income adjusted for the Province's ownership share in Hydro One following the final offering in May 2017 and including the First Nations sale in December 2017. 2017-18 to 2020-21 projections are based on CEFD projections using the latest public information and now reflect the re-categorization from sales and Rentals to Hydro One net income of the full impact of Hydro One broadening.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial ONFA consolidation adjustments, minus the interest on debt payable to OEFC. The provision is now assumed to continue after 2017-18. There is currently a PRRT submission to continue ESDI payments to OEFC beyond 2017-18.

5. Reflects that DRC eliminated for residential users, after December 31, 2015. The end date of DRC for remaining users is legislated to be on April 1, 2018. Estimates are subject to change based on actual consumption.

6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Electricity Sector Change Since Budget	$ Millions					
($million)	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Changes from Budget 2017 as of October 2017						
Income from Investment in Government Business Enterprises						
OPG Income	(5)	52	(596)	(632)	(909)	2016-17 small decrease due to IFRS adjustment revision and OPG Net Income revision. 2017-18 increase is largely from re-categorization from Sales and Rentals to OPG net income (and OPG PILs) of the sale of OPG head office properties -- re-categorisation itself is fiscally-neutral, as Sales and Rentals, following re-categorisation, will be lower than shown in Budget 2017; plus some in-year upside (about $95M), before the OEB rate decision for OPG. Recategorisation amount in net income (about $280 million) is largely offset by estimated negative fiscal impact (about -$320M in net income, -$110M in PILs below) from OEB Dec. 28, 2017 rate decision for OPG, including effective date of new OPG rates of June 1, 2017 rather than Jan. 1, 2017 . (See OPG worksheet for detailed numbers.) Decrease in 2018-19 onward is due mainly to taking on projeceted IFRS adjustment impacts in those years as well as OEB Dec. 28, 2017 rate decision. The OEB Dec. 28, 2017 rate decision estimated impacts are allocated between OPG net income and PILs on a 75%/25% basis.
ONFA and other Fair Value Adjustments	35	171	-	-	-	Largely revision to ONFA fair value as of September 30, 2017
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	
HOI Income	(16)	(190)	(235)	(216)	(233)	2016-17 slight decrease from Budget 2017 Interim projection. 2017-18 onwards reflects i) re-categorization from Sales and Rentals to Hydro One net income of the impact of a lower Provincial share of Hydro One net income from Hydro One share sales ii) impact of OEB Sep. 2017 decision on Hydro One transmission rates and iii) interest expense on Avitsa debentures (in 2017-18 and 2018-19).
Brampton Income	3.3					
Total OPG and HOI Income	**17**	**33.0**	**(831)**	**(848)**	**(1,143)**	
Other Fees and Licences	**-**	**-**	**8**	**10**	**10**	
Electricity Expenses of the Province						
Provision for Electricity Sector	53	101	(9)	-	(48)	**[NOTE: A positive number on this line indicates a decrease in the provision, while a negative number means an increase in provision expense.]** Changes to the Provision (ESDI) expense in 2017-18 mainly reflect higher OPG net income due to recategorisation from Sales and Rentals (see above), offset by lower OPG net income due to OEB's Dec. 28, 2017 rate decision and lower Hydro One net income due to OEB's Sep. 2017 transmission rate decision. Note ESDI is also lowered as HYdro One net income now reflects the full impact of Hydro One share sales. Part of this impact was previously reflected in Sales and Rentals. The projected change in 2019-20 and 2020-21 is due to the continuation of ESDI beyond 2017-18 (approved in principle in the current PRRT). In the 2017 Budget outlook, ESDI was assumed to end after 2017-18. ESDI estimates for 2018-19 and 2018-19 are reduced due to negative balances in 2017-18 and 2018-19,
Public Debt Interest - Electricity Sector	(22)	38	38	38	38	2016-17 PDI at ($514m) was slightly larger than ($492m) projected at Interim. 2017-18 change reflects revised projections for Provincial debt interest related to HydroOne's April 2016 offering. Note the impact of the final offering will be refelected in PDI during 2018.
Total Electricity Expenses of the Province	**31**	**138**	**29**	**38**	**(10)**	

Electricity Sector Change Since Budget	$ Millions					
($million)	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs)	(40)	(28)	(24)	(35)	(43)	2016-17 decrease largely due to an OPCD Public Accounts PILs adjustment related to reconciling between OPCD and OEFC net opening assets. OPG PILs also slightly lower than projected.
Other Revenue						
Electricity Debt Retirement Charge	(4)	-	-	-	-	
Power Supply Contract Recoveries	99	(110)	(142)	(167)	(170)	Variance in 16-17 is largely due to retroactive payments that the OEFC made to certain non-utility generators (NUGs) with former Ontario Hydro power purchase agreement (PPA) contracts with OEFC. OEFC was required to make these payment following the dismissal by the Supreme Court of Canada of OEFC's application for leave to appeal a judgment of the Court of Appeal of Ontario on a 2015 court decision. Going-forward, variance is largely due to suspension or early termination of some NUG PPAs in response to the IESO's NUG curtailment initiative.
Net Reduction of Power Purchase Contracts	0.1	(0)	(0)	(0)	(0)	
Other Fees and Licences	-	-	(8)	(10)	(10)	
Revenue Pool Residual	-	-	-		-	
Miscellaneous	14	-	-	-	-	
Expenses						
Interest on Debt	19	(53)	(64)	(69)	(98)	2017-18 reflects revised debt interest outlook net of revisions to OEFC interest revenue from OPG and Province.
Power Supply Contract Costs	(99)	110	142	167	170	Same as Power supply contract recoveries above. Power supply contract costs are fully recovered by power supply contract recoveries.
Electricity Consumer Price Protection Fund	-	-	-	-	-	
Demand Management Support Costs	1.8	-	-	-	-	
Provision for Electricity Sector	(53)	(101)	9	-	48	see explanation above for "Provision for Electriocty Sector" (line 17)
Other (Finance)	(1.0)	-	(1)	(1)	(1)	
Total OEFC Income	**(63)**	**(181)**	**(88)**	**(115)**	**(105)**	
Impact on Surplus/(Deficit)[1]	**(14.6)**	**(10)**	**(882)**	**(914)**	**(1,247)**	Note: A significant component of the changes above affecting this net is from a fiscally-neutral recategorisation of revenue impacts from the Asset Optimisation (AO) initiative previously shown in Sales and Rentals in Budget 2017 for commercial confidentiality. The pure changes to non-AO electricity sector changes is significantly fiscally negative. See summary table below for breakdown of total change between these components.
Information: Breakdown of change between revenue and expense						
Total Revenue Impact	87	(105)	(997)	(1,049)	(1,356)	
Total Expenditure impact	101	(95)	(115)	(135)	(109)	

Electricity Sector Outlook (PSAB)

Negative Revenue Risks ($ Millions)	Plan			
($ millions)	2017-18	2018-19	2019-20	2020-21
Generic				
OPG Generation Risk: Nuclear Reliability (-1.6 TWh)[1]	(120)	(120)	(120)	(120)
1% decrease in Hydro One actual load[2]	(57)	(59)	(62)	(63)
Lower OPG's Equity weighting & Return on Equity (ROE)[3]	(12)	(20)	(26)	(45)
Lower Hydro One Return on Equity (ROE)[4]	(9)	(36)	(38)	(40)
Regulatory				
Hydro One Distribution rate application[5]	(50)	(50)	(50)	(50)
OPG Switch from accrual based to cash based accounting for pension and OPEB[6]	—	(600)		
Regulatory Risk - Timing of OPG Rate Decision[7]	—			
OEB Staff Recommendations wrt OPG rate application(May 2017)[8]	—			
Nuclear Liabilities Cash vs. Accrual[9]	—			
OEB decision on Hydro One tax recapture (if one-time write-down)[10]	(440)			
Accounting				
OPG IFRS Consolidation Risks[11]		—	—	—
Other Risks				
ONFA adjustment decrease[12]	(50)			
Avista Acquisition - Termination fee		(49)		

Note: These risks do not reflect the impacts on electricity sector revenue and expense of reclassification of the Asset Optimization

1. OPG's market and generation risks related to nuclear reliability similar to the scenarios OPG developed for its sales margins to capture major market risk factors (e.g., natural gas prices, coal prices, foreign exchange, nuclear reliability) in its 2012 business plan. Currently, only the nuclear reliability risk is captured at the current regulated rate for OPG's nuclear generation.

2. Estimated revenue impact if Hydro One load for Transmission and Distribution is 1% lower than projected for all years in CEFD Hydro One Forecast. Based on the assumption a 1% increase in load is directly proportional to a 1% change in revenue requirements.

3. Risk range for Hydro One transmission and distribution reflects potential risk of lower ROE by 0.5% vs assumed ROEs in business plan along with reduced deemed debt to equity weighting of 55%/45% from the current 51%/49%.

4. Risk range for Hydro One transmission and distribution reflects potential risk of lower ROE by 0.5% vs assumed ROEs in CEFD Hydro One Forecast based on the most recent rate applications and forecasted ROE rates.

5. OEB is expected to make a decision on Hydro One's Distibution rate application for 2018 during the first half of 2018.

6. Previous risk removed shifted from 2017-18 to 2018-19. OEB's September 2017 Report, established accrual accounting method as default rate setting method to recover Pension and Other Pension Benefits (OPEBs) costs and recommended continuance of variance account tracking the difference between cash vs. accrual basis reporting for Pension and OPEB. This finding mitigates this risk. However, OEB December 28, OPG rate decision instructs OPG to submit request to dispose of Pension and OPEB deferral and variance account balances during 2018 for its 2019 payment application. OEB's final decision will be made at that time. Note, the impact of a decision could fall in 2019-20 depending on timing of the OEB decision.

7. **Previous risk removed with timing impact now reflected in OPG outlook.**. OEB December 28, decision and order provides an effective date for new rates of June 1, 2017. OPG's business plan assumed OEB decision would be effective as of January 1, 2017. OPG estimated an impact of -$60M for each month for which OEB decsion is not retroactive. The resulting $300M estimated impact has been included in the OPG outlook.

8. **Previous risk removed .** Estimated impact of OEB December 28the decision and order with respect to OPG rates is now reflected on the OPG Outlook.

9. **Previous risk removed.** Risk is related to potential switch to cash-basis accounting for regulated recovery of nuclear payment anmounts. OEB December 28, 2017 Decision and Order has deferred this issue to next OPG rate application in 2021 for 2022 to 2027 period.

10. The OEB's Sep. 28, 2017 ruling on Hydro One's Transmission rate application included direction on sharing, with ratepayers, tax savings related to the Hydro One IPO. Hydro One filed a Motion to Review this decision with the OEB and has also filed a court appeal. Hydro One's 2017 Q3 financial report notes that if the Motion to Review and appeal are unsuccesful teh company would record a one-time write-down of $885 million reflecting the OEB decision. The risk above reflects this risk at teh Province's 49.9% average share allocation for 2017-18. Hydro One noted that timing for the Motion to Review and appeal is uncertain. It expects the OEB Review to start in Q1 but noted that it could run in to Q2.

11. **Previous risk removed.** OPCD provided IFRS impact estimates (largely related to OPG) at the time of Budget 2017. A portion of these were reflected in in OPG's and Hydro One's net income outlook at the time of the 2017. The current Electricity Outlook now reflects this additional IFRS risk. Table below outlines OPG IFRS Risks versus what is built into the 2017 Budget Fiscal Plan.

	2017-18	2018-19	2019-20	2020-21
OPG IFRS Risk	(400)	(475)	(700)	(750)
Risks Built into Fiscal Plan at 2017 Budget	(400)	0	(200)	0
Additional Risks now picked up in this Electricity Outlook	0	(475)	(500)	(750)

Electricity Sector Outlook (PSAB)

Positive Revenue Risks				
($ millions)	**Plan**			
	2017-18	**2018-19**	**2019-20**	**2020-21**
Generic				
OPG Generation Risk: Nuclear Reliability (+1.1 TWh)[1]	85	85	85	85
1% increase in Hydro One actual load[2]	57	59	61	63
Higher OPG Return on Equity (ROE)[3]	6	22	19	33
Higher Hydro One Return on Equity (ROE)[4]	19	69	50	50
Regulatory				
Accounting				
Other Risks				
ONFA adjustment increase[5]	50			

strategy or updates to AO strategy.

1. OPG's market and generation risks related to nuclear reliability similar to the scenarios OPG developed for its sales margins to capture major market risk factors (e.g., natural gas prices, coal prices, foreign exchange, nuclear reliability) in its 2012 business plan. Currently, only the nuclear reliability risk is captured at the current regulated rate for OPG's nuclear generation.

2. Estimated revenue impact if Hydro One load for Transmission and Distribution is 1% higher than projected for all years in CEFD Hydro One Forecast. Based on the assumption a 1% increase in load is directly proportional to a 1% change in revenue requirements.

3. Risk range for OPG reflects potential risk of higher ROE in 2018-2021 (for nuclear base) vs assumed ROE in OPG's 2016 business plan and corresponding rate application. Assumed ROE is 9.85%, respresenting recent in 2010.

4. Risk range for Hydro One transmission and distribution reflects potential risk of higher ROE vs assumed ROEs in the Hydro One CEFD Forecast for 2018-2021. Assumed ROE is 9.85%, representing recent high in 2010.

5. Reflects risk around the consolidation adjustment to OPG net income, whereby the realized portion of gains or losses of OPG's nuclear funds are added or subtracted from OPG net income. Currently $171M positive adjustment is included in the OPG outlook. The ONFA adjustment is expected to be finalized in February 2018.

ONTARIO ELECTRICITY FINANCIAL CORPORATION
On Deck Outlook as of March 2017

$ Millions

	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Revenue						
Revenue Pool Residual						
Debt Retirement Charge	859	625	623	-	-	-
Payments-in-lieu of tax:						
OPG	268	302	315	366	408	537
Legacy Hydro One (Including Brampton)	2,929	7	2	2	2	2
Hydro One CIT dedicated to OEFC	3	20	20	22	23	25
MEUs	27	44	68	86	105	114
Total PILs & CIT dedicated to OEFC[1]	3,228	373	405	476	538	679
Interest :						
OPG	173	179	168	153	135	135
H1						
IESO	2	3	3	3	3	3
Province	520	492	492	492	492	492
Other	28	10	5	5	5	5
Total Interest	723	684	668	653	635	635
Power Supply Contract Recoveries	875	739	292	325	301	273
Amortization of NUG liability	172	129	74	41	30	28
Electricity sector dedicated income	3	342	525	-	-	-
Gain to OEFC under s. 50.3	172	-	-	-	-	-
Miscellaneous	9	-	-	-	-	-
	6,041	2,893	2,587	1,495	1,504	1,615
Expense						
Debt interest	1,319	1,216	1,090	1,027	977	885
Interest on nuclear risk funding						
Demand Management Support Costs	8	10	10	-	-	-
Amortization of deferred debt costs	-	-	-			
Power Supply Contract Costs	875	739	292	325	301	273
Debt Guarantee fee	127	122	102	91	88	81
Operating	7	6	6	6	6	6
	2,336	2,093	1,500	1,449	1,372	1,245
Excess (Deficiency) of Revenue over Expense	**3,705**	**800**	**1,087**	**46**	**132**	**370**
Prior period adjustment	87					
Stranded Debt - Year End	**4,393**	**3,593**	**2,506**	**2,460**	**2,328**	**1,958**

Note: All the Hydro One ownership broadening impacts, other than the ownership change from the initial IPO in 2015 and the secondary offering in April 2016, were reflected in Sales and Rentals as of the 2017 Budget.

ONTARIO ELECTRICITY FINANCIAL CORPORATION
On Deck Outlook as of October 2017

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Revenue						
Revenue Pool Residual						
Debt Retirement Charge	859	621	623	0	0	0
Payments-in-lieu of tax:						
OPG	268	224	287	342	373	494
Legacy Hydro One (Including Brampton)	2,929	4	2	2	2	2
Hydro One CIT dedicated to OEFC	3	25	20	22	23	25
MEUs	27	112	68	86	105	114
Total PILs & CIT dedicated to OEFC[1]	3,228	364	377	452	503	635
Interest :						
OPG	173	167	169	179	175	148
H1						
IESO	2	2	3	3	3	3
Province	520	514	454	454	454	454
Other	28	20	20	20	10	10
Total Interest	723	703	646	656	642	615
Power Supply Contract Recoveries	875	838	182	183	134	103
Amortization of NUG liability	172	129	74	41	30	28
Electricity sector dedicated income	3	302	24	9	0	48
Gain to OEFC under s. 50.3[2]	172	411	550	0	0	0
Miscellaneous	9	14	0	0	0	0
	6,041	3,382	2,477	1,340	1,309	1,429
Expense						
Debt interest	1,319	1,216	1,121	1,094	1,053	963
Interest on nuclear risk funding						
Demand Management Support Costs	8	8	10	0	0	0
Amortization of deferred debt costs	0	0	0			
Power Supply Contract Costs	875	838	182	183	134	103
Debt Guarantee fee	127	122	102	99	98	91
Operating	7	7	6	7	7	7
	2,336	2,191	1,421	1,383	1,292	1,164
Excess (Deficiency) of Revenue over Expense	3,705	**1,191**	**1,056**	**(42)**	**17**	**265**
Prior period adjustment	87					
Stranded Debt - Year End	4,393	**3,202**	**2,146**	**2,189**	**2,172**	**1,906**

1

Payments-in-lieu of tax:	**2015-16 Public Accounts**
OPG	290
Legacy Hydro One (Including Brampton)	2,941
Hydro One CIT dedicated to OEFC	0
MEUs	15
	3,247

2 2017-18 value preliminary estimate, subject to change.

ONTARIO ELECTRICITY FINANCIAL CORPORATION

Changes from Budget 2017 as of October 2017 **$ Millions**

	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Revenue						
Debt Retirement Charge	(4)	-	-	-	-	
Payments-in-lieu of tax:						
OPG	(78)	(28)	(24)	(35)	(43)	2016-17 decrease largely due to reconciling between OPCD and OEFC net opening assets. OPG PILs also slightly lower than projected. 2017-18 and onward decrease is due to estimated impact of OEB Dec. 29=8, 2017 rate decision.
Legacy Hydro One (Including Brampton)	(3)	-	-	-	-	
Hydro One CIT dedicated to OEFC	5	-	-	-	-	Adjustment based on updated information in Hydro One rate application
MEUs	68	-	-	-	-	Large increase in 2016-17 from $80M payment during transfer of H01 Brampton to new consolidated MEU Alectra.
Total PILs	(9)	(28)	(24)	(35)	(43)	
Interest :						
OPG	(12)	1	26	40	13	Update to OPG interest outlook (wrt interest on OEFC loan).
H1	-	-	-	-	-	
IESO	(1)	-	-	-	-	
Province	22	(38)	(38)	(38)	(38)	2016-17 PDI at ($514m) was slightly larger than ($492m) projected at Interim. 2017-18 change reflects revised projections for Provincial debt interest related to Hydro equity.
Other	10	15	15	5	5	
Total Interest	19	(22)	3	7	(20)	
Power Supply Contract Recoveries	99	(110)	(142)	(167)	(170)	Variance is largely due to retroactive payments that the OEFC made to certain non-utility-generators (NUGs) with former Ontario Hydro power purchase agreement contracts with OEFC. OEFC was required to make these payment following the dismissal by the Supreme Court of Canada of OEFC's application for leave to appeal a judgment of the Court of Appeal of Ontario on a 2015 court decision.
Amortization of NUG liability	0	(0)	(0)	(0)	(0)	
Electricity sector dedicated income	(41)	(501)	9	-	48	The decrease in OEFC ESDI in 2017-18 reflects i) the IFRS adjustment of $400 million in 2017-18 that was not reflected in the OEFC ESDI projection at the time of the 2017 Budget (Note the IFRS adjustment was reflected in OPG net income for the 2017 Budget fiscal plan) and ii) the lower OPG and Hydro One net income due to OEB's 2017 rate decisions. ESDI is alo lowered as the full impact of Hydro One share dispositions is now refelected in lower Hydro One net income tothe Province. Part of this impact was previously reflected in Sales and Rentals. The projected change in 2019-20 and 2020-21 is due to the continuation of ESDI beyond 2017-18 (approved in principle in the current PRRT). In the 2017 Budget outlook, ESDI was assumed to end after 2017-18. ESDI estimates for 2018-19 and 2018-19 are reduced due to negative balances in 2017-18 and 2018-19,
Gain to OEFC under s. 50.3	411	550	-	-	-	
Miscellaneous	14	-	-	-	-	
	489	(111)	(155)	(195)	(186)	
Expense						
Debt interest	-	31	67	76	78	Revised outlook for OEFC debt interest outlook
Interest on nuclear risk funding	-	-	-	-	-	
Demand Management Support Costs	(2)	-	-	-	-	
Amortization of deferred debt costs	-	-	-	-	-	
Power Supply Contract Costs	99	(110)	(142)	(167)	(170)	Same as Power supply contract recoveries above. Power supply contract costs are fully recovered by power supply contract recoveries.
Debt Guarantee fee	-	-	8	10	10	
Operating	1	-	1	1	1	
	98	(79)	(66)	(80)	(81)	
Excess (Deficiency) of Revenue over Expense	**391**	**(31)**	**(88)**			
Stranded Debt - Year End	**3,202**	**2,146**	**2,189**	**2,172**	**1,906**	

Provision for Electricity Sector (Dedicated Electricity Earnings/Electricity Sector Dedicated Earnings)

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Income from Investment in Government Business Enterprises						
OPG Income	291	299	149	137	(7)	156
Hydro One Income[1]	232	501	329	327	388	419
Hydro One Brampton (if applied separately)		15				
Total Income	**523**	**815**	**478**	**463**	**381**	**575**
Public Debt Interest - Electricity Sector						
OPG			(300)	(300)	(300)	(300)
Hydro One[1]			(154)	(154)	(154)	(154)
Public Debt Interest - Electricity Sector (OEFC Interest revenue)	**(520)**	**(514)**	**(454)**	**(454)**	**(454)**	**(454)**
MOF Provision Expense (before adjustments)	**3**	**302**	**24**	**9**	**(73)**	**121**
Other Adjustments						
Prior-year Adjustment[2]		3				
Exclude Brampton[3]		(15)				
MOF Provision Expense (after other adjustments)	**0**	**290**	**24**	**9**	**(73)**	**121**
Cumulative Shortfall Adjustment						
Opening Balance	0	0	0	0	0	(73)
Deduction / (Addition)	0	0	0	0	(73)	73
Ending Balance	0	0	0	0	(73)	0
Dedicated Electricity Earnings (all adjustments) (Public Accounts)	**0**	**290**	**24**	**9**	**0**	**48**
Electricity Sector Dedicated Income (OEFC Annual Report)	**3**	**302**	**24**	**9**	**0**	**48**

Notes:

1. The Hydro One financials above now reflects the Provincial share allocation as of January 2018.

2. 2016-17 Adjustment was due to the discrepancy between the numbers in MOF expense in PA 2015-16 and OEFC Financials in 2015-16 due to timing issues. $3M adjustment rectifies this discrepancy

3. Brampton was excluded from the Ministry of Finance's ESDI allocation.

Ontario Power Generation

OPG Income - Budget 2017

$ Millions

	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
OPG Net Income After Tax (Adjusted)	291	304	97	732	625	1,066
OPG Net Income After Tax	*291*	*379*	*480*	*678*	*726*	*913*
Extraordinary Gains	-	-	-	-	-	-
GA - OPG Trust Interest Revenue			*17*	*54*	*99*	*153*
OPG IFRS consolidation risk picked up in Fiscal Plan		(75)	(400)		(200)	
ONFA and other Fair Value Adjustments	(75)	8				
ONFA Adjustments	-	8				
Other Fair Value Adjustments	(75)					

OPG PIL - Budget 2017

$ Millions

	Actual	Interim		Pl
	2015-16	2016-17	2017-18	2018-19
Net Income Before Tax	383	396	572	867
Net Income After Tax (Adjusted)	291	304	97	732
Income Taxes	92	92	92	135
GRC: Payable to OEFC	198	196	205	212
Proxy Property Tax	16	14	18	19
Ontario Capital Tax	0	0	0	0
Total	**306**	**302**	**315**	**366**

OPG Income - January 2018

$ Millions

	Actual	Actual	Current Outlook			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
OPG Net Income	291	377	857	678	726	913
Adjustment for OPG HQ gain on sale[1]			(283)			
Unpacking updated OPG Gain on sale (net income)			283.27			
OEB December 28, 2017 Rate Decision Impact[2]			(320)	(109)	(115)	(136)
Extraordinary Gains	0	0	0	0	0	0
GA Financing - OPG Trust Interest Revenue[3]			12	42	82	128
OPG IFRS consolidation risk reflected in Fiscal Plan[4]		(78.00)	(400)		(200)	
Update IFRS Risk			0	(475)	(500)	(750)
OPG Net Income (Adjusted before ONFA)	**291**	**299**	**149**	**137**	**(7)**	**156**
ONFA Adjustments	247	49	171			
Other Fair Value Adjustments	(75)	(6)				
ONFA and other Fair Value Adjustments	**172**	**43**	**171**			
OPG Net Income	**463**	**342**	**320**	**137**	**(7)**	**156**

OPG PIL - January 2018

$ Millions

	Actual	Actual		Current
	2015-16	2016-17	2017-18	2018-19
Income Before Tax	383	308	723	235
OPG Net Income (Adjusted before ONFA)	291	299	149	137
OPG Income Tax (PILs)	92	9	162	135
OEB December 28, 2017 Rate Decision Impact[2]			(107)	(36)
Tax adjustment for OPG HQ gain on sale[1]			(95)	
Unpack PILs related to HQ gain on sale			95	
GRC: Payable to OEFC	198	201	214	224
Proxy Property Tax to OEFC	16	14	18	19
Ontario Capital Tax	0	0	0	0
Total OPG PILs	**306**	**224**	**287**	**342**

1. OPG's May 2017 head office facilities sale impacts are re-categorized from Sales and Rentals to OPG net income and PILs in the current Electricity Outlook update.
2. OEB December 28, 2017 estimated rate decision impacts are split between net income and PILs and a 75%/25% basis.
3. This reflects interest earnings on GA financing costs which are consolidated back to Province
4. See Risks tab for IFRS impacts that were not reflected in Fiscal Plan, and table below.

	2017-18	2018-19	2019-20	2020-21
OPG IFRS Risk	(400)	(475)	(700)	(750)

Hydro One Ownership Calculation:		SOURCE:
Total number of shares outstanding[1]	595,000,000	1. Hydro One Ltd Annual Report 2015, pg 94 of PDF, pg 92 of the Report.
Additional Common Shares Issued since IPO	386,711	
IPO November 2015		
Initial Public Offering(2015)[2]	81,100,000	2. From news release: http://hydroone.mediaroom.com/2015-11-05-Hydro-One-Limited-Announces-Closing-of-IPO
Over allotment option (2015)[3]	8,150,000	3. From news release: http://hydroone.mediaroom.com/2015-11-12-Hydro-One-Limited-Announces-Closing-of-IPO-Over-Allotment-Option
Sales to PWU/SEP Trusts	5,646,340	
Total	94,896,340	
Province's remaining ownership, Nov 2015 (# Shares)	**500,103,660**	
Province's remaining ownership, Nov 2015 (%)	**84.05%**	
Secondary Offering April 2016		
Secondary Offering (2016)	72,434,800	4. Hydro One Ltd. Q2 Report, pg 1 http://www.hydroone.com/InvestorRelations/FinancialReporting/Documents/Hydro%20One%20Ltd%20Second%20Quarter%20
Over allotment option (2016)	10,865,200	
Total	83,300,000	
Province's remaining ownership, Apr 2016 (# Shares)	**416,803,660**	
Province's remaining ownership, Apr 2016 (%)	**70.05%**	
Final Offering May 2017		
Final Offering (2017)	120,000,000	Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by-the-Provin
Over allotment option (2017)	-	Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by-the-Provin
Total	120,000,000	
Province's remaining ownership, May 8, 2017 (# Shares)	296,803,660	Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by-the-Provin
Province's remaining ownership, May 8, 2017 (%)	**49.88%**	
First Nations Sale, closed on December 29, 2017	14,391,012	Source: http://www.S:\Users\CEF\Hydro 2018\OEFC\RbP\Outlook\01. January\Backup\20180103-0 - H1 First Nations Sales\
	2.4170865%	Source: https://news.ontario.ca/mei/en/2017/05/ontario-raises-28-billion-from-final-hydro-one-share-offering.html
Province's remaining onwership - post First Nations Sale (#Shares)	282,412,648	
Province's remaining onwership - post First Nations Sale (%)	**47.43%**	
Avista Impact (projected closing date 2nd half of 2018)		
Contingent Convertible Debenture	$1,540,000,000	
Conversion Price	$21	
Potential Dilution (# Shares)	71,962,617	
Revised Total number of shares outstanding	**666,962,617**	
Province's remaining onwership - post Avista Acquisition (#Shares)	282,412,648	
Province's remaining onwership - post Avista Aquisition (%)	**42.34%**	

Ownership Percentage in 2017-18 Fiscal Year	Number of Months	Percentage of Year
70.05%	1	8.3%
49.88%	8	66.7%
47.43%	3	25.0%
	12	
Average 2017-18 FY Ownership:	**51.0%**	

Ownership Percentage in 2018-19 Fiscal Year (assume Avista closing end of September 2018)	Number of Months	Percentage of Year
47.43%	6	50.0%
42.34%	6	50.0%
	12	
Average 2018-19 FY Ownership:	**44.9%**	

Ownership Percentage in 2019-20 Fiscal Year Onwards
42.34%

Accretive to earnings per share and cash flow for Hydro One in the first full year post closing
above is from Hydro One transaction overview. Check what this means for timing of additional shares and /or earnings.

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Hydro One Net Income and PILs

Hydro One Income - Budget 2017
($ millions)

	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Hydro One Net Income After Tax	685	737	742	802	862	931
Hydro One - Unrealized Gains Adjustment						

2016-17 to 2020-21 from CEFD Hydro One 2016 model.

Hydro One PIL - Budget 2017
($ millions)

	2015-16	2016-17	2017-18	2018-19
Net Income After Tax	685	737	742	802
Income Taxes PILs	132	160	181	205
Proxy Property Tax	2	2	2	2
Ontario Capital Tax	0	0	0	0
Total	**134**	**162**	**183**	**207**

Hydro One Income - December 2017
($ millions) **$ Millions**

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Hydro One Net Income After Tax			645	690	780	845
Debenture Costs Impacts (After Tax)			(34)	(39)		
Hydro One Net Income After Tax - Including Adjustments	670	680	612	651	780	845
Hydro One - Net Income Attributable to Preferred Shareholders	15	18				
Hydro One - Unrealized Gains Adjustment						

Hydro One (100% Ownership)
($ millions) **$ Millions**

	Actual 2015-16	Actual 2016-17	2017-18	Current 2018-19
Net Income After Tax - Common Shares	670	680	612	651
Net Income After Tax - Preferred Shares	15	18		
Income Taxes PILs	132	160	181	205
Proxy Property Tax	2	2	2	2
Ontario Capital Tax	0	0	0	0

Public Debt Interest and Section 50.3 payments

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Hydro One Public Debt Interest and Section 50.3 payments						
Government Annual Interest Costs - Hydro One	220	220	220	220	220	220
Reduction in Interest Costs due to Broadening[1]		(29)	(66)	(66)	(66)	(66)
Province Annual Interest Costs - Hydro One Debt	**220**	**191**	**154**	**154**	**154**	**154**
Province Annual Interest Cost - OPG Debt	300	300	300	300	300	300
Total Public Debt Interest	**520**	**514**	**454**	**454**	**454**	**454**

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Gain to OEFC under s. 50.3	172	411	550	0	0	0

1. The Hydro One reduction in interest costs above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering are currently reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

ID# (Track Cha	Fiscal Year	alue (Hardcode	Value (Linked)	Description	Source Details	Source (Link)
20170501-2	2016-17	411,152,733	411,152,733	s 50.3 Gain for	Calculation provided by SIFB	
20170501-3	2016-17	29	29	Reduction in Int	Internal Calculation	
20170501-3	2017-18	66	66	Reduction in Int	Internal Calculation	
20170501-3	n/a	220	220	Annual Interest	Internal Calculation	

ID# (Track Cha	Fiscal Year	alue (Hardcode	Value (Linked)	Description	Source Details	Source (Link)
n/a	n/a	5126		($M) Provinces	OEFC 1999-2000 FS, pg 24	
n/a	n/a	5.85%		Annual Interest	OEFC 1999-2000 FS, pg 26	
		299.871				

OPG's Annual Interest Costs: 300

20170713-1	2016-17	-513,768,361	Provincial interest cost for equity investment in OPG, H1 in 2016-17 Monthly Balances Sheet (from FTD) S:\Users\CEF\Hydro 2017\OEFC\RbP\Outlook\07. July\Backup\20170713-1\interest fr

om Province.pdf

PROVINCIAL CONSOLIDATION ADJUSTMENTS
Ontario Nuclear Funds Agreement

Adjustment for Change in OPG Reported Net Income

Adjustment for DSF Unrealized Earnings

Unrealized Earnings as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Bruce Variance Account Adjustment
OPG Net Income Adjustment

Adjustment for UFSF Unrealized Earnings

Unrealized Earnings as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Bruce Variance Account Adjustment
OPG Net Income Adjustment

Unrealized Earnings -- Fiscal YTD

Adjustment for Change in Due to Province

Adjustment for DSF Due to Province
Due to Province (cost basis) as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Change in Due to Province -- Fiscal YTD

Adjustment for UFSF Due to Province

Due to Province (cost basis) as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Change in Due to Province -- Fiscal YTD

Provincial Consolidation Adjustment

Other Data

	Actual 2016-17	2017-18
Debt Retirement Charge	621	0

	2016-17	2017-18
Power Supply Contract Recoveries	838	182

	2016-17	2017-18
Interest		
OPG	167	169
IESO	2	3
Other (Net)	20	20
Expense		
Debt interest	1216	1121

	Actual 2016-17	2017-18
MEU - PIL Income Tax	109.8	
MEU - PIL Property Tax	0.6	
MEU - GRC	1.2	
TOTAL MEU PILs	111.6	

	Actual 2016-17	2017-18
Miscellaneous/Other (OEFC FS)	14	
Demand Management Support Costs (IEI)	8	10
Operating [Expense]	7	6
Interest on nuclear risk funding	-	-
Amortization of deferred debt costs	-	-
Amortization of NUG liability	129	74
Debt Guarantee Fee	122	102

Expense (Electrictiy Summary Tab)		
Other (Finance)	-7	-6
Demand Management Support Costs (IEI)	-8	-10
Debt Guarantee Fee	(122)	(102)

Plan		
2018-19	2019-20	2020-21
0	0	0

Plan		
2018-19	2019-20	2020-21
183	134	103

Plan		
2018-19	2019-20	2020-21
179	175	148
3	3	3
20	10	10
1094	1053	963

Plan		
2018-19	2019-20	2020-21

Plan		
2018-19	2019-20	2020-21
7	7	7
-	-	-
-	-	-
41	30	28
99	98	91
-7	-7	-7
(99)	(98)	(91)

ID# (Track Changes	Fiscal Year	Value (Hardcoded)	Value (Linked)
20170510-2	2016-17	$ 739,216,115	
20170510-2	2017-18	$ 291,629,707	
20170510-2	2018-19	$ 324,906,017	
20170510-2	2019-20	$ 300,648,570	
20170510-2	2020-21	$ 273,240,858	
20170501-4	2016-17	179	179
20170501-4	2017-18	169	169
20170501-4	2018-19	179	179
20170501-4	2019-20	175	175
20170501-4	2020-21	148	148
20170501-5	2016-17	1216	1,216
20170501-5	2017-18	1121	1,121
20170501-5	2018-19	1094	1,094
20170501-5	2019-20	1053	1,053
20170501-5	2020-21	963	963
20170731-3	2016-17	621	
20170811-1	2016-17	109.8	
20170811-1	2016-17	0.6	
20170811-1	2016-17	1.2	
20170815-5	2016-17	$ 838,000,000	
20170815-6	2016-17	$ 14,000,000	
20170815-8	2016-17	8	
20170815-9	2017-18	10	
20170815-10	2016-17	7	
20171211-2	2017-18	6	6
20171211-2	2018-19	7	7
20171211-2	2019-20	7	7
20171211-2	2020-21	7	7
20170815-7	2016-17	167	
20170815-7	2016-17	2	
20170815-7	2016-17	20	
20170815-7			

ID# (Track Changes	Fiscal Year	Value (Hardcoded)	Value (Linked)
20170905-1	2016-17	129	129
20170905-1	2017-18	74	74

20170905-1	2018-19	41	41
20170905-1	2019-20	30	30
20170905-1	2020-21	28	28
20170905-2	2016-17	122	
20170906-1	2017-18	3	3
20170906-1	2018-19	3	3
20170906-1	2019-20	3	3
20170906-1	2020-21	3	3
20170906-1	2017-18	20	5
20170906-1	2018-19	20	5
20170906-1	2019-20	10	5
20170906-1	2020-21	10	5
20171211-0	2017-18	1121	1,121
20171211-0	2018-19	1094	1,094
20171211-0	2019-20	1053	1,053
20171211-0	2020-21	963	963
20171211-1	2017-18	102	102
20171211-1	2018-19	99	99
20171211-1	2019-20	98	98
20171211-1	2020-21	91	91
20171211-1			
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20171211-1			
20171211-1			
20171211-1			

ID# (Track Changes	Fiscal Year	Value (Hardcoded)	Value (Linked)
20180104-2	2017-18	$ 181,776,685	
20180104-2	2018-19	$ 182,785,215	
20180104-2	2019-20	$ 133,962,519	
20180104-2	2020-21	$ 102,554,665	

Description	Source Details	Source (Link)
The table below contains an updated preliminary N	SPFB Estimates, Email	
• The tables below provides both last year's submission for NUG costs by CEFD and this year's estimates (both of which exclude HST) based on the most recent NUG model.	SPFB Estimates, BN SPFB Estimates, BN SPFB Estimates, BN SPFB Estimates, BN	
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
Updating DRC from OEFC AR (Drafts)	2017 OEFC DRAFT FS	S:\Users\CEF\Hydro 2017\OEFC'
MEU - PIL Income Tax	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
MEU - PIL Property Tax	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
MEU - GRC	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
Updating to actuals	2017 OEFC AR	2017 OEFC Annual Report - Eng
Updating to actuals	2017 OEFC AR	2017 OEFC Annual Report - Eng
Updating to Actuals	2017 OEFC AR	S:\Users\CEF\Hydro 2017\OEFC'
OEFC 2017-18 IEI/Demand Management Suppor	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Operating Expense - Updating to Actuals	2017 OEFC AR	S:\Users\CEF\Hydro 2017\OEFC'
Revised Operating Expense from FTD Forecast	FTD - October PRRT	
OPG Interest Revenue - Actuals 2016-17	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
IESO Interest Revenue - Actuals 2016-17		
Other (Net) Interest Revenue - Actuals 2016-17		

Description	Source Details	Source (Link)
		S:\Users\CEF\Hydro 2017\OEFC'
	Amortization Schedule.	S:\Users\CEF\Hydro 2017\OEFC'

Sourcing the NUG liability amortization schedule.	Tab: Summary Fiscal Impact	S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Gurantee Fee - Updating to Actuals	2017 OEFC AR (pg 13 (	\\ofina.on.ca\ofadfs\Users\CEF\H
IESO Interest Revenue Plan	OEFC Revenue Forecast for Board - April 2017	\\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H
Other Interest Revenue Plan		\\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H
OEFC Debt Interest Expense (no change, just re-linking)	FTD - October PRRT	S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Guarantee Fee	FTD - October PRRT	S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC'

Description	Source Details	Source (Link)
Updated FY 2017-18 estimates of NUG costs	SPFB Estimates, BN	Power Purchases and Sales Fore
Updated FY 2017-18 estimates of NUG costs	SPFB Estimates, BN	Power Purchases and Sales Fore
Updated FY 2017-18 estimates of NUG costs	SPFB Estimates, BN	Power Purchases and Sales Fore
Updated FY 2017-18 estimates of NUG costs	SPFB Estimates, BN	Power Purchases and Sales Fore

\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
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\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board

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\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
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\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board

\RbP\Outlook\07. July\Backup\20170731-3 - DRC Update\2017 OEFC Annual Report - English - DRAFT.PDF

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\RbP\Outlook\08. August\Backup\20170811-1 - Updating PILs for 2016-17\OEFC 2016-17 Pils summary.pdf

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\RbP\Outlook\08. August\Backup\20170815-8 - 2016-17 Demand Management Support Costs (IEI)\2017 OEFC
\RbP\Outlook\08. August\Backup\20170815-9 - 2017-18 Demand Management Support Costs (IEI)\OEFC rever
\RbP\Outlook\08. August\Backup\20170815-10 - 2016-17 Operating (Expense)\2017 OEFC Annual Report - Enc

\RbP\Outlook\08. August\Backup\20170815-7 - 2016-17 Updated Interest on Debt Revenue\RE Revised OEFC

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ydro 2017\OEFC\RbP\Outlook\09. September\Backup\20170906-1 - OEFC Revenue Forecast for Board
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\RbP\Outlook\12. December\Backup\20171211-1 - Interest Numbers from FTD\OEFC forecast PRRT planning_
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Colour Codes

Formulas are in black text

Hard coded numbers are in blue text

References elsewhere are in purple

Green bold text with or without highlights mean updates required

Policies to follow when making updates to the Outlook

*** To quickly jump to the source numbers for a link, press "**Ctrl + [**"

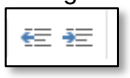
All new numbers must be fully sourced, and follow the colour codes above

Most numbers and text are Arial Size 10, unless it is a title

Add back up materials in a folder with the same numbers as in the 'Track Changes' tab

If there is a reason for italics, or other colours, or formatting make sure it is clear. Othe

Use indents to make things more clear to read



If numbers are taken from another tab they should ONLY be direct links, no calculation

Electricity Summary - (Budget17/On Deck) - Reflects Public Accounts/Financial Statem

OEFC - (Budget17/On Deck) - Reflects OEFC Annual Reports

*Due to slight discrepancies between Public Accounts reporting and OEFC Annual Rep

Outlook Updates Frequency

Frequency	Description	Tab
Monthly	OPG Net Income in-year forecast	OPG
Monthly	OPG PILs in-year forecast	OPG
Quarterly	ONFA Consolidation Adjustment	ONFA
Quarterly	OPG Cash vs Accrual Variance Account	Revenue (Risks)

ɔ.
rwise expect it to be cleared

ı, adjustment should be done. Even if its just making a negative to a positive. Perform all the calculations on the

ıents

ɔorts, the numbers may not be identical

source tab then bring the number into the next tab. (Eg. Formulas like this become hard to troubleshoot ='Hydro

One'!AR29+'Hydro One'!AR31+'Hydro One'!AR32), let's avoid them.

From: Ronald Kwan
To: John Kim
Subject: RE: FAA
Date: Tuesday, October 10, 2017 11:34:35 AM

Hi John,

I'd rather not go DMO-to-DMO. Can Risk wait a couple days, as I try Steen?

Ron

From: John Kim
Sent: October-10-17 11:25
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Subject: FW: FAA

Hi Ron,

Would you mind if I channel this DMO to DMO to get the model to be released? Risk is looking for the update for FES' IOD update potentially.

Thanks,

John

From: Christie, Tim (ENERGY) [mailto:Tim.Christie@ontario.ca]
Sent: Wednesday, September 27, 2017 8:56 AM
To: John Kim <John.Kim@ofina.on.ca>
Subject: RE: FAA

We're still going back and forth with OPG on that so it's not quite landed yet. If Ron's coming to the 8am tomorrow he could raise it with the DM to give me clearance to share.

Tim

From: John Kim [mailto:John.Kim@ofina.on.ca]
Sent: September-26-17 4:22 PM
To: Christie, Tim (ENERGY)
Subject: RE: FAA

You may refer it as the residential bill forecast. It's be the updated version of the earlier model you shared with us on the FHP, accumulated debt, interest, etc.

From: Christie, Tim (ENERGY) [mailto:Tim.Christie@ontario.ca]
Sent: Tuesday, September 26, 2017 3:03 PM

To: John Kim <John.Kim@ofina.on.ca>
Subject: RE: FAA

Hi John, what are you looking for? Updated residential bill forecasts?

Tim

From: John Kim [mailto:John.Kim@ofina.on.ca]
Sent: September-26-17 2:59 PM
To: Christie, Tim (ENERGY)
Subject: FW: FAA

Hi Tim,

Would you have the modelling you can share?

Some parts of the OFA are working on some guarantee fee estimates.

Thanks,

John

From: Cayley, Daniel (ENERGY) [mailto:Daniel.Cayley@ontario.ca]
Sent: Tuesday, August 22, 2017 12:49 PM
To: John Kim <John.Kim@ofina.on.ca>
Subject: RE: FAA

Hi John – things are still in flux – nothing to share as of now I'm afraid.

Regards,

Daniel

From: John Kim [mailto:John.Kim@ofina.on.ca]
Sent: August 22, 2017 10:42 AM
To: Cayley, Daniel (ENERGY)
Subject: FW: FAA

Hi Daniel….could you let me know?

From: John Kim
Sent: Tuesday, August 22, 2017 10:41 AM
To: Tim Christie (ENERGY) <Tim.Christie@ontario.ca>
Subject: RE: FAA

Hi Tim,

Would you have latest set of modelling tables available? We are working on various submissions (including one related to provincial guarantee for OPG) where we require at least the latest set of numbers.

Thanks,

John

From: Christie, Tim (ENERGY) [mailto:Tim.Christie@ontario.ca]
Sent: Monday, August 14, 2017 4:28 PM
To: John Kim <John.Kim@ofina.on.ca>
Subject: RE: FAA

Hi John, many things have been updated including the underlying residential bill forecast as well as the FAA analysis that Navigant undertook. A few of the inputs are still undergoing revision so the product is not yet final.

Tim

From: John Kim [mailto:John.Kim@ofina.on.ca]
Sent: August-14-17 4:12 PM
To: Christie, Tim (ENERGY)
Subject: FAA

Hi Tim,

I have a couple of questions. The deck on LTEP had a number of slides that seemed to have updated information since the Cabinet submission numbers.

Where the slides refer to 'Direct to FAA', do the figures reflect simply updated cost information or also the fair allocation concept.

Where are you guys in terms of the modelling….are you updating the numbers/scenarios in the slides?

If you prefer, happy to chat over the phone.

John

Y. John Kim
Director, Electricity Finance Branch
Ontario Financing Authority
e-mail: john.kim@ofina.on.ca
Ph: 416-212-6996

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From:	John Kim
To:	Ronald Kwan; Shajee Kathirgamanathan; Usman Zahid
Cc:	Bruno Amara; Gavin He
Subject:	RE: FES Items for Today
Date:	Friday, November 10, 2017 3:17:47 PM
Attachments:	1. Electricity Sector Outlook (2017 10 20v4)_Sent.pdf

Hi Ron,

Yes, and here it is with revision.

Thanks,

John

From: Ronald Kwan
Sent: Friday, November 10, 2017 3:09 PM
To: Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Usman Zahid <Usman.Zahid@ofina.on.ca>
Cc: John Kim <John.Kim@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>
Subject: RE: FES Items for Today

Hi,

I'd rather put it differently.

The Outlook presents potential in-year pressures (positive and negative) that may be offset as the year progresses. The Electricity Finance Branch will continue to monitor and communicate with other divisions on when and if the fiscal plan is to be updated for the electricity sector. At the time of the Fall Economic Outlook and Fiscal Review, the fiscal plan has not been updated to reflect the information on pressures contained here.

Is that the only text added?

Ron

From: Shajee Kathirgamanathan
Sent: November-10-17 14:26
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; Usman Zahid <Usman.Zahid@ofina.on.ca>
Cc: John Kim <John.Kim@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>
Subject: RE: FES Items for Today

Hi Ron,

Please see revised Outlook file with the disclaimer on the first page.

If it looks good then this file can be sent back with the initial OFHP supporting data pdf sent earlier for inclusion in the binder.

Thanks,
Shajee

Shajee Kathirgamanathan
Office: 416-325-1402 | Mobile: 647-294-3359
shajee.kathirgamanathan@ofina.on.ca

From: Ronald Kwan
Sent: Friday, November 10, 2017 12:20 PM
To: Usman Zahid <Usman.Zahid@ofina.on.ca>
Cc: John Kim <John.Kim@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>
Subject: RE: FES Items for Today

Hi,

Could we note on the Outlook file that these are potential pressures at a point in time, but it was not recommended for FES itself to pick up any of the pressures? As such, fine to send both for proposed inclusion.

Thanks,
Ron

From: Usman Zahid
Sent: November-10-17 10:52
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: John Kim <John.Kim@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>
Subject: FW: FES Items for Today

Hi Ron,

Attached are two items for inclusion into the TB/MBC Binder. The first item is a PDF version of the Electricity Sector Outlook (similar to what was submitted previously). The second item is information on the financing of FHP. EFB have said they are open to omitting the second item if appropriate.

Regards,
Usman

From: Shajee Kathirgamanathan
Sent: Friday, November 10, 2017 10:37 AM
To: Usman Zahid <Usman.Zahid@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>
Subject: RE: FES Items for Today

Hi Usman,

Please find attached the two documents for inclusions into EFB's portion of the TB Binder.

1) PDF'ed version of the Electricity Sector Outlook. Similar to what we submitted last time
2) Information we received on the financing of the Fair Hydro Plan. We didn't use this information per se, so we're open to omitting it should it be decided to exclude.

Files saved here:
S:\Users\CEF\Hydro 2017\FES\TB Binder\EFB

Thanks,
Shajee

Shajee Kathirgamanathan
Office: 416-325-1402 | Mobile: 647-294-3359
shajee.kathirgamanathan@ofina.on.ca

From: Usman Zahid
Sent: Friday, November 10, 2017 9:33 AM
To: John Kim <John.Kim@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>
Subject: FES Items for Today

Hi All,

TB/MBC Binder Materials: Due by noon, please get to Ron ASAP.

Placemats: Due at 2pm, please get in right after TB/MBC binder Materials.

Regards,
Usman

The Outlook presents potential in-year pressures (positive and negative) that may be offset as the year progresses. The Electricity Finance Branch will continue to monitor and communicate with other divisions on when and if the fiscal plan is to be updated for the electricity sector. At the time of the Fall Economic Outlook and Fiscal Review, the fiscal plan has not been updated to reflect the information on pressures contained here.

Electricity Sector Outlook

October 2017

Disclosure:

All information contained in this workbook is confidential and commercially sensitive

All projected numbers are estimates and subjected to change

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Electricity Sector Outlook
Including Line Items for Consolidation

Electricity Summary - On Deck

			MOF Expense Items (consolidated)	Current Outlook			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**38**	Power Supply Contract Costs	(292)	(325)	(301)	(273)
Expense	**MOF (OEFC)**	**40**	Demand Management Support Costs	(10)	-	-	-
Expense	**MOF (OEFC)**	**41**	Provision for Electricity Sector	140	-	-	-
Expense	**MOF**	**17**	Provision for Electricity Sector	(140)	-	-	-
Expense	**MOF (OEFC)**	**42**	Other (Finance)	(6)	(6)	(6)	(6)
			Total MOF Expense	**(308)**	**(331)**	**(307)**	**(279)**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**7**	OPG Income	147	720	608	1,041
Revenue	**ENE**	**8**	OPG - ONFA and other Fair Value Adjustments	-	-	-	-
Revenue	**ENE**	**10**	HOI Income	447	484	566	612
Revenue		**11**	Brampton Income	-	-	-	-
Revenue	**MOF (OEFC)**	**26**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	381	479	531	668
Revenue	**MOF (OEFC)**	**29**	Electricity Debt Retirement Charge	623	-	-	-
Revenue	**MOF (OEFC)**	**30**	Power Supply Contract Recoveries	292	325	301	273
Revenue	**MOF (OEFC)**	**31**	Net Reduction of Power Purchase Contracts	74	41	30	28
Revenue	**MOF (OEFC)**	**34**	Miscellaneous	-	-	-	-
			Total MOF Revenue	**1,964**	**2,049**	**2,036**	**2,623**
			OFA IOD Expense				
			Public Debt Interest - Electricity Sector	(454)	(454)	(454)	(454)
			Interest on Debt	(475)	(438)	(411)	(348)
			Total OFA IOD Expense	**(929)**	**(892)**	**(865)**	**(802)**
			Impact on Surplus/Deficit	**727**	**826**	**864**	**1,542**
			check	**-**	**-**	**-**	**-**

Electricity Summary - Budget 17

	For Discussion		MOF Expense Items (consolidated)	Plan			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**38**	Power Supply Contract Costs	(292)	(325)	(301)	(273)
Expense	**MOF (OEFC)**	**40**	Demand Management Support Costs	(10)	0	0	0
Expense	**MOF (OEFC)**	**41**	Provision for Electricity Sector	125	0	0	0
Expense	**MOF**	**17**	Provision for Electricity Sector	(125)	0	0	0
Expense	**MOF (OEFC)**	**42**	Other (Finance)	(6)	(6)	(6)	(6)
			Total MOF Expense	**(308)**	**(331)**	**(307)**	**(279)**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**7**	OPG Income	97	732	625	1,066
Revenue	**ENE**	**8**	OPG - ONFA and other Fair Value Adjustments	0	0	0	0
Revenue	**ENE**	**10**	HOI Income	520	562	603	652
			Brampton Income				
Revenue	**MOF (OEFC)**	**25**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	405	476	538	679
Revenue	**MOF (OEFC)**	**29**	Electricity Debt Retirement Charge	623	0	0	0
Revenue	**MOF (OEFC)**	**30**	Power Supply Contract Recoveries	292	325	301	273
Revenue	**MOF (OEFC)**	**31**	Net Reduction of Power Purchase Contracts	74	41	30	28
Revenue	**MOF (OEFC)**	**34**	Miscellaneous	0	0	0	0
			Total MOF Revenue	**2,011**	**2,136**	**2,098**	**2,697**
			OFA IOD Expense				
		17	Public Debt Interest - Electricity Sector	(492)	(492)	(492)	(492)
		36	Interest on Debt	(422)	(374)	(342)	(250)
			Total OFA IOD Expense	**(914)**	**(866)**	**(834)**	**(742)**
			Impact on Surplus/Deficit	**789**	**939**	**957**	**1,676**
			check	**-**	**-**	**-**	**-**

Electricity Summary - Change

			MOF Expense Items (consolidated)	Variance from Plan			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**69**	Power Supply Contract Costs	0	0	0	(0)
Expense	**MOF (OEFC)**	**71**	Demand Management Support Costs	0	0	0	0
Expense	**MOF (OEFC)**	**72**	Provision for Electricity Sector	15	0	0	0
Expense	**MOF**	**48**	Provision for Electricity Sector	(15)	0	0	0
Expense	**MOF (OEFC)**	**73**	Other (Finance)	0	0	0	0
			Total MOF Expense	**0**	**0**	**0**	**(0)**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**38**	OPG Income	50	(12)	(17)	(24)
Revenue	**ENE**	**39**	OPG - ONFA and other Fair Value Adjustments	0	0	0	0
Revenue	**ENE**	**41**	HOI Income	(73)	(78)	(38)	(40)
			Brampton Income	0	0	0	0
Revenue	**MOF (OEFC)**	**25**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	(24)	3	(7)	(10)
Revenue	**MOF (OEFC)**	**60**	Electricity Debt Retirement Charge	0	0	0	0
Revenue	**MOF (OEFC)**	**61**	Power Supply Contract Recoveries	(0)	(0)	(0)	0
Revenue	**MOF (OEFC)**	**62**	Net Reduction of Power Purchase Contracts	(0)	(0)	(0)	(0)
Revenue	**MOF (OEFC)**	**65**	Miscellaneous	0	0	0	0
			Total MOF Revenue	**(47)**	**(87)**	**(62)**	**(74)**
			OFA IOD Expense				
		17	Public Debt Interest - Electricity Sector	38	38	38	38
		36	Interest on Debt	(53)	(64)	(69)	(98)
			Total OFA IOD Expense	**(15)**	**(26)**	**(31)**	**(60)**
			Impact on Surplus/Deficit	**(62)**	**(113)**	**(93)**	**(134)**
			check	***-***	***0***	***(0)***	***(0)***

Electricity Sector Outlook	$ Millions					
	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
On Deck Outlook as of March 2017						
Income from Investment in Government Business Enterprises						
OPG Income[1]	291	304	97	732	625	1,066
OPG - ONFA and other Fair Value Adjustments[2]	172	8	-	-	-	-
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	-
HOI Income[3]	236	516	520	562	603	652
Brampton Income	20	15	-	-	-	-
Total OPG and HOI Income	**719**	**842**	**617**	**1,294**	**1,229**	**1,717**
Other Fees and Licences	**127**	**122**	**102**	**91**	**88**	**81**
Electricity Expenses of the Province						
Provision for Electricity Sector[4]	(3)	(342)	(125)		-	-
Public Debt Interest - Electricity Sector	(520)	(492)	(492)	(492)	(492)	(492)
Subtotal	(523)	(834)	(617)	(492)	(492)	(492)
Public Debt Interest - Impact of ONFA						
Amortization of Deferred Revenue re profit on sale of H1 notes						
Total Electricity Expenses of the Province	**(523)**	**(834)**	**(617)**	**(492)**	**(492)**	**(492)**
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	3,228	373	405	476	538	679
Other Revenue						
Electricity Debt Retirement Charge[5]	859	625	623	-	-	-
Power Supply Contract Recoveries	875	739	292	325	301	273
Net Reduction of Power Purchase Contracts	172	129	74	41	30	28
Other Fees and Licences	(127)	(122)	(102)	(91)	(88)	(81)
Miscellaneous	9	-	-	-	-	-
Expenses						
Interest on Debt	(596)	(532)	(422)	(374)	(342)	(250)
Power Supply Contract Costs	(875)	(739)	(292)	(325)	(301)	(273)
Electricity Consumer Price Protection Fund	-	-	-	-	-	-
Demand Management Support Costs[6]	(8)	(10)	(10)	-	-	-
Provision for Electricity Sector	3	342	125	-	-	-
Other (Finance)	(7)	(6)	(6)	(6)	(6)	(6)
Total OEFC Income	**3,533**	**800**	**687**	**46**	**132**	**370**
Impact on Surplus/(Deficit)	**3,856**	**930**	**789**	**939**	**957**	**1,676**

Notes: The Hydro One net income outlook above (2016-17 to 2020-21) reflects the Province's current 70% ownership share, after the initial IPO in 2015 [and the secondary offering in April 2016]. Net estimated fiscal impacts from future Hydro One offerings are reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

Notes:

1.OPG's 2016-17 outlook reflected its reported earnings. 2017-18 outlook reflects OPG's latest monthly update. Out-years reflect OPG's preliminary 2017-19 business plan and long-term outlook to 2019-20 (as fiscalized by OPG). 2020-21 estimates are based on OPG's calendar year-based business plan projections and as fiscalized by CEFD staff.

2. Provincial consolidation adjustments for unrealized earnings on the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds, as of the end of December 2016.

3. Hydro One 2016-17 income reflects its reported net income, adjusted for Hydro One IPO impacts. 2017-18 to 2020-21 projections are based on CEFD projections using the latest public information. The Hydro One net income outlook above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering are currently reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial ONFA consolidation adjustments, minus the interest on debt payable to OEFC. The provision is currently assumed to end once the DRC ends on a legislated fixed end date of April 1, 2018.

5. Reflects April 23, 2014 announcement that DRC will be eliminated for residential users, after December 31, 2015. The end date of DRC for remaining users is legislated to be on April 1, 2018. Estimates are subject to change based on actual consumption.

6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Electricity Sector Outlook

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
On Deck Outlook as of October 2017						
Income from Investment in Government Business Enterprises						
OPG Income[1]	291	299	147	720	608	1,041
OPG - ONFA and other Fair Value Adjustments[2]	172	43	-	-	-	-
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	-
HOI Income[3]	236	500	447	484	566	612
Brampton Income	20	18	-	-	-	-
Total OPG and HOI Income	**719**	**860**	**594**	**1,204**	**1,174**	**1,654**
Other Fees and Licences (Debt Guarantee fee)	**127**	**122**	**102**	**91**	**88**	**81**
Electricity Expenses of the Province						
Provision for Electricity Sector[4]	-	(290)	(140)			
Public Debt Interest - Electricity Sector	(520)	(514)	(454)	(454)	(454)	(454)
Subtotal	(520)	(803)	(594)	(454)	(454)	(454)
Public Debt Interest - Impact of ONFA						
Amortization of Deferred Revenue re profit on sale of H1 notes						
Total Electricity Expenses of the Province	**(520)**	**(803)**	**(594)**	**(454)**	**(454)**	**(454)**
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	3,247	334	381	479	531	668
Other Revenue						
Electricity Debt Retirement Charge[5]	859	621	623	-	-	-
Power Supply Contract Recoveries	875	838	292	325	301	273
Net Reduction of Power Purchase Contracts	172	129	74	41	30	28
Other Fees and Licences	(127)	(122)	(102)	(91)	(88)	(81)
Miscellaneous	9	14	-	-	-	-
Expenses						
Interest on Debt	(596)	(513)	(475)	(438)	(411)	(348)
Power Supply Contract Costs	(875)	(838)	(292)	(325)	(301)	(273)
Electricity Consumer Price Protection Fund	-	-	-	-	-	-
Demand Management Support Costs[6]	(8)	(8)	(10)	-	-	-
Provision for Electricity Sector	-	290	140	-	-	-
Other (Finance)	(7)	(7)	(6)	(6)	(6)	(6)
Total OEFC Income	**3,549**	**737**	**625**	**(15)**	**56**	**261**
Impact on Surplus/(Deficit)	**3,876**	**915**	**727**	**826**	**864**	**1,542**
variance to OEFC check	*(156)*	*(454)*	*(550)*	*-*	*0*	*-*

Notes:

1.OPG's 2016-17 outlook reflected its reported earnings. 2017-18 outlook reflects OPG's latest monthly update. Out-years reflect OPG's preliminary 2017-19 business plan and long-term outlook to 2019-20 (as fiscalized by OPG). 2020-21 estimates are based on OPG's calendar year-based business plan projections and as fiscalized by CEFD staff.

2. Provincial consolidation adjustments for unrealized earnings on the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds, as of the end of December 2016.

3. Hydro One 2016-17 income reflects its reported net income, adjusted for Hydro One IPO impacts. 2017-18 to 2020-21 projections are based on CEFD projections using the latest public information. The Hydro One net income outlook above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering are currently reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial ONFA consolidation adjustments, minus the interest on debt payable to OEFC. The provision is currently assumed to end once the DRC ends on a legislated fixed end date of April 1, 2018.

5. Reflects April 23, 2014 announcement that DRC will be eliminated for residential users, after December 31, 2015. The end date of DRC for remaining users is legislated to be on April 1, 2018. Estimates are subject to change based on actual consumption.

6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Electricity Sector Change Since Budget

$ Millions

($million)	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Changes from Budget 2017 as of October 2017						
Income from Investment in Government Business Enterprises						
OPG Income	(5)	50	(12)	(17)	(24)	2016-17 small decrease due to IFRS adjustment revision and OPG Net Income revision. 2017-18 increase mainly due to deferral of Pickering Unit 6 planned outage to Jan 18, deferral of sale of land at Hearn site from Q1 2017 to later in 2017, partially offsdet by lower gropss margin.
ONFA and other Fair Value Adjustments	35	-	-	-	-	Largely revision to ONFA fair value as of March 31, 2017
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	
HOI Income	(16)	(73)	(78)	(38)	(40)	2016-17 slight decrease from Budget 2017 Interim projection. 2017-18 onwards reflects impacts of OEB decision on Hydro One rates, interest expense on Avitsa debentures (in 2017-18 and 2018-19) and update to Hydro One model update based on Hydro One Q2 results.
Brampton Income	3.3					
Total OPG and HOI Income	**17**	**(22.9)**	**(90)**	**(55)**	**(64)**	
Other Fees and Licences	**-**	**-**	**-**	**-**	**-**	
Electricity Expenses of the Province						
Provision for Electricity Sector	53	(15)	-	-	-	Changes in the Proviision (ESDI) expense reflect net changes in the outlook for Public Debt Interest, and OPG and HOI net income (excludinging ONFA adjustments).
Public Debt Interest - Electricity Sector	(22)	38	38	38	38	2016-17 PDI at ($514m) was slightly larger than ($492m) projected at Interim. 2017-18 change reflects revised projections for Provincial debt interest related to Hydro equity.
Total Electricity Expenses of the Province	**31**	**23**	**38**	**38**	**38**	
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs)	(40)	(24)	3	(7)	(10)	2016-17 decrease largely due to an OPCD Public Accounts PILs adjustment related to reconciling between OPCD and OEFC net opening assets. OPG PILs also slightly lower than projected.
Other Revenue						
Electricity Debt Retirement Charge	(4)	-	-	-	-	
Power Supply Contract Recoveries	99	(0)	(0)	(0)	0	Variance is largely due to retroactive payments that the OEFC made to certain non-utility-generato (NUGs) with former Ontario Hydro power purchase agreement contracts with OEFC. OEFC was required to make these payment following the dismissal by the Supreme Court of Canada of OEFC's application for leave to appeal a judgment of the Court of Appeal of Ontario on a 2015 co decision.
Net Reduction of Power Purchase Contracts	0.1	(0)	(0)	(0)	(0)	
Other Fees and Licences	-	-	-	-	-	
Revenue Pool Residual	-	-	-	-	-	
Miscellaneous	14	-	-	-	-	Higher than projected at Interim.
Expenses						
Interest on Debt	19	(53)	(64)	(69)	(98)	2016-17 higher than projected at Interim. 2017-18 reflects revised debt interest outlook net of revisions to OEFC interest revenue from OPG and Province.
Power Supply Contract Costs	(99)	0	0	0	(0)	Same as Power supply contract recoveries above. Power supply contract costs are fully recovered by power supply contract recoveries.
Electricity Consumer Price Protection Fund	-	-	-	-	-	
Demand Management Support Costs	1.8	-	-	-	-	
Provision for Electricity Sector	(53)	15	-	-	-	Changes in the Proviision (ESDI) expense (negative expense or revenue to OEFC) reflect net changes in the outlook for Public Debt Interest, and OPG and HOI net income (excludinging ONFA adjustments).
Other (Finance)	(1.0)	-	-	-	-	
Total OEFC Income	**(63)**	**(62)**	**(61)**	**(76)**	**(108)**	
Impact on Surplus/(Deficit)	**(14.6)**	**(62)**	**(113)**	**(93)**	**(134)**	

Information: Breakdown of change between revenue and expense

Total Revenue Impact	87	(47)	(87)	(62)	(74)	
Total Expenditure impact	101	15	26	31	60	

Electricity Sector Outlook (PSAB)

Negative Revenue Risks	$ Millions			
($ millions)	Plan			
	2017-18	2018-19	2019-20	2020-21
Generic				
OPG Generation Risk: Nuclear Reliability (-1.6 TWh)[1]	(120)	(120)	(120)	(120)
1% decrease in Hydro One actual load[2]	(57)	(59)	(62)	(63)
Lower OPG's Equity weighting & Return on Equity (ROE)[3]	(12)	(20)	(26)	(45)
Lower Hydro One Return on Equity (ROE)[4]	(9)	(36)	(38)	(40)
Regulatory				
Hydro One Distribution rate application[5]	(50)	(50)	(50)	(50)
OPG Switch from accrual based to cash based accounting for pension and OPEB[6]	(600)			
Regulatory Risk - Timing of Rate Decision[7]	(540)			
OEB Staff Recommendations wrt OPG rate application(May 2017)[8]	(175)	(143)	(151)	(175)
Nuclear Liabilities Cash vs. Accrual[9]	(450)	(450)	(450)	(450)
OEB decision on Hydro One tax recapture (if one-time write-down)[10]	(251)			
Accounting				
Net OPG IFRS Consolidation Risks - Scenario 1b: 15 year historical, update discount rate each year.[11]	-	(475)	(500)	(750)
Other Risks				
Avista Acquisition - Termination fee		(103)		

Note: These risks do not reflect the impacts on electricity sector revenue and expense of reclassification of the Asset Optimi

1. OPG's market and generation risks related to nuclear reliability similar to the scenarios OPG developed for its sales margins to capture major market risk factors (e.g., natural gas prices, coal prices, foreign exchange, nuclear reliability) in its 2012 business plan. Currently, only the nuclear reliability risk is captured at the current regulated rate for OPG's nuclear generation.

2. Estimated revenue impact if Hydro One load for Transmission and Distribution is 1% lower than projected for all years in CEFD Hydro One Forecast. Based on the assumption a 1% increase in load is directly proportional to a 1% change in revenue requirements.

3. Risk range for Hydro One transmission and distribution reflects potential risk of lower ROE by 0.5% vs assumed ROEs in business plan along with reduced deemed debt to equity weighting of 55%/45% from the current 51%/49%.

4. Risk range for Hydro One transmission and distribution reflects potential risk of lower ROE by 0.5% vs assumed ROEs in CEFD Hydro One Forecast based on the most recent rate applications and forecasted ROE rates.

5. OEB is expected to make a decision on Hydro One's Distibution rate application for 2018 during the first half of 2018.

6. The OEB directed a switch to cash-based accounting for years 2014 and 2015. However, the OEB also directed OPG to track the difference between cash based and accrual based accounting in a deferral account, while a generic proceeding is underway for all OEB-regulated electric and gas utilities. OEB September 2017 Report, recommends continuance of variance account which would mitigate this risk. However, the final decision (expected in Fall 2017) will be with the OEB Board.

7. Risk refelects OPG impact if the OEB rate rulings are applied as of the final decision date rather than retroactive to January 1, 2017 . OPG's business plan assumed OEB decision would be effective as of January 1, 2017. OPG estimated an impact of -$60M for each month for which OEB decsion is not retroactive.

8. Reflects OEB staff report (May 2017) reccomendations with respect to OPG's rate application. (Inlcudes OPG rate application updates).

9. Risk refelects impact of OEB decision that OPG switch to cash-basis accounting for regulated recovery of nuclear payment anmounts. OEB staff report (May 2017) appears to mitigate this risk as it makes no decision and recommends revisiting this issue in 5 years at next OEB application.

10. The OEB's Sep. 28, 2017 ruling on Hydro One's Transmission rate application included direction on sharing, with ratepayers, tax savings related to the Hydro One IPO. The estimated annual ongoing impact of this is factored into the current outlook. This risk reflects the impact if a decision is made by Hydro One that the impact of the ruling has to be accounted for as an immediate one-time write-down.
Note: Corresponding Positive Revenue Risks would also need to be incorporated for 2018-19 to 2020-21 if this risk is to be recognized. The risk reflect ther roughly 50% proncial ownership pending recategorization from teh AO Sales and Rentals outlook.

11. OPCD provided IFRS impact estimates at the time of Budget 2017. A portion of these were reflected in in OPG's and Hydro One's net inc0me outlook. The Risk above reflect the impacts iof IFRS not refelcted in the Budget 2017 fiscal plan.
Table below outlines OPG IFRS Risks versus what is built into the Fiscal Plan.

	2017-18	2018-19	2019-20	2020-21
OPG IFRS Risk	(400)	(475)	(700)	(750)
Risks Built into Fiscal Plan	(400)	0	(200)	0
Additional Risks to be picked up	0	(475)	(500)	(750)

Electricity Sector Outlook (PSAB)

Positive Revenue Risks				
($ millions)	**Plan**			
	2017-18	**2018-19**	**2019-20**	**2020-21**
Generic				
OPG Generation Risk: Nuclear Reliability (+1.1 TWh)[1]	85	85	85	85
1% increase in Hydro One actual load[2]	57	59	61	63
Higher OPG Return on Equity (ROE)[3]	6	22	19	33
Higher Hydro One Return on Equity (ROE)[4]	19	69	50	50
Regulatory				
Hydro One Motion to Review OEB Transmission ruling[5]	40	54	41	43
OEB decision on Hydro One tax recapture (if one-time write-down)[6]		6	7	10
Other Risks				
ONFA adjustment increase (as of September 2017 Q3)[7]	171			

zation strategy or updates to AO strategy.

1. OPG's market and generation risks related to nuclear reliability similar to the scenarios OPG developed for its sales margins to capture major market risk factors (e.g., natural gas prices, coal prices, foreign exchange, nuclear reliability) in its 2012 business plan. Currently, only the nuclear reliability risk is captured at the current regulated rate for OPG's nuclear generation.

2. Estimated revenue impact if Hydro One load for Transmission and Distribution is 1% higher than projected for all years in CEFD Hydro One Forecast. Based on the assumption a 1% increase in load is directly proportional to a 1% change in revenue requirements.

3. Risk range for OPG reflects potential risk of higher ROE in 2018-2021 (for nuclear base) vs assumed ROE in OPG's 2016 business plan and corresponding rate application. Assumed ROE is 9.85%, respresenting recent in 2010.

4. Risk range for Hydro One transmission and distribution reflects potential risk of higher ROE vs assumed ROEs in the Hydro One CEFD Forecast for 2018-2021. Assumed ROE is 9.85%, representing recent high in 2010.

5. On October 18, 2017, Hydro One filed a Notice of Motion to Review and vary the Decision and Order dated September 28, 2017. Upside risks based on Hydro One's motions to vary the OEB decision.

6. The OEB's Sep. 28, 2017 ruling on Hydro One's Transmission rate application included direction on sharing, with ratepayers, tax savings related to the Hydro One IPO. The estimated annual ongoing impact of this is factored into the current outlook. This risk reflects the impact if a decision is made by Hydro One that the impact of the ruling has to be accounted for as an immediate one-time write-down.
Note: Corresponding Negative Revenue Risks would also need to be incorporated for 2017-18 if this risk is to be recognized

7. Reflects consolidation adjustment to OPG net income, whereby the realized portion of gains or losses of OPG's nuclear funds are added or subtracted from OPG net income.

ONTARIO ELECTRICITY FINANCIAL CORPORATION

On Deck Outlook as of March 2017

$ Millions

	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Revenue						
Revenue Pool Residual						
Debt Retirement Charge	859	625	623	-	-	-
Payments-in-lieu of tax:						
OPG	268	302	315	366	408	537
Legacy Hydro One (Including Brampton)	2,929	7	2	2	2	2
Hydro One CIT dedicated to OEFC	3	20	20	22	23	25
MEUs	27	44	68	86	105	114
Total PILs & CIT dedicated to OEFC[1]	3,228	373	405	476	538	679
Interest :						
OPG	173	179	168	153	135	135
H1						
IESO	2	3	3	3	3	3
Province	520	492	492	492	492	492
Other	28	10	5	5	5	5
Total Interest	723	684	668	653	635	635
Power Supply Contract Recoveries	875	739	292	325	301	273
Amortization of NUG liability	172	129	74	41	30	28
Electricity sector dedicated income	3	342	525	-	-	-
Gain to OEFC under s. 50.3	172	-	-	-	-	-
Miscellaneous	9	-	-	-	-	-
	6,041	2,893	2,587	1,495	1,504	1,615
Expense						
Debt interest	1,319	1,216	1,090	1,027	977	885
Interest on nuclear risk funding						
Demand Management Support Costs	8	10	10	-	-	-
Amortization of deferred debt costs	-	-	-			
Power Supply Contract Costs	875	739	292	325	301	273
Debt Guarantee fee	127	122	102	91	88	81
Operating	7	6	6	6	6	6
	2,336	2,093	1,500	1,449	1,372	1,245
Excess (Deficiency) of Revenue over Expense	**3,705**	**800**	**1,087**	**46**	**132**	**370**
Prior period adjustment	87					
Stranded Debt - Year End	**4,393**	**3,593**	**2,506**	**2,460**	**2,328**	**1,958**

Note: All the Hydro One ownership broadening impacts, other than the ownership change from the initial IPO in 2015 [and the secondary offering in April 2016], are in the asset optimisation line (Sales and Rentals) and not in the current Outlook file.

ONTARIO ELECTRICITY FINANCIAL CORPORATION

On Deck Outlook as of October 2017 **$ Millions**

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Revenue						
Revenue Pool Residual						
Debt Retirement Charge	859	621	623	0	0	0
Payments-in-lieu of tax:						
OPG	268	224	299	378	411	539
Legacy Hydro One (Including Brampton)	2,929	4	2	2	2	2
Hydro One CIT dedicated to OEFC	3	25	12	13	13	13
MEUs	27	112	68	86	105	114
Total PILs & CIT dedicated to OEFC[1]	3,228	364	381	479	531	668
Interest :						
OPG	173	167	169	179	175	148
H1						
IESO	2	2	3	3	3	3
Province	520	514	454	454	454	454
Other	28	20	20	20	10	10
Total Interest	723	703	646	656	642	615
Power Supply Contract Recoveries	875	838	292	325	301	273
Amortization of NUG liability	172	129	74	41	30	28
Electricity sector dedicated income	3	302	140	0	0	0
Gain to OEFC under s. 50.3[2]	172	411	550	0	0	0
Miscellaneous	9	14	0	0	0	0
	6,041	3,382	2,706	1,501	1,504	1,585
Expense						
Debt interest	1,319	1,216	1,121	1,094	1,053	963
Interest on nuclear risk funding						
Demand Management Support Costs	8	8	10	0	0	0
Amortization of deferred debt costs	0	0	0			
Power Supply Contract Costs	875	838	292	325	301	273
Debt Guarantee fee	127	122	102	91	88	81
Operating	7	7	6	6	6	6
	2,336	2,191	1,531	1,516	1,448	1,323
Excess (Deficiency) of Revenue over Expense	3,705	**1,191**	**1,175**	**(15)**	**56**	**261**
Prior period adjustment	87					
Stranded Debt - Year End	4,393	**3,202**	**2,027**	**2,042**	**1,985**	**1,724**

1

Payments-in-lieu of tax:	2015-16 Public Accounts
OPG	290
Legacy Hydro One (Including Brampton)	2,941
Hydro One CIT dedicated to OEFC	0
MEUs	15
	3,247

2 **2017-18 value preliminary estimate, subject to change.**

ONTARIO ELECTRICITY FINANCIAL CORPORATION

Changes from Budget 2017 as of October 2017 **$ Millions**

	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Revenue						
Debt Retirement Charge	(4)	-	-	-	-	
Payments-in-lieu of tax:						
OPG	(78)	(16)	12	4	2	2016-17 variance is largely due to method of reporting OPG PILs by OEFC and OPG.
Legacy Hydro One (Including Brampton)	(3)	-	-	-	-	
Hydro One CIT dedicated to OEFC	5	(8)	(9)	(10)	(12)	Adjustment based on updated information in Hydro One rate application
MEUs	68	-	-	-	-	Large increase in 2016-17 from $80M payment during transfer of H01 Brampton to new consolidated MEU Alectra.
Total PILs	(9)	(24)	3	(7)	(10)	
Interest :						
OPG	(12)	1	26	40	13	Update to OPG interest outlook (wrt interest on OEFC loan).
H1	-	-	-	-	-	
IESO	(1)	-	-	-	-	
Province	22	(38)	(38)	(38)	(38)	2016-17 PDI at ($514m) was slightly larger than ($492m) projected at Interim. 2017-18 change reflects revised projections for Provincial debt interest related to Hydro equity.
Other	10	15	15	5	5	
Total Interest	19	(22)	3	7	(20)	
Power Supply Contract Recoveries	99	(0)	(0)	(0)	0	Variance is largely due to retroactive payments that the OEFC made to certain non-utility-generators (NUGs) with former Ontario Hydro power purchase agreement contracts with OEFC. OEFC was required to make these payment following the dismissal by the Supreme Court of Canada of OEFC's application for leave to appeal a judgment of the Court of Appeal of Ontario on a 2015 court decision.
Amortization of NUG liability	0	(0)	(0)	(0)	(0)	
Electricity sector dedicated income	(41)	(385)	-	-	-	Changes to ESDI (offset ny MoF Provision expense) largely reflect combined revisions to OPG and Hydro One net income and revisions to public debt intetest.
Gain to OEFC under s. 50.3	411	550	-	-	-	
Miscellaneous	14	-	-	-	-	
	489	119	6	(0)	(30)	
Expense						
Debt interest	-	31	67	76	78	Revised outlook for OEFC debt interest outlook
Interest on nuclear risk funding	-	-	-	-	-	
Demand Management Support Costs	(2)	-	-	-	-	
Amortization of deferred debt costs	-	-	-	-	-	
Power Supply Contract Costs	99	(0)	(0)	(0)	0	Same as Power supply contract recoveries above. Power supply contract costs are fully recovered by power supply contract recoveries.
Debt Guarantee fee	-	-	-	-	-	
Operating	1	-	-	-	-	
	98	31	67	76	78	
Excess (Deficiency) of Revenue over Expense	**391**	**88**	**(61)**			
Stranded Debt - Year End	**3,202**	**2,027**	**2,042**	**1,985**	**1,724**	

Provision for Electricity Sector (Dedicated Electricity Earnings/Electricity Sector Dedicated Earnings)

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Income from Investment in Government Business Enterprises						
OPG Income	291	299	147	720	608	1,041
Hydro One Income[1]	232	501	447	484	566	612
Hydro One Brampton (if applied separately)		15				
Total Income	**523**	**815**	**594**	**1,204**	**1,174**	**1,654**
Public Debt Interest - Electricity Sector						
OPG			(300)	(300)	(300)	(300)
Hydro One[1]			(154)	(154)	(154)	(154)
Public Debt Interest - Electricity Sector (OEFC Interest revenue)	**(520)**	**(514)**	**(454)**	**(454)**	**(454)**	**(454)**
MOF Provision Expense (before adjustments)	**3**	**302**	**140**	**750**	**720**	**1,199**
Other Adjustments						
Prior-year Adjustment[2]		3				
Exclude Brampton[3]		(15)				
MOF Provision Expense (after other adjustments)	**0**	**290**	**140**	**750**	**720**	**1,199**
Cumulative Shortfall Adjustment						
Opening Balance	0	0	0	0	0	0
Deduction / (Addition)	0	0	0	0	0	0
Ending Balance	0	0	0	0	0	0
Dedicated Electricity Earnings (all adjustments) (Public Accounts)	**0**	**290**	**140**	**750**	**720**	**1,199**
Electricity Sector Dedicated Income (OEFC Annual Report)	**3**	**302**	**140**			

Notes:

1. The Hydro One financials above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering are currently reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

2. 2016-17 Adjustment was due to the discrepancy between the numbers in MOF expense in PA 2015-16 and OEFC Financials in 2015-16 due to timing issues. $3M adjustment rectifies this discrepancy

3. Brampton was excluded from the Ministry of Finance's ESDI allocation.

Ontario Power Generation

OPG Income - Budget 2017

$ Millions

	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
OPG Net Income After Tax (Adjusted)	291	304	97	732	625	1,066
OPG Net Income After Tax	*291*	*379*	*480*	*678*	*726*	*913*
Extraordinary Gains	-	-	-	-	-	-
GA - OPG Trust Interest Revenue			*17*	*54*	*99*	*153*
OPG IFRS consolidation risk picked up in Fiscal Plan		(75)	(400)		(200)	
ONFA and other Fair Value Adjustments	(75)	8				
ONFA Adjustments	-	8				
Other Fair Value Adjustments	(75)					

OPG PIL - Budget 2017

$ Millions

	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Net Income Before Tax	383	396	572	867	795	1364
Net Income After Tax (Adjusted)	291	304	97	732	625	1066
Income Taxes	92	92	92	135	170	298
GRC: Payable to OEFC	198	196	205	212	219	220
Proxy Property Tax	16	14	18	19	19	19
Ontario Capital Tax	0	0	0	0	0	0
Total	**306**	**302**	**315**	**366**	**408**	**537**

OPG Income - October 2017

$ Millions

	Actual	Actual	Current Outlook			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
OPG Net Income	291	377	818	678	726	913
Adjustment for OPG HQ gain on sale[1]			(283)			
Extraordinary Gains	0	0	0	0	0	0
GA Financing - OPG Trust Interest Revenue[2]			12	42	82	128
OPG IFRS consolidation risk reflected in Fiscal Plan[3]		(78.00)	(400)		(200)	
OPG Net Income (Adjusted before ONFA)	**291**	**299**	**147**	**720**	**608**	**1,041**
ONFA Adjustments	247	49				
Other Fair Value Adjustments	(75)	(6)				
ONFA and other Fair Value Adjustments	**172**	**43**				
OPG Net Income	**463**	**342**	**147**	**720**	**608**	**1,041**

OPG PIL - August 2017

$ Millions

	Actual	Actual	Current Outlook			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Income Before Tax	383	308	684	855	778	1340
OPG Net Income (Adjusted before ONFA)	291	299	147	720	608	1041
OPG Income Tax (PILs)	92	9	162	135	170	298
Tax adjustment for OPG HQ gain on sale[1]			(95)			
GRC: Payable to OEFC	198	201	214	224	222	222
Proxy Property Tax to OEFC	16	14	18	19	19	19
Ontario Capital Tax	0	0	0	0	0	0
Total OPG PILs	**306**	**224**	**299**	**378**	**411**	**539**

1. As part of Asset Optimization Plan the projected proceeds are currently reported in OEP/MoF Sales and Rentals line. To be re-categorized after the transaction is completed and in coordination with OEP and SIFB.
2. This reflects interest earnings on GA financing costs which are consolidated back to Province
3. See Risks tab for IFRS impacts that were not reflected in Fiscal Plan, and table below.

	2017-18	2018-19	2019-20	2020-21
OPG IFRS Risk	(400)	(475)	(700)	(750)
Risks Built into Fiscal Plan	(400)	0	(200)	0
Additional Risks to be picked up	0	(475)	(500)	(750)

Hydro One Net Income and PILs

Hydro One Income - Budget 2017
($ millions)

	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Hydro One Net Income After Tax	685	737	742	802	862	931
Hydro One - Unrealized Gains Adjustment						

2016-17 to 2020-21 from CEFD Hydro One 2016 model.

Hydro One PIL - Budget 2017
($ millions)

	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Net Income After Tax	685	737	742	802	862	931
Income Taxes PILs	132	160	181	205	212	225
Proxy Property Tax	2	2	2	2	2	2
Ontario Capital Tax	0	0	0	0	0	0
Total	**134**	**162**	**183**	**207**	**214**	**227**

Hydro One (Post IPO Scenario) - Budget 2017
($ millions)

	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Assumed Provincial share		70.0%	70.0%	70.0%	70.0%	70.0%
Hydro One Net Income	236	516	520	562	603	652
Brampton Net Income	20	15				
Hydro One PILs		0	0	0	0	0
Hydro One CIT	3	20	20	22	23	25
Brampton PILs		5				
Proxy Property Tax		2	2	2	2	2
Total	**2886**	**27**	**22**	**24**	**25**	**27**

Hydro One Income - October 2017
($ millions) — $ Millions

	Actual	Actual	Current Outlook			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Hydro One Net Income After Tax			623	666	753	818
Debenture Costs Impacts (After Tax)			(34)	(39)		
Hydro One Net Income After Tax - Including Adjustments	670	680	589	627	753	818
Hydro One - Net Income Attributable to Preferred Shareholders	15	18				
Hydro One - Unrealized Gains Adjustment						

2017-18 to 2020-21 from CEFD Hydro One 2016 model.

Hydro One (100% Ownership)
($ millions) — $ Millions

	Actual	Actual	Current Outlook			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Net Income After Tax - Common Shares	670	680	589	627	753	818
Net Income After Tax - Preferred Shares	15	18				
Income Taxes PILs	132	160	181	205	212	225
Proxy Property Tax	2	2	2	2	2	2
Ontario Capital Tax	0	0	0	0	0	0
Total	**134**	**162**	**183**	**207**	**214**	**227**

Hydro One (Post IPO Scenario) - March 2017
$ Millions

	Actual	Actual	Current Outlook			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Assumed Provincial share		70.1%	70.1%	70.1%	70.1%	70.1%
Net Income After Tax - Common Shares	670	680	589	627	753	818
Net Income After Tax - Preferred Shares	15	18	18	18	18	18
adjustment for lower Provincial share		(204)	(177)	(188)	(225)	(245)
Hydro one IPO-related and other adjustments*	(449)					
Hydro One IFRS Adjustment to Province		7				
OPCD adjustment for Equity advances		(2)				
Adjust OEB decision/rebasing to ~50% provincial ownership**			16	27	21	22
Hydro One - Unrealized Gains Adjustment						
Total Hydro One Income - Province	**236**	**500**	**447**	**484**	**566**	**612**
Brampton Net Income - For Provision/ESDI	20	15				
other adjustments	(24)	2				
Combined Income for ESDI	232	501	447	484	566	612
Brampton Net Income - Public Accounts	**20**	**18**				
Hydro One PILs		2				
Proxy Property Tax		2	2	2	2	2
Brampton PILs						
Hydro One CIT	3	25	12	13	13	13
Total H1 PILs (incl. CIT)		29	14	15	15	15
Total H1 PILs (excl CIT)		4	2	2	2	2
Total	**2,886**	**29**	**14**	**15**	**15**	**15**

* Hydro one IPO-related and other adjustments	2015-16
Deferred Tax Asset (Post IPO Portion)- 100%	(2,619)
Deferred Tax Asset (Pre IPO Portion) - 100%	(191)
Deferred Tax Asset - Province	2,392
Loss of H1 Net Income	(50)
Consolidation adjustment	19

** An adjustment is made for OEB decision and rebasing impacts to show them at about 50% Provincial allocation, pending recategorization of AO amounts from Sales and Rentals.

Hydro One 2015-16 Net Income Estimation (USGAAP) ($M)

Q2 2015[1]	Q3 2015[2]	Q4 2015[1]	Q1 2016[2]	Fiscal Year 2015-16
131	188	143	208	**670**
	9		6	**15**

2016	Q1 2017	cal Year 2016-17
721	167	**680**
19	5	**18**

2015-16 PILs Estimation (Accounting Numbers)	Exc. B	Inc. B
2015 Income Tax	105	105
Q1 2016 Income Tax	33	33
Q1 2015 Income Tax	(45)	(45)
Income Taxes PILs	93	93
Departure Tax	2,600	2,600
Additional PILs	191	191
Brampton PILs	(4)	
Proxy Property Tax	2	2
Total	**2882**	**2886**

Public Debt Interest and Section 50.3 payments

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Hydro One Public Debt Interest and Section 50.3 payments						
Government Annual Interest Costs - Hydro One	220	220	220	220	220	220
Reduction in Interest Costs due to Broadening[1]		(29)	(66)	(66)	(66)	(66)
Province Annual Interest Costs - Hydro One Debt	**220**	**191**	**154**	**154**	**154**	**154**
Province Annual Interest Cost - OPG Debt	300	300	300	300	300	300
Total Public Debt Interest	**520**	**514**	**454**	**454**	**454**	**454**

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Gain to OEFC under s. 50.3	172	411	550	0	0	0

1. The Hydro One reduction in interest costs above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering are currently reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

PROVINCIAL CONSOLIDATION ADJUSTMENTS
Ontario Nuclear Funds Agreement

	2015-16	2016-17	2017-18
Adjustment for Change in OPG Reported Net Income			
Adjustment for DSF Unrealized Earnings			
Unrealized Earnings as at beginning of year	0	0	
Unrealized Earnings as at fiscal year end / latest quarter	(175)	0	
Bruce Variance Account Adjustment	(82)	0	
OPG Net Income Adjustment	(93)	0	
Adjustment for UFSF Unrealized Earnings			
Unrealized Earnings as at beginning of year	0	0	
Unrealized Earnings as at fiscal year end / latest quarter	(82)	56	
Bruce Variance Account Adjustment	(42)	28	
OPG Net Income Adjustment	(40)	28	
Unrealized Earnings -- Fiscal YTD	**(133)**	**28**	
Adjustment for Change in Due to Province			
Adjustment for DSF Due to Province			
Due to Province (cost basis) as at beginning of year	0	39	
Unrealized Earnings as at fiscal year end / latest quarter	39	79	
Change in Due to Province -- Fiscal YTD	**39**	**40**	
Adjustment for UFSF Due to Province			
Due to Province (cost basis) as at beginning of year	295	370	
Unrealized Earnings as at fiscal year end / latest quarter	370	407	
Change in Due to Province -- Fiscal YTD	**75**	**37**	
Provincial Consolidation Adjustment	**247**	**49**	

Other Data

	Actual	Plan			
	2016-17	2017-18	2018-19	2019-20	2020-21
Debt Retirement Charge	621	0	0	0	0

	Plan				
	2016-17	2017-18	2018-19	2019-20	2020-21
Power Supply Contract Recoveries	838	292	325	301	273

	Plan				
	2016-17	2017-18	2018-19	2019-20	2020-21
Interest					
OPG	167	169	179	175	148
IESO	2	3	3	3	3
Other (Net)	20	20	20	10	10
Expense					
Debt interest	1216	1121	1094	1053	963

	Actual	Plan			
	2016-17	2017-18	2018-19	2019-20	2020-21
MEU - PIL Income Tax	109.8				
MEU - PIL Property Tax	0.6				
MEU - GRC	1.2				
TOTAL MEU PILs	111.6				

	Actual	Plan			
	2016-17	2017-18	2018-19	2019-20	2020-21
Miscellaneous/Other (OEFC FS)	14				
Demand Management Support Costs (IEI)	8	10			
Operating [Expense]	7	6	6	6	6
Interest on nuclear risk funding	-	-	-	-	-
Amortization of deferred debt costs	-	-	-	-	-
Amortization of NUG liability	129	74	41	30	28
Debt Guarantee Fee	122				

Expense (Electrictiy Summary Tab)					
Other (Finance)	-7	-6	-6	-6	-6
Demand Management Support Costs (IEI)	-8	-10			
Debt Guarantee Fee	(122)				

From:	Usman Zahid
To:	Shajee Kathirgamanathan; Ronald Kwan
Cc:	John Kim; Bruno Amara; Gavin He
Subject:	RE: FES Items for Today
Date:	Friday, November 10, 2017 2:55:33 PM

Thanks Everyone! I will send this in.

Regards,
Usman

From: Shajee Kathirgamanathan
Sent: Friday, November 10, 2017 2:26 PM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; Usman Zahid <Usman.Zahid@ofina.on.ca>
Cc: John Kim <John.Kim@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>
Subject: RE: FES Items for Today

Hi Ron,

Please see revised Outlook file with the disclaimer on the first page.

If it looks good then this file can be sent back with the initial OFHP supporting data pdf sent earlier for inclusion in the binder.

Thanks,
Shajee

Shajee Kathirgamanathan
Office: 416-325-1402 | Mobile: 647-294-3359
shajee.kathirgamanathan@ofina.on.ca

From: Ronald Kwan
Sent: Friday, November 10, 2017 12:20 PM
To: Usman Zahid <Usman.Zahid@ofina.on.ca>
Cc: John Kim <John.Kim@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>
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Hi,

Could we note on the Outlook file that these are potential pressures at a point in time, but it was not recommended for FES itself to pick up any of the pressures? As such, fine to send both for proposed inclusion.

Thanks,
Ron

From: Usman Zahid
Sent: November-10-17 10:52
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: John Kim <John.Kim@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>
Subject: FW: FES Items for Today

Hi Ron,

Attached are two items for inclusion into the TB/MBC Binder. The first item is a PDF version of the Electricity Sector Outlook (similar to what was submitted previously). The second item is information on the financing of FHP. EFB have said they are open to omitting the second item if appropriate.

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From: Shajee Kathirgamanathan
Sent: Friday, November 10, 2017 10:37 AM
To: Usman Zahid <Usman.Zahid@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>
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Hi Usman,

Please find attached the two documents for inclusions into EFB's portion of the TB Binder.

1) PDF'ed version of the Electricity Sector Outlook. Similar to what we submitted last time
2) Information we received on the financing of the Fair Hydro Plan. We didn't use this information per se, so we're open to omitting it should it be decided to exclude.

Files saved here:
S:\Users\CEF\Hydro 2017\FES\TB Binder\EFB

Thanks,
Shajee

Shajee Kathirgamanathan
Office: 416-325-1402 | Mobile: 647-294-3359
shajee.kathirgamanathan@ofina.on.ca

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Hi All,

TB/MBC Binder Materials: Due by noon, please get to Ron ASAP.

Placemats: Due at 2pm, please get in right after TB/MBC binder Materials.

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From:	Shajee Kathirgamanathan
To:	Ronald Kwan; Usman Zahid
Cc:	John Kim; Bruno Amara; Gavin He
Subject:	RE: FES Items for Today
Date:	Friday, November 10, 2017 2:25:58 PM
Attachments:	1. Electricity Sector Outlook (2017 10 20v3)_Sent.pdf

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Files saved here:
S:\Users\CEF\Hydro 2017\FES\TB Binder\EFB

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Shajee

Shajee Kathirgamanathan
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shajee.kathirgamanathan@ofina.on.ca

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Subject: FES Items for Today

Hi All,

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Placemats: Due at 2pm, please get in right after TB/MBC binder Materials.

Regards,
Usman

Please note that this Electricity Sector Outlook document reflect current information and outlines both positive and negative risks to the outlook at a point in time.

The Electricity Finance Branch is not recommending that the Fall Statement fiscal plan be updated based on the information contained here.

Electricity Sector Outlook

October 2017

Disclosure:

All information contained in this workbook is confidential and commercially sensitive

All projected numbers are estimates and subjected to change

This workbook and all information or analysis contained in it is property of the Ontario Financing Authority.
Please consult with OFA before sharing of information.

Commercially Sensitive and Confidential Advice to Cabinet for Consideration of Options for Discussion Purposes Only

Electricity Sector Outlook
Including Line Items for Consolidation

Electricity Summary - On Deck

			MOF Expense Items (consolidated)	Current Outlook			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**38**	Power Supply Contract Costs	(292)	(325)	(301)	(273)
Expense	**MOF (OEFC)**	**40**	Demand Management Support Costs	(10)	-	-	-
Expense	**MOF (OEFC)**	**41**	Provision for Electricity Sector	140	-	-	-
Expense	**MOF**	**17**	Provision for Electricity Sector	(140)	-	-	-
Expense	**MOF (OEFC)**	**42**	Other (Finance)	(6)	(6)	(6)	(6)
			Total MOF Expense	**(308)**	**(331)**	**(307)**	**(279)**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**7**	OPG Income	147	720	608	1,041
Revenue	**ENE**	**8**	OPG - ONFA and other Fair Value Adjustments	-	-	-	-
Revenue	**ENE**	**10**	HOI Income	447	484	566	612
Revenue		**11**	Brampton Income	-	-	-	-
Revenue	**MOF (OEFC)**	**26**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	381	479	531	668
Revenue	**MOF (OEFC)**	**29**	Electricity Debt Retirement Charge	623	-	-	-
Revenue	**MOF (OEFC)**	**30**	Power Supply Contract Recoveries	292	325	301	273
Revenue	**MOF (OEFC)**	**31**	Net Reduction of Power Purchase Contracts	74	41	30	28
Revenue	**MOF (OEFC)**	**34**	Miscellaneous	-	-	-	-
			Total MOF Revenue	**1,964**	**2,049**	**2,036**	**2,623**
			OFA IOD Expense				
			Public Debt Interest - Electricity Sector	(454)	(454)	(454)	(454)
			Interest on Debt	(475)	(438)	(411)	(348)
			Total OFA IOD Expense	**(929)**	**(892)**	**(865)**	**(802)**
			Impact on Surplus/Deficit	**727**	**826**	**864**	**1,542**
			check	**-**	**-**	**-**	**-**

Electricity Summary - Budget 17

	For Discussion		MOF Expense Items (consolidated)	Plan			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**38**	Power Supply Contract Costs	(292)	(325)	(301)	(273)
Expense	**MOF (OEFC)**	**40**	Demand Management Support Costs	(10)	0	0	0
Expense	**MOF (OEFC)**	**41**	Provision for Electricity Sector	125	0	0	0
Expense	**MOF**	**17**	Provision for Electricity Sector	(125)	0	0	0
Expense	**MOF (OEFC)**	**42**	Other (Finance)	(6)	(6)	(6)	(6)
			Total MOF Expense	**(308)**	**(331)**	**(307)**	**(279)**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**7**	OPG Income	97	732	625	1,066
Revenue	**ENE**	**8**	OPG - ONFA and other Fair Value Adjustments	0	0	0	0
Revenue	**ENE**	**10**	HOI Income	520	562	603	652
			Brampton Income				
Revenue	**MOF (OEFC)**	**25**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	405	476	538	679
Revenue	**MOF (OEFC)**	**29**	Electricity Debt Retirement Charge	623	0	0	0
Revenue	**MOF (OEFC)**	**30**	Power Supply Contract Recoveries	292	325	301	273
Revenue	**MOF (OEFC)**	**31**	Net Reduction of Power Purchase Contracts	74	41	30	28
Revenue	**MOF (OEFC)**	**34**	Miscellaneous	0	0	0	0
			Total MOF Revenue	**2,011**	**2,136**	**2,098**	**2,697**
			OFA IOD Expense				
		17	Public Debt Interest - Electricity Sector	(492)	(492)	(492)	(492)
		36	Interest on Debt	(422)	(374)	(342)	(250)
			Total OFA IOD Expense	**(914)**	**(866)**	**(834)**	**(742)**
			Impact on Surplus/Deficit	**789**	**939**	**957**	**1,676**
			check	**-**	**-**	**-**	**-**

Electricity Summary - Change

			MOF Expense Items (consolidated)	Variance from Plan			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**69**	Power Supply Contract Costs	0	0	0	(0)
Expense	**MOF (OEFC)**	**71**	Demand Management Support Costs	0	0	0	0
Expense	**MOF (OEFC)**	**72**	Provision for Electricity Sector	15	0	0	0
Expense	**MOF**	**48**	Provision for Electricity Sector	(15)	0	0	0
Expense	**MOF (OEFC)**	**73**	Other (Finance)	0	0	0	0
			Total MOF Expense	**0**	**0**	**0**	**(0)**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**38**	OPG Income	50	(12)	(17)	(24)
Revenue	**ENE**	**39**	OPG - ONFA and other Fair Value Adjustments	0	0	0	0
Revenue	**ENE**	**41**	HOI Income	(73)	(78)	(38)	(40)
			Brampton Income	0	0	0	0
Revenue	**MOF (OEFC)**	**25**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	(24)	3	(7)	(10)
Revenue	**MOF (OEFC)**	**60**	Electricity Debt Retirement Charge	0	0	0	0
Revenue	**MOF (OEFC)**	**61**	Power Supply Contract Recoveries	(0)	(0)	(0)	0
Revenue	**MOF (OEFC)**	**62**	Net Reduction of Power Purchase Contracts	(0)	(0)	(0)	(0)
Revenue	**MOF (OEFC)**	**65**	Miscellaneous	0	0	0	0
			Total MOF Revenue	**(47)**	**(87)**	**(62)**	**(74)**
			OFA IOD Expense				
		17	Public Debt Interest - Electricity Sector	38	38	38	38
		36	Interest on Debt	(53)	(64)	(69)	(98)
			Total OFA IOD Expense	**(15)**	**(26)**	**(31)**	**(60)**
			Impact on Surplus/Deficit	**(62)**	**(113)**	**(93)**	**(134)**
			check	***-***	***0***	***(0)***	***(0)***

Electricity Sector Outlook	$ Millions					
	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
On Deck Outlook as of March 2017						
Income from Investment in Government Business Enterprises						
OPG Income[1]	291	304	97	732	625	1,066
OPG - ONFA and other Fair Value Adjustments[2]	172	8	-	-	-	-
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	-
HOI Income[3]	236	516	520	562	603	652
Brampton Income	20	15	-	-	-	-
Total OPG and HOI Income	**719**	**842**	**617**	**1,294**	**1,229**	**1,717**
Other Fees and Licences	**127**	**122**	**102**	**91**	**88**	**81**
Electricity Expenses of the Province						
Provision for Electricity Sector[4]	(3)	(342)	(125)		-	-
Public Debt Interest - Electricity Sector	(520)	(492)	(492)	(492)	(492)	(492)
Subtotal	(523)	(834)	(617)	(492)	(492)	(492)
Public Debt Interest - Impact of ONFA						
Amortization of Deferred Revenue re profit on sale of H1 notes						
Total Electricity Expenses of the Province	**(523)**	**(834)**	**(617)**	**(492)**	**(492)**	**(492)**
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	3,228	373	405	476	538	679
Other Revenue						
Electricity Debt Retirement Charge[5]	859	625	623	-	-	-
Power Supply Contract Recoveries	875	739	292	325	301	273
Net Reduction of Power Purchase Contracts	172	129	74	41	30	28
Other Fees and Licences	(127)	(122)	(102)	(91)	(88)	(81)
Miscellaneous	9	-	-	-	-	-
Expenses						
Interest on Debt	(596)	(532)	(422)	(374)	(342)	(250)
Power Supply Contract Costs	(875)	(739)	(292)	(325)	(301)	(273)
Electricity Consumer Price Protection Fund	-	-	-	-	-	-
Demand Management Support Costs[6]	(8)	(10)	(10)	-	-	-
Provision for Electricity Sector	3	342	125	-	-	-
Other (Finance)	(7)	(6)	(6)	(6)	(6)	(6)
Total OEFC Income	**3,533**	**800**	**687**	**46**	**132**	**370**
Impact on Surplus/(Deficit)	**3,856**	**930**	**789**	**939**	**957**	**1,676**

Notes: The Hydro One net income outlook above (2016-17 to 2020-21) reflects the Province's current 70% ownership share, after the initial IPO in 2015 [and the secondary offering in April 2016]. Net estimated fiscal impacts from future Hydro One offerings are reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

Notes:

1.OPG's 2016-17 outlook reflected its reported earnings. 2017-18 outlook reflects OPG's latest monthly update. Out-years reflect OPG's preliminary 2017-19 business plan and long-term outlook to 2019-20 (as fiscalized by OPG). 2020-21 estimates are based on OPG's calendar year-based business plan projections and as fiscalized by CEFD staff.

2. Provincial consolidation adjustments for unrealized earnings on the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds, as of the end of December 2016.

3. Hydro One 2016-17 income reflects its reported net income, adjusted for Hydro One IPO impacts. 2017-18 to 2020-21 projections are based on CEFD projections using the latest public information. The Hydro One net income outlook above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering are currently reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial ONFA consolidation adjustments, minus the interest on debt payable to OEFC. The provision is currently assumed to end once the DRC ends on a legislated fixed end date of April 1, 2018.

5. Reflects April 23, 2014 announcement that DRC will be eliminated for residential users, after December 31, 2015. The end date of DRC for remaining users is legislated to be on April 1, 2018. Estimates are subject to change based on actual consumption.

6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Electricity Sector Outlook

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
On Deck Outlook as of October 2017						
Income from Investment in Government Business Enterprises						
OPG Income[1]	291	299	147	720	608	1,041
OPG - ONFA and other Fair Value Adjustments[2]	172	43	-	-	-	-
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	-
HOI Income[3]	236	500	447	484	566	612
Brampton Income	20	18	-	-	-	-
Total OPG and HOI Income	**719**	**860**	**594**	**1,204**	**1,174**	**1,654**
Other Fees and Licences (Debt Guarantee fee)	**127**	**122**	**102**	**91**	**88**	**81**
Electricity Expenses of the Province						
Provision for Electricity Sector[4]	-	(290)	(140)			
Public Debt Interest - Electricity Sector	(520)	(514)	(454)	(454)	(454)	(454)
Subtotal	(520)	(803)	(594)	(454)	(454)	(454)
Public Debt Interest - Impact of ONFA						
Amortization of Deferred Revenue re profit on sale of H1 notes						
Total Electricity Expenses of the Province	**(520)**	**(803)**	**(594)**	**(454)**	**(454)**	**(454)**
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	3,247	334	381	479	531	668
Other Revenue						
Electricity Debt Retirement Charge[5]	859	621	623	-	-	-
Power Supply Contract Recoveries	875	838	292	325	301	273
Net Reduction of Power Purchase Contracts	172	129	74	41	30	28
Other Fees and Licences	(127)	(122)	(102)	(91)	(88)	(81)
Miscellaneous	9	14	-	-	-	-
Expenses						
Interest on Debt	(596)	(513)	(475)	(438)	(411)	(348)
Power Supply Contract Costs	(875)	(838)	(292)	(325)	(301)	(273)
Electricity Consumer Price Protection Fund	-	-	-	-	-	-
Demand Management Support Costs[6]	(8)	(8)	(10)	-	-	-
Provision for Electricity Sector	-	290	140	-	-	-
Other (Finance)	(7)	(7)	(6)	(6)	(6)	(6)
Total OEFC Income	**3,549**	**737**	**625**	**(15)**	**56**	**261**
Impact on Surplus/(Deficit)	**3,876**	**915**	**727**	**826**	**864**	**1,542**
variance to OEFC check	*(156)*	*(454)*	*(550)*	*-*	*0*	*-*

Notes:

1.OPG's 2016-17 outlook reflected its reported earnings. 2017-18 outlook reflects OPG's latest monthly update. Out-years reflect OPG's preliminary 2017-19 business plan and long-term outlook to 2019-20 (as fiscalized by OPG). 2020-21 estimates are based on OPG's calendar year-based business plan projections and as fiscalized by CEFD staff.

2. Provincial consolidation adjustments for unrealized earnings on the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds, as of the end of December 2016.

3. Hydro One 2016-17 income reflects its reported net income, adjusted for Hydro One IPO impacts. 2017-18 to 2020-21 projections are based on CEFD projections using the latest public information. The Hydro One net income outlook above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering are currently reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial ONFA consolidation adjustments, minus the interest on debt payable to OEFC. The provision is currently assumed to end once the DRC ends on a legislated fixed end date of April 1, 2018.

5. Reflects April 23, 2014 announcement that DRC will be eliminated for residential users, after December 31, 2015. The end date of DRC for remaining users is legislated to be on April 1, 2018. Estimates are subject to change based on actual consumption.

6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Electricity Sector Change Since Budget

$ Millions

($million)	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Changes from Budget 2017 as of October 2017						
Income from Investment in Government Business Enterprises						
OPG Income	(5)	50	(12)	(17)	(24)	2016-17 small decrease due to IFRS adjustment revision and OPG Net Income revision. 2017-18 increase mainly due to deferral of Pickering Unit 6 planned outage to Jan 18, deferral of sale of land at Hearn site from Q1 2017 to later in 2017, partially offsdet by lower gropss margin.
ONFA and other Fair Value Adjustments	35	-	-	-	-	Largely revision to ONFA fair value as of March 31, 2017
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	
HOI Income	(16)	(73)	(78)	(38)	(40)	2016-17 slight decrease from Budget 2017 Interim projection. 2017-18 onwards reflects impacts of OEB decision on Hydro One rates, interest expense on Avitsa debentures (in 2017-18 and 2018-19) and update to Hydro One model update based on Hydro One Q2 results.
Brampton Income	3.3					
Total OPG and HOI Income	**17**	**(22.9)**	**(90)**	**(55)**	**(64)**	
Other Fees and Licences	**-**	**-**	**-**	**-**	**-**	
Electricity Expenses of the Province						
Provision for Electricity Sector	53	(15)	-	-	-	Changes in the Proviision (ESDI) expense reflect net changes in the outlook for Public Debt Interest, and OPG and HOI net income (excludinging ONFA adjustments).
Public Debt Interest - Electricity Sector	(22)	38	38	38	38	2016-17 PDI at ($514m) was slightly larger than ($492m) projected at Interim. 2017-18 change reflects revised projections for Provincial debt interest related to Hydro equity.
Total Electricity Expenses of the Province	**31**	**23**	**38**	**38**	**38**	
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs)	(40)	(24)	3	(7)	(10)	2016-17 decrease largely due to an OPCD Public Accounts PILs adjustment related to reconciling between OPCD and OEFC net opening assets. OPG PILs also slightly lower than projected.
Other Revenue						
Electricity Debt Retirement Charge	(4)	-	-	-	-	
Power Supply Contract Recoveries	99	(0)	(0)	(0)	0	Variance is largely due to retroactive payments that the OEFC made to certain non-utility-generato (NUGs) with former Ontario Hydro power purchase agreement contracts with OEFC. OEFC was required to make these payment following the dismissal by the Supreme Court of Canada of OEFC's application for leave to appeal a judgment of the Court of Appeal of Ontario on a 2015 co decision.
Net Reduction of Power Purchase Contracts	0.1	(0)	(0)	(0)	(0)	
Other Fees and Licences	-	-	-	-	-	
Revenue Pool Residual	-	-	-	-	-	
Miscellaneous	14	-	-	-	-	Higher than projected at Interim.
Expenses						
Interest on Debt	19	(53)	(64)	(69)	(98)	2016-17 higher than projected at Interim. 2017-18 reflects revised debt interest outlook net of revisions to OEFC interest revenue from OPG and Province.
Power Supply Contract Costs	(99)	0	0	0	(0)	Same as Power supply contract recoveries above. Power supply contract costs are fully recovered by power supply contract recoveries.
Electricity Consumer Price Protection Fund	-	-	-	-	-	
Demand Management Support Costs	1.8	-	-	-	-	
Provision for Electricity Sector	(53)	15	-	-	-	Changes in the Proviision (ESDI) expense (negative expense or revenue to OEFC) reflect net changes in the outlook for Public Debt Interest, and OPG and HOI net income (excludinging ONFA adjustments).
Other (Finance)	(1.0)	-	-	-	-	
Total OEFC Income	**(63)**	**(62)**	**(61)**	**(76)**	**(108)**	
Impact on Surplus/(Deficit)	**(14.6)**	**(62)**	**(113)**	**(93)**	**(134)**	

Information: Breakdown of change between revenue and expense

Total Revenue Impact	87	(47)	(87)	(62)	(74)	
Total Expenditure impact	101	15	26	31	60	

Electricity Sector Outlook (PSAB)

Negative Revenue Risks	$ Millions			
($ millions)	Plan			
	2017-18	2018-19	2019-20	2020-21
Generic				
OPG Generation Risk: Nuclear Reliability (-1.6 TWh)[1]	(120)	(120)	(120)	(120)
1% decrease in Hydro One actual load[2]	(57)	(59)	(62)	(63)
Lower OPG's Equity weighting & Return on Equity (ROE)[3]	(12)	(20)	(26)	(45)
Lower Hydro One Return on Equity (ROE)[4]	(9)	(36)	(38)	(40)
Regulatory				
Hydro One Distribution rate application[5]	(50)	(50)	(50)	(50)
OPG Switch from accrual based to cash based accounting for pension and OPEB[6]	(600)			
Regulatory Risk - Timing of Rate Decision[7]	(540)			
OEB Staff Recommendations wrt OPG rate application(May 2017)[8]	(175)	(143)	(151)	(175)
Nuclear Liabilities Cash vs. Accrual[9]	(450)	(450)	(450)	(450)
OEB decision on Hydro One tax recapture (if one-time write-down)[10]	(251)			
Accounting				
Net OPG IFRS Consolidation Risks - Scenario 1b: 15 year historical, update discount rate each year.[11]	-	(475)	(500)	(750)
Other Risks				
Avista Acquisition - Termination fee		(103)		

Note: These risks do not reflect the impacts on electricity sector revenue and expense of reclassification of the Asset Optimi

1. OPG's market and generation risks related to nuclear reliability similar to the scenarios OPG developed for its sales margins to capture major market risk factors (e.g., natural gas prices, coal prices, foreign exchange, nuclear reliability) in its 2012 business plan. Currently, only the nuclear reliability risk is captured at the current regulated rate for OPG's nuclear generation.

2. Estimated revenue impact if Hydro One load for Transmission and Distribution is 1% lower than projected for all years in CEFD Hydro One Forecast. Based on the assumption a 1% increase in load is directly proportional to a 1% change in revenue requirements.

3. Risk range for Hydro One transmission and distribution reflects potential risk of lower ROE by 0.5% vs assumed ROEs in business plan along with reduced deemed debt to equity weighting of 55%/45% from the current 51%/49%.

4. Risk range for Hydro One transmission and distribution reflects potential risk of lower ROE by 0.5% vs assumed ROEs in CEFD Hydro One Forecast based on the most recent rate applications and forecasted ROE rates.

5. OEB is expected to make a decision on Hydro One's Distibution rate application for 2018 during the first half of 2018.

6. The OEB directed a switch to cash-based accounting for years 2014 and 2015. However, the OEB also directed OPG to track the difference between cash based and accrual based accounting in a deferral account, while a generic proceeding is underway for all OEB-regulated electric and gas utilities. OEB September 2017 Report, recommends continuance of variance account which would mitigate this risk. However, the final decision (expected in Fall 2017) will be with the OEB Board.

7. Risk refelects OPG impact if the OEB rate rulings are applied as of the final decision date rather than retroactive to January 1, 2017 . OPG's business plan assumed OEB decision would be effective as of January 1, 2017. OPG estimated an impact of -$60M for each month for which OEB decsion is not retroactive.

8. Reflects OEB staff report (May 2017) reccomendations with respect to OPG's rate application. (Inlcudes OPG rate application updates).

9. Risk refelects impact of OEB decision that OPG switch to cash-basis accounting for regulated recovery of nuclear payment anmounts. OEB staff report (May 2017) appears to mitigate this risk as it makes no decision and recommends revisiting this issue in 5 years at next OEB application.

10. The OEB's Sep. 28, 2017 ruling on Hydro One's Transmission rate application included direction on sharing, with ratepayers, tax savings related to the Hydro One IPO. The estimated annual ongoing impact of this is factored into the current outlook. This risk reflects the impact if a decision is made by Hydro One that the impact of the ruling has to be accounted for as an immediate one-time write-down.
Note: Corresponding Positive Revenue Risks would also need to be incorporated for 2018-19 to 2020-21 if this risk is to be recognized. The risk reflect ther roughly 50% proncial ownership pending recategorization from teh AO Sales and Rentals outlook.

11. OPCD provided IFRS impact estimates at the time of Budget 2017. A portion of these were reflected in in OPG's and Hydro One's net inc0me outlook. The Risk above reflect the impacts iof IFRS not refelcted in the Budget 2017 fiscal plan.
Table below outlines OPG IFRS Risks versus what is built into the Fiscal Plan.

	2017-18	2018-19	2019-20	2020-21
OPG IFRS Risk	(400)	(475)	(700)	(750)
Risks Built into Fiscal Plan	(400)	0	(200)	0
Additional Risks to be picked up	0	(475)	(500)	(750)

Electricity Sector Outlook (PSAB)

Positive Revenue Risks				
($ millions)	**Plan**			
	2017-18	**2018-19**	**2019-20**	**2020-21**
Generic				
OPG Generation Risk: Nuclear Reliability (+1.1 TWh)[1]	85	85	85	85
1% increase in Hydro One actual load[2]	57	59	61	63
Higher OPG Return on Equity (ROE)[3]	6	22	19	33
Higher Hydro One Return on Equity (ROE)[4]	19	69	50	50
Regulatory				
Hydro One Motion to Review OEB Transmission ruling[5]	40	54	41	43
OEB decision on Hydro One tax recapture (if one-time write-down)[6]		6	7	10
Other Risks				
ONFA adjustment increase (as of September 2017 Q3)[7]	171			

zation strategy or updates to AO strategy.

1. OPG's market and generation risks related to nuclear reliability similar to the scenarios OPG developed for its sales margins to capture major market risk factors (e.g., natural gas prices, coal prices, foreign exchange, nuclear reliability) in its 2012 business plan. Currently, only the nuclear reliability risk is captured at the current regulated rate for OPG's nuclear generation.

2. Estimated revenue impact if Hydro One load for Transmission and Distribution is 1% higher than projected for all years in CEFD Hydro One Forecast. Based on the assumption a 1% increase in load is directly proportional to a 1% change in revenue requirements.

3. Risk range for OPG reflects potential risk of higher ROE in 2018-2021 (for nuclear base) vs assumed ROE in OPG's 2016 business plan and corresponding rate application. Assumed ROE is 9.85%, respresenting recent in 2010.

4. Risk range for Hydro One transmission and distribution reflects potential risk of higher ROE vs assumed ROEs in the Hydro One CEFD Forecast for 2018-2021. Assumed ROE is 9.85%, representing recent high in 2010.

5. On October 18, 2017, Hydro One filed a Notice of Motion to Review and vary the Decision and Order dated September 28, 2017. Upside risks based on Hydro One's motions to vary the OEB decision.

6. The OEB's Sep. 28, 2017 ruling on Hydro One's Transmission rate application included direction on sharing, with ratepayers, tax savings related to the Hydro One IPO. The estimated annual ongoing impact of this is factored into the current outlook. This risk reflects the impact if a decision is made by Hydro One that the impact of the ruling has to be accounted for as an immediate one-time write-down.
Note: Corresponding Negative Revenue Risks would also need to be incorporated for 2017-18 if this risk is to be recognized

7. Reflects consolidation adjustment to OPG net income, whereby the realized portion of gains or losses of OPG's nuclear funds are added or subtracted from OPG net income.

ONTARIO ELECTRICITY FINANCIAL CORPORATION

On Deck Outlook as of March 2017

$ Millions

	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Revenue						
Revenue Pool Residual						
Debt Retirement Charge	859	625	623	-	-	-
Payments-in-lieu of tax:						
OPG	268	302	315	366	408	537
Legacy Hydro One (Including Brampton)	2,929	7	2	2	2	2
Hydro One CIT dedicated to OEFC	3	20	20	22	23	25
MEUs	27	44	68	86	105	114
Total PILs & CIT dedicated to OEFC[1]	3,228	373	405	476	538	679
Interest :						
OPG	173	179	168	153	135	135
H1						
IESO	2	3	3	3	3	3
Province	520	492	492	492	492	492
Other	28	10	5	5	5	5
Total Interest	723	684	668	653	635	635
Power Supply Contract Recoveries	875	739	292	325	301	273
Amortization of NUG liability	172	129	74	41	30	28
Electricity sector dedicated income	3	342	525	-	-	-
Gain to OEFC under s. 50.3	172	-	-	-	-	-
Miscellaneous	9	-	-	-	-	-
	6,041	2,893	2,587	1,495	1,504	1,615
Expense						
Debt interest	1,319	1,216	1,090	1,027	977	885
Interest on nuclear risk funding						
Demand Management Support Costs	8	10	10	-	-	-
Amortization of deferred debt costs	-	-	-			
Power Supply Contract Costs	875	739	292	325	301	273
Debt Guarantee fee	127	122	102	91	88	81
Operating	7	6	6	6	6	6
	2,336	2,093	1,500	1,449	1,372	1,245
Excess (Deficiency) of Revenue over Expense	**3,705**	**800**	**1,087**	**46**	**132**	**370**
Prior period adjustment	87					
Stranded Debt - Year End	**4,393**	**3,593**	**2,506**	**2,460**	**2,328**	**1,958**

Note: All the Hydro One ownership broadening impacts, other than the ownership change from the initial IPO in 2015 [and the secondary offering in April 2016], are in the asset optimisation line (Sales and Rentals) and not in the current Outlook file.

ONTARIO ELECTRICITY FINANCIAL CORPORATION

On Deck Outlook as of October 2017 **$ Millions**

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Revenue						
Revenue Pool Residual						
Debt Retirement Charge	859	621	623	0	0	0
Payments-in-lieu of tax:						
OPG	268	224	299	378	411	539
Legacy Hydro One (Including Brampton)	2,929	4	2	2	2	2
Hydro One CIT dedicated to OEFC	3	25	12	13	13	13
MEUs	27	112	68	86	105	114
Total PILs & CIT dedicated to OEFC[1]	3,228	364	381	479	531	668
Interest :						
OPG	173	167	169	179	175	148
H1						
IESO	2	2	3	3	3	3
Province	520	514	454	454	454	454
Other	28	20	20	20	10	10
Total Interest	723	703	646	656	642	615
Power Supply Contract Recoveries	875	838	292	325	301	273
Amortization of NUG liability	172	129	74	41	30	28
Electricity sector dedicated income	3	302	140	0	0	0
Gain to OEFC under s. 50.3[2]	172	411	550	0	0	0
Miscellaneous	9	14	0	0	0	0
	6,041	3,382	2,706	1,501	1,504	1,585
Expense						
Debt interest	1,319	1,216	1,121	1,094	1,053	963
Interest on nuclear risk funding						
Demand Management Support Costs	8	8	10	0	0	0
Amortization of deferred debt costs	0	0	0			
Power Supply Contract Costs	875	838	292	325	301	273
Debt Guarantee fee	127	122	102	91	88	81
Operating	7	7	6	6	6	6
	2,336	2,191	1,531	1,516	1,448	1,323
Excess (Deficiency) of Revenue over Expense	3,705	**1,191**	**1,175**	**(15)**	**56**	**261**
Prior period adjustment	87					
Stranded Debt - Year End	4,393	**3,202**	**2,027**	**2,042**	**1,985**	**1,724**

1

Payments-in-lieu of tax:	2015-16 Public Accounts
OPG	290
Legacy Hydro One (Including Brampton)	2,941
Hydro One CIT dedicated to OEFC	0
MEUs	15
	3,247

2 **2017-18 value preliminary estimate, subject to change.**

ONTARIO ELECTRICITY FINANCIAL CORPORATION

Changes from Budget 2017 as of October 2017 **$ Millions**

	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Revenue						
Debt Retirement Charge	(4)	-	-	-	-	
Payments-in-lieu of tax:						
OPG	(78)	(16)	12	4	2	2016-17 variance is largely due to method of reporting OPG PILs by OEFC and OPG.
Legacy Hydro One (Including Brampton)	(3)	-	-	-	-	
Hydro One CIT dedicated to OEFC	5	(8)	(9)	(10)	(12)	Adjustment based on updated information in Hydro One rate application
MEUs	68	-	-	-	-	Large increase in 2016-17 from $80M payment during transfer of H01 Brampton to new consolidated MEU Alectra.
Total PILs	(9)	(24)	3	(7)	(10)	
Interest :						
OPG	(12)	1	26	40	13	Update to OPG interest outlook (wrt interest on OEFC loan).
H1	-	-	-	-	-	
IESO	(1)	-	-	-	-	
Province	22	(38)	(38)	(38)	(38)	2016-17 PDI at ($514m) was slightly larger than ($492m) projected at Interim. 2017-18 change reflects revised projections for Provincial debt interest related to Hydro equity.
Other	10	15	15	5	5	
Total Interest	19	(22)	3	7	(20)	
Power Supply Contract Recoveries	99	(0)	(0)	(0)	0	Variance is largely due to retroactive payments that the OEFC made to certain non-utility-generators (NUGs) with former Ontario Hydro power purchase agreement contracts with OEFC. OEFC was required to make these payment following the dismissal by the Supreme Court of Canada of OEFC's application for leave to appeal a judgment of the Court of Appeal of Ontario on a 2015 court decision.
Amortization of NUG liability	0	(0)	(0)	(0)	(0)	
Electricity sector dedicated income	(41)	(385)	-	-	-	Changes to ESDI (offset ny MoF Provision expense) largely reflect combined revisions to OPG and Hydro One net income and revisions to public debt intetest.
Gain to OEFC under s. 50.3	411	550	-	-	-	
Miscellaneous	14	-	-	-	-	
	489	119	6	(0)	(30)	
Expense						
Debt interest	-	31	67	76	78	Revised outlook for OEFC debt interest outlook
Interest on nuclear risk funding	-	-	-	-	-	
Demand Management Support Costs	(2)	-	-	-	-	
Amortization of deferred debt costs	-	-	-	-	-	
Power Supply Contract Costs	99	(0)	(0)	(0)	0	Same as Power supply contract recoveries above. Power supply contract costs are fully recovered by power supply contract recoveries.
Debt Guarantee fee	-	-	-	-	-	
Operating	1	-	-	-	-	
	98	31	67	76	78	
Excess (Deficiency) of Revenue over Expense	**391**	**88**	**(61)**			
Stranded Debt - Year End	**3,202**	**2,027**	**2,042**	**1,985**	**1,724**	

Provision for Electricity Sector (Dedicated Electricity Earnings/Electricity Sector Dedicated Earnings)

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Income from Investment in Government Business Enterprises						
OPG Income	291	299	147	720	608	1,041
Hydro One Income[1]	232	501	447	484	566	612
Hydro One Brampton (if applied separately)		15				
Total Income	**523**	**815**	**594**	**1,204**	**1,174**	**1,654**
Public Debt Interest - Electricity Sector						
OPG			(300)	(300)	(300)	(300)
Hydro One[1]			(154)	(154)	(154)	(154)
Public Debt Interest - Electricity Sector (OEFC Interest revenue)	**(520)**	**(514)**	**(454)**	**(454)**	**(454)**	**(454)**
MOF Provision Expense (before adjustments)	**3**	**302**	**140**	**750**	**720**	**1,199**
Other Adjustments						
Prior-year Adjustment[2]		3				
Exclude Brampton[3]		(15)				
MOF Provision Expense (after other adjustments)	**0**	**290**	**140**	**750**	**720**	**1,199**
Cumulative Shortfall Adjustment						
Opening Balance	0	0	0	0	0	0
Deduction / (Addition)	0	0	0	0	0	0
Ending Balance	0	0	0	0	0	0
Dedicated Electricity Earnings (all adjustments) (Public Accounts)	**0**	**290**	**140**	**750**	**720**	**1,199**
Electricity Sector Dedicated Income (OEFC Annual Report)	**3**	**302**	**140**			

Notes:

1. The Hydro One financials above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering are currently reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

2. 2016-17 Adjustment was due to the discrepancy between the numbers in MOF expense in PA 2015-16 and OEFC Financials in 2015-16 due to timing issues. $3M adjustment rectifies this discrepancy

3. Brampton was excluded from the Ministry of Finance's ESDI allocation.

Ontario Power Generation

OPG Income - Budget 2017

$ Millions

	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
OPG Net Income After Tax (Adjusted)	291	304	97	732	625	1,066
OPG Net Income After Tax	*291*	*379*	*480*	*678*	*726*	*913*
Extraordinary Gains	-	-	-	-	-	-
GA - OPG Trust Interest Revenue			*17*	*54*	*99*	*153*
OPG IFRS consolidation risk picked up in Fiscal Plan		(75)	(400)		(200)	
ONFA and other Fair Value Adjustments	(75)	8				
ONFA Adjustments	-	8				
Other Fair Value Adjustments	(75)					

OPG PIL - Budget 2017

$ Millions

	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Net Income Before Tax	383	396	572	867	795	1364
Net Income After Tax (Adjusted)	291	304	97	732	625	1066
Income Taxes	92	92	92	135	170	298
GRC: Payable to OEFC	198	196	205	212	219	220
Proxy Property Tax	16	14	18	19	19	19
Ontario Capital Tax	0	0	0	0	0	0
Total	**306**	**302**	**315**	**366**	**408**	**537**

OPG Income - October 2017

$ Millions

	Actual	Actual	Current Outlook			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
OPG Net Income	291	377	818	678	726	913
Adjustment for OPG HQ gain on sale[1]			(283)			
Extraordinary Gains	0	0	0	0	0	0
GA Financing - OPG Trust Interest Revenue[2]			12	42	82	128
OPG IFRS consolidation risk reflected in Fiscal Plan[3]		(78.00)	(400)		(200)	
OPG Net Income (Adjusted before ONFA)	**291**	**299**	**147**	**720**	**608**	**1,041**
ONFA Adjustments	247	49				
Other Fair Value Adjustments	(75)	(6)				
ONFA and other Fair Value Adjustments	**172**	**43**				
OPG Net Income	**463**	**342**	**147**	**720**	**608**	**1,041**

OPG PIL - August 2017

$ Millions

	Actual	Actual	Current Outlook			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Income Before Tax	383	308	684	855	778	1340
OPG Net Income (Adjusted before ONFA)	291	299	147	720	608	1041
OPG Income Tax (PILs)	92	9	162	135	170	298
Tax adjustment for OPG HQ gain on sale[1]			(95)			
GRC: Payable to OEFC	198	201	214	224	222	222
Proxy Property Tax to OEFC	16	14	18	19	19	19
Ontario Capital Tax	0	0	0	0	0	0
Total OPG PILs	**306**	**224**	**299**	**378**	**411**	**539**

1. As part of Asset Optimization Plan the projected proceeds are currently reported in OEP/MoF Sales and Rentals line. To be re-categorized after the transaction is completed and in coordination with OEP and SIFB.
2. This reflects interest earnings on GA financing costs which are consolidated back to Province
3. See Risks tab for IFRS impacts that were not reflected in Fiscal Plan, and table below.

	2017-18	2018-19	2019-20	2020-21
OPG IFRS Risk	(400)	(475)	(700)	(750)
Risks Built into Fiscal Plan	(400)	0	(200)	0
Additional Risks to be picked up	0	(475)	(500)	(750)

Hydro One Net Income and PILs

Hydro One Income - Budget 2017
($ millions)

	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Hydro One Net Income After Tax	685	737	742	802	862	931
Hydro One - Unrealized Gains Adjustment						

2016-17 to 2020-21 from CEFD Hydro One 2016 model.

Hydro One PIL - Budget 2017
($ millions)

	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Net Income After Tax	685	737	742	802	862	931
Income Taxes PILs	132	160	181	205	212	225
Proxy Property Tax	2	2	2	2	2	2
Ontario Capital Tax	0	0	0	0	0	0
Total	**134**	**162**	**183**	**207**	**214**	**227**

Hydro One (Post IPO Scenario) - Budget 2017
($ millions)

	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Assumed Provincial share		70.0%	70.0%	70.0%	70.0%	70.0%
Hydro One Net Income	236	516	520	562	603	652
Brampton Net Income	20	15				
Hydro One PILs		0	0	0	0	0
Hydro One CIT	3	20	20	22	23	25
Brampton PILs		5				
Proxy Property Tax		2	2	2	2	2
Total	**2886**	**27**	**22**	**24**	**25**	**27**

Hydro One Income - October 2017
($ millions) — $ Millions

	Actual	Actual	Current Outlook			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Hydro One Net Income After Tax			623	666	753	818
Debenture Costs Impacts (After Tax)			(34)	(39)		
Hydro One Net Income After Tax - Including Adjustments	670	680	589	627	753	818
Hydro One - Net Income Attributable to Preferred Shareholders	15	18				
Hydro One - Unrealized Gains Adjustment						

2017-18 to 2020-21 from CEFD Hydro One 2016 model.

Hydro One (100% Ownership)
($ millions) — $ Millions

	Actual	Actual	Current Outlook			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Net Income After Tax - Common Shares	670	680	589	627	753	818
Net Income After Tax - Preferred Shares	15	18				
Income Taxes PILs	132	160	181	205	212	225
Proxy Property Tax	2	2	2	2	2	2
Ontario Capital Tax	0	0	0	0	0	0
Total	**134**	**162**	**183**	**207**	**214**	**227**

Hydro One (Post IPO Scenario) - March 2017
$ Millions

	Actual	Actual	Current Outlook			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Assumed Provincial share		70.1%	70.1%	70.1%	70.1%	70.1%
Net Income After Tax - Common Shares	670	680	589	627	753	818
Net Income After Tax - Preferred Shares	15	18	18	18	18	18
adjustment for lower Provincial share		(204)	(177)	(188)	(225)	(245)
Hydro one IPO-related and other adjustments*	(449)					
Hydro One IFRS Adjustment to Province		7				
OPCD adjustment for Equity advances		(2)				
Adjust OEB decision/rebasing to ~50% provincial ownership**			16	27	21	22
Hydro One - Unrealized Gains Adjustment						
Total Hydro One Income - Province	**236**	**500**	**447**	**484**	**566**	**612**
Brampton Net Income - For Provision/ESDI	20	15				
other adjustments	(24)	2				
Combined Income for ESDI	232	501	447	484	566	612
Brampton Net Income - Public Accounts	**20**	**18**				
Hydro One PILs		2				
Proxy Property Tax		2	2	2	2	2
Brampton PILs						
Hydro One CIT	3	25	12	13	13	13
Total H1 PILs (incl. CIT)		29	14	15	15	15
Total H1 PILs (excl CIT)		4	2	2	2	2
Total	**2,886**	**29**	**14**	**15**	**15**	**15**

* Hydro one IPO-related and other adjustments	2015-16
Deferred Tax Asset (Post IPO Portion)- 100%	(2,619)
Deferred Tax Asset (Pre IPO Portion) - 100%	(191)
Deferred Tax Asset - Province	2,392
Loss of H1 Net Income	(50)
Consolidation adjustment	19

** An adjustment is made for OEB decision and rebasing impacts to show them at about 50% Provincial allocation, pending recategorization of AO amounts from Sales and Rentals.

Hydro One 2015-16 Net Income Estimation (USGAAP) ($M)

Q2 2015[1]	Q3 2015[2]	Q4 2015[1]	Q1 2016[2]	Fiscal Year 2015-16
131	188	143	208	**670**
	9		6	**15**

2016	Q1 2017	cal Year 2016-17
721	167	**680**
19	5	**18**

2015-16 PILs Estimation (Accounting Numbers)	Exc. B	Inc. B
2015 Income Tax	105	105
Q1 2016 Income Tax	33	33
Q1 2015 Income Tax	(45)	(45)
Income Taxes PILs	93	93
Departure Tax	2,600	2,600
Additional PILs	191	191
Brampton PILs	(4)	
Proxy Property Tax	2	2
Total	**2882**	**2886**

Public Debt Interest and Section 50.3 payments

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Hydro One Public Debt Interest and Section 50.3 payments						
Government Annual Interest Costs - Hydro One	220	220	220	220	220	220
Reduction in Interest Costs due to Broadening[1]		(29)	(66)	(66)	(66)	(66)
Province Annual Interest Costs - Hydro One Debt	**220**	**191**	**154**	**154**	**154**	**154**
Province Annual Interest Cost - OPG Debt	300	300	300	300	300	300
Total Public Debt Interest	**520**	**514**	**454**	**454**	**454**	**454**

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Gain to OEFC under s. 50.3	172	411	550	0	0	0

1. The Hydro One reduction in interest costs above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering are currently reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

PROVINCIAL CONSOLIDATION ADJUSTMENTS
Ontario Nuclear Funds Agreement

	2015-16	2016-17	2017-18
Adjustment for Change in OPG Reported Net Income			
Adjustment for DSF Unrealized Earnings			
Unrealized Earnings as at beginning of year	0	0	
Unrealized Earnings as at fiscal year end / latest quarter	(175)	0	
Bruce Variance Account Adjustment	(82)	0	
OPG Net Income Adjustment	(93)	0	
Adjustment for UFSF Unrealized Earnings			
Unrealized Earnings as at beginning of year	0	0	
Unrealized Earnings as at fiscal year end / latest quarter	(82)	56	
Bruce Variance Account Adjustment	(42)	28	
OPG Net Income Adjustment	(40)	28	
Unrealized Earnings -- Fiscal YTD	**(133)**	**28**	
Adjustment for Change in Due to Province			
Adjustment for DSF Due to Province			
Due to Province (cost basis) as at beginning of year	0	39	
Unrealized Earnings as at fiscal year end / latest quarter	39	79	
Change in Due to Province -- Fiscal YTD	**39**	**40**	
Adjustment for UFSF Due to Province			
Due to Province (cost basis) as at beginning of year	295	370	
Unrealized Earnings as at fiscal year end / latest quarter	370	407	
Change in Due to Province -- Fiscal YTD	**75**	**37**	
Provincial Consolidation Adjustment	**247**	**49**	

Other Data

	Actual	Plan			
	2016-17	2017-18	2018-19	2019-20	2020-21
Debt Retirement Charge	621	0	0	0	0

	Plan				
	2016-17	2017-18	2018-19	2019-20	2020-21
Power Supply Contract Recoveries	838	292	325	301	273

	Plan				
	2016-17	2017-18	2018-19	2019-20	2020-21
Interest					
OPG	167	169	179	175	148
IESO	2	3	3	3	3
Other (Net)	20	20	20	10	10
Expense					
Debt interest	1216	1121	1094	1053	963

	Actual	Plan			
	2016-17	2017-18	2018-19	2019-20	2020-21
MEU - PIL Income Tax	109.8				
MEU - PIL Property Tax	0.6				
MEU - GRC	1.2				
TOTAL MEU PILs	111.6				

	Actual	Plan			
	2016-17	2017-18	2018-19	2019-20	2020-21
Miscellaneous/Other (OEFC FS)	14				
Demand Management Support Costs (IEI)	8	10			
Operating [Expense]	7	6	6	6	6
Interest on nuclear risk funding	-	-	-	-	-
Amortization of deferred debt costs	-	-	-	-	-
Amortization of NUG liability	129	74	41	30	28
Debt Guarantee Fee	122				

Expense (Electrictiy Summary Tab)					
Other (Finance)	-7	-6	-6	-6	-6
Demand Management Support Costs (IEI)	-8	-10			
Debt Guarantee Fee	(122)				

From: Usman Zahid
To: John Kim; Ronald Kwan; Shajee Kathirgamanathan
Cc: Bruno Amara; Gavin He
Subject: RE: FES Items for Today
Date: Friday, November 10, 2017 3:32:49 PM

Thanks John,

I will send this out.

Usman

From: John Kim
Sent: Friday, November 10, 2017 3:18 PM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Usman Zahid <Usman.Zahid@ofina.on.ca>
Cc: Bruno Amara <Bruno.Amara@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>
Subject: RE: FES Items for Today

Hi Ron,

Yes, and here it is with revision.

Thanks,

John

From: Ronald Kwan
Sent: Friday, November 10, 2017 3:09 PM
To: Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Usman Zahid <Usman.Zahid@ofina.on.ca>
Cc: John Kim <John.Kim@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>
Subject: RE: FES Items for Today

Hi,

I'd rather put it differently.

The Outlook presents potential in-year pressures (positive and negative) that may be offset as the year progresses. The Electricity Finance Branch will continue to monitor and communicate with other divisions on when and if the fiscal plan is to be updated for the electricity sector. At the time of the Fall Economic Outlook and Fiscal Review, the fiscal plan has not been updated to reflect the information on pressures contained here.

Is that the only text added?

Ron

From: Shajee Kathirgamanathan
Sent: November-10-17 14:26
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; Usman Zahid <Usman.Zahid@ofina.on.ca>
Cc: John Kim <John.Kim@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>
Subject: RE: FES Items for Today

Hi Ron,

Please see revised Outlook file with the disclaimer on the first page.

If it looks good then this file can be sent back with the initial OFHP supporting data pdf sent earlier for inclusion in the binder.

Thanks,
Shajee

Shajee Kathirgamanathan
Office: 416-325-1402 | Mobile: 647-294-3359
shajee.kathirgamanathan@ofina.on.ca

From: Ronald Kwan
Sent: Friday, November 10, 2017 12:20 PM
To: Usman Zahid <Usman.Zahid@ofina.on.ca>
Cc: John Kim <John.Kim@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>
Subject: RE: FES Items for Today

Hi,

Could we note on the Outlook file that these are potential pressures at a point in time, but it was not recommended for FES itself to pick up any of the pressures? As such, fine to send both for proposed inclusion.

Thanks,
Ron

From: Usman Zahid
Sent: November-10-17 10:52
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: John Kim <John.Kim@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Shajee

Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>
Subject: FW: FES Items for Today

Hi Ron,

Attached are two items for inclusion into the TB/MBC Binder. The first item is a PDF version of the Electricity Sector Outlook (similar to what was submitted previously). The second item is information on the financing of FHP. EFB have said they are open to omitting the second item if appropriate.

Regards,
Usman

From: Shajee Kathirgamanathan
Sent: Friday, November 10, 2017 10:37 AM
To: Usman Zahid <Usman.Zahid@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>
Subject: RE: FES Items for Today

Hi Usman,

Please find attached the two documents for inclusions into EFB's portion of the TB Binder.

1) PDF'ed version of the Electricity Sector Outlook. Similar to what we submitted last time
2) Information we received on the financing of the Fair Hydro Plan. We didn't use this information per se, so we're open to omitting it should it be decided to exclude.

Files saved here:
S:\Users\CEF\Hydro 2017\FES\TB Binder\EFB

Thanks,
Shajee

Shajee Kathirgamanathan
Office: 416-325-1402 | Mobile: 647-294-3359
shajee.kathirgamanathan@ofina.on.ca

From: Usman Zahid
Sent: Friday, November 10, 2017 9:33 AM
To: John Kim <John.Kim@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>
Subject: FES Items for Today

Hi All,

TB/MBC Binder Materials: Due by noon, please get to Ron ASAP.

Placemats: Due at 2pm, please get in right after TB/MBC binder Materials.

Regards,
Usman

From:	Ken Kandeepan
To:	Scott Nelms (ENERGY)
Cc:	Veinot, Cindy (TBS); John Kim; Carlos Yep; Nadine Petsche (MOF); Mike Manning; Ronald Kwan; John Psinas
Subject:	RE: FHP - OPG Performance Fee
Date:	Thursday, July 06, 2017 2:29:56 PM

Hi Scott

I reviewed the email from Jackson Huang that you attached against E&Y's opinion (dated May 17) specifically against any mention of a management fee. Page 4 of the opinion states;" The purpose of the Trust is to allow OPG to earn a return on the Intangible Asset from the IESO by effectively managing financing to earn a spread, earn management fees, and earn interest fees. For the reasons noted above, OPG has control over the decisions to be made about the relevant activities".

It appears that E&Y conceptually envisages a management fee in addition to the spread earned by OPG on the 5% debt it funds and interest fees on the 44% funded by the Province's equity injection.

Drawing parallels between the proposed FHP structure and ONFA, is in my opinion not particularly useful. The latter manages tangible monetary assets that earn income based on specific investment decisions. Such is not the case in the latter where the asset is intangible and its attraction is the owner's ability to benefit from certain legislated revenue streams that allow the repayment of the liabilities incurred in purchasing said asset. I am cc'ing Ron Kwan on this since he may want to add to the ONFA, FHP comparison. The bottom line is there is no asset management in the FHP, rather and management fees should be conceptually a reimbursement of the costs incurred by the FSM in discharging its mandate.

I would therefore propose a spectrum of options to address the management fee:

On the narrow end of the spectrum it can be argued that the act of lending the 44% equity funding to the Trust constitutes the "interest fees" referred to above in the opinion. Any spread that OPG includes in the rate charged to the Trust – we understand that OPG will indeed include a spread on the basis that this debt is defined as subordinate – can represent the management fee.

The middle of the spectrum can be represented by a spread component, over and above what OPG includes to address the sub debt issue, that constitutes the management fee. And at the broader end of the spectrum OPG can include a specific spread not just on the 44% funded via the equity injection but also on the 5% it funds through its own borrowings.

Finally your attached email proposes the following: pls see my comments in red

(i) inversely in relation to the weighted-average interest rate (for example, weighted by dollar amount of each funding obligation) of all new funding obligations incurred during a calendar year; and/or. Not sure what "inversely" means in this context, if the idea is to include a simple spread on the weighted average borrowing rate this is no different from what we have proposed above.

(ii) as a percentage [fixed under regulation or determined by OEB] of the "surplus" (where

present value of all funding obligations discounted at a fixed rate [to be prescribed or determined by OEB] > actual present value of all funding obligations) or "deficit" during a period
[Note: this most closely tracks the adjustment mechanism in ONFA and creates a direct relationship between the FSM fees and the dollar effect of FSM's management; a period can be more than one calendar year which means the FSM fees payable for a calendar year would not change until a triggering event]. This is very confusing; what is “actual present value”

Thanks and happy to discuss.

Ken k

-----Original Message-----
From: Nelms, Scott (MOF) [mailto:Scott.Nelms@ontario.ca]
Sent: Wednesday, July 05, 2017 4:36 PM
To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>; Veinot, Cindy (TBS) <Cindy.Veinot@ontario.ca>; John Kim <John.Kim@ofina.on.ca>; Carlos Yep <Carlos.Yep@ofina.on.ca>; Nadine Petsche (MOF) <Nadine.Petsche@ontario.ca>
Subject: FW: FHP - OPG Performance Fee

Fee note as discussed. The note focuses on OEB role, but perhaps we should revisit the quantum of the fee. Let me know if you have comments.

Sent with BlackBerry Work
(www.blackberry.com)

From: Calwell, Carolyn (ENERGY/MEDEI/MRI)
<Carolyn.Calwell@ontario.ca<mailto:Carolyn.Calwell@ontario.ca>>
Date: Wednesday, Jul 05, 2017, 1:20 PM
To: Nelms, Scott (MOF) <Scott.Nelms@ontario.ca<mailto:Scott.Nelms@ontario.ca>>, McKinlay, Tom (ENERGY) <Tom.McKinlay@ontario.ca<mailto:Tom.McKinlay@ontario.ca>>
Cc: Montgomery, Kaitlin (MOF)
<Kaitlin.Montgomery@ontario.ca<mailto:Kaitlin.Montgomery@ontario.ca>>
Subject: RE: FHP - OPG Performance Fee

I think we are aligned. Does OFA have some suggestions about how to structure the fee? Feel free to float the “option 2” from the note and see if they have suggestions about how to make it better. I haven’t yet sent that note up, as I am trying to work in some research that Jackson did (attached for your reference).

From: Nelms, Scott (MOF)
Sent: July-05-17 12:15 PM
To: Calwell, Carolyn (ENERGY/MEDEI/MRI); McKinlay, Tom (ENERGY)
Cc: Montgomery, Kaitlin (MOF)

Subject: FW: FHP - OPG Performance Fee

Fyi – more complications on the fee issue.

From: Ken Kandeepan [mailto:Ken.Kandeepan@ofina.on.ca]
Sent: July 5, 2017 11:59 AM
To: Nelms, Scott (MOF)
Cc: Kwan, Ronald (OFA); Yep, Carlos (OFA); Monroe, Graham (OFA); Manning, Mike (OFA); Devine, James (OFA); Veinot, Cindy (TBS)
Subject: FHP - OPG Performance Fee

Hi Scott

I am writing this to you as an FYI since there may be some push back from OPG. I am cc'ing Cindy as well given the accounting implications raised by OPG. As you may be aware, OPG provided us with the proposed methodology for computing the performance fee. Both the benchmark and the actual include the 44% debt issued by OPG to the Trust which is in turn fully funded by the Province's equity injection.

Given that there are no capital market decision-making associated with this component of the debt, we are reluctant to sign off on OPG's methodology in its current form. OPG is not particularly happy with our response and posits that the accounting treatment requires a performance fee. While I agree that the E&Y opinion does refer to a performance fee I am a little doubtful that E&Y specified that all of the debt should be part of the computation. I have requested that OPG provide me with any specific reference by E&Y on the performance fee methodology. If E&Y does require that the benchmark and actual include the total debt issuance, we can reconsider our stance.

Finally, the performance fee methodology computes the fee for a particular year by applying the difference between the benchmark and the actual on the 5% that is borrowed by OPG. We requested and obtained confirmation that the performance fee will be limited to new borrowings by OPG and not apply to any refinancing. OPG finds this acceptable and it also ensures that the performance fee will be capped at $1.2 million or so per annum.

Thanks

Ken k

This message, including any attachments, is meant only for the use of the individual(s) to whom it is

intended and may contain information that is privileged/confidential. Any unauthorized use, copying or disclosure is strictly prohibited. If you are not the intended recipient or have received this message in error, please notify us immediately by reply e-mail and permanently delete this message, including any attachments, without reading them, and destroy all copies. Thank you.

From: Ronald Kwan
To: John Kim
Subject: RE: FHP - OPG Performance Fee
Date: Thursday, July 06, 2017 3:32:02 PM

Hi John,

Would you be able to send the attachment?

Thanks,
Ron

From: Ken Kandeepan
Sent: July-06-17 14:30
To: Scott Nelms (ENERGY) <Scott.Nelms@ontario.ca>
Cc: Veinot, Cindy (TBS) <Cindy.Veinot@ontario.ca>; John Kim <John.Kim@ofina.on.ca>; Carlos Yep <Carlos.Yep@ofina.on.ca>; Nadine Petsche (MOF) <Nadine.Petsche@ontario.ca>; Mike Manning <Mike.Manning@ofina.on.ca>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>; John Psinas <John.Psinas@ofina.on.ca>
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It appears that E&Y conceptually envisages a management fee in addition to the spread earned by OPG on the 5% debt it funds and interest fees on the 44% funded by the Province's equity injection.

Drawing parallels between the proposed FHP structure and ONFA, is in my opinion not particularly useful. The latter manages tangible monetary assets that earn income based on specific investment decisions. Such is not the case in the latter where the asset is intangible and its attraction is the owner's ability to benefit from certain legislated revenue streams that allow the repayment of the liabilities incurred in purchasing said asset. I am cc'ing Ron Kwan on this since he may want to add to the ONFA, FHP comparison. The bottom line is there is no asset management in the FHP, rather and management fees should be conceptually a reimbursement of the costs incurred by the FSM in discharging its mandate.

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the basis that this debt is defined as subordinate – can represent the management fee.

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[Note: this most closely tracks the adjustment mechanism in ONFA and creates a direct relationship between the FSM fees and the dollar effect of FSM's management; a period can be more than one calendar year which means the FSM fees payable for a calendar year would not change until a triggering event]. This is very confusing; what is "actual present value"

Thanks and happy to discuss.

Ken k

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Sent: Wednesday, July 05, 2017 4:36 PM
To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>; Veinot, Cindy (TBS) <Cindy.Veinot@ontario.ca>; John Kim <John.Kim@ofina.on.ca>; Carlos Yep <Carlos.Yep@ofina.on.ca>; Nadine Petsche (MOF) <Nadine.Petsche@ontario.ca>
Subject: FW: FHP - OPG Performance Fee

Fee note as discussed. The note focuses on OEB role, but perhaps we should revisit the quantum of the fee. Let me know if you have comments.

Sent with BlackBerry Work
(www.blackberry.com)

From: Calwell, Carolyn (ENERGY/MEDEI/MRI)
<Carolyn.Calwell@ontario.ca<mailto:Carolyn.Calwell@ontario.ca>>
Date: Wednesday, Jul 05, 2017, 1:20 PM

To: Nelms, Scott (MOF) <Scott.Nelms@ontario.ca<mailto:Scott.Nelms@ontario.ca>>, McKinlay, Tom (ENERGY) <Tom.McKinlay@ontario.ca<mailto:Tom.McKinlay@ontario.ca>>
Cc: Montgomery, Kaitlin (MOF)
<Kaitlin.Montgomery@ontario.ca<mailto:Kaitlin.Montgomery@ontario.ca>>
Subject: RE: FHP - OPG Performance Fee

I think we are aligned. Does OFA have some suggestions about how to structure the fee? Feel free to float the "option 2" from the note and see if they have suggestions about how to make it better. I haven't yet sent that note up, as I am trying to work in some research that Jackson did (attached for your reference).

From: Nelms, Scott (MOF)
Sent: July-05-17 12:15 PM
To: Calwell, Carolyn (ENERGY/MEDEI/MRI); McKinlay, Tom (ENERGY)
Cc: Montgomery, Kaitlin (MOF)
Subject: FW: FHP - OPG Performance Fee

Fyi – more complications on the fee issue.

From: Ken Kandeepan [mailto:Ken.Kandeepan@ofina.on.ca]
Sent: July 5, 2017 11:59 AM
To: Nelms, Scott (MOF)
Cc: Kwan, Ronald (OFA); Yep, Carlos (OFA); Monroe, Graham (OFA); Manning, Mike (OFA); Devine, James (OFA); Veinot, Cindy (TBS)
Subject: FHP - OPG Performance Fee

Hi Scott

I am writing this to you as an FYI since there may be some push back from OPG. I am cc'ing Cindy as well given the accounting implications raised by OPG. As you may be aware, OPG provided us with the proposed methodology for computing the performance fee. Both the benchmark and the actual include the 44% debt issued by OPG to the Trust which is in turn fully funded by the Province's equity injection.

Given that there are no capital market decision-making associated with this component of the debt, we are reluctant to sign off on OPG's methodology in its current form. OPG is not particularly happy with our response and posits that the accounting treatment requires a performance fee. While I agree that the E&Y opinion does refer to a performance fee I am a little doubtful that E&Y specified that all of the debt should be part of the computation. I have requested that OPG provide me with any specific reference by E&Y on the performance fee methodology. If E&Y does require that the benchmark and actual include the total debt issuance, we can reconsider our stance.

Finally, the performance fee methodology computes the fee for a particular year by applying the difference between the benchmark and the actual on the 5% that is borrowed by OPG. We requested and obtained confirmation that the performance fee will be limited to new borrowings by

OPG and not apply to any refinancing. OPG finds this acceptable and it also ensures that the performance fee will be capped at $1.2 million or so per annum.

Thanks

Ken k

This message, including any attachments, is meant only for the use of the individual(s) to whom it is intended and may contain information that is privileged/confidential. Any unauthorized use, copying or disclosure is strictly prohibited. If you are not the intended recipient or have received this message in error, please notify us immediately by reply e-mail and permanently delete this message, including any attachments, without reading them, and destroy all copies. Thank you.

From:	John Kim
To:	Ronald Kwan
Cc:	Usman Zahid; Gavin He
Subject:	RE: OFHP fees reg
Date:	Friday, October 13, 2017 2:57:37 PM
Attachments:	Draft Fees Regulation for OPG Trust and OFHP_OFA Q&As_Markup4.docx

Hi Ron,

CMD provided some additional detail….not sure if useful.

Thanks,

John

All files saved here:
S:\Users\CEF\Hydro 2017\Electricity Prices\Mitigation Proposals\Debt Financing the GA\Implementation\OFHP_GA - Performance Fee

---

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Subject: FW: OFHP fees reg

Hi Ron,

We have consolidated comments / edits from FTD and CMD.

Thanks,

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Hi Carlos,

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Subject: FW: OFHP fees reg

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Just catching up on emails and attached see additional request related to the draft reg.

I will aim to provide draft response to the Qs below tomorrow based on our comments and CMD's, as well.

Thanks,

John

From: Katona, Keley (MOF) [mailto:Keley.Katona@ontario.ca]
Sent: Thursday, October 12, 2017 2:06 PM
To: John Kim <John.Kim@ofina.on.ca>
Cc: Tim Christie (ENERGY) <Tim.Christie@ontario.ca>; Daniel Cayley (ENERGY) <Daniel.Cayley@ontario.ca>; Montgomery, Kaitlin (MOF) <Kaitlin.Montgomery@ontario.ca>
Subject: FW: OFHP fees reg

Hi John,

Further to my call, attached is the latest draft reg. Could you review the NTD for the OFA and also address any outstanding questions per below? This was discussed at a meeting that Gadi and Ron attended this morning and it's likely tracking to Cabinet next week with the goal of finalizing before the weekend.

Thanks,
Keley

From: Cayley, Daniel (ENERGY)
Sent: October-11-17 2:04 PM
To: Kim, John (OFA)
Cc: Christie, Tim (ENERGY)
Subject: OFHP fees reg

Hi John – our lawyers have a few questions below related to the OPG fair hydro plan fees reg that they were hoping to get your input on as soon as possible. Please let me know if you think a call with us/our lawyers would be faster than getting us written answers.

#1 – On the process for establishing the base fee and variable fee, which could theoretically spill over into the year to which the new fees would apply (if OEB approval was not obtained until then), the thinking would be to have the old fees apply until the new fees were approved by the OEB, and then have a "retroactive" adjustment of the fees (retroactively adjusting them back to the beginning of the year the new fees take effect). Since the base fee and variable fee are payable monthly, the "retroactive" adjustment would be made in the month following the month in which the new fees were finalized. The question for OFA is whether it would be appropriate to have a retroactive fee adjustment.

#2 – Re: discussion between OPG and OFA about what "market comparable fees", OPG has proposed that there be a requirement for five sets of fees, four of which would be fees charged by full-service managers of securitization vehicles, and the fifth of which would be fees charged by an asset manager (or management and financial services provider) in respect of any one of pension funds, other structured investment funds, hedge funds or other similar structured funds. Does the OFA have any comments on this approach or the viability of finding five such comparators? The Board has suggested that the FSM be required to submit fee comparators but that the Board have the ability to also include comparators that it chooses (e.g. on the advice of consultants/experts it retains).

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#4 – Can the OFA provide comments on the below draft definition of “market comparable fees” reads as follows (the NTDs are for OFA’s input)?

ıarket comparable fees” means fees, expressed as a **[yearly?]** percentage rate, charged by asset managers **[or management and financial service providers?]** in Canada or another jurisdiction specified by the Board for services that are similar to the services provided by the Financial Services Manager under the Act in terms of,

[NTD: (1) Confirm *yearly* percentage rate. (2) Confirm whether to include “or management and financial service providers”. If this is to be included, what does this mean? Is it a well-recognized industry term of art?]

the type of services provided, being services in respect of funds including **securitization vehicles**, pension funds, other **structured** investment funds, hedge funds and other similar **structured** funds, **[NTD: Confirm “securitization vehicles” and “structured”.]**

the scope of the services provided,

the level of the services provided, and

the dollar amount of assets under management;

Thanks,

Daniel

Draft Fees Regulation for OPG Trust and OFHP

Question 1: On the process for establishing the base fee and variable fee, which could theoretically spill over into the year to which the new fees would apply (if OEB approval was not obtained until then), the thinking would be to have the old fees apply until the new fees were approved by the OEB, and then have a "retroactive" adjustment of the fees (retroactively adjusting them back to the beginning of the year the new fees take effect). Since the base fee and variable fee are payable monthly, the "retroactive" adjustment would be made in the month following the month in which the new fees were finalized. The question for OFA is whether it would be appropriate to have a retroactive fee adjustment.

OFA Comment: OFA would defer this item to Energy and OFA staff are of the view that retroactive adjustments of the fees applying once the rates are finalized would be acceptable. This would mean that the old rates would continue to apply until the decisions are made by the OEB.

Question 2: Re: discussion between OPG and OFA about what "market comparable fees", OPG has proposed that there be a requirement for five sets of fees, four of which would be fees charged by full-service managers of securitization vehicles, and the fifth of which would be fees charged by an asset manager (or management and financial services provider) in respect of any one of pension funds, other structured investment funds, hedge funds or other similar structured funds. Does the OFA have any comments on this approach or the viability of finding five such comparators? The Board has suggested that the FSM be required to submit fee comparators but that the Board have the ability to also include comparators that it chooses (e.g. on the advice of consultants/experts it retains).

OFA Comment: OFA had indicated that the earlier proposal of 10 bps for the initial proposed base fee was too high and since then a decision to set the initial proposed base fee at 7.5 bps was made. While the 7.5 bps would be applicable in the first year of operations it was also agreed that the OEB will retain an outside expert to provide recommendations on an appropriate rate based on a market survey. In the draft regulation provided by Energy on October 12, 2017, the draft regulation would require the OEB to set the base fee rates based on the market comparable fees. OFA staff are of the view that there should be no references made in the draft regulation about investment vehicles listed in the Question 2 and in Question 4, including securitization vehicles, actively managed investment funds, structured investment funds, hedge funds and/or other types of structured funds. Securitization vehicles, for example, involve significant amount of work 'packaging' a large number of underlying assets into an investment structure. [See more detailed example below.] The financing entity has a very different structure and operates differently from securitization vehicles, hedge funds etc., so such market comparable fees/rates referencing such investment types would not be good representation of the benchmark in this situation.

More Detailed Analysis:

The Financing entity will buy a global asset of $2.5B from IESO and will receive 480 payments from IESO (i.e. ,12 monthly payments for 40 years)

Commented [JK1]: CMD provided additional detail.

A vehicle leasing securitization program will consist of leases with an average term of 36 months with monthly payments and average amount of $25,000 [illustratively]

i.e. To manage a $2.5 billion program for 3yrs would consist of 100,000 leases ($2,500,000,000 divided by $25,000 average lease), involve 3,600,000 payments (100,000 leases X 36 monthly payments) and this would need to be done another 13 times (i.e., for 39 years).

Question 3: Are there "market comparable fees" that allow the person charging the fees to also recover out-of-pocket costs over and above the fees?

OFA Comment: OFA staff are of the view that this is acceptable if done in accordance with the Act and if appropriately audited.

Question 4: Can the OFA provide comments on the below draft definition of "market comparable fees" reads as follows (the NTDs are for OFA's input)?

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From: Ronald Kwan
To: John Kim
Cc: Usman Zahid; Gavin He
Subject: RE: OFHP fees reg
Date: Friday, October 13, 2017 3:10:13 PM

Thanks John.

Looks fine to send along.

I did note an inconsistency in terminology across the two documents. While the questions refer to "retroactive, "retrospective" is used in the draft reg., which would seem to me the word that should be used consistently in the Q&A document too.

Ron

From: John Kim
Sent: October-13-17 14:58
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Usman Zahid <Usman.Zahid@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>
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the level of the services provided, and

the dollar amount of assets under management;

Thanks,

Daniel

From:	Francisco Chinchon
To:	Ronald Kwan
Cc:	Gavin He; Darren Scanlan; John Kim; Bruno Amara
Subject:	RE: OPG BP Submission
Date:	Wednesday, April 26, 2017 4:44:46 PM
Attachments:	2017 04 26 OPG concurrence letter v9_markup.docx

I have a few edits on the concurrence letter. Except for confusing ONFA with the RP, there is nothing wrong with what they added but I think it could be said in a better way…

From: Ronald Kwan
Sent: Wednesday, April 26, 2017 4:34 PM
To: John Kim <John.Kim@ofina.on.ca>; Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>
Cc: Gavin He <Gavin.He@ofina.on.ca>
Subject: Fw: OPG BP Submission

Hi,

Comments?

Ron

From: Nelms, Scott (MOF) <Scott.Nelms@ontario.ca>
Sent: April 26, 2017 4:06 PM
To: Nancy Kennedy (MOHLTC); Ronald Kwan
Cc: Vivienne Skoberne (MOHLTC); Montgomery, Kaitlin (MOF)
Subject: OPG BP Submission

Hi Nancy, Ron,

Please see the attached OPG BP package and draft concurrence letter. This has been shared with ENE DMO / MO. Ron, I think you were planning to share up with MoF on our side.

Thanks,
Scott

Mr. Bernard Lord
Chair
Ontario Power Generation
1900-700 University Avenue
Toronto ON M5G 1X6

Dear Mr. Lord,

Thank you for your submission of Ontario Power Generation's (OPG) 2017-2019 Business Plan ("the Plan"). We have reviewed the Plan and find it to be consistent with our government's expectations.

I support the operational and financial targets set by OPG in its business plan. We recognize the substantial cost reductions that OPG has recently achieved and expect OPG to work closely with the Province to fully realize the additional efficiencies incorporated in the Plan in a manner that is consistent with the continued safe and environmentally responsible operation of OPG's facilities.

We commend OPG on its successful start to the Darlington Refurbishment Project, a key objective of Ontario's 2013 Long-Term Energy Plan (2013 LTEP). As a priority project for the government, I expect that OPG will continue to focus on delivering the project as per the schedule and budget contained in the Release Quality Estimate approved by the OPG Board and by the government. I also expect OPG to continue to minimize project risks consistent with the nuclear refurbishment principles set out in the 2013 LTEP, and seek concurrence prior to commencing ~~subsequent unit~~ refurbishment~~s after~~of Unit ~~2~~3 ~~is successfully returned to service~~before the end of 2017.

We continue to support the planned operation of Pickering units up to 2022/2024, subject to OPG obtaining necessary regulatory approvals, as the station's output will provide reliable, cost-effective and emission-free electricity supply during the Darlington and initial Bruce refurbishments. I expect OPG to keep the Ministry apprised throughout the regulatory processes and as we proceed to update the Long-Term Energy Plan. .

I understand that the recently approved Ontario Nuclear Funds Agreement (ONFA) Reference Plan has resulted in a reduction of the estimated liabilities for future decommissioning and long-term management of waste from Ontario's nuclear fleet. With many decades of nuclear generation in the Province's future, we expect OPG to continue managing its decommissioning and waste management obligations and related segregated funds in a prudent manner. I recognize that the ONFA Reference Plan is based[, among others,] on OPG's proposed siting of a Deep Geological Repository (DGR) for low and intermediate level waste at the Bruce site [in the Municipality of Kincardine]. OPG's DGR is a key component of Ontario's plans to ensure that nuclear remains the backbone of our electricity system for years to come.

I appreciate the efforts of OPG staff, management and the Board of Directors to date as we worked to develop a plan to refinance the Global Adjustment (GA). Refinancing the GA would provide significant and immediate rate relief by spreading the cost of electricity investments over the expected lifecycle of the infrastructure that has been

built. OPG will be instrumental to the success of this initiative and we plan to introduce legislation that would, if passed, enable OPG to work with the Independent Electricity System Operator (IESO) to implement this plan. I also expect to make the necessary changes to OPG's articles of amalgamation to provide the financing flexibility to implement the refinancing of the GA to meet the Province's price objectives announced on March 2, 2017.

I expect OPG to continue to keep the government informed with regard to the company's key ongoing and emerging initiatives and progress in achieving its financial and operational performance commitments. –As OPG's performance directly impacts Ontario's fiscal plan, we note the importance of achieving or exceeding [all of] OPG's financial performance commitments

Consistent with Section 7 of the Memorandum of Agreement, in advance of commencing discussions for the renewal of its collective agreements with its unions, I expect that OPG shall seek advice from the Ministry on Provincial policy direction and relevant fiscal considerations affecting labour negotiations.

This letter constitutes our concurrence with OPG's Board approved 2017-2019 Business Plan as provided for under the Memorandum of Agreement between OPG and the Shareholder dated July 17, 2015.

This letter also confirms the approval of special status for OPG to approve international travel, under Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive. OPG shall submit semi-annual reports on international travel to the Ministry of Energy, as described in the submission received from OPG's President and CEO, dated January 24, 2017.

Sincerely,

Glenn Thibeault
Minister of Energy

c: Jeff Lyash, President and Chief Executive Officer, OPG
Serge Imbrogno, Deputy Minister, Ministry of Energy
Scott Thompson, Deputy Minister, Ministry of Finance
Andrew Teliszewsky, Chief of Staff, Ministry of Energy
Ali Ghiassi, Chief of Staff, Ministry of Finance

From:	Ronald Kwan
To:	John Kim
Cc:	Francisco Chinchon; Bruno Amara; Adam Prokop
Subject:	RE: OPG BP concurrence - Energy materials
Date:	Monday, April 24, 2017 12:53:12 PM
Attachments:	2017 04 11 OPG Business Plan Review v7_Markup5.pptx

Hi John,

I had some edits, primarily to slide 6, which I regard as important to recast.

Ron

From: John Kim
Sent: April-24-17 12:17
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Adam Prokop <Adam.Prokop@ofina.on.ca>
Subject: RE: OPG BP concurrence - Energy materials

Here's the deck….we'd delete most, if not all, of the comments.

Thanks,

John

From: John Kim
Sent: Monday, April 24, 2017 11:46 AM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>
Subject: OPG BP concurrence - Energy materials

Hi Ron,

Pls. see attached with proposed edits from SIFB to the concurrence letter. We are still looking at the deck and will be forthcoming soon.

They have a meeting with Serge at 3:30 so would appreciate any comments soon.

John

Y. John Kim
Director, Electricity Finance Branch
Corporate & Electricity Finance Division
Ontario Financing Authority

Ph: 416-212-6996
Email: john.kim@ofina.on.ca

Ontario

MINISTRY OF
ENERGY

OPG Business Plan

May 2017

Context

- As required by the Memorandum of Agreement (MOA) between Ontario Power Generation and the Minister of Energy, OPG provided its Business Plan for 2017-2019 to the Ministry of Energy on November 29, 2016 for concurrence
  - Note that while OPG is seeking concurrence for its three year 2017-19 business plan, the plan also includes financial projections for 2020 and 2021
- The Minister's concurrence requires presentation of OPG's business plan before TB/MBC
- The Ministry of Energy review and analysis of OPG's business plan is supported by the Electricity Investment and Governance Secretariat, a unit within the Ministry of Finance and the Corporate and Electricity Finance Division of the Ontario Financing Authority
- The following presentation provides an overview of OPG's business plan, including:
  1. Business Plan Overview
  2. Other Considerations

Context *(cont'd)*

- Proceeding with Provincial concurrence now will demonstrate that OPG has support from its shareholder as it implements the plan and provides clarity to the Ontario Energy Board (OEB) as it reviews OPG's current rate application covering the 2017-2021 period

- Business plan forecasts may be affected by Ontario's Fair Hydro Plan (OFHP). Given the stage of implementation of OFHP and the timing of the receipt of the business plan in November 2016, these changes are not reflected in OPG's plan

  - The Ministry anticipates that as part of supporting the financing and administration of the global adjustment smoothing mechanism, OPG would purchase the right to future cash flows from IESO, financed partly by capital infusions from the Province, and majority by third-party lending

  - These changes are generally expected to be fiscally neutral as they would result in an increase in Provincial interest on debt, offset by increases in OPG net income

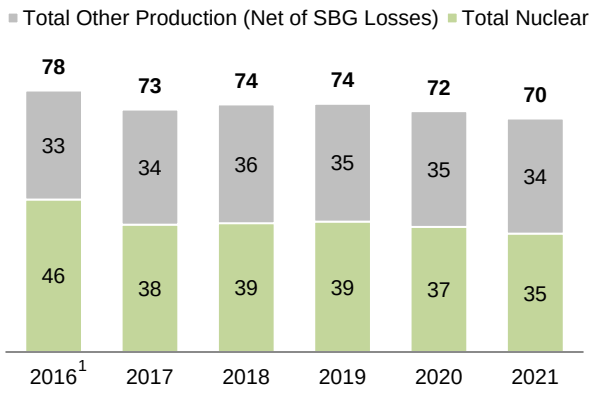
  - In addition, the Province's net debt position should remain unchanged

1. Business Plan Overview

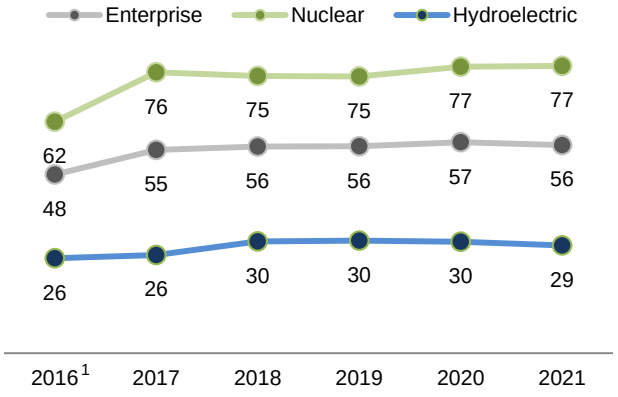
a) Production & Total Cost of Generation

- OPG's production is expected to fall to 69.8 TWh by 2021 from 78.2 TWh in 2016
  - Reflects a declining trend in the Darlington production due to refurbishment outages starting in October 2016
  - Also includes a partial overlap starting in 2021 between second and third unit refurbishments
- While Operations, Maintenance and Administration (OM&A) remains relatively stable over the planning period (see next slide), total generating cost (TGC)* shows an increasing trend over the planning period relative to 2016, reflecting:
  - Lower nuclear production due to Darlington refurbishment outages, and
  - Increased sustaining capital spending (included in TGC) on two large hydroelectric projects, the Lower Mattagami dam safety upgrade and the Sir Adam Beck I GS power canal liner rehabilitation

Production (TWh)



Total Generating Cost ($/MWh)



1. Actuals

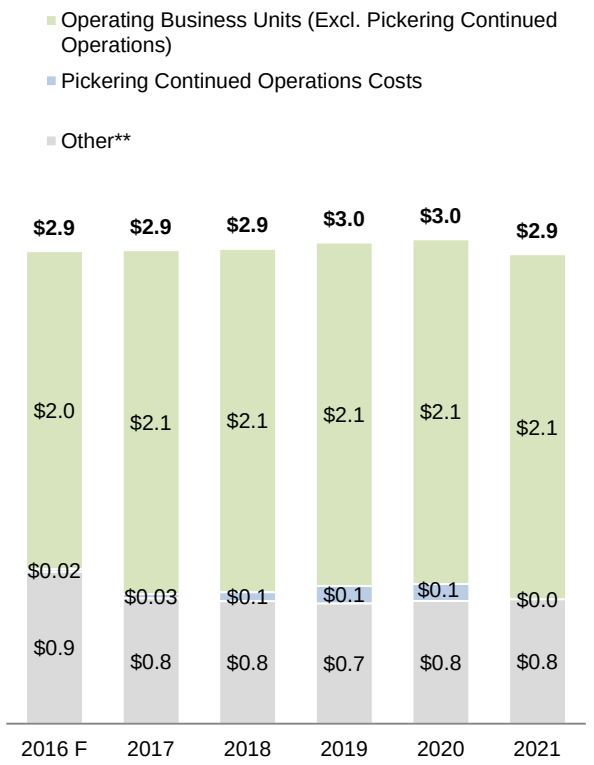
*TGC = OM&A expenses from ongoing operations + fuel and Gross Revenue Charge expenses for OPG-operated stations + sustaining capital expenditures) divided by OPG generation adjusted for surplus baseload generation losses

1. Business Plan Overview

b) Operations, Maintenance and Administration (OM&A) Expenses

- Annual OM&A expenses from ongoing operations are expected to stay consistent over the plan period, averaging $2.9B per year
- Increases over 2016 are mainly attributable to:
  - Increases in business unit expenditures, including changes in nuclear outage scope at Darlington, and planned hiring to fill staffing gaps
  - Incremental outage and other program costs to enable Pickering continued operations
  - Partially offset by declining pension and OPEB costs over the period due to projected pension asset returns, increased employee contributions, and adoption of a new method for applying discount rates to determine interest components of pension costs

OM&A from Ongoing Operations* ($B)



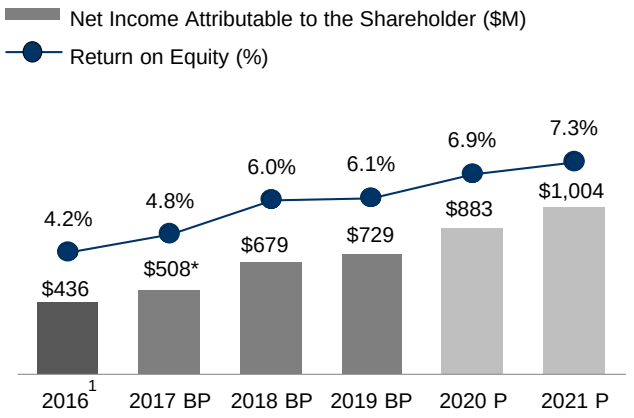
*Excludes Darlington refurbishment OM&A expenses and all OEB variance and deferral account offsets
** Includes centrally held pension /OPEB costs and support services

1. Business Plan Overview

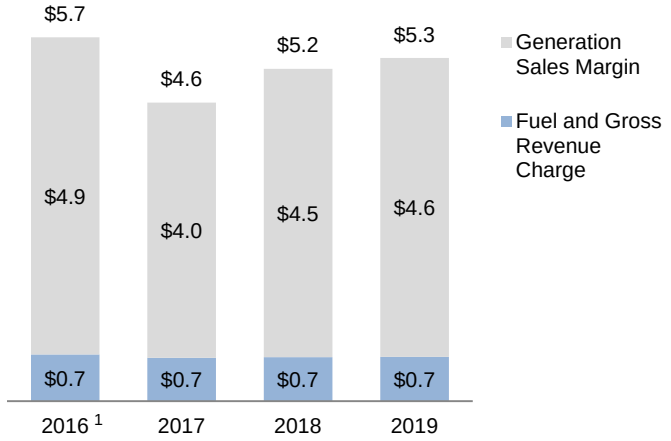
c) Financials

- OPG is forecasting net income attributable to the Shareholder to reach $1B in 2021, from $436M in 2016
  - 2017 net income is forecast to increase as a result of new regulated rates, a gain on sale of OPG's head office, higher capitalized interest for the Darlington Refurbishment expenditures partially offset by reduced production as a result of planned outages at Sir Adam Beck I and DeCew II hydro stations
  - Net income in 2018 and 2019 is planned to increase, primarily due to higher forecast production, and earnings from oncoming stations, including Nanticoke solar in 2019
- As a result, return-on-equity (ROE) is estimated to increase from 4.2% in 2016 to 7.3% by 2021
- Overall, the 2017-19 Business Plan is largely unchanged relative to last year's plan in terms of commitments for Net Income, and Total Shareholder Return

Net Income ($M) and ROE (%)



Revenue Margin ($B)



*Includes extraordinary gain associated with the sale of OPG head office

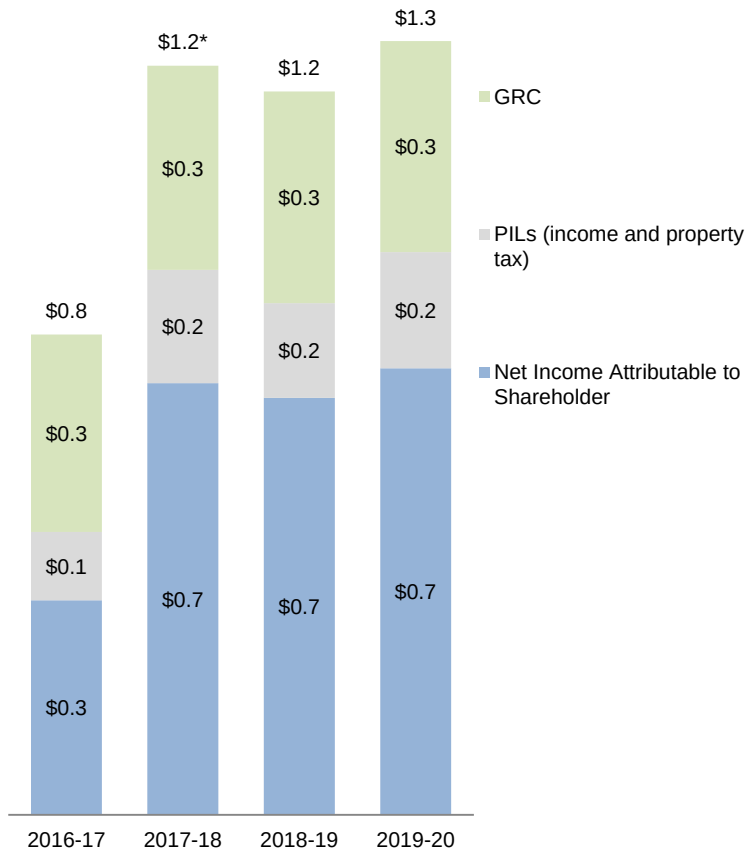
1. Actuals

1. Business Plan Overview

d) Provincial Fiscal Impacts: Shareholder Return and Payments-in-Lieu of Taxes

- Total fiscal revenue impacts to the Province, including net income return to the shareholder and payments-in-lieu of taxes, averages ~$1B over the period
  - Provincial revenues from OPG are dedicated to servicing and paying down stranded debt and the investment cost of the Province acquiring the equity in OPG.
- ~~Total r~~Return to the shareholder improves ~~over the period largely~~ due to changes in net income, which OPG attributes to:
  - Assumed OEB rate outcomes
  - Completion of the first Darlington unit refurbishment
  - Further cost efficiencies
- Net income is consolidated by the Province as Revenue from Government Business Enterprises (GBEs)
- Income tax PILs, Gross Revenue Charges (GRC) and property tax PILs paid to ~~are consolidated by~~ the Ontario Electricity Financial Corporation (OEFC) to help service and pay down stranded debt are consolidated in Public Accounts under Taxation Revenue
- OPG also pays a portion of the Gross Revenue Charge (GRC) ~~and Property Taxes to the OEFC to the Province's Consolidated Revenue Fund~~

Total Fiscal Revenues ~~Shareholder Return~~ ($B)



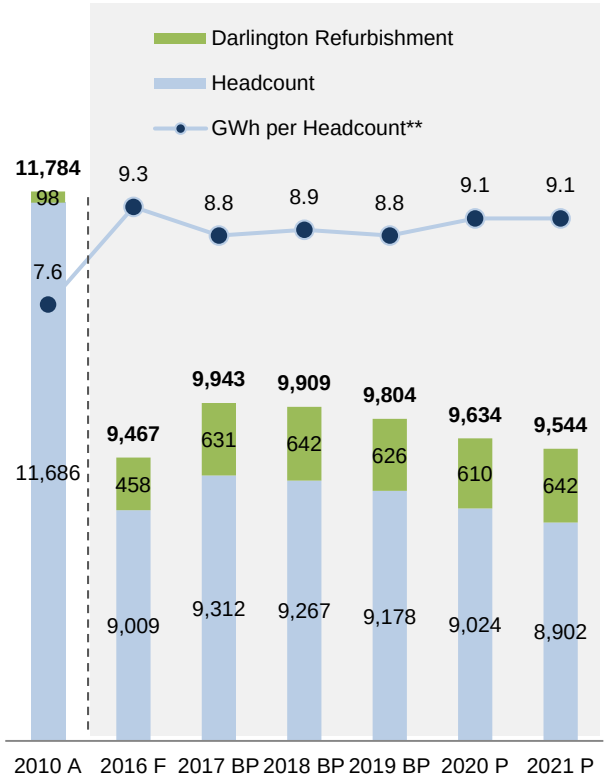
*Includes gain associated with the sale of OPG head office

1. Business Plan Overview

e) Business Transformation Initiative & Labour Costs

- As part of a company-wide business transformation, OPG has saved over $1B in costs from January 2011 to December 2016
  - Headcount has fallen from 11,686 in 2010 to a forecasted 9,009 in 2016 while GWh per headcount has increased from 7.6 to 9.3
- However, OPG is ramping up recruitment between 2016 and 2017 to fill key vacancies in certain areas (particularly in the Nuclear business unit) due to high levels of attrition from employee demographics, as well as continued Pickering operations beyond 2020
  - OPG is forecasting regular headcount to show a net increase of ~300 by the end of 2017 before gradually decreasing to 4% lower than 2017 levels in 2021
- In addition, to date OPG has hired ~60 Term employees, a new category of non-regular staff negotiated with the Power Workers' Union (PWU) through collective bargaining in 2015
  - Intention is to add fewer regular staff in circumstances where they are likely to be laid off as a result of the end of Pickering commercial operations

Ongoing Operations Regular Headcount and Productivity



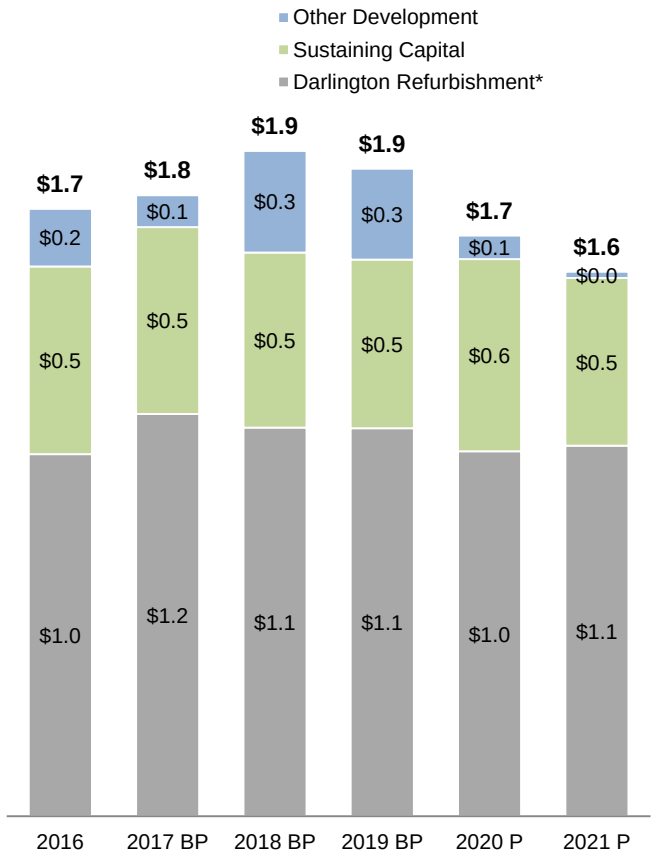
**Production is normalized by adding back hydroelectric surplus baseload generation losses and, in 2017- 2021, the lower production due to the Darlington refurbishment outages

1. Business Plan Overview

f) Operating Highlights - Projects and Capital Expenditures

- OPG continues to focus on delivery of its major projects over the plan period, including:
  - **Darlington Refurbishment**: Unit 2 is assumed to be returned to service in February 2020 with the second unit refurbishment commencing immediately thereafter and the third unit refurbishment starting in July 2021, assuming necessary concurrence from the Province is obtained
  - **Sustaining Capital:** Expenditures average $570M, including:
    - Nuclear expenditures unrelated to refurbishment at Darlington and costs for continued operation of Pickering
    - Regulated hydro expenditures including upgrades at Sir Adam Beck and upgrades to DeCew II
    - Lower Mattagami upgrades in 2018 and 2019
  - **Other Developments:** Investments in current and emerging generation technologies including solar and energy storage including construction and operation of the Nanticoke solar facility

Capital Expenditure Estimates ($B)



*Includes expenditures budgeted by Support Services

2. Other Considerations

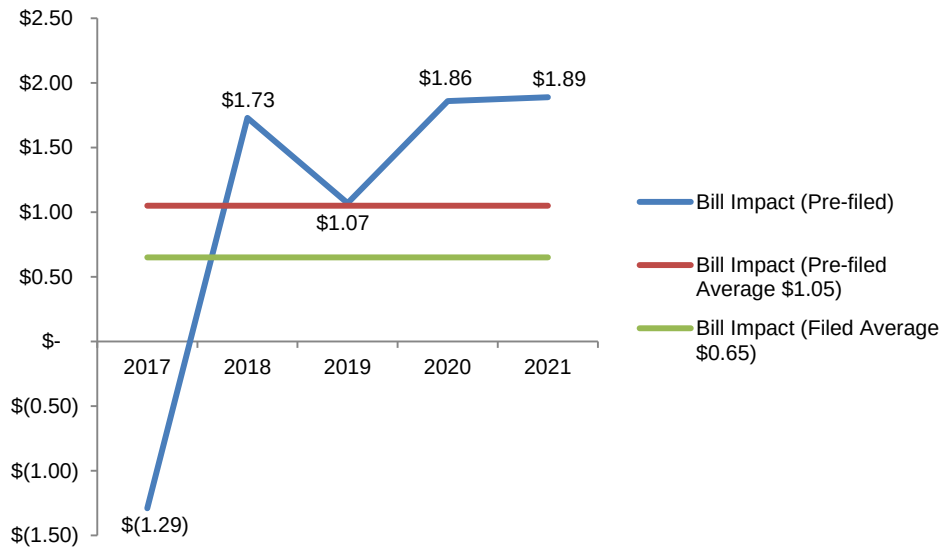
Rate Application

- OPG's 2017-19 Business Plan is dependent on the outcome of its rate filing with the OEB for the five-year period from 2017-2021
- Oral hearings began February 21, 2017 with a decision expected in Q3 2017
- OPG's 2017-19 Business Plan assumes new rates are effective January 1, 2017
  - The OEB setting a later effective date would negatively impact OPG's 2017-18 fiscal year net income by ~$50-60M per month of delay*

Rate-Smoothing Proposal:

- On March 2, 2017 the Province filed an amendment to O.Reg.53/05, which enables OPG to smooth its rates based on OPG's total bill impact, rather than on the basis of nuclear rates only
- On March 8, 2017 OPG filed a revised rate smoothing proposal with the OEB, which is expected to decrease the average annual impact on the monthly customer bill for an average consumption of 750 KWh/month from about $1.05 to 65 cents per month per year

Comparison of Annual Bill Impact ($/Month per year)



*Forecasted in May 2016

2. Other Considerations

Sales

	OPG Head Office	R.L. Hearn Site	Lakeview Site
Current Status	Completed	Agreement Reached	OPG and Infrastructure Ontario are preparing for marketing
Site Description	700 University Ave. and parking garage at 40 Murray St. in Toronto	~33 acres at the R.L. Hearn site in Toronto	~67 acres to be transferred by the purchaser to the City of Mississauga (Municipal Park Lands) and ~110 acres to be developed for mixed uses (Uplands)
Buyer	KingSett Canadian Real Estate Income Fund LP	Studios of America Limited Partner	TBD
Value	Estimated up-front 2017-18 fiscal impact of ~$375M (includes after-tax gain as well as PILs to OEFC)	TBD	TBD
Other Considerations	N/A	N/A	Negotiations with the City have been lengthy and costs to remediate/prepare site may be significant due to concerns regarding site condition
Timing	The sale closed in April 2017	Anticipated to close in Q3 2017	Marketing is planned to start in April 2017, pending negotiations with the City, with an anticipated closing in 2017

2. Other Considerations

Special Status for OPG to Approve International Travel

- On January 24, 2017, OPG's President and CEO wrote to the Deputy Minister requesting authority for OPG to approve international travel for its employees
  - Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive allows agencies/organizations, for which international travel may be integral to their business, to seek TB/MBC approval for special status to ensure that the approval process does not have an undue negative effect on its ability to conduct business
- OPG has indicated that international travel is integral to the safe and prudent operation of its business and that special status will enable efficient decision-making while lowering travel costs
  - OPG cites the importance of enabling its engagement with the international community (in particular in regards to nuclear safety), procurement activities, and investment and due diligence processes for its pension fund and nuclear funds
  - OPG requires a high level of international business travel at approximately 90-100 trips annually, while Darlington accounts for 45% and is expected to see increases
  - OPG indicated that the approval process, which took 23 days on average in 2016, delays flight bookings which results in higher costs as airlines raise fares closer to the travel date
  - OPG believes the inability to make timely commitments on events and meetings impacts employee engagement as well as its international relationships and reputation
- OPG has asked that this application be included with the Ministry's submission to TB/MBC seeking concurrence with OPG's 2017-19 business plan

Appendix

2016 Year-End Financials

OPG Balance Sheet as at Dec 31 $B	2016
Assets	
Cash and cash equivalents	0.2
Available-for-sale securities	0.2
Receivables from related parties	0.4
Nuclear fixed asset removal and nuclear waste management funds	0.02
Other current assets	0.9
Total current assets	**$1.7**
Net property, plant and equipment	**$20.0**
Net intangible assets	**$0.1**
Nuclear fixed asset removal and nuclear waste management funds	16.0
Regulatory assets	5.9
Other long-term assets	0.7
Other assets	**$22.5**
Total assets	**$44.4**
Liabilities	
Accounts payable and accrued charges	1.2
Short-term debt and long-term debt due within one year	1.1
Income taxes payable and other current liabilities	0.1
Total current liabilities	**$2.4**
Long-term debt	4.4
Fixed asset removal and nuclear waste management liabilities	19.5
Pension liabilities	3.0
Other post-employment benefit liabilities	2.9
Other liabilities	1.7
	$31.5
Total liabilities	**$33.9**
Equity	
Equity attributable to the Shareholder	10.4
Equity attributable to non-controlling interest	0.1
Total equity	**$10.5**
Total liabilities and equity	**$44.4**

OPG Income Statement Year Ended Dec 31 $B	2016
Revenue	$5.7
Fuel expense	0.7
Gross margin	**$4.9**
Operations, maintenance and administration	2.7
Depreciation and amortization	1.3
Accretion on fixed asset removal and nuclear waste management liabilities	0.9
Earnings on nuclear fixed asset removal and nuclear waste management funds	-0.7
Other expenses	0.02
Total expenses	**$4.2**
Income before other (gains) losses, interest and income taxes	**$0.7**
Other (gains) losses	-0.02
Income before interest and income taxes	**$0.7**
Net interest expense	0.1
Income before income taxes	**$0.6**
Income tax expense	0.2
Net income	**$0.5**
Net income attributable to the Shareholder	**$0.4**
Net income attributable to non-controlling interest	**$0.02**

From:	Ronald Kwan
To:	John Kim
Cc:	Francisco Chinchon; Bruno Amara
Subject:	RE: OPG BP concurrence - Energy materials
Date:	Monday, April 24, 2017 1:06:36 PM
Attachments:	2017 03 14 OPG concurrence letter v6_markup2.docx

Hi John,

Some suggestions.

I think we should explain the ONFA-related edits. I suggested some comments, which SIFB may want to review.

Ron

From: John Kim
Sent: April-24-17 11:46
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>
Subject: OPG BP concurrence - Energy materials

Hi Ron,

Pls. see attached with proposed edits from SIFB to the concurrence letter. We are still looking at the deck and will be forthcoming soon.

They have a meeting with Serge at 3:30 so would appreciate any comments soon.

John

Y. John Kim
Director, Electricity Finance Branch
Corporate & Electricity Finance Division
Ontario Financing Authority
Ph: 416-212-6996
Email: john.kim@ofina.on.ca

Mr. Bernard Lord
Chair
Ontario Power Generation
1900-700 University Avenue
Toronto ON M5G 1X6

Dear Mr. Lord,

Thank you for your submission of Ontario Power Generation's (OPG) 2017-2019 Business Plan ("the Plan"). We have reviewed the Plan and find it to be consistent with our government's expectations.

I support the operational and financial targets set by OPG in its business plan. We recognize the substantial cost reductions that OPG has recently achieved and expect OPG to work closely with the Province to fully realize the additional efficiencies incorporated in the Plan in a manner that is consistent with financial targets and the continued safe and environmentally responsible operation of OPG's facilities.

We commend OPG on its successful start to the Darlington Refurbishment Project, a key objective of Ontario's 2013 Long-Term Energy Plan (2013 LTEP). As a priority project for the government, I expect that OPG will continue to focus on delivering the project as per the schedule and budget contained in the Release Quality Estimate approved by the OPG Board and by the government. I also expect OPG to continue to minimize project risks consistent with the nuclear refurbishment principles set out in the 2013 LTEP, and seek concurrence prior to commencing subsequent unit refurbishments after Unit 2 is successfully returned to service.

We continue to support the planned operation of Pickering units up to 2024 as the station's output will provide reliable, cost-effective and emission-free electricity supply during the Darlington and initial Bruce refurbishments. I expect OPG to seek concurrence to proceed with ongoing Pickering operation after the necessary regulatory approvals are complete.

I understand that the recently approved Ontario Nuclear Funds Agreement (ONFA) Reference Plan has resulted in a reduction of the estimated liabilities ~~costs to consumers~~ for future decommissioning and long-term management of waste from Ontario's nuclear fleet. ~~plants. In addition, the segregated nuclear funds set aside under ONFA have reached fully funded status.~~ With many decades of nuclear generation in the Province's future, we expect OPG to continue managing its decommissioning and waste management obligations [and segregated funds] in a prudent manner~~, the decision to fund these costs now provides security for future generations of Ontarians~~.

I appreciate the efforts of OPG staff, management and the Board of Directors to date as we worked to develop a plan to refinance the Global Adjustment (GA). Refinancing the GA would provide significant and immediate rate relief by spreading the cost of electricity investments over the expected lifecycle of the infrastructure that has been built. OPG will be instrumental to the success of this initiative and we plan to introduce legislation that would, if passed, enable OPG to work with the Independent Electricity System Operator (IESO) to implement this plan.

Commented [RK1]: Recommended not to use this wording, particularly also using the fully-funded wording that follows.

Under ONFA, for prudence, the Province required OPG to accelerate contributions to the funds, in advance of collecting the amounts from ratepayers. Even if the funds are currently estimated to be fully-funded, OPG (and the Province as Shareholder) still needs to recover its nuclear liabilities costs in rates.

Commented [RK2]: If wording is retained, should be reworded.

"As a result of the lower estimated liabilities and recent financial market performance, the segregated nuclear funds set aside under ONFA are currently estimated to be fully funded."

I expect OPG to continue to keep the government informed with regard to the company's key ongoing and emerging initiatives and progress in achieving its financial and operational performance commitments. As OPG's performance directly impacts Ontario's fiscal plan, we note the importance of achieving or exceeding OPG's financial performance commitments.

This letter constitutes our concurrence with OPG's Board approved 2017-2019 Business Plan as provided for under the Memorandum of Agreement between OPG and the Shareholder dated July 17, 2015.

Sincerely,

Glenn Thibeault
Minister of Energy

c: Jeff Lyash, President and Chief Executive Officer, OPG
Ali Ghiassi, Chief of Staff, Ministry of Finance
Scott Thompson, Deputy Minister, Ministry of Finance
Serge Imbrogno, Deputy Minister, Ministry of Energy

Commented [RK3]: Only add in if Energy CoS is included.

From:	Ronald Kwan
To:	John Kim
Cc:	Deena Padamadan; Bruno Amara; Shajee Kathirgamanathan
Subject:	RE: OPG Business Plan Meeting (2017 05 01 v2)_Markup.pptx
Date:	Thursday, May 04, 2017 1:53:47 AM
Attachments:	OPG Business Plan Meeting (2017 05 01 v2)_Markup3.pptx

Hi John,

I added in an extract of the appendix table from the TBS BN, but the net income difference does not seem to add up (differs by 8, which may be the ONFA adjustment amount) – does the table need to be fixed (on slide 3 as well as the appendix E table?

Ron

From: Ronald Kwan
Sent: May-03-17 6:26 PM
To: John Kim <John.Kim@ofina.on.ca>
Cc: Deena Padamadan <Deena.Padamadan@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>
Subject: RE: OPG Business Plan Meeting (2017 05 01 v2)_Markup.pptx

Hi,

I took out the specific refurb example, and took out the 20-21 column in the additional IFRS risk, as we don't have it, not that it does not exist.

Ron

From: John Kim
Sent: May-03-17 18:10
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Deena Padamadan <Deena.Padamadan@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>
Subject: OPG Business Plan Meeting (2017 05 01 v2)_Markup.pptx

Hi Ron,

Pls. see attached back pocket for tomorrow's meeting.

John

DRAFT

OPG Fiscal Impacts

Corporate and Electricity Finance Division
2017-05-01

DRAFT

OPG Fiscal Impact

- The table below illustrates OPG's fiscal impacts in the 2017 Budget forecast.

	2016-17	2017-18	2018-19	2019-20	2020-21
OPG Net Income - 2017 Ontario Budget / Fiscal Plan					
OPG 2017-19 Business Plan[1]	349	702	678	726	913[1]
OPG Monthly Shareholder Update (February 2017)	30				
OPG IFRS Consolidation Risk[2]	(75)	(400)	-	(200)	-
OPG Head Office Sales (Reported under Sales and Rentals)[3]		(222)			
GA Refinancing – OPG Trust Interest Revenue		17	54	99	153
OPG Net Income (After Tax, Adjusted)	**304**	**97**	**732**	**625**	**1,066**
ONFA Adjustments[4]	8	-	-	-	-
OPG Income Tax PILs - 2017 Ontario Budget / Fiscal Plan					
OPG 2017-19 Business Plan	96	166	135	170	298[1]
OPG Monthly Shareholder Update (February 2017)	(4)				
OPG Head Office Sales (Reported under Sales and Rentals)[3]		(74)			
OPG Income Tax PILs (Adjusted)	92	92	135	170	298

1 Fiscalized projection from OPG Business Plan

2 IFRS risk is related to Province's reporting of nuclear asset retirement obligations. The Ontario Auditor General recommended (2016 AG Report) that the Province include Hydro One and OPG financial information in the consolidated financial statements using the IFRS reporting framework as required by PSAB standards, versus the companies U.S. GAAP basis of reporting.

3 For public Budget reporting, projected net impacts of Province asset optimization strategy including, OPG Head Office sale, are reported under Sales and Rentals for commercial confidentiality. OPG proceeds estimate updated per 2017 Budget.

4 Provincial consolidation adjustments for unrealized earnings on decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds.

DRAFT

OPG Fiscal Impact Changes

- The table below illustrates OPG's fiscal impact variances in the 2017 Budget vs 2016 Budget.

OPG Net Income and Income tax ($ Millions)				
	2016-17	2017-18	2018-19	2019-20
2016 Budget[1]				
Net Income	471	586	673	
Income Tax	224	159	182	
2017 Budget				
Net Income 2017 Budget	312	97	732	625
Income tax 2017 Budget	92	92	135	170
2016 Budget vs. 2017 Budget (including IFRS and sales & rental adjustments)				
Net Income	-167	-489	59	
Income taxes	-132	-67	-47	
2016 Budget vs. 2017 Budget (Before IFRS and sales & rental adjustments)				
Net Income	-84	133	59	200
Income taxes	-132	7	-47	0

1. 2016 Budget fiscal plan was largely based on OPG's 2015 multi-year business plan, as the 2016 multi-year business plan was approved and submitted following the timeframe for locking the numbers for the early 2016 Budget.
2. OPG February 2017 Monthly Update
3. IFRS risk is related to Province's reporting of nuclear asset retirement obligations. The Ontario Auditor General recommended (2016 AG Report) that the Province include Hydro One and OPG financial information in the consolidated financial statements using the IFRS reporting framework as required by PSAB standards, versus the companies U.S. GAAP basis of reporting.
4. For public Budget reporting, projected net impacts of Province asset optimization strategy including, OPG Head Office sale, are reported under Sales and Rentals for commercial confidentiality. OPG proceeds estimate updated per 2017 Budget.
5. Provincial consolidation adjustments for unrealized earnings on decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds.

DRAFT

Updated OPG Fiscal Impacts

- The table below illustrates updated OPG's net income, income tax PILs and ONFA adjustment figures from the 2017 Budget forecast.

	2016-17	2017-18	2018-19	2019-20	2020-21
Other updates since Budget 2017					
March 2017 Shareholder Update: OPG Net Income	385	-	-	-	-
March 2017 Shareholder Update: Income Tax Expense	94	-	-	-	-
ONFA Adjustments (as at Mar 31, 2017)	49	-	-	-	-

Risks

- **OEB Risks:** OPG's multi-year rate application to the Ontario Energy Board for the period starting January 1, 2017, is currently in process. Potential OEB decisions providing for lower rates, including disallowance of recovery of OPG's operating costs, current or future deferral and variance account balances (including for the proposed nuclear rate smoothing) and unfavourable future treatment of pension costs would adversely affect OPG's results, resulting in negative fiscal impacts.
- **IFRS Risks:** A change in the basis of accounting used for consolidation of OPG results from U.S. GAAP to International Financial Reporting Standards (IFRS) on the Province's financial statements is expected to result in potentially significant fiscal impacts.

	2016-17	2017-18	2018-19	2019-20
Net additional OPG IFRS Consolidation Risks	-	(25)	(525)	(475)

- **Financing Costs:** Higher cost public capital market borrowing (vs the Province's borrowing cost for OEFC to lend to OPG) would have a negative fiscal impact.

Risks – Darlington Refurbishment

- **Darlington Refurbishment Risk:** Darlington Refurbishment is executed consistent with the approved project budget and schedule. Failure to maintain cost and schedule commitments for the project could potentially result in significant write-offs against net income as well as reputational damage. In addition, inability to carry out the refurbishment of the first unit as planned may result in the Province of Ontario (Province) not proceeding with OPG's refurbishment of the remaining units.

Electricity Sector Rules of Thumb

- **OPG Rule of Thumb**: For every $50M change in OPG revenues due to changes in regulated prices, all-in rate impact of about 0.04 ¢/kWh (less than 0.25% of total bill)

OPG Risks	Fiscal Impact
Realised gains in ONFA funds v plan -/+ 1%	-/+ $100 million
Change in Regulated Prices -/+ 1%	-/+ $40 million
Regulated ROE -/+ 1%	-/+ $45 million
Nuclear regulated price -/+ 0.1 ¢/kWh	-/+ $40 million
Hydro regulated price -/+ 0.1 ¢/kWh	-/+ $20 million
Nuclear output -/+ 1 TWh	-/+ $70 million
Hydro output -/+ 1 TWh	-/+ $45 million

From: Ronald Kwan
To: John Kim
Cc: Deena Padamadan; Bruno Amara; Shajee Kathirgamanathan
Subject: RE: OPG Business Plan Meeting (2017 05 01 v2)_Markup.pptx
Date: Wednesday, May 03, 2017 6:25:40 PM
Attachments: OPG Business Plan Meeting (2017 05 01 v2)_Markup2.pptx

---

Hi,

I took out the specific refurb example, and took out the 20-21 column in the additional IFRS risk, as we don't have it, not that it does not exist.

Ron

From: John Kim
Sent: May-03-17 18:10
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Deena Padamadan <Deena.Padamadan@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>
Subject: OPG Business Plan Meeting (2017 05 01 v2)_Markup.pptx

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John

DRAFT

OPG Fiscal Impacts

Corporate and Electricity Finance Division
2017-05-01

DRAFT

OPG Fiscal Impact

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OPG 2017-19 Business Plan	96	166	135	170	298[1]
OPG Monthly Shareholder Update (February 2017)	(4)				
OPG Head Office Sales (Reported under Sales and Rentals)[3]		(74)			
OPG Income Tax PILs (Adjusted)	92	92	135	170	298

1 Fiscalized projection from OPG Business Plan

2 IFRS risk is related to Province's reporting of nuclear asset retirement obligations. The Ontario Auditor General recommended (2016 AG Report) that the Province include Hydro One and OPG financial information in the consolidated financial statements using the IFRS reporting framework as required by PSAB standards, versus the companies U.S. GAAP basis of reporting.

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DRAFT

Updated OPG Fiscal Impacts

- The table below illustrates updated OPG's net income, income tax PILs and ONFA adjustment figures from the 2017 Budget forecast.

	2016-17	2017-18	2018-19	2019-20	2020-21
Other updates since Budget 2017					
March 2017 Shareholder Update: OPG Net Income	385	-	-	-	-
March 2017 Shareholder Update: Income Tax Expense	94	-	-	-	-
ONFA Adjustments (as at Mar 31, 2017)	49	-	-	-	-

Risks

- **OEB Risks:** OPG's multi-year rate application to the Ontario Energy Board for the period starting January 1, 2017, is currently in process. Potential OEB decisions providing for lower rates, including disallowance of recovery of OPG's operating costs, current or future deferral and variance account balances (including for the proposed nuclear rate smoothing) and unfavourable future treatment of pension costs would adversely affect OPG's results, resulting in negative fiscal impacts.
- **IFRS Risks:** A change in the basis of accounting used for consolidation of OPG results from U.S. GAAP to International Financial Reporting Standards (IFRS) on the Province's financial statements is expected to result in potentially significant fiscal impacts.

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- **Financing Costs:** Higher cost public capital market borrowing (vs the Province's borrowing cost for OEFC to lend to OPG) would have a negative fiscal impact.

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- **Darlington Refurbishment Risk:** Darlington Refurbishment is executed consistent with the approved project budget and schedule. Failure to maintain cost and schedule commitments for the project could potentially result in significant write-offs against net income as well as reputational damage. In addition, inability to carry out the refurbishment of the first unit as planned may result in the Province of Ontario (Province) not proceeding with OPG's refurbishment of the remaining units.

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- **OPG Rule of Thumb**: For every $50M change in OPG revenues due to changes in regulated prices, all-in rate impact of about 0.04 ¢/kWh (less than 0.25% of total bill)

OPG Risks	Fiscal Impact
Realised gains in ONFA funds v plan -/+ 1%	-/+ $100 million
Change in Regulated Prices -/+ 1%	-/+ $40 million
Regulated ROE -/+ 1%	-/+ $45 million
Nuclear regulated price -/+ 0.1 ¢/kWh	-/+ $40 million
Hydro regulated price -/+ 0.1 ¢/kWh	-/+ $20 million
Nuclear output -/+ 1 TWh	-/+ $70 million
Hydro output -/+ 1 TWh	-/+ $45 million

From:	John Kim
To:	Ronald Kwan
Cc:	Deena Padamadan; Bruno Amara; Shajee Kathirgamanathan
Subject:	RE: OPG Business Plan Meeting (2017 05 01 v2)_Markup.pptx
Date:	Thursday, May 04, 2017 8:13:50 AM
Attachments:	OPG Business Plan Meeting (2017 05 01 v2)_Markup4.pptx

Hi Ron,

If I understand you right, yes, it is the 8M ONFA that is the difference. Made the change in red.

Thanks,

John

From: Ronald Kwan
Sent: Thursday, May 04, 2017 1:54 AM
To: John Kim <John.Kim@ofina.on.ca>
Cc: Deena Padamadan <Deena.Padamadan@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>
Subject: RE: OPG Business Plan Meeting (2017 05 01 v2)_Markup.pptx

Hi John,

I added in an extract of the appendix table from the TBS BN, but the net income difference does not seem to add up (differs by 8, which may be the ONFA adjustment amount) – does the table need to be fixed (on slide 3 as well as the appendix E table?

Ron

From: Ronald Kwan
Sent: May-03-17 6:26 PM
To: John Kim <John.Kim@ofina.on.ca>
Cc: Deena Padamadan <Deena.Padamadan@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>
Subject: RE: OPG Business Plan Meeting (2017 05 01 v2)_Markup.pptx

Hi,

I took out the specific refurb example, and took out the 20-21 column in the additional IFRS risk, as we don't have it, not that it does not exist.

Ron

From: John Kim
Sent: May-03-17 18:10

To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Deena Padamadan <Deena.Padamadan@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>
Subject: OPG Business Plan Meeting (2017 05 01 v2)_Markup.pptx

Hi Ron,

Pls. see attached back pocket for tomorrow's meeting.

John

DRAFT

OPG Fiscal Impacts

Corporate and Electricity Finance Division
2017-05-01

DRAFT

OPG Fiscal Impact

- The table below illustrates OPG's fiscal impacts in the 2017 Budget forecast.

	2016-17	2017-18	2018-19	2019-20	2020-21
OPG Net Income - 2017 Ontario Budget / Fiscal Plan					
OPG 2017-19 Business Plan[1]	349	702	678	726	913[1]
OPG Monthly Shareholder Update (February 2017)	30				
OPG IFRS Consolidation Risk[2]	(75)	(400)	-	(200)	-
OPG Head Office Sales (Reported under Sales and Rentals)[3]		(222)			
GA Refinancing – OPG Trust Interest Revenue		17	54	99	153
OPG Net Income (After Tax, Adjusted)	**304**	**97**	**732**	**625**	**1,066**
ONFA Adjustments[4]	8	-	-	-	-
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DRAFT

OPG Fiscal Impact Changes

- The table below illustrates OPG's fiscal impact variances in the 2017 Budget vs 2016 Budget.

OPG Net Income and Income tax ($ Millions)				
	2016-17	2017-18	2018-19	2019-20
2016 Budget[1]				
Net Income	471	586	673	
Income Tax	224	159	182	
2017 Budget				
Net Income 2017 Budget	312	97	732	625
Income tax 2017 Budget	92	92	135	170
2016 Budget vs. 2017 Budget (including IFRS and sales & rental adjustments)				
Net Income	-159	-489	59	
Income taxes	-132	-67	-47	
2016 Budget vs. 2017 Budget (Before IFRS and sales & rental adjustments)				
Net Income	-84	133	59	200
Income taxes	-132	7	-47	0

1. 2016 Budget fiscal plan was largely based on OPG's 2015 multi-year business plan, as the 2016 multi-year business plan was approved and submitted following the timeframe for locking the numbers for the early 2016 Budget.
2. OPG February 2017 Monthly Update
3. IFRS risk is related to Province's reporting of nuclear asset retirement obligations. The Ontario Auditor General recommended (2016 AG Report) that the Province include Hydro One and OPG financial information in the consolidated financial statements using the IFRS reporting framework as required by PSAB standards, versus the companies U.S. GAAP basis of reporting.
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Nuclear output -/+ 1 TWh	-/+ $70 million
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From:	Ronald Kwan
To:	Mike Manning; Ken Kandeepan; Carlos Yep; Veinot, Cindy (TBS)
Subject:	RE: OPG Performance fees
Date:	Monday, May 15, 2017 3:58:58 PM

Hi,

Agreed.

Ron

From: Mike Manning
Sent: May-15-17 14:47
To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>; Carlos Yep <Carlos.Yep@ofina.on.ca>; Veinot, Cindy (TBS) <Cindy.Veinot@ontario.ca>
Subject: RE: OPG Performance fees

Like the small number, still some challenges on setting up a benchmark, but expect we should move forward.
Mike

From: Ken Kandeepan
Sent: Monday, May 15, 2017 2:43 PM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; Mike Manning <Mike.Manning@ofina.on.ca>; Carlos Yep <Carlos.Yep@ofina.on.ca>; Veinot, Cindy (TBS) <Cindy.Veinot@ontario.ca>
Subject: RE: OPG Performance fees

Hi All

Given the comparatively low materiality and the fact that the benchmark will be set by the OFA with OPG absorbing any underperformance makes this viable from my perspective. Pls let me know if you agree.

If so I will touch base with Gadi just to make sure and respond to Scott.

Thanks

Ken k

From: Nelms, Scott (MOF) [mailto:Scott.Nelms@ontario.ca]
Sent: Monday, May 15, 2017 9:17 AM
To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
Cc: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; Mike Manning <Mike.Manning@ofina.on.ca>; Carlos Yep <Carlos.Yep@ofina.on.ca>; Veinot, Cindy (TBS) <Cindy.Veinot@ontario.ca>

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- Risk / reward goes both ways. Unlike most management fee structures where the performance fee provides an at risk upside to the manager, but no downside, the distribution of potential benefits and losses is symmetric between ratepayers and OPG.
- OPG's current thinking is that it would work with OFA to set a benchmark for borrowing costs at the start of the year based on GOC yields + a premium. If OPG over-performs (under-performs) the benefit (downside) would be shared between the company and ratepayers 50/50 up to +/- $1M. Above or below $1M, all of the benefit (downside) would flow to ratepayers.
- OPG does not particularly like this symmetry but this is apparently required to meet accounting requirements.
- From my perspective, $1M is a small number, so I am not too concerned about overall impacts on ratepayers.

Thanks,
Scott

From: Ken Kandeepan [mailto:Ken.Kandeepan@ofina.on.ca]
Sent: May 13, 2017 7:32 PM
To: Nelms, Scott (MOF)
Cc: Kwan, Ronald (OFA); Manning, Mike (OFA); Yep, Carlos (OFA); Veinot, Cindy (TBS)
Subject: RE: OPG Performance fees

Hi Scott

Yes the MOF does like OPG to make money since on a PSAB basis it benefits the Province's fiscal position. In this instance however, the marginal increase to the fiscal bottom line comes at the expense of the ratepayers in terms of additional debt, hence our push back.

Pls see below my responses on the two issues that you have raised. I am cc'ing Cindy as well since she may have her own thoughts and a discussion maybe value added in terms of arriving at a common understanding.

Thanks

Ken K

From: Nelms, Scott (MOF) [mailto:Scott.Nelms@ontario.ca]
Sent: Friday, May 12, 2017 2:54 PM
To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
Cc: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; Mike Manning <Mike.Manning@ofina.on.ca>; Carlos Yep <Carlos.Yep@ofina.on.ca>

Subject: RE: OPG Performance fees

MoF asking OPG to make less money! This feels so backward!

I will chat with OPG to dig in to the rationale. I take your point that OPG will benefit from the loans to the trust. However, I see two weaknesses with the argument:

1) Lenders don't typically consolidate borrowers, so it takes more than interest revenues to meet this test. Not sure if you are referring to the "Power" or "profit" principle. If the former the Province lends to IO for all its needs and yet exercises power since IO is consolidated with the Province in much the same way the Trust and OPG will be consolidated. Note that OPG benefits from the interest income on the 44% relating to the equity injection even if the Trust is not consolidated.
2) Earning interest income on equity is going to take down the company's ROE (one of the key metrics that we are tracking on overall company performance). Therefore I wouldn't see this as a particularly compelling allocation of funds from a commercial perspective. This is a good point however, OPG considers the 44% it lends to the Trust as sub-debt most likely priced higher than the debt borrowed by the Trust from the markets. In the event the interest on the 44% is less than OPG's current ROE of the company, your point holds however, if the interest is higher it actually adds to OPG's ROE.

Scott

From: Ken Kandeepan [mailto:Ken.Kandeepan@ofina.on.ca]
Sent: May 12, 2017 11:24 AM
To: Nelms, Scott (MOF)
Cc: Kwan, Ronald (OFA); Manning, Mike (OFA); Yep, Carlos (OFA)
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OPG argues that the latter of the two fundamental principles, "Power" and "Profit" allowing the Trust to be consolidated with OPG requires the implementation of a performance fee structure. The counter argument is that OPG already has access to profit, by virtue of its position as the funding entity for 44% of the debt incurred by the Trust. OPG uses the funds it receives from the Province's equity injection, for which it pays no interest, for this purpose.

Upon consolidation with the Trust, OPG's interest income will therefore increase by the amount of the interest the Trust receives on 44% of its overall debt, a relatively risk free profit source, at least over the duration of the Fair Hydro Plan. While the use of a benchmark is appropriate and

contributes to an efficient borrowing program, any performance fees arising from beating the benchmark will effectively be funded by the ratepayers, by increasing the investment asset and the associated debt to be repaid by ratepayers.

Mike and I will be happy to provide any further technical assistance that you may require as you raise this issue.

Thanks

Ken k

This message, including any attachments, is meant only for the use of the individual(s) to whom it is intended and may contain information that is privileged/confidential. Any unauthorized use, copying or disclosure is strictly prohibited. If you are not the intended recipient or have received this message in error, please notify us immediately by reply e-mail and permanently delete this message, including any attachments, without reading them, and destroy all copies. Thank you.

From:	Mike Manning
To:	Ken Kandeepan; Ronald Kwan; Carlos Yep; Veinot, Cindy (TBS)
Subject:	RE: OPG Performance fees
Date:	Monday, May 15, 2017 2:46:31 PM

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From: Ken Kandeepan
Sent: Monday, May 15, 2017 2:43 PM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; Mike Manning <Mike.Manning@ofina.on.ca>; Carlos Yep <Carlos.Yep@ofina.on.ca>; Veinot, Cindy (TBS) <Cindy.Veinot@ontario.ca>
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From:	Ken Kandeepan
To:	Ronald Kwan; Mike Manning; Carlos Yep; Veinot, Cindy (TBS)
Subject:	RE: OPG Performance fees
Date:	Monday, May 15, 2017 2:43:12 PM

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Scott

From: Ken Kandeepan [mailto:Ken.Kandeepan@ofina.on.ca]
Sent: May 12, 2017 11:24 AM
To: Nelms, Scott (MOF)
Cc: Kwan, Ronald (OFA); Manning, Mike (OFA); Yep, Carlos (OFA)
Subject: OPG Performance fees

Hi Scott

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Ken k

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From: John Kim
To: Ronald Kwan
Subject: RE: OPG Performance fees
Date: Monday, May 15, 2017 10:22:55 AM

Hi Ron,

Some early comments. OPG has been coming up with these ideas, we had one earlier that seems to have changed to the 1M one. If the idea is to meet accounting requirements and the impact is fairly small, it looks OK to me.

Might be a good idea to not get all fussed over some of these ideas as could end up looking like over-reacting and I'm not even sure at what level of OPG these ideas are being originated.

I take power and profit to mean OPG having the ability to make commercial decisions and profit to mean for conducting business for commercial/profit-making reasons.

John

From: Ronald Kwan
Sent: Monday, May 15, 2017 9:41 AM
To: John Kim <John.Kim@ofina.on.ca>
Subject: FW: OPG Performance fees

Hi John,

Comments?

Ron

From: Nelms, Scott (MOF) [mailto:Scott.Nelms@ontario.ca]
Sent: May-15-17 09:17
To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
Cc: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; Mike Manning <Mike.Manning@ofina.on.ca>; Carlos Yep <Carlos.Yep@ofina.on.ca>; Veinot, Cindy (TBS) <Cindy.Veinot@ontario.ca>
Subject: RE: OPG Performance fees

I talked to OPG on this. Here are some other considerations:

- Risk / reward goes both ways. Unlike most management fee structures where the performance fee provides an at risk upside to the manager, but no downside, the distribution of potential benefits and losses is symmetric between ratepayers and OPG.
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- OPG does not particularly like this symmetry but this is apparently required to meet accounting requirements.
- From my perspective, $1M is a small number, so I am not too concerned about overall impacts on ratepayers.

Thanks,
Scott

From: Ken Kandeepan [mailto:Ken.Kandeepan@ofina.on.ca]
Sent: May 13, 2017 7:32 PM
To: Nelms, Scott (MOF)
Cc: Kwan, Ronald (OFA); Manning, Mike (OFA); Yep, Carlos (OFA); Veinot, Cindy (TBS)
Subject: RE: OPG Performance fees

Hi Scott

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Thanks

Ken K

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Sent: Friday, May 12, 2017 2:54 PM
To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
Cc: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; Mike Manning <Mike.Manning@ofina.on.ca>; Carlos Yep <Carlos.Yep@ofina.on.ca>
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From:	Nelms, Scott (MOF)
To:	Ken Kandeepan
Cc:	Ronald Kwan; Mike Manning; Carlos Yep; Veinot, Cindy (TBS)
Subject:	RE: OPG Performance fees
Date:	Monday, May 15, 2017 9:16:54 AM

I talked to OPG on this. Here are some other considerations:

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Cc: Kwan, Ronald (OFA); Manning, Mike (OFA); Yep, Carlos (OFA); Veinot, Cindy (TBS)
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Sent: Friday, May 12, 2017 2:54 PM

To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
Cc: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; Mike Manning <Mike.Manning@ofina.on.ca>; Carlos Yep <Carlos.Yep@ofina.on.ca>
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Cc: Kwan, Ronald (OFA); Manning, Mike (OFA); Yep, Carlos (OFA)
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From: Ken Kandeepan
To: Scott Nelms (ENERGY)
Cc: Ronald Kwan; Mike Manning; Carlos Yep; Veinot, Cindy (TBS)
Subject: RE: OPG Performance fees
Date: Saturday, May 13, 2017 7:31:35 PM

Hi Scott

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To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
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From: Nelms, Scott (MOF)
To: Ken Kandeepan
Cc: Ronald Kwan; Mike Manning; Carlos Yep
Subject: RE: OPG Performance fees
Date: Friday, May 12, 2017 2:54:08 PM

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From:	Ken Kandeepan
To:	Scott Nelms (ENERGY)
Cc:	Ronald Kwan; Mike Manning; Carlos Yep; Veinot, Cindy (TBS)
Subject:	RE: OPG Performance fees
Date:	Sunday, May 21, 2017 10:42:33 AM

Hi Scott

Sorry for the delay in responding, after a discussion with Gadi the OFA is comfortable with the approach proposed by OPG. We also recommend that the $1M upside/downside limit on performance fees in relation to a pre-determined benchmark be enshrined in the Financing Plan to be developed by OPG. The OFA is also willing to work with OPG on the development of the benchmark.

Thanks

Ken k

From: Nelms, Scott (MOF) [mailto:Scott.Nelms@ontario.ca]
Sent: Monday, May 15, 2017 9:17 AM
To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
Cc: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; Mike Manning <Mike.Manning@ofina.on.ca>; Carlos Yep <Carlos.Yep@ofina.on.ca>; Veinot, Cindy (TBS) <Cindy.Veinot@ontario.ca>
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To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
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From:	Sud, Manu (ENERGY)
To:	HO Philip -FIN & C CTRL
Cc:	GORE Michael -FIN & C CTRL; PAN Rebecca -FIN & C CTRL; DYKXHOORN Sandra -STAKEREL; CHANG Stephanie -ASSRNCE&ERM; Ogunrinde, Deni (ENERGY); Graham Young (MOI); Talwar, Shruti (ENERGY); John Kim; Ronald Kwan
Subject:	RE: OPG Q1 2018 Submission to Province
Date:	Friday, May 04, 2018 3:44:32 PM

Hi Philip, We are looking into the Q1 submission and getting comments reviewed. We will aim to have the comments back to you by early to mid next week. Thank you for your patience.
Manu

From: HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
Sent: May-02-18 11:42 PM
To: Talwar, Shruti (ENERGY) <Shruti.Talwar@ontario.ca>; Sud, Manu (ENERGY) <Manu.Sud@ontario.ca>; Kim, John (OFA) <John.Kim@ofina.on.ca>; Kwan, Ronald (OFA) <Ronald.Kwan@ofina.on.ca>
Cc: GORE Michael -FIN & C CTRL <michael.gore@opg.com>; PAN Rebecca -FIN & C CTRL <rebecca.pan@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; CHANG Stephanie -ASSRNCE&ERM <stephanie.chang@opg.com>
Subject: OPG Q1 2018 Submission to Province

Hi All,

Please find attached OPG's draft Q1 2018 Interim Financial Results Press Release, Management's Discussion and Analysis (MD&A), and Financial Statements for the Province's review.

We would greatly appreciate comments on the above **no later than Friday, May 4th**.

These documents will be filed with the Ontario Securities Commission on **Tuesday, May 15th**.

Kindly forward all comments directly to Philip Ho – philip.ho@opg.com.

To assist the review process, the following are the key items in the Q1 2018 MD&A:

Highlights	
Recent Developments	MD&A pgs.5-8
OEB's Payment Amounts Order on OPG's Application for New Regulated Prices	MD&A pgs.5-7
Darlington Refurbishment	MD&A pgs.7; 13-14

Philip Ho, CPA, CA | Senior Manager, External Reporting & Accounting Policy | Ontario Power Generation
700 University Avenue, Toronto ON M5G 1X6 | Phone: (416) 592-3320| E-mail: philip.ho@opg.com

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From: John Kim
To: Ronald Kwan; Francisco Chinchon
Cc: Usman Zahid; Darren Scanlan
Subject: RE: OPG Q1 2018 Submission to Province
Date: Thursday, May 03, 2018 10:16:06 AM

Hi Ron,

I wasn't planning on sharing with FTD as I'm not sure what role they have in OPG financials but would be happy to do so.

Will do on the OPCD and Legal front.

Thanks,

John

From: Ronald Kwan
Sent: Thursday, May 03, 2018 10:07 AM
To: Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>
Cc: Usman Zahid <Usman.Zahid@ofina.on.ca>; Darren Scanlan <Darren.Scanlan@ofina.on.ca>
Subject: RE: OPG Q1 2018 Submission to Province

Thanks Francisco.

John, OPCD may want to see the FHT reporting and the size of the receivable to be reported. Note that this is, of course, confidential until released by OPG, so not really to affect their response to the Globe, unless already available publicly elsewhere.

Ron

From: Francisco Chinchon
Sent: May-03-18 10:03
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>
Cc: Usman Zahid <Usman.Zahid@ofina.on.ca>; Darren Scanlan <Darren.Scanlan@ofina.on.ca>
Subject: RE: OPG Q1 2018 Submission to Province

Hi,

Staff is reviewing, from our side no need for additional review. We will probably suggest some tweaks to the real estate sales language.

Thanks,

Francisco

From: Ronald Kwan
Sent: Thursday, May 03, 2018 9:58 AM
To: John Kim <John.Kim@ofina.on.ca>; Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>
Cc: Usman Zahid <Usman.Zahid@ofina.on.ca>
Subject: FW: OPG Q1 2018 Submission to Province

Hi,

Please review.

Any parts you'd want FTD, OPCD, or MOF Legal to review?

Thanks,
Ron

From: HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
Sent: May-02-18 23:42
To: Shruti.Talwar@ontario.ca; Manu.Sud@ontario.ca; John Kim <John.Kim@ofina.on.ca>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: GORE Michael -FIN & C CTRL <michael.gore@opg.com>; PAN Rebecca -FIN & C CTRL <rebecca.pan@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; CHANG Stephanie -ASSRNCE&ERM <stephanie.chang@opg.com>
Subject: OPG Q1 2018 Submission to Province

Hi All,

Please find attached OPG's draft Q1 2018 Interim Financial Results Press Release, Management's Discussion and Analysis (MD&A), and Financial Statements for the Province's review.

We would greatly appreciate comments on the above **no later than Friday, May 4th**.

These documents will be filed with the Ontario Securities Commission on **Tuesday, May 15th**.

Kindly forward all comments directly to Philip Ho – philip.ho@opg.com.

To assist the review process, the following are the key items in the Q1 2018 MD&A:

Highlights	
Recent Developments	MD&A pgs.5-8
OEB's Payment Amounts Order on OPG's Application for New Regulated Prices	MD&A pgs.5-7
Darlington Refurbishment	MD&A pgs.7; 13-14

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From: Francisco Chinchon
To: Ronald Kwan; John Kim
Cc: Usman Zahid; Darren Scanlan
Subject: RE: OPG Q1 2018 Submission to Province
Date: Thursday, May 03, 2018 10:03:22 AM

Hi,

Staff is reviewing, from our side no need for additional review. We will probably suggest some tweaks to the real estate sales language.

Thanks,

Francisco

From: Ronald Kwan
Sent: Thursday, May 03, 2018 9:58 AM
To: John Kim <John.Kim@ofina.on.ca>; Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>
Cc: Usman Zahid <Usman.Zahid@ofina.on.ca>
Subject: FW: OPG Q1 2018 Submission to Province

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From:	John Kim
To:	"HO Philip -FIN & C CTRL"
Cc:	Ronald Kwan; GORE Michael -FIN & C CTRL; PAN Rebecca -FIN & C CTRL; DYKXHOORN Sandra -STAKEREL; CHANG Stephanie -ASSRNCE&ERM; Gavin He
Subject:	RE: OPG Q1 2018 Submission to Province
Date:	Thursday, May 10, 2018 4:15:45 PM
Attachments:	Q1 2018 MDA - DRAFT PROVINCE MAILING_CEFD_v2.docx Q1 2018 OPG FS PROVINCE MAILING_CEFD_v2.docx Q1 2018 Press Release - DRAFT - PROVINCE MAILING_CEFDcomments.docx

Hi Philip,

Pls. see attached.

Thanks,

John

From: HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
Sent: Wednesday, May 02, 2018 11:42 PM
To: Shruti.Talwar@ontario.ca; Manu.Sud@ontario.ca; John Kim <John.Kim@ofina.on.ca>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: GORE Michael -FIN & C CTRL <michael.gore@opg.com>; PAN Rebecca -FIN & C CTRL <rebecca.pan@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; CHANG Stephanie -ASSRNCE&ERM <stephanie.chang@opg.com>
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ONTARIO POWER GENERATION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

2018 FIRST QUARTER REPORT

[DRAFT]

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ONTARIO POWER GENERATION

ONTARIO POWER GENERATION INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) should be read in conjunction with the unaudited interim consolidated financial statements and accompanying notes of Ontario Power Generation Inc. (OPG or Company) as at and for the three months ended March 31, 2018. OPG's unaudited interim consolidated financial statements are prepared in accordance with United States generally accepted accounting principles (US GAAP) and are presented in Canadian dollars.

For a complete description of OPG's corporate strategies, risk management, corporate governance, and the effect of critical accounting policies and estimates on OPG's results of operations and financial condition, this MD&A should also be read in conjunction with OPG's audited consolidated financial statements, accompanying notes, Annual Information Form, and MD&A as at and for the year ended December 31, 2017.

As required by *Ontario Regulation 395/11*, as amended, a regulation under the *Financial Administration Act* (Ontario) (FAA), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. Since January 1, 2012, OPG also has received exemptive relief from the Ontario Securities Commission (OSC) that allows OPG to apply US GAAP. In April 2018, the OSC approved an exemption which allows the Company to continue to apply US GAAP up to January 1, 2024. The term of the exemption is subject to certain conditions, which may result in the expiry of the exemption prior to January 1, 2024. For details, refer to the section, *Change in Accounting Policies and Estimates* under the heading, *Exemptive Relief for Reporting under US GAAP.* This MD&A is dated May 15, 2018.

FORWARD-LOOKING STATEMENTS

The MD&A contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could", and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

All forward-looking statements involve inherent assumptions, risks, and uncertainties, including those set out in the section, *Risk Management,* and forecasts discussed in the section, *Core Business, Strategy, and Outlook.* All forward-looking statements could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's generating station performance and availability, fuel costs, surplus baseload generation (SBG), cost of fixed asset removal and nuclear waste management, performance and earnings of investment funds, refurbishment of existing facilities, development and construction of new facilities, pension and other post-employment benefit (OPEB) obligations and funds, income taxes, proposed new legislation, the ongoing evolution of Ontario's electricity industry, environmental and other regulatory requirements, operating licence applications to the Canadian Nuclear Safety Commission (CNSC), health, safety and environmental developments, business continuity events, the weather, financing and liquidity, applications to the Ontario Energy Board (OEB) for regulatory prices, the impact of regulatory decisions by the OEB, Ontario's Fair Hydro Plan and forecasts of earnings, cash flows, Return on Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI), Total Generating Cost (TGC), Operations, Maintenance and Administration (OM&A) expenditures, retention of critical talent, supplier and third party performance, and project expenditures. Accordingly, undue reliance should not be placed on any forward-looking statement. The forward-looking statements included in this

MD&A are made only as of the date of this MD&A. Except as required by applicable securities laws, OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events, or otherwise.

THE COMPANY

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG was established under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (Province or Shareholder).

As at March 31, 2018, OPG's electricity generation portfolio had an in-service capacity of 16,218 megawatts (MW). OPG operates two nuclear generating stations, 66 hydroelectric generating stations, three thermal generating stations, and one wind power turbine. In addition, OPG and TransCanada Energy Ltd. co-own the 550 MW Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS), and OPG and ATCO Power Canada Ltd. co-own the 560 MW Brighton Beach gas-fired combined cycle GS (Brighton Beach). OPG's 50 percent share of the in-service capacity and generation volume of these co-owned facilities is included in the generation portfolio statistics set out in this report. The income from the co-owned facilities is accounted for using the equity method of accounting, and OPG's share of income is presented as income from investments subject to significant influence in the Contracted Generation Portfolio segment.

OPG also owns two other nuclear generating stations, the Bruce A GS and the Bruce B GS, which are leased on a long-term basis to Bruce Power LP. Income from these leased stations is included as leasing revenue under the Regulated – Nuclear Generation segment. The leased stations are not included in the generation portfolio statistics set out in this report. A description of OPG's segments is provided in OPG's 2017 annual MD&A in the section, *Business Segments*.

All of OPG's owned and co-owned generating facilities are located in Ontario. OPG does not operate PEC, Brighton Beach, the Bruce A GS and the Bruce B GS.

In-Service Generating Capacity

OPG's in-service generating capacity by business segment as of March 31, 2018 and December 31, 2017 was as follows:

	As at	
(MW)	**March 31 2018**	**December 31 2017**
Regulated – Nuclear Generation [1]	**5,728**	5,728
Regulated – Hydroelectric	**6,426**	6,426
Contracted Generation Portfolio [2]	**4,064**	4,056
Total	**16,218**	16,210

[1] The in-service generating capacity as of March 31, 2018 and December 31, 2017 excludes Unit 2 of the Darlington Nuclear GS (Darlington GS). The unit, which has a generating capacity of 878 MW, was taken offline in mid-October 2016 and is currently undergoing refurbishment.

[2] Includes OPG's share of in-service generating capacity of 275 MW for PEC and 280 MW for Brighton Beach.

During the three months ended March 31, 2018, total in-service capacity increased by 8 MW. The increase was due to the completion of the overhaul and upgrade of Unit 1 of the Harmon hydroelectric GS, which was returned to service in February 2018 as part of the Contracted Generation Portfolio segment.

HIGHLIGHTS

Overview of Results

This section provides an overview of OPG's unaudited interim consolidated operating results and summarizes OPG's income before interest and income taxes by business segment. Significant factors which contributed to OPG's results during the three months ended March 31, 2018, compared to the same period in 2017, are discussed below. A detailed discussion of OPG's performance by reportable segment is included in the section, *Discussion of Operating Results by Business Segment*.

(millions of dollars – except where noted) (unaudited)	Three Months Ended March 31 2018	2017
Revenue	**1,407**	1,176
Fuel expense	**155**	155
Operations, maintenance and administration	**722**	708
Depreciation and amortization	**186**	167
Other (gains) expenses, net [3]	**(227)**	47
Income before interest and income taxes	**571**	99
Net interest expense	**19**	19
Income tax expense	**13**	12
Net income	**539**	68
Net income attributable to the Shareholder	**535**	64
Net income attributable to non-controlling interest [1]	**4**	4
Electricity production (TWh) [2]	**18.8**	18.6
Cash flow		
Cash flow provided by operating activities	**226**	168
Segment Results		
Regulated – Nuclear Generation	**75**	(118)
Regulated – Hydroelectric	**171**	180
Contracted Generation Portfolio	**78**	77
Total electricity generation business segments	**324**	139
Regulated – Nuclear Waste Management	**(33)**	(47)
Fair Hydro Trust	**4**	-
Other [3]	**276**	7
Income before interest and income taxes	**571**	99

[1] Relates to the 25 percent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in the Lower Mattagami Limited Partnership, the 33 percent interest of Coral Rapids Power Corporation (CRP), a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership (PSS), and the 10 percent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP. CRP increased its partnership interest in PSS to 33 percent in April 2017.

[2] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

[3] For the three months ended March 31, 2018, includes the pre-tax gain on sale of the former Lakeview GS site.

Net income attributable to the Shareholder was $535 million for the first quarter of 2018, representing an increase of $471 million compared to the same quarter in 2017. Income before interest and income taxes was $571 million for the first quarter of 2018, representing an increase of $472 million compared to the same quarter in 2017. The following summarizes the significant factors which contributed to the variance:

Significant factors that increased income before interest and income taxes:

- Higher revenue from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments of approximately $210 million, reflecting the impact of new regulated prices approved by the OEB in its December 2017 decision and March 2018 payment amounts order on OPG's application for new regulated prices. Further details can be found under the heading, *Recent Developments – OEB's Payment Amounts Order on OPG's Application for New Regulated Prices*.
- Higher revenue of approximately $25 million, partially offset by an increase in fuel expense of $5 million, reflecting higher electricity generation of 0.4 terawatt hours (TWh) from the Regulated – Nuclear Generation segment.
- A pre-tax gain on the sale of the former Lakeview GS site of $273 million was recognized in net income upon completion of the transaction in the first quarter of 2018. The sale was undertaken pursuant to a Shareholder Declaration and a Shareholder Resolution. Further details can be found under the heading, *Recent Developments – Sale of Lakeview Site*.
- Higher earnings of $14 million from the Regulated – Nuclear Waste Management segment, primarily due to higher earnings from the nuclear fixed asset removal and nuclear waste management funds (Nuclear Segregated Funds), partially offset by an increase in accretion expense on the nuclear fixed asset removal and nuclear waste management liabilities (Nuclear Liabilities).

Significant factors that reduced income before interest and income taxes:

- Higher depreciation and amortization expenses of $19 million, mainly due to a higher amount of depreciation expense deferred in regulatory variance and deferral accounts in the first quarter of 2017. The higher deferrals in 2017 were due to costs not included in the regulated prices in effect prior to the OEB's December 2017 decision.
- Higher OM&A expenses of $14 million, mainly in the Regulated – Nuclear Generation segment, reflecting higher services and materials costs associated with planned outages at the nuclear stations.
- Lower hydroelectric incentive mechanism payments of $7 million in the Regulated – Hydroelectric segment.

Net interest expense for the first quarter of 2018 was comparable with the same quarter in 2017.

Income tax expense increased by $1 million in the first quarter of 2018, compared to the same quarter in 2017, primarily due to higher income before income taxes, largely offset by a higher amount of deferred income tax expense recorded as a regulatory asset and a reduction in income taxes resulting from a dividend distribution.

Recent Developments

OEB's Payment Amounts Order on OPG's Application for New Regulated Prices

The OEB's decision on OPG's May 2016 five-year application for new regulated prices for nuclear and regulated hydroelectric generation was issued on December 28, 2017, following a public hearing process, with an effective date for the new regulated prices of June 1, 2017. The decision included the OEB's findings with respect to ratemaking methodologies for OPG's regulated facilities, the basis for inputs into the hydroelectric incentive mechanism formula, and the elements of the nuclear revenue requirement. Pursuant to the OEB's decision, the new base regulated prices for the regulated hydroelectric facilities for each of the years 2017 to 2021 are to be determined by annually escalating the base regulated prices in effect prior to June 1, 2017, with some adjustments, using an approved formula equal to an industry-specific weighted inflation factor based on indices published annually by the OEB, less a stretch factor adjustment. For the nuclear facilities, a revenue requirement is determined for each of the years 2017

to 2021 based on the OEB-allowed level of operating costs and a return of and on invested capital, reduced by a stretch factor amount. Consistent with the requirement of *Ontario Regulation 53/05*, OPG's overall production-weighted regulated price is smoothed, with a portion of the approved nuclear revenue requirements for the 2017-2021 period deferred for future collection in the Rate Smoothing Deferral Account. The difference between the non-deferred portion of the annual nuclear revenue requirement, calculated by multiplying the approved nuclear base regulated price determined under rate smoothing and the approved forecast of OPG's nuclear electricity production, and the total approved nuclear revenue requirement determines the amount deferred for future collection. Further details on OPG's December 2017 decision can be found in OPG's 2017 annual MD&A in the section, *Highlights* under the heading, *Recent Developments – OEB's Decision on OPG's Application for New Regulated Prices*.

To reflect management's best estimate of the impact of the OEB's decision, in the fourth quarter of 2017, OPG recorded incremental net revenue for the June 1, 2017 to December 31, 2017 interim period based on the draft payment amounts order. The revenue was recorded as an increase in regulatory assets for the June 1, 2017 to December 31, 2017 interim period revenue shortfall based on proposed new regulated prices, net of a regulatory liability for the Rate Smoothing Deferral Account.

On March 29, 2018, the OEB issued the final payment amounts order establishing new regulated prices for OPG's regulated facilities, with an implementation date of March 1, 2018. For the regulated hydroelectric facilities, the OEB approved the base regulated prices as calculated by OPG in the draft payment amounts order it submitted to the OEB on January 17, 2018. The final payment amounts order set base regulated prices for the regulated hydroelectric facilities for the June 1, 2017 to December 31, 2017 period and for the January 1, 2018 to December 31, 2018 period, based on the approved incentive regulation formula and inflation indices published by the OEB. For the 2019-2021 period, the base regulated prices for the regulated hydroelectric facilities will be determined annually before the beginning of each year using the approved formula and published indices.

For the nuclear facilities, the OEB approved the 2017-2021 revenue requirements as submitted by OPG in the draft payment amounts order, with minor adjustments. The OEB also made certain adjustments to OPG's rate smoothing proposal and resulting nuclear base regulated prices for the June 1, 2017 to December 31, 2017 period and each of the years 2018 to 2021 submitted in the draft payment amounts order. Pursuant to the final payment amounts order, no amounts will be deferred in the Rate Smoothing Deferral Account until 2019 with approximately $500 million to be deferred over the 2019-2021 period. Parties to OPG's application were given an opportunity to review and comment on OPG's draft payment amounts order prior to the OEB's issuance of the final payment amounts order.

The OEB's adjustments to OPG's rate smoothing proposal and resulting nuclear base regulated prices in the final payment amounts order resulted in a partial reversal of the regulatory asset for the June 1, 2017 to December 31, 2017 interim period revenue shortfall recorded in the fourth quarter of 2017, largely offset by the reversal of the regulatory liability for the Rate Smoothing Deferral Account recorded in the fourth quarter of 2017. Taken together, these reversals did not have a material impact on the results of operations for the first quarter of 2018.

In addition, for the period from March 1, 2018 to December 31, 2020, the final payment amounts order authorized interim period shortfall riders to collect the revenue shortfall for the June 1, 2017 to February 28, 2018 period based on the newly approved base regulated prices. The order established separate rate riders for the March 1, 2018 to December 31, 2020 period to recover variance and deferral account balances approved in the application. As the interim period shortfall riders and the variance and deferral account riders will collect amounts previously recorded as regulatory assets, they will contribute to improved cash flow from operations but are not expected to have a material impact on net income.

The OEB's final payment amounts order authorized the following regulated prices for electricity generated from OPG's nuclear and regulated hydroelectric facilities for the 2017-2021 period, effective June 1, 2017:

($/MWh)	**2017 June 1 to December 31**	**2018**	**2019**	**2020**	**2021**
Regulated – Nuclear Generation					
Base regulated price [1]	77.96	78.64	77.00	85.00	89.70
Variance and deferral account rate rider [2]	-	1.05	2.79	2.04	-
	77.96	79.69	79.79	87.04	89.70
Regulated – Hydroelectric					
Base regulated price [1, 3]	41.67	42.05	-	See Note 3	-
Variance and deferral account rate rider [2]	-	0.52	-	-	-
	41.67	42.57	-	-	-

[1] As part of the payment amounts order process, the OEB authorized separate rate riders to allow for the recovery of the revenue shortfall between the new base regulated prices and the previously approved base regulated prices that OPG continued to receive during the interim period between June 1, 2017 and February 28, 2018, over the March 1, 2018 to December 31, 2020 period. The revenue shortfall was recorded as a regulatory asset in the fourth quarter of 2017 and the first quarter of 2018. The nuclear interim period shortfall rider is $2.89/MWh during the March 1, 2018 to December 31, 2018 period, $7.71/MWh in 2019 and $5.64/MWh in 2020. The regulated hydroelectric interim period shortfall rider is $0.13/MWh during the March 1, 2018 to December 31, 2018 period, $0.35/MWh in 2019 and $0.24/MWh in 2020.

[2] Consistent with the OEB's December 2017 decision, in 2018, OPG plans to file an application with the OEB requesting disposition of the next set of variance and deferral account balances, which may result in additional variance and deferral account riders prospectively over the period, depending on the outcome of the application.

[3] Base regulated prices for the regulated hydroelectric facilities for the 2019-2021 period will be determined annually before the beginning of each year using the OEB-approved incentive regulation formula and OEB-published inflation indices.

Darlington Refurbishment

In early May 2018, OPG completed the second major segment of the Unit 2 refurbishment of the Darlington GS, the removal of reactor components, and has transitioned into the third major segment, the installation and reassembly of new reactor components.

Planning activities for the refurbishment of Unit 3 of the Darlington GS continue. In February 2018, the Government of Ontario confirmed its commitment to proceed with the Unit 3 refurbishment. The Darlington Refurbishment project continues to track on schedule and to the $12.8 billion budget.

The Darlington Refurbishment project is discussed further in the section, *Core Business, Strategy, and Outlook* under the heading, *Project Excellence*.

Payment of Dividend to Shareholder

In April 2017, OPG completed the sale of its head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street in Toronto, Ontario. The sale was undertaken pursuant to a Shareholder Declaration and a Shareholder Resolution received by OPG in December 2015. Pursuant to the Shareholder Declaration and the Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014* (Trillium Trust Act), OPG was required to transfer the proceeds from this disposition, net of prescribed deductions under the Trillium Trust Act, into the Province's Consolidated Revenue Fund. In accordance with these requirements, a special dividend of $283 million was authorized by OPG's Board of Directors and transferred into the Consolidated Revenue Fund in March 2018.

Sale of Lakeview Site

In March 2018, OPG completed the sale of its former Lakeview GS site property located in Mississauga, Ontario, with an after-tax gain on sale of $205 million recognized in net income in the first quarter of 2018. The sale was undertaken pursuant to a Shareholder Declaration and a Shareholder Resolution received by OPG in June 2016. Pursuant to the Shareholder Declaration and the Shareholder Resolution, and as prescribed in the Trillium Trust Act, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Trillium Trust Act, into the Province's Consolidated Revenue Fund. OPG expects that the amount of designated proceeds to be transferred into the Consolidated Revenue Fund will be largely consistent with the after-tax gain on sale~~, and is working with the Ontario Ministry of Finance to finalize the amount.~~ **[MONITOR]** In accordance with the Shareholder Resolution, approximately 67 acres of the site will be transferred to the City of Mississauga by the purchaser, for parkland, institutional, and cultural uses.

Commented [RK1]: OPG may be providing required information to MOF, but the amount is determined by a Treasury Board regulation. I'd suggest simply deleting the words, as indicated.

Electricity Generation

Electricity generation for the three months ended March 31, 2018 and 2017 was as follows:

(TWh)	Three Months Ended March 31 2018	2017
Regulated – Nuclear Generation	**10.4**	10.0
Regulated – Hydroelectric	**7.7**	8.0
Contracted Generation Portfolio [1]	**0.7**	0.6
Total OPG electricity generation	**18.8**	18.6
Total electricity generation by other generators in Ontario [2]	**19.1**	18.6

[1] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

[2] Non-OPG generation is calculated as the Ontario electricity demand plus net exports, as published by the Independent Electricity System Operator (IESO), minus OPG electricity generation.

Total OPG electricity generation increased by 0.2 TWh during the first quarter of 2018, compared to the same quarter in 2017. This was mainly due to higher electricity generation of 0.4 TWh from the Regulated – Nuclear Generation segment, partially offset by lower electricity generation of 0.3 TWh from the Regulated – Hydroelectric segment.

The increase in electricity generation from the Regulated – Nuclear segment was primarily due to fewer planned outage days at the Darlington GS. The lower electricity generation from the Regulated – Hydroelectric segment was primarily due to lower water flows on the northwestern and eastern Ontario river systems.

OPG's operating results are affected by changes in grid-supplied electricity demand resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. For the first quarter of 2018, Ontario's electricity demand as reported by the IESO was 35.0 TWh compared to 34.3 TWh for the same quarter in 2017, excluding electricity exports out of the province.

Power that is surplus to the Ontario market is managed by the IESO, mainly through generation reductions at hydroelectric and certain nuclear stations, and other grid-connected renewable resources. Baseload generation supply surplus in Ontario continued to be prevalent during first quarter of 2018, resulting in total forgone hydroelectric generation for OPG of 0.8 TWh, which was comparable to the same quarter in 2017. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions during these periods was offset by the impact of a regulatory variance account authorized by the OEB. Production forgone at OPG's regulated hydroelectric stations due to SBG conditions was 0.8 TWh in the first quarter of 2018, which was comparable to the same quarter in 2017. OPG did not forgo any electricity production at its nuclear stations due to SBG conditions.

Average Sales Prices

The majority of OPG's generation is from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments. The regulated prices authorized by the OEB for electricity generated from OPG's nuclear and regulated hydroelectric generating stations are discussed further in the section, *Highlights* under the heading, *Recent Developments – OEB's Payment Amounts Order on OPG's Application for New Regulated Prices* and OPG's 2017 annual MD&A in the section, *Revenue Mechanisms for Regulated and Non-Regulated Generation*.

The average sales price for the Regulated – Nuclear Generation segment was 7.2 cents per kilowatt hour (¢/kWh) during the first quarter of 2018, compared to 5.8 ¢/kWh during the same quarter in 2017. The increase in the average sales price primarily reflected the impact of the new base regulated prices approved by the OEB in its December 2017 decision and March 2018 payment amounts order, partially offset by a partial reversal of the regulatory asset for the June 1, 2017 to December 31, 2017 interim period revenue shortfall to reflect the March 2018 payment amounts order. While the reversal of the regulatory liability for the Rate Smoothing Deferral Account that also resulted from the issuance of the March 2018 payment amounts order largely offset the revenue and income impact of the partial reversal of the June 1, 2017 to December 31, 2017 revenue shortfall regulatory asset, it did not impact the average sales price for the first quarter of 2018 as amounts deferred under rate smoothing are not included in the calculation of the average sales price until the period they are settled with ratepayers.

The average sales price for the Regulated – Hydroelectric segment was 4.2 ¢/kWh during each of the first quarters of 2018 and 2017. The average sales price was comparable in these periods as the impact of the new base regulated prices approved by the OEB in its December 2017 decision and March 2018 payment amounts order was offset by lower revenue under the hydroelectric incentive mechanism in the first quarter of 2018.

Cash Flow from Operations

Cash flow provided by operating activities for the three months ended March 31, 2018 was $226 million, compared to $168 million for the same period in 2017. The increase was due to higher generation revenue receipts as a result of higher electricity generation from the Regulated – Nuclear Generation segment, higher cash receipts from non-generation revenues, and lower payments of income tax installments compared to the same period in 2017. The increase in cash flow provided by operating activities was partly offset by higher OM&A expenditures as a result of increased outage expenditures.

Return on Equity Excluding Accumulated Other Comprehensive Income

ROE Excluding AOCI is an indicator of OPG's performance consistent with the Company's strategy to provide value to the Shareholder. ROE Excluding AOCI is measured over a 12-month period. ROE Excluding AOCI for the twelve months ended March 31, 2018 was 11.5 percent, compared to 7.6 percent for the twelve months ended December 31, 2017. The increase in ROE Excluding AOCI was primarily due to higher net income attributable to the Shareholder as a result of increased revenue reflecting the impact of the new base regulated prices approved by the OEB in its December 2017 decision and March 2018 payment amounts order, and the gain on the sale of the former Lakeview GS site recorded in the first quarter of 2018. ROE Excluding AOCI for these periods also reflected the after-tax gain of $283 million on the sale of the Company's head office premises and associated parking facility recorded in the second quarter of 2017. The gains on the sale of the former Lakeview GS site and the head office premises and associated parking facility, including the effect of the associated special dividend authorized in March 2018, together with the associated tax effects of these transactions, contributed approximately 4.9 percent to ROE Excluding AOCI for the twelve months ended March 31, 2018 (twelve months ended December 31, 2017 – contribution of approximately 2.5 percent).

Enterprise Total Generating Cost per Megawatt-Hour

The Enterprise TGC per megawatt hour (MWh) was $49.84 for the three months ended March 31, 2018, compared to $47.86 for the same period in 2017. The increase was mainly a result of higher OM&A expenses before the impact of

regulatory variance and deferral accounts and higher sustaining capital expenditures, partially offset by higher nuclear electricity generation.

Nuclear Total Generating Cost per Megawatt-Hour

The Nuclear TGC per MWh was $70.90 for the three months ended March 31, 2018, compared to $69.87 for the same period in 2017. The increase in Nuclear TGC per MWh was primarily due to higher OM&A expenses before the impact of regulatory variance and deferral account and higher sustaining capital expenditures, partially offset by higher nuclear electricity generation.

Hydroelectric Total Generating Cost per Megawatt-Hour

The Hydroelectric TGC per MWh was $20.42 for the three months ended March 31, 2018, compared to $19.79 for the same period in 2017. The increase in the Hydroelectric TGC per MWh was primarily due to the decrease in hydroelectric electricity generation as a result of lower water flows on the northwestern and eastern Ontario river systems.

ROE Excluding AOCI, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are not measurements in accordance with US GAAP, and should not be considered alternative measures to net income or any other performance measure under US GAAP. OPG believes that these non-GAAP financial measures are effective indicators of its performance and are consistent with the Company's strategic imperatives and related objectives. The definition and calculation of ROE Excluding AOCI, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are found in the section, *Supplementary Non-GAAP Financial Measures*.

CORE BUSINESS, STRATEGY, AND OUTLOOK

The discussion in this section is qualified in its entirety by the cautionary statements included in the section, *Forward-Looking Statements,* at the beginning of the MD&A.

OPG's mission is to provide low cost power in a safe, clean, reliable and sustainable manner for the benefit of its customers and its Shareholder. OPG also seeks to pursue, on a commercial basis, generation development projects and other business growth opportunities to the benefit of the Shareholder.

The following sections provide an update to OPG's disclosures in the 2017 annual MD&A related to its four key strategic imperatives – operational excellence, project excellence, financial strength, and social licence. A detailed discussion of these strategic imperatives is included in the 2017 annual MD&A in the section, *Core Business, Strategy, and Outlook*.

Operational Excellence

Operational excellence at OPG is accomplished by the safe and environmentally responsible generation of reliable and cost-effective electricity from the Company's generating assets through a highly trained and engaged workforce.

Public Safety

To ensure continued public safety, radiation exposure to members of the public resulting from the operation of OPG's nuclear generating stations is estimated on an annual basis for individuals living or working near the stations. The annual dose to the public resulting from operations of each nuclear facility is expressed in microsieverts (µSv), which is an international unit of radiation dose measurement. For 2017, the annual public doses resulting from the Darlington GS operations and the Pickering Nuclear GS (Pickering GS) operations were 0.7 µSv and 1.8 µSv, respectively, which is approximately 0.1 percent and 0.2 percent of the annual legal limit of 1,000 µSv, respectively.

Electricity Generation Production and Reliability

The status updates for OPG's electricity generation portfolio as of March 31, 2018 are summarized below:

- OPG's current five-year operating licence for the Pickering GS was approved by the CNSC in 2013 and expires on August 31, 2018. This current licence was issued assuming that the station would shut down in 2020. As previously announced, OPG is continuing to execute on a plan to extend safe and reliable operation of the Pickering GS to 2024. In June 2017, OPG confirmed to the CNSC that it intends to cease commercial operation of all Pickering units on December 31, 2024. In August 2017, OPG submitted a ten-year licence renewal application to the CNSC in order to extend commercial operation to December 31, 2024 and place the station in a safe storage state in 2028. The first public hearing for the Pickering GS licence renewal application took place on April 4, 2018 and provided an opportunity for OPG to present its submission to the CNSC that outlined how the Pickering GS meets technical requirements and is qualified to continue operations. The final set of public hearings will take place between June 26 and June 28, 2018. Based on the evidence and documentation submitted to the CNSC, OPG continues to believe it is well positioned to obtain a licence renewal that would support its extended operations plan for the Pickering GS to 2024.
- In 2016, OPG submitted applications with the CNSC seeking a ten-year licence renewal for the Pickering Waste Management Facility (PWMF) to August 31, 2028. On February 7, 2018, following public hearings in April 2017, the CNSC announced that the PWMF licence was renewed for a ten-year period and will be valid until August 31, 2028.
- During the first quarter of 2018, OPG completed the overhaul and rehabilitation of Unit 1 of the Sir Adam Beck Pump GS to ensure reliable unit operation for approximately the next 20 years, as well as the overhaul and upgrade of Unit 1 of the Harmon GS, which increased the station's generating capacity by 8 MW.
- Work is continuing on the overhauls and upgrade of Unit 2 of the DeCew Falls GS and Unit 2 of the Little Long GS and the overhauls and rehabilitation of Unit 2 of the Lower Notch GS and Unit 6 of the Sir Adam Beck Pump GS.
- The definition phase work continues for the Water Conveyance System project to rehabilitate the Sir Adam Beck 1 GS canal and associated structures to ensure their continued safe and reliable operations for approximately the next 50 years.
- Commencement of definition phase work for the frequency conversion of Units 1 and 2 of the Sir Adam Beck 1 GS and the overhaul and upgrade of the R.H. Saunders GS units.
- As part of the process to decommission the Nanticoke GS, OPG safely demolished the station's stacks in February 2018. The removal of the powerhouse and associated structures is in progress. A competitive bidding process for the demolition of the Lambton GS is continuing, with a contract for the removal of the powerhouse and associated structures expected to be issued during 2018. The costs of the decommissioning activities are charged to a previously established decommissioning provision.

Environmental Performance

In February 2018, the CNSC released sampling results from its 2017 independent environmental monitoring program, which confirmed that the public and environment around the Pickering GS are protected and that there are no expected health impacts. Samples were collected in publicly accessible areas outside the Pickering GS site perimeter and included air, lake water, soil, and wild vegetation. Samples of food were also taken from a local farm near the Pickering GS.

In the first quarter of 2018, the Government of Canada introduced legislation to amend the *Fisheries Act* (Bill C-68) and to replace the *Canadian Environmental Assessment Act, 2012* with a more comprehensive *Impact Assessment*

Act (Bill C-69). If passed by Parliament, this legislation could introduce new regulatory requirements to further protect fish and fish habitat, and for assessing designated projects. OPG is reviewing the proposed changes and exploring opportunities to mitigate any associated risks.

Disclosures related to the Company's environmental policy and environmental risks can be found in OPG's 2017 annual MD&A.

People and Culture

A well trained and engaged workforce is fundamental to the achievement of OPG's strategic imperatives. To succeed in a demanding business environment, OPG is focused on building a diverse, healthy, engaged workforce and fostering a culture of collaboration, accountability and innovation. OPG also continues to communicate and implement the values and behaviours expected from its employees in order to maintain a strong focus on safety, performance excellence, continuous improvement, and corporate citizenship.

In March 2018, the Employee Assistance Society of North America awarded OPG the annual Corporate Award of Excellence. These awards are given to organizations that showcase the excellence, innovation and impact of employee assistance programs in the workplace with a view to enhance employee well-being and support a healthy and productive working environment. OPG was recognized for its commitment to an organizational culture that values safety and good mental health as critical components of the organization's success.

Project Excellence

OPG is pursuing a number of generation development and other major projects in support of Ontario's electricity planning initiatives. The status updates for OPG's major projects as of March 31, 2018 are outlined below.

Project	Capital expenditures		Approved budget	Expected in-service date	Current status
(millions of dollars)	Year-to-date	Life-to-date			
Darlington Refurbishment	241	4,675	12,800 [1]	First unit - 2020 Last unit - 2026	The removal of existing Unit 2 reactor components was completed in early May 2018, with the installation of new components commencing thereafter. Planning activities for the refurbishment of Unit 3 are continuing. The overall project is tracking on schedule and on budget.
Ranney Falls Hydroelectric GS	8	36	77	2019	Construction is continuing in the expanded forebay, powerhouse and spillway area. Fabrication of the sectional gates and two head gates has been completed. Turbine and generator unit fabrication is in progress. The project is tracking on schedule and on budget.
Nanticoke Solar Facility	5	8	107	2019	Significant contracts for equipment and engineering construction services were executed and site preparation commenced in the first quarter of 2018. The facility is expected to be completed in the first quarter of 2019. **[MONITOR]**
Deep Geologic Repository (DGR) for Low and Intermediate Level Radioactive Waste (L&ILW)	- [2]	208 [2]			In August 2017, the federal Minister of Environment and Climate Change requested further information related to the project's environmental assessment (EA). OPG is continuing to work on a response to this information request.

[1] The total project budget of $12.8 billion is for the refurbishment of all four units at the Darlington GS. Project costs that do not meet capitalization criteria are charged to OM&A expenses in the period incurred.
[2] Expenditures are charged against the Nuclear Liabilities.

Darlington Refurbishment

The Darlington generating units are approaching their originally designed end-of-life. Refurbishment of the four generating units is expected to extend the operating life of the station by approximately 30 years. The approved budget for the four-unit refurbishment is $12.8 billion, which includes the costs of the prerequisite projects in support of the execution phase of the refurbishment. The first refurbished unit is scheduled to be returned to service in the first quarter of 2020 and the last unit is scheduled to be completed by 2026.

OPG commenced the refurbishment of the first unit, Unit 2, in October 2016. The de-fuelling of the reactor and islanding of Unit 2, the physical separation of the unit under refurbishment from the three operating units, was completed in the first half of 2017, signifying the completion of the first major segment of the project.

The second major segment included the disassembly and removal of the existing reactor components. In early May 2018, OPG completed the removal of the reactor components, which included end fittings, pressure tubes, and calandria tubes, signifying the completion of the second major segment of the project.

The Unit 2 refurbishment has transitioned into the third major segment, the installation and reassembly of reactor components, including new feeder tubes and fuel channel assemblies. Construction activities on the Heavy Water Storage and Drum Handling Facility are also continuing.

In February 2018, the Government of Ontario confirmed its commitment to proceed with the refurbishment of the second unit at the Darlington GS, Unit 3. In March 2018, OPG's Board of Directors approved the funding to complete planning and prerequisite activities for the Unit 3 refurbishment. Planning activities for the Unit 3 refurbishment are progressing in accordance with the overall project schedule. OPG is ensuring that lessons learned from the Unit 2 refurbishment are appropriately incorporated into the Unit 3 refurbishment, and is entering into commitments to procure major components that require long lead times. Prerequisite activities for Unit 3 refurbishment have commenced, with the Unit 3 refurbishment execution expected to commence upon the return to service of Unit 2. As of March 31, 2018, $137 million has been invested in planning and prerequisite activities related to the Unit 3 refurbishment.

The Darlington Refurbishment project continues to track on schedule and to the $12.8 billion budget.

Ranney Falls Hydroelectric GS

In 2017, OPG began construction work on a 10 MW single-unit powerhouse on the existing Ranney Falls GS site. The new unit will replace an existing unit that reached its end of life in 2014. Construction continues in the expanded forebay, powerhouse and spillway area. Fabrication of the sectional gates and two head gates has been completed, with assembly and site delivery in progress. Turbine and generator unit fabrication is also in progress. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget. The Ranney Falls GS is included in the Regulated – Hydroelectric segment.

Nanticoke Solar Facility

The project encompasses the construction of a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands under a contract with the IESO, through Nanticoke Solar LP, a partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation. Significant contracts for equipment and engineering construction services were executed and site preparation commenced in the first quarter of 2018. The facility is expected to be completed in the first quarter of 2019 **[MONITOR]**, with a budget of $107 million. The project is included in the Contracted Generation Portfolio segment.

Deep Geologic Repository for Low and Intermediate Level Waste

OPG has proposed a deep geologic repository as the preferred solution for the safe long-term management of the L&ILW produced from the continued operation of OPG-owned nuclear generating stations. Agreement has been

reached with local municipalities for OPG to develop the L&ILW DGR on lands adjacent to OPG's Western Waste Management Facility (WWMF) in Kincardine, Ontario.

Before the CNSC can make licensing decisions for the proposal, an EA must be conducted. The environmental effects of the proposed L&ILW DGR were examined by the CNSC and Canadian Environmental Assessment Agency (CEAA)-appointed Joint Review Panel (JRP) to meet the requirements of the *Canadian Environmental Assessment Act* as well as the project specific Environmental Impact Statement Guidelines. The JRP submitted its report on the EA to the federal Minister of Environment in May 2015, concluding that, given mitigation, there is unlikely to be significant environmental impact from the project and recommending that the Minister approve the EA. In December 2016, at the request of the federal Minister of Environment and Climate Change, OPG submitted additional information on certain aspects of the EA, with further information provided in May 2017 at the request of the CEAA. In June 2017, the CEAA notified OPG that it had sufficient and adequate information to proceed with the next step of the EA process and advised that a draft report and updated terms and conditions would be prepared for public review.

In August 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of potential cumulative effects of the project on the Saugeen Ojibway Nation's (SON) physical and cultural heritage, including a description of the potential effects of the project on the SON's spiritual and cultural connection to the land, taking into account the results of the SON Community Process. OPG continues its engagement with the SON towards securing support for the project and to formulate a response to the information request.

The L&ILW DGR at the WWMF site remains OPG's preferred solution for the safe long-term management of the L&ILW. The in-service date of the L&ILW DGR is expected to be approximately six to seven years from the start of construction.

Financial Strength

As a commercial enterprise, OPG's financial priority is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future expansion.

Increasing Revenue, Reducing Costs and Achieving Appropriate Return

In line with its commercial mandate, OPG is focused on increasing revenue and net income and achieving an appropriate rate of return on the Shareholder's investment, while taking into account the impact on Ontario electricity customers by seeking further efficiencies in the Company's cost structure.

For the regulated operations, achievement of the above objectives is largely dependent on outcomes of applications for regulated prices to the OEB and growth of the asset base earning a return as part of the regulated prices. The OEB's December 2017 decision and March 2018 payment amounts order establishing new regulated prices effective June 1, 2017 provide substantial price certainty for the regulated business up to 2021.

While the OEB set costs for determining the new regulated prices below OPG's forecasted levels, including through the use of stretch factors under incentive ratemaking, the new regulated prices will result in a substantial increase in revenue and net income compared to the previously approved prices.

To further improve the financial strength of the regulated operations, OPG continues to focus on optimizing operational performance and outage plans across the generating fleet and pursue further efficiency improvements in the Company's cost structure and operating model. This includes continuing to progress the multi-year OPG25 initiative, which involves identifying and implementing a coordinated set of plans and targets to ensure the optimization of the Company's longer-term operating model, business strategies and organizational design between now and the planned end of Pickering commercial operation in 2024.

OPG's capital structure currently reflects lower levels of debt than the deemed capital structure of 45 percent equity and 55 percent debt maintained by the OEB's December 2017 decision on new regulated prices. OPG continues to evaluate strategies to enhance Shareholder returns by optimizing the Company's capital structure through better alignment with the deemed capital structure, taking into account the overall financial strength of the Company and the potential impact on the Company's investment grade credit rating.

Consistent with the OEB's December 2017 decision, later in 2018, OPG plans to file an application with the OEB requesting disposition of the Pension & OPEB Cash Versus Accrual Differential Deferral Account balance as at December 31, 2017 and the balances accumulated between December 31, 2015 and December 31, 2017 in other variance and deferral account balances. If approved by the OEB, recovery of these balances would contribute to improved cash flow from operations.

Ensuring Availability of Cost Effective Funding

In April 2018, DBRS Limited (DBRS) re-affirmed the long-term credit rating on OPG's debt at 'A (low)' and OPG's commercial paper rating at 'R-1 (low)'. All ratings from DBRS have a stable outlook.

Social Licence

As the largest electricity generator in Ontario with diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust. OPG is committed to maintaining high standards of public safety and corporate citizenship, including environmental stewardship, transparency, community engagement, and Indigenous relations.

OPG is focused on building long-term, mutually beneficial working relationships with Indigenous communities, businesses and organizations across Ontario, and continues to support procurement, employment and educational opportunities with Indigenous communities. OPG seeks to establish these relationships based on a foundation of respect for the languages, customs, and political, social and cultural organizations of Indigenous communities. In the first quarter of 2018, the Dictionary of Moose Cree, an OPG-supported project that preserves the unique language and culture of the Moose Cree First Nation, was recognized by the Lieutenant Governor of Ontario. The language initiative was funded by OPG as a cultural project under the 2010 Amisk-oo-skow Agreement between OPG and the Moose Cree First Nation.

OPG's commitment in the area of Indigenous relations includes pursuing generation-related development partnerships on the basis of long-term commercial arrangements and other joint projects. In addition to the development of the Nanticoke solar facility in partnership with the Six Nations of the Grand River, OPG is currently working with the Kiashke Zaaging Anishinaabek (KZA), also known as the Gull Bay First Nation, to construct a new renewable micro grid that will utilize solar generation, battery storage, and micro grid control technology to reduce the community's reliance on diesel generation. As the lead developer of the project, OPG will work with several collaborators to construct the micro grid on KZA reserve land. Upon completion, the micro grid will be transferred to KZA for ownership and operation. The micro grid project is OPG's fifth development project in partnership with an Indigenous community.

OPG is committed to improving Indigenous access to procurement and employment opportunities, including increasing the profile of the nuclear generation industry in Indigenous communities. In 2018, this includes continuing to track the implementation of the Indigenous Business Engagement Initiative launched in 2017 to increase access to procurement opportunities for Indigenous businesses interested in supplying materials and services to OPG, and continuing to identify ways to increase the Indigenous representation in OPG's workforce. Recruitment initiatives include the launch of the Indigenous Opportunities in Nuclear program in the first quarter of 2018 using the Darlington Refurbishment project as a catalyst, and the continuing development of a dedicated Indigenous recruitment and retention strategy.

Outlook

The financial performance of OPG's regulated operations is driven, in large part, by the outcome of applications for regulated prices to the OEB.

In 2018, the full-year effect of the new regulated prices established by the OEB's December 2017 decision and March 2018 payment amounts order effective June 1, 2017 will contribute to an improvement in net income and ROE Excluding AOCI over the 2017 results. An improvement in cash flow from operating activities during the remainder of 2018, compared to 2017, is also expected, as OPG begins to receive revenue from the IESO based on new regulated prices as of March 1, 2018, the implementation date for the regulated prices. The Fair Hydro Trust segment will also modestly improve cash flow from operating activities in 2018. OPG expects to continue to have the necessary financial capacity and sufficient access to cost effective financing sources to continue to fund its capital requirements and other disbursements, including purchases of subordinated debt issued by the Fair Hydro Trust (the Trust) to fund a portion of the Trust's acquisition of Investment Interest from the IESO, being the irrevocable right to recover Global Adjustment costs deferred by the IESO under the *Ontario Fair Hydro Plan Act, 2017* (Fair Hydro Act or the Act) and associated financing and other costs.

Several OEB-authorized regulatory variance and deferral accounts will continue to contribute to reducing the relative variability of the Company's net income and ROE Excluding AOCI. Among others, these accounts include those related to the revenue impact of variability in water flows and forgone production due to SBG conditions at the regulated hydroelectric stations. As there are no variance or deferral accounts in place related to the impact of generation performance of the nuclear stations on revenue from base regulated prices, the Regulated – Hydroelectric segment generally is expected to produce overall more predictable earnings. OPG continues to operate and maintain its nuclear facilities with a view to optimize their performance and availability, while focusing on improving the overall reliability and predictability of the fleet.

Electricity generated from most of OPG's non-regulated assets is subject to ESAs with the IESO or other long-term contracts. Based on these agreements, OPG expects the Contracted Generation Portfolio segment to continue to contribute a generally stable level of earnings and cash flow from operating activities going forward.

Lower nuclear generation due to the Darlington Refurbishment outages will continue, as planned, to negatively impact the Enterprise TGC and Nuclear TGC measures for the duration of the refurbishment project. Lower hydroelectric generation due to outages related to various refurbishment and operational projects may negatively impact Enterprise TGC and Hydroelectric TGC for the duration of these projects. Variability in sustaining capital investment expenditures and nuclear outage profile may also impact TGC measures in future periods.

OPG's total forecast capital expenditures for the 2018 year are approximately $2.1 billion. This includes amounts for the Darlington Refurbishment project, hydroelectric and other development projects including the Ranney Falls GS redevelopment and construction of the Nanticoke solar facility, and sustaining capital investments across the generating fleet. OPG's major projects are discussed in the section, *Project Excellence*.

In addition to the operating and financial performance of the electricity generation business, OPG's results are affected by earnings on the Nuclear Segregated Funds established under the Ontario Nuclear Funds Agreement (ONFA) between OPG and the Province, which are reported in the Regulated – Nuclear Waste Management segment. Variations in rates of return for the funds based on financial market conditions, including changes in the Ontario consumer price index (CPI) that affect earnings on the portion of the Used Fuel Segregated Fund guaranteed by the Province, can be volatile and cause fluctuations in the Company's income in the near term. This volatility is reduced by the impact of the OEB-authorized Bruce Lease Net Revenues Variance Account and during periods when the funds are in a fully funded or overfunded position. As at March 31, 2018, the Decommissioning Segregated Fund was overfunded by approximately 26 percent, and the Used Fuel Segregated Fund was marginally overfunded, by less than one percent, based on the current ONFA reference plan. Variability in asset performance due to volatility

inherent in financial markets and changes in Ontario CPI, or changes in funding liability estimates, may result in either or both funds becoming underfunded in the future.

OPG's results include the earnings from the Fair Hydro Trust segment, primarily related to interest income from the Trust. Management expects that these earnings will increase in 2018 as additional Investment Interest is acquired. OPG's involvement as the Financial Services Manager under the Fair Hydro Act is expected to put downward pressure on ROE Excluding AOCI as a result of increases in shareholder's equity through future issuances of Class A shares to partially fund OPG's purchases of the Trust's subordinated debt, partially offset by the impact of incremental earnings from the Trust.

ENVIRONMENT, SOCIAL GOVERNANCE, AND SUSTAINABILITY

OPG's Darlington and Pickering nuclear generating stations and renewable fleet of hydroelectric generating stations produce clean, reliable electricity with virtually no greenhouse gas emissions. However, OPG recognizes that efforts are required to plan for the impacts of climate change and has identified climate change adaptation as a strategic priority for the company. OPG monitors developments in climate science, adaptation activities, and potential changes to policy and regulatory requirements, and is continuing to work with stakeholders to better define adaptation requirements.

OPG has established an Environment, Social Governance and Sustainability (ESG) steering committee consisting of a diverse group of representatives from various disciplines within the Company. The mandate of the committee is to evaluate the potential impact of environmental issues on the Company, oversee the development of a formal climate change strategy, assess and monitor the evolution of the climate-related risks, and develop associated financial reporting disclosures.

OPG is in the process of developing its ESG framework to best reflect and disclose information that is meaningful to stakeholders. OPG plans to structure its ESG framework around four core themes:

- **Metrics and targets** to assess and manage relevant climate-related risks and opportunities;
- **Risk management** processes to identify, assess and manage climate-related risks;
- **Strategy** for incorporating climate change impacts into business planning and decision-making; and
- **Governance** for integrating the climate change strategy in the business.

In developing its ESG framework, OPG expects to leverage industry-specific and other emerging guidance on best practices related to ESG reporting. OPG also continues to monitor the Canadian Securities Administrators' project to review the disclosures of risks and financial impacts associated with climate change.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

Regulated – Nuclear Generation Segment

(millions of dollars) (unaudited)	Three Months Ended March 31 2018	2017
Revenue from contracts with customers	**871**	643
Leasing revenue	**9**	9
Revenue	**880**	652
Fuel expense	**73**	68
Gross margin	**807**	584
Operations, maintenance and administration	**604**	589
Depreciation and amortization	**121**	107
Property taxes	**7**	6
Income (loss) before interest and income taxes	**75**	(118)

Income before income interest and income taxes from the segment increased by $193 million during the first quarter of 2018, compared to the same quarter in 2017. The increase in earnings was primarily due to an increase in revenue of $228 million, reflecting the impact of new regulated prices approved by the OEB in its December 2017 decision and March 2018 payment amounts order on OPG's application for new regulated prices, effective June 1, 2017. The higher earnings were also partially due to an increase in electricity generation of 0.4 TWh during the first quarter of 2018, compared to the same quarter in 2017, which contributed approximately $25 million to the year-over-year increase in revenue.

The increase in OM&A expenses of $15 million in the first quarter of 2018, compared to the same quarter in 2017, partially offset the increase in segment earnings. The increase in OM&A expenses was primarily due to higher services and materials costs associated with major planned outages.

Higher depreciation and amortization expenses of $14 million in the first quarter of 2018 were mainly due to a higher amount of depreciation expense deferred in regulatory variance and deferral accounts in the first quarter of 2017. The higher deferrals in 2017 were due to costs not included in the regulated prices in effect prior to the OEB's December 2017 decision. In addition, new assets in service for the Pickering GS contributed to the increase in depreciation and amortization expenses.

At the end of 2017, OPG revised the accounting end-of-life assumptions for the Pickering GS from December 31, 2020 to December 31, 2022 for Units 1 and 4 and to December 31, 2024 for Units 5 to 8, and recorded a corresponding change in the nuclear asset retirement obligation and associated asset retirement costs capitalized as part of the carrying value of property, plant and equipment, effective December 31, 2017. The change in these end-of-life assumptions took into account technical assessments completed to date as part of OPG's plan to extend the commercial operation of the Pickering GS to 2024 and the safety case reflected in the Pickering GS licence renewal application submitted to the CNSC in 2017. The resulting decrease in depreciation expense associated with the change in these end-of-life assumptions in the first quarter of 2018, compared to the same quarter in 2017, was offset by the impact of regulatory variance and deferral accounts, including a new deferral account proposed by OPG in its December 2017 accounting order application to the OEB and subsequently authorized by the OEB on an interim basis pending a final decision on the application. **[MONITOR]**

The Unit Capability Factors for the Darlington GS and Pickering GS were as follows:

	Three Months Ended March 31	
	2018	**2017**
Unit Capability Factor *(%)* [1]		
Darlington GS	**96.5**	85.3
Pickering GS	**74.5**	78.5

[1] The nuclear Unit Capability Factor excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS was excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

The Unit Capability Factor at the Darlington GS increased in the first quarter of 2018, compared to the same quarter in 2017, primarily due to a lower number of planned outage days at the station in the first quarter of 2018.

The decrease in the Unit Capability Factor at the Pickering GS in the first quarter of 2018, compared to the same quarter in 2017, was primarily due to a higher number of planned outage days in the cyclical maintenance schedule at the station in the first quarter of 2018.

Regulated – Nuclear Waste Management Segment

	Three Months Ended March 31	
(millions of dollars) (unaudited)	**2018**	**2017**
Other revenue	**33**	27
Operations, maintenance and administration	**33**	29
Accretion on nuclear fixed asset removal and nuclear waste management liabilities	**243**	234
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(210)**	(189)
Loss before interest and income taxes	**(33)**	(47)

Earnings from the segment improved by $14 million in the first quarter of 2018, compared to the same quarter in 2017. The improvement was primarily due to higher earnings from the Nuclear Segregated Funds, partially offset by an increase in accretion expense on the Nuclear Liabilities.

The year-over-year increase in earnings from the Nuclear Segregated Funds was primarily due to the growth rate in the present value of the underlying funding liabilities per the current ONFA reference plan in effect since January 1, 2017, as both the Decommissioning Segregated Fund and the Used Fuel Fund were in an overfunded position since the beginning of 2017 and were not impacted by market returns and the rate of return guaranteed by the Province for a portion of the Used Fuel Segregated Fund. When both funds are in an overfunded position, OPG limits the amount of Nuclear Segregated Funds assets reported on the balance sheet to the present value of the underlying life cycle funding liabilities per the most recently approved ONFA reference plan. Further details on the accounting for the Nuclear Segregated Funds can be found in OPG's 2017 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

Regulated – Hydroelectric Segment

(millions of dollars) (unaudited)	Three Months Ended March 31 2018	2017
Revenue from contracts with customers [1]	**356**	363
Fuel expense	**65**	73
Gross margin	**291**	290
Operations, maintenance and administration	**80**	76
Depreciation and amortization	**36**	34
Other losses	**4**	-
Income before interest and income taxes	**171**	180

[1] During the three months ended March 31, 2018 and 2017, the Regulated – Hydroelectric segment revenue reflected incentive payments of $1 million and $8 million, respectively, related to the OEB-approved hydroelectric incentive mechanism. The mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers. The incentive payments are reduced to remove incentive revenues arising in connection with SBG conditions.

Income before interest and income taxes from the segment decreased by $9 million during the first quarter of 2018, compared to the same quarter in 2017. The decrease in earnings was primarily due to lower hydroelectric incentive mechanism payments, higher OM&A expenses as a result of increased maintenance work programs, and retirement of replaced equipment.

The above factors were partially offset by the increase in revenue of approximately $5 million in the first quarter of 2018 to reflect the impact of new regulated prices approved by the OEB in its December 2017 decision and March 2018 payment amounts order, effective June 1, 2017.

The Hydroelectric Availability for the stations included in the Regulated – Hydroelectric segment was as follows:

	Three Months Ended March 31 2018	2017
Hydroelectric Availability *(%)*	**87.3**	89.5

The Hydroelectric Availability decreased in the first quarter of 2018, compared to the same period in 2017, primarily due to a higher number of unplanned outage days at the eastern and northeastern Ontario regions' regulated hydroelectric stations.

Contracted Generation Portfolio Segment

(millions of dollars) (unaudited)	Three Months Ended March 31 2018	2017
Revenue from contract with customers	**149**	143
Fuel expense	**17**	14
Gross margin	**132**	129
Operations, maintenance and administration	**41**	39
Depreciation and amortization	**20**	19
Accretion on fixed asset removal liabilities	**2**	2
Property taxes	**1**	2
Income from investments subject to significant influence	**(10)**	(10)
Income before interest and income taxes	**78**	77

Income before interest and income taxes from the segment in the first quarter of 2018 was comparable to the same quarter in 2017.

The increase in gross margin of $3 million was primarily due to revenue from the Peter Sutherland Sr. GS that was placed in-service at the end of the first quarter of 2017. The increase in OM&A expenses of $2 million reflected higher station expenditures at the Lennox GS.

The Hydroelectric Availability and the Thermal Equivalent Forced Outage Rate (EFOR) for the Contracted Generation Portfolio segment were as follows:

	Three Months Ended March 31 2018	2017
Hydroelectric Availability *(%)*	**80.1**	83.6
Thermal EFOR *(%)*	**0.3**	12.6

The Hydroelectric Availability decreased in the first quarter of 2018, compared to the same quarter in 2017, primarily due to a higher number of planned outage days as a result of the overhaul and upgrade of Unit 2 of the Little Long GS.

The lower Thermal EFOR in the first quarter of 2018, compared to the same quarter in 2017, was primarily due to a higher number of unplanned outage days at a Lennox GS unit as a result of a transmission outage in the first quarter of 2017.

Fair Hydro Trust Segment

(millions of dollars) (unaudited)	Three Months Ended March 31 2018	2017
Earnings from Fair Hydro Trust	**4**	-
Income before interest and income taxes	**4**	-

The Fair Hydro Trust was established in December 2017 as the financing entity contemplated by the Fair Hydro Act, for the purpose of acquiring Investment Interest from the IESO. In order for the Trust to finance such acquisitions, it incurs senior debt from capital markets and subordinated debt from OPG. The Company consolidates the financial results of the Trust in accordance with US GAAP.

Commented [CEFD2]: We assume this includes the junior subordinated debt?

In March 2018 and April 2018, the Trust purchased Investment Interests from the IESO in the amount of $460 million and $149 million, respectively. Fifty-one percent of the funding requirements for each acquisition totalling approximately $311 million was financed by the Trust through a revolving warehouse facility ranked as senior notes, and the remaining 49 percent totalling approximately $298 million was funded through the following sources:

- the Province provided 44 percent of the funding requirements for each acquisition, or a total of $268 million, through an equity injection in OPG in exchange for approximately 6.1 million non-voting Class A shares at a price of $43.74 per share; and
- OPG provided five percent of the funding requirements, or $30 million.

Earnings from Fair Hydro Trust were $4 million during the first quarter of 2018, primarily due to net interest income for the period.

Refer to the section, *Liquidity and Capital Resources* under the heading, *Financing Activities* for further details on the Trust's financing arrangements.

LIQUIDITY AND CAPITAL RESOURCES

OPG's primary sources of liquidity and capital are funds generated from operations, bank financing, credit facilities provided by the Ontario Electricity Financial Corporation (OEFC), long-term corporate debt, including public debt offerings and notes payable to the OEFC, private placement project financing, and equity issuances. These sources are used for multiple purposes including: to invest in plants and technologies, to undertake major projects, to fund long-term obligations such as contributions to the pension fund and the Nuclear Segregated Funds, to make payments under the OPEB plans, to fund expenditures on Nuclear Liabilities not eligible for reimbursement from the Nuclear Segregated Funds, to service and repay long-term debt, to provide general working capital, and to fund a portion of OPG's purchases of subordinated debt issued by the Fair Hydro Trust.

Commented [JK3]: Equity issuances are specifically for FHT only so would it not be better to indicate as such, vs. the current draft which indicates pooling of funds.

Changes in cash and cash equivalents for the three months ended March 31, 2018 and 2017 were as follows:

(millions of dollars) (unaudited)	Three Months Ended March 31 2018	2017
Cash and cash equivalents, beginning of period [1]	**234**	186
Cash flow provided by operating activities	**226**	168
Cash flow used in investing activities	**(604)**	(413)
Cash flow provided by financing activities	**472**	279
Net increase in cash and cash equivalents	**94**	34
Cash and cash equivalents, end of period [1]	**328**	220

[1] Includes restricted cash.

For a discussion of cash flow provided by operating activities, refer to the details in the section, *Highlights* under the heading, *Overview of Results*.

Investing Activities

Electricity generation is a capital-intensive business. It requires continued investment in plants and technologies to maintain and improve operating performance including asset reliability, safety and environmental performance, to increase the generating capacity of existing stations, and to invest in the development of new generating stations, emerging technologies and other business growth opportunities.

Cash flow used in investing activities during the first quarter of 2018 increased by $191 million compared to the same quarter in 2017. The increase in net cash flow used in investing activities was primarily due to the Trust's acquisition of Investment Interest from the IESO of $460 million in March 2018, partially offset by the receipt of proceeds from the sale of the former Lakeview GS site in March 2018.

Financing Activities

As at March 31, 2018, long-term debt outstanding was $6,896 million, including $263 million due within one year and including the Fair Hydro Trust's senior debt reported on OPG's interim consolidated balance sheets. This included $1,400 million outstanding under OPG's $2,350 million general corporate credit facility agreement with the OEFC that expires on December 31, 2018. The Fair Hydro Trust's senior debt outstanding was $836 million as at March 31, 2018.

During the first quarter of 2018, OPG issued a total of $600 million senior notes payable to OEFC maturing in 2048. The effective and coupon interest rates on these notes ranged from 3.87 percent to 4.00 percent.

In December 2017, the Fair Hydro Trust entered into an $800 million two-year revolving warehouse facility agreement expiring in December 2019. As at March 31, 2018, there were outstanding senior notes of $336 million under this credit facility, $235 million of which was used to finance 51 percent of the Trust's funding requirement for the acquisition of the Investment Interest from the IESO in March 2018 in the amount of $460 million. An additional $76 million was issued under the credit facility in April 2018 to finance fifty-one percent of the Trust's funding requirement for the acquisition of the Investment Interest from the IESO in April 2018 in the amount of $149 million.

In February 2018, the Fair Hydro Trust issued $500 million of senior notes payable with a coupon interest rate of 3.36 percent and an effective interest rate of 3.44 percent, payable semi-annually until maturity in May 2033. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility issued by the Trust in December 2017 to provide a portion of the funding requirement for the Trust's purchase of the first tranche of Investment Interest from the IESO in December 2017.

In April 2018, the Trust issued $400 million of senior notes payable with a coupon interest rate of 3.52 percent and an effective interest rate of 3.60 percent, payable semi-annually until maturity in May 2038. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility after the Investment Interest acquisition in April 2018. Following this repayment, the facility had $12 million outstanding.

BALANCE SHEET HIGHLIGHTS

The following section provides highlights of OPG's unaudited interim consolidated financial position using selected balance sheet data:

(millions of dollars) (unaudited)	As At March 31 2018	As At December 31 2017
Property, plant and equipment – net	**21,515**	21,322
The increase was primarily due to capital expenditures on the Darlington Refurbishment and other projects, partially offset by depreciation expense.		
Nuclear fixed asset removal and nuclear waste management funds *(current and non-current portions)*	**16,909**	16,724
The increase was primarily due to earnings on the Nuclear Segregated Funds, partially offset by reimbursement of eligible expenditures on nuclear fixed asset removal and nuclear waste management activities.		
Regulatory assets and liabilities – net *(current and non-current portions)*	**6,773**	6,637
The increase was primarily due to the continued recognition of net revenue in January and February 2018 in the revenue shortfall account resulting from the OEB's December 2017 decision on new regulated prices and an increase in future income taxes.		
Long-term debt *(current and non-current portions)*	**6,876**	6,319
The increase was primarily due to the issuance of senior notes payable to the OEFC of $600 million and the net issuance of senior notes payable by the Fair Hydro Trust of $232 million. The increase was offset by debt repayments totalling $275 million.		
Fixed asset removal and nuclear waste management liabilities	**20,639**	20,421
The increase was primarily a result of accretion expense representing the increase in the present value liabilities due to the passage of time, partially offset by expenditures on nuclear fixed asset removal and waste management activities		

Off-Balance Sheet Arrangements

In the normal course of operations, OPG engages in a variety of transactions that, under US GAAP, are either not recorded in the Company's interim consolidated financial statements or are recorded in the Company's interim consolidated financial statements using amounts that differ from the full contract amounts. Principal off-balance sheet activities for OPG include guarantees and long-term contracts.

CHANGES IN ACCOUNTING POLICIES AND ESTIMATES

OPG's significant accounting policies are outlined in Note 3 to the audited consolidated financial statements as at and for the year ended December 31, 2017. A discussion of new accounting policies resulting from the adoption of new accounting standards effective January 1, 2018, recent accounting pronouncements, and change in accounting estimates are included in Note 2 to OPG's unaudited interim consolidated financial statements as at and for the three months ended March 31, 2018 under the heading, *Significant Accounting Policies and Estimates*. Disclosure regarding OPG's critical accounting policies is included in OPG's 2017 annual MD&A.

Exemptive Relief for Reporting under US GAAP

In April 2018, OPG received an extension to its exemptive relief from the OSC requirements of section 3.2 of National Instrument 52-107 *Acceptable Accounting Policies and Auditing Standards*. The exemption allows OPG to file consolidated financial statements based on US GAAP, rather than International Financial Reporting Standards (IFRS), without becoming a Securities and Exchange Commission registrant. This exemption replaces the exemptive relief received by OPG from the OSC in February 2014. The exemption will terminate on the earliest of the following:

- January 1, 2024;
- the financial year that commences after OPG ceases to have activities subject to rate regulation; and
- the effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within IFRS specific to entities with rate-regulated activities.

As a result of adopting US GAAP in 2011 as required by the FAA regulation, OPG's plan to convert to IFRS, effective January 1, 2012, was discontinued. OPG had substantively completed the IFRS conversion project when it suspended the project. If a future transition to IFRS for the purposes of OPG's consolidated financial statements is required, conversion work can be effectively restarted with sufficient lead time to evaluate and conclude on changes that occurred subsequent to the decision to suspend the project. OPG continues to monitor the IASB's current standard-setting project related to entities with rate-regulated activities and is evaluating alternatives with respect to the Company's future financial reporting.

RISK MANAGEMENT

The following provides an update to the discussion of the Company's risks and risk management activities included in OPG's 2017 annual MD&A. As such, the disclosure in this section should be read in conjunction with the *Risk Management* section included in the annual MD&A.

Risks to Achieving Operational Excellence

Proposed Asbestos Regulations

The Government of Canada is in the final stages of developing new regulations to prohibit the use of asbestos and products containing asbestos. The new *Prohibition of Asbestos and Asbestos Products Regulations* (the proposed Regulations) are expected to come into effect in 2018. The proposed Regulations would prohibit the import, sale and use of asbestos and the manufacture, import, sale and use of products containing asbestos, with a limited number of exclusions. In addition, the proposed Regulations would not prohibit the use of asbestos and products containing asbestos that were installed prior to the proposed Regulations coming into force.

OPG is assessing the risk and impact of the proposed Regulations, particularly affecting the use of spare parts and the existing inventory which may contain asbestos. A key concern is the application of this regulation within OPG's nuclear fleet, where a significant number of spare parts are known to contain asbestos and may be required to address an emergent condition or to complete a maintenance outage to return the unit to operation. OPG has

provided submissions to Environment and Climate Change Canada and to the CNSC to ensure the issues and potential impacts are understood by the respective regulatory bodies.

Risks to Maintaining Financial Strength

Commodity Markets

Changes in the market price of fuels used to produce electricity can adversely impact OPG's earnings and cash flow from operations.

To manage the risk of unpredictable increases in the price of fuels, the Company has fuel hedging programs, which include using fixed price and indexed contracts.

The percentages hedged of OPG's fuel requirements are shown in the following table. These amounts are based on yearly forecasts of generation and supply mix and, as such, are subject to change as these forecasts are updated.

	2018 [1]	2019	2020
Estimated fuel requirements hedged [2]	79%	75%	77%

[1] Based on actual fuel requirements hedged for the three months ended March 31, 2018 and forecast for the remainder of the year.

[2] Represents the approximate portion of megawatt-hours of expected generation production (and year-end inventory targets) from each type of OPG-operated facility (nuclear, hydroelectric and thermal) for which the Company has entered into contractual arrangements or obligations in order to secure the price of fuel, or which is subject to rate regulation. In the case of hydroelectric generation, this represents the gross revenue charge and water rental charges. Excess fuel inventories (nuclear and thermal) in a given year are attributed to the next year for the purpose of measuring hedge ratios.

Foreign Exchange

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are primarily denominated in or tied to US dollars. To manage this risk, OPG periodically employs various financial instruments such as forwards and other derivative contracts, in accordance with approved risk management policies. As at March 31, 2018, OPG had no foreign exchange contracts outstanding.

Trading

OPG's financial performance can be affected by its trading activities. OPG's electricity trading operations are closely monitored, with total exposures measured and reported to senior management on a daily basis. The main metric used to measure the financial risk of trading activity is Value at Risk (VaR). VaR is defined as a probabilistic maximum potential future loss expressed in monetary terms for a portfolio based on normal market conditions over a set period of time. For the first quarter of 2018, the VaR utilization ranged between nil and $1 million.

Credit

The Company's credit risk exposure is a function of its electricity sales, trading and hedging activities, treasury activities including investing and commercial transactions with various suppliers of goods and services. OPG's credit exposure relating to energy markets transactions as at March 31, 2018 was $449 million, including $436 million to the IESO. OPG's credit risk exposure relating to electricity sales is considered low as the majority of sales are through the IESO-administered spot market. The IESO oversees the credit worthiness of all market participants. In accordance with the IESO's prudential support requirements, market participants are required to provide collateral to cover funds that they might owe to the market. Of the $13 million remaining exposure as at March 31, 2018, over 95 percent was with investment grade counterparties. Other major components of OPG's credit risk exposure include those associated with vendors that are contracted to provide services or products. OPG manages its exposure to various suppliers or counterparties by evaluating their financial condition and ensuring that the Company holds appropriate collateral or other forms of security.

RELATED PARTY TRANSACTIONS

Given that the Province owns all of the outstanding common shares and Class A shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One Limited, the IESO, and the OEFC. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As a wholly owned government business enterprise of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions are summarized below:

	Three Months Ended March 31			
	2018		2017	
(millions of dollars) (unaudited)	**Income**	**Expense**	**Income**	**Expense**
Hydro One				
Electricity sales	**4**	**-**	4	-
Services	**-**	**5**	1	5
Dividends	**2**	**-**	2	-
Province of Ontario				
Change in Decommissioning Segregated Fund amount due to Province [1]	**-**	**(2)**	-	163
Change in Used Fuel Segregated Fund amount due to Province [1]	**-**	**(21)**	-	217
Hydroelectric gross revenue charge	**-**	**28**	-	28
ONFA guarantee fee	**-**	**-**	-	2
OEFC				
Hydroelectric gross revenue charge	**-**	**38**	-	38
Interest expense on long-term notes	**-**	**37**	-	41
Income taxes, net of investment tax credits	**-**	**53**	-	12
IESO				
Electricity related revenue	**1,232**	**-**	1,067	-
Earnings from Fair Hydro Trust	**4**	**-**	-	-
	1,242	**138**	1,074	506

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at March 31, 2018 and December 31, 2017, the Nuclear Segregated Funds were reported net of amounts due to the Province of $4,439 million and $4,462 million, respectively.

The receivables, financing receivables, equity securities, payable and long-term debt balances between OPG and its related parties are summarized below:

(millions of dollars) (unaudited)	**March 31 2018**	**December 31 2017**
Receivables from related parties		
Hydro One	**1**	1
IESO – Electricity related receivables	**436**	354
IESO – Fair Hydro Trust [1]	**7**	7
OEFC	**2**	-
PEC	**4**	4
Province of Ontario	**2**	3
Financing receivables		
IESO – Fair Hydro Trust	**1,639**	1,179
Equity securities		
Hydro One shares	**170**	188
Accounts payable and accrued charges		
Hydro One	**-**	1
OEFC	**35**	52
Province of Ontario	**11**	9
IESO – Electricity related payables	**1**	5
IESO – Fair Hydro Trust	**1**	3
Long-term debt (including current portion)		
Notes payable to OEFC	**3,520**	3,195

[1] Balance consists of unbilled cost recovery revenue.

OPG may hold Province of Ontario bonds and treasury bills in the Nuclear Segregated Funds and the OPG registered pension fund. As at March 31, 2018, the Nuclear Segregated Funds held $1,319 million of Province of Ontario bonds (December 31, 2017 – $1,502 million) and $1 million of Province of Ontario treasury bills (December 31, 2017 – $9 million). As at March 31, 2018, the registered pension fund did not hold Province of Ontario treasury bills (December 31, 2017 – $1 million). These Province of Ontario bonds and treasury bills are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

In March and April 2018, the Fair Hydro Trust purchased Investment Interests from the IESO for an exchange amount of $460 million and $149 million, respectively, which have been classified as financing receivables on OPG's unaudited interim consolidated balance sheets. The transactions were settled in cash using proceeds from the Trust's issuance of senior debt to third parties and subordinated debt to OPG. Pursuant to the general regulation of the Fair Hydro Act, the IESO is required to pay and remit carrying costs of the Trust, excluding repayment of principal on any debt obligations, up to July 31, 2021. Commencing May 1, 2021, residential, farm, small businesses and other eligible customers will be invoiced by their local distribution company for the Clean Energy Adjustment to pay the carrying costs of the Trust and principal on debt. These funds will be remitted to the Trust through the IESO and will be used to settle all funding and other related expenses of the Trust that underlie the financing receivables.

Commented [GH4]: The Fair Hydro Trust purchase amount, $1,639M, provided in the table above is from the purchases in December 2017 and March 2018. So I think this should be clarified here.

As at March 31, 2018, OPG's unaudited interim consolidated balance sheets included approximately $7 million of unbilled cost recovery revenue from the IESO (December 31, 2017 – $7 million), primarily for OPG's general fee for 2017 as the Financial Services Manager under the Act relating to incurred third-party and certain direct labour costs.

The Province has provided a limited guarantee to specified creditors of the Fair Hydro Trust. The limited guarantee would be triggered in the event that the Trust's ability to receive amounts in respect of its Investment Interest to pay for certain funding obligations is adversely affected due to one or more of the following: the Province changes the Fair Hydro Act or any other legislation or regulation; a significant change in Ontario's electricity market undertaken by the Province; or a court declares that the Act is invalid or unconstitutional.

INTERNAL CONTROLS OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

The Company maintains a comprehensive system of policies, procedures, and processes that represents its framework for internal controls over financial reporting and for its disclosure controls and procedures (together, ICOFR). There were no changes in the Company's internal control system during the current interim period that has or is reasonably likely to have a material impact to the ICOFR.

QUARTERLY FINANCIAL HIGHLIGHTS

The following tables set out selected annual financial from OPG's unaudited interim consolidated financial statements for each of the eight most recently completed quarters.

(millions of dollars – except where noted) *(unaudited)*	**March 31 2018**	**December 31 2017**	**September 30 2017**	**June 30 2017**
Revenue	**1,407**	**1,619**	**1,217**	**1,146**
Net income	**539**	**366**	**140**	**307**
Less: Net income attributable to non-controlling interest	**4**	**4**	**9**	**4**
Net income attributable to the Shareholder	**535**	**362**	**131**	**303**
Earnings per share, attributable to the Shareholder *(dollars)*	**$1.99**	**$1.41**	**$0.51**	**$1.18**

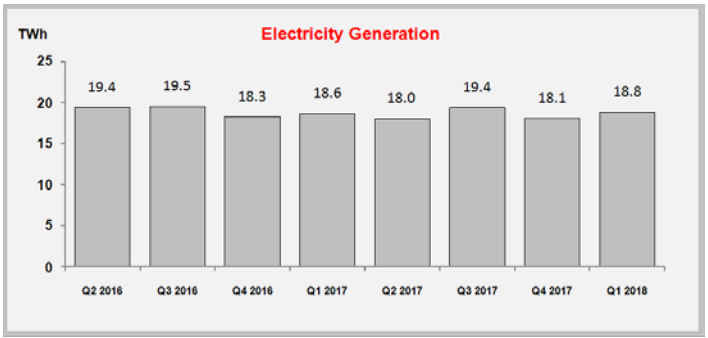
(millions of dollars – except where noted) *(unaudited)*	**March 31 2017**	**December 31 2016**	**September 30 2016**	**June 30 2016**
Revenue	1,176	1,388	1,400	1,387
Net income (loss)	68	(8)	198	135
Less: Net income attributable to non-controlling interest	4	5	4	3
Net income (loss) attributable to the Shareholder	64	(13)	194	132
Earnings per share, attributable to the Shareholder *(dollars)*	$0.25	($0.05)	$0.76	$0.51

Trends

OPG's quarterly results are affected by changes in grid-supplied electricity demand, primarily resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. Weather conditions affect water flows, electricity demand, and prevalence of SBG conditions. Historically, OPG's revenues have been higher in the first quarter of a fiscal year as a result of winter heating demands and in the third quarter due to air conditioning and cooling demands. The financial impact of forgone production due to SBG conditions at the regulated hydroelectric stations and the financial impact of differences between forecast water flows reflected in OEB-approved regulated prices and the actual water flows are mitigated by regulatory accounts authorized by the OEB.

The outage cycle at each of OPG's nuclear generating stations determines the number and frequency of planned outages in a particular year. The outage cycle is designed to ensure the continued safe and reliable long-term operations of the plant and its compliance with CNSC regulatory requirements. The frequency of planned outages under the outage cycle may result in year-over-year variability in OPG's operating results, including the impact on revenue and OM&A expenses. In addition, the timing of planned outages at a nuclear generating station during the year can cause variability in year-over-year operating results for partial periods of a fiscal year but is not a significant driver of variability for full fiscal year results.

OPG's financial results are also affected by earnings on the Nuclear Segregated Funds, net of the impact of the Bruce Lease Net Revenues Variance Account. The volatility of earnings on the Nuclear Segregated Funds is mitigated by their funded status.



SUPPLEMENTARY NON-GAAP FINANCIAL MEASURES

In addition to providing net income and other financial information in accordance with US GAAP, certain non-GAAP financial measures are also presented in OPG's MD&A. These non-GAAP measures do not have any standardized meaning prescribed by US GAAP, and therefore, may not be comparable to similar measures presented by other issuers. OPG utilizes these measures to make operating decisions and assess performance. Readers of the MD&A would utilize these measures in assessing the Company's financial performance from ongoing operations. The Company believes that these indicators are important since they provide additional information about OPG's performance, facilitate comparison of results over different periods, and present measures consistent with the Company's strategies to provide value to the Shareholder, improve cost performance, and ensure availability of cost effective funding. These non-GAAP financial measures have not been presented as an alternative to net income or any other measure in accordance with US GAAP, but as indicators of operating performance.

The definitions of the non-GAAP financial measures are as follows:

(1) ROE Excluding AOCI is defined as net income attributable to the Shareholder divided by average equity attributable to the Shareholder excluding AOCI, for the period.

ROE Excluding AOCI is measured over a 12-month period and is calculated as follows:

(millions of dollars – except where noted) (unaudited)	Twelve Months Ended March 31 2018	December 31 2017
ROE Excluding AOCI		
Net income attributable to the Shareholder	**1,331**	860
Divided by: Average equity attributable to the Shareholder, excluding AOCI	**11,602**	11,351
ROE Excluding AOCI *(percent)*	**11.5**	7.6

(2) Enterprise Total Generating Cost per MWh is used to measure OPG's overall organizational cost performance. Enterprise TGC per MWh is defined as OM&A expenses (excluding the Darlington Refurbishment project and other generation development project costs, the impact of regulatory accounts, and expenses ancillary to OPG's electricity generation business), fuel expense for OPG-operated stations including hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory accounts), and capital expenditures (excluding the Darlington Refurbishment project and other generation development projects) incurred during the period, divided by total electricity generation from OPG-operated generating stations plus electricity generation forgone due to SBG conditions during the period.

	Three Months Ended March 31	
(millions of dollars – except where noted) (unaudited)	**2018**	**2017**
Enterprise TGC		
Total OM&A expenses	**722**	708
Total fuel expense	**155**	155
Total capital expenditures	**359**	408
Less: Darlington Refurbishment capital and OM&A costs	**(259)**	(309)
Less: Other generation development project capital and OM&A costs	**(17)**	(17)
Add (Less): OM&A and fuel expenses deferred in (refundable through) regulatory accounts	**26**	(11)
Less: Nuclear fuel expense for non OPG-operated stations	**(15)**	(13)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**6**	11
Less: OM&A expenses ancillary to electricity generation business	**(4)**	(5)
Other adjustments	**-**	(2)
	973	925
Adjusted electricity generation *(TWh)*		
Total OPG electricity generation	**18.8**	18.6
Adjust for electricity generation forgone due to SBG conditions and OPG's share of electricity generation from co-owned facilities	**0.7**	0.7
	19.5	19.3
Enterprise TGC per MWh *($/MWh)* [1]	**49.84**	**47.86**

[1] Amounts may not calculate due to rounding.

(3) Nuclear Total Generating Cost per MWh is used to measure the cost performance of OPG's nuclear generating assets. Nuclear TGC per MWh is defined as OM&A expenses of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs, the impact of regulatory accounts, and expenses ancillary to the nuclear electricity generation business), nuclear fuel expense for OPG-operated stations (excluding the impact of regulatory accounts), and capital expenditures of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs) incurred during the period, divided by nuclear electricity generation for the period.

(millions of dollars – except where noted) (unaudited)	Three Months Ended March 31 **2018**	**2017**
Nuclear TGC		
Regulated – Nuclear Generation OM&A expenses	**604**	589
Regulated – Nuclear Generation fuel expense	**73**	68
Regulated – Nuclear Generation capital expenditures	**313**	366
Less: Darlington Refurbishment capital and OM&A costs	**(259)**	(309)
Add (Less): Regulated – Nuclear Generation OM&A and fuel expenses deferred in (refundable through) regulatory accounts	**24**	(2)
Less: Nuclear fuel expense for non OPG-operated stations	**(15)**	(13)
Less: Regulated – Nuclear Generation OM&A expenses ancillary to electricity generation business	**(2)**	(1)
Other adjustments	**(1)**	-
	737	698
Nuclear electricity generation *(TWh)*	**10.4**	10.0
Nuclear TGC per MWh *($/MWh)* [1]	**70.90**	69.87

[1] Amounts may not calculate due to rounding.

(4) Hydroelectric Total Generating Cost per MWh is used to measure the cost performance of OPG's hydroelectric generating assets. Hydroelectric TGC per MWh is defined as OM&A expenses of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding generation development project costs, the impact of regulatory accounts, and expenses ancillary to the hydroelectric electricity generation business), hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory accounts), and capital expenditures of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding expenditures related to the Peter Sutherland Sr. GS, Ranney Falls GS, and other hydroelectric generation development projects) incurred during the period, divided by total hydroelectric electricity generation plus hydroelectric electricity generation forgone due to SBG conditions during the period. OPG reports hydroelectric gross revenue charge and water rental payments as fuel expense.

	Three Months Ended March 31	
(millions of dollars – except where noted) (unaudited)	**2018**	**2017**
Hydroelectric TGC		
Regulated – Hydroelectric OM&A expenses	**80**	76
Regulated – Hydroelectric fuel expense	**65**	73
Contracted Generation Portfolio OM&A expenses	**41**	39
Contracted Generation Portfolio fuel expense	**17**	14
Regulated – Hydroelectric and Contracted Generation Portfolio capital expenditures	**36**	37
Less: Regulated – Hydroelectric and Contracted Generation Portfolio generation development project capital and OM&A costs	**(18)**	(16)
Less: Thermal OM&A and fuel expenses and capital expenditures in the Contracted Generation Portfolio	**(44)**	(39)
Add (Less): Regulated – Hydroelectric OM&A and fuel expenses deferred in (refundable through) regulatory accounts	**2**	(9)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**6**	11
Other adjustments	**-**	(1)
	185	185
Adjusted hydroelectric electricity generation *(TWh)*		
Regulated – Hydroelectric electricity generation	**7.7**	8.0
Contracted Generation Portfolio electricity generation	**0.7**	0.6
Adjust for hydroelectric electricity generation forgone due to SBG conditions and non-hydroelectric electricity generation of the Contracted Generation Portfolio, including OPG's share of electricity generation from co-owned facilities	**0.7**	0.7
	9.1	9.3
Hydroelectric TGC per MWh *($/MWh)* [1]	**20.42**	19.79

[1] Amounts may not calculate due to rounding.

(5) Gross margin is defined as revenue less fuel expense**.**

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ONTARIO POWER GENERATION INC.

INTERIM CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

MARCH 31, 2018

[DRAFT]

INTERIM CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

Three Months Ended March 31 *(millions of dollars except where noted)*	**2018**	**2017**
Revenue	**1,407**	1,176
Fuel expense	**155**	155
Gross margin	**1,252**	1,021
Operations, maintenance and administration	**722**	708
Depreciation and amortization	**186**	167
Accretion on fixed asset removal and nuclear waste management liabilities	**247**	238
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(210)**	(189)
Earnings from Fair Hydro Trust *(Note 15)*	**(4)**	-
Income from investments subject to significant influence	**(10)**	(10)
Property taxes	**9**	11
	940	925
Income before other gains, interest and income taxes	**312**	96
Other gains *(Note 18)*	**259**	3
Income before interest and income taxes	**571**	99
Net interest expense *(Note 5)*	**19**	19
Income before income taxes	**552**	80
Income tax expense *(Note 19)*	**13**	12
Net income	**539**	68
Net income attributable to the Shareholder	**535**	64
Net income attributable to non-controlling interest	**4**	4
Basic and diluted earnings per share *(dollars) (Note 13)*	**1.99**	0.25

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

Three Months Ended March 31 *(millions of dollars)*	**2018**	**2017**
Net income	**539**	68
Other comprehensive income, net of income taxes *(Note 8)*		
Reclassification to income of amounts related to pension and other post-employment benefits [1]	**3**	3
Reclassification to income of losses on derivatives designated as cash flow hedges [2]	**4**	4
Unrealized gain on available-for-sale securities [3]	**-**	5
Other comprehensive income for the period	**7**	12
Comprehensive income	**546**	80
Comprehensive income attributable to the Shareholder	**542**	76
Comprehensive income attributable to non-controlling interest	**4**	4

[1] Net of income tax expenses of $1 million for each of March 31, 2018 and 2017.

[2] Net of income tax expenses of $1 million for each of March 31, 2018 and 2017.

[3] Net of income tax expense of nil and $1 million for March 31, 2018 and 2017, respectively.

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

Three Months Ended March 31 *(millions of dollars)*	2018	2017
Operating activities		
Net income	**539**	68
Adjust for non-cash items:		
Depreciation and amortization	**186**	167
Accretion on fixed asset removal and nuclear waste management liabilities	**247**	238
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(210)**	(189)
Pension and other post-employment benefit costs *(Note 9)*	**99**	113
Deferred income taxes	**(6)**	11
Regulatory assets and liabilities	**(141)**	(28)
Other gains	**(257)**	(1)
Other	**(13)**	(4)
Reimbursement of eligible expenditures on nuclear fixed asset removal and nuclear waste management	**23**	22
Contributions to pension funds and expenditures on other post-employment benefits and supplementary pension plans	**(79)**	(88)
Distributions received from investments subject to significant influence	**12**	14
Net changes to other long-term assets and liabilities	**(20)**	(38)
Net changes to non-cash working capital balances *(Note 16)*	**(154)**	(117)
Cash flow provided by operating activities	**226**	168
Investing activities		
Acquisition of Fair Hydro Trust financing receivables	**(460)**	-
Proceeds from deposit note	**-**	45
Net proceeds from sale of property, plant and equipment	**273**	-
Investment in property, plant and equipment and intangible assets	**(417)**	(458)
Cash flow used in investing activities	**(604)**	(413)
Financing activities		
Issuance of Class A shares *(Note 12)*	**202**	-
Issuance of OPG long-term debt *(Note 5)*	**600**	200
Repayment of OPG long-term debt	**(275)**	(50)
Issuance of Fair Hydro Trust long-term debt *(Note 5)*	**732**	-
Repayment of Fair Hydro Trust long-term debt	**(500)**	
Distribution to non-controlling interest	**(4)**	(4)
Dividend to the Province's Consolidated Revenue Fund *(Note 17)*	**(283)**	-
Issuance of short-term debt	**1,295**	589
Repayment of short-term debt	**(1,295)**	(456)
Cash flow provided by financing activities	**472**	279
Net increase in cash, cash equivalents and restricted cash	**94**	34
Cash, cash equivalents and restricted cash, beginning of period	**234**	186
Cash, cash equivalents and restricted cash, end of period	**328**	220

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

(millions of dollars)	March 31 2018	December 31 2017
Assets		
Current assets		
Cash, cash equivalents and restricted cash *(Note 3)*	**328**	234
Equity securities	**170**	188
Receivables from related parties	**452**	369
Nuclear fixed asset removal and nuclear waste management funds	**23**	23
Fuel inventory	**299**	309
Materials and supplies	**96**	103
Regulatory assets *(Note 4)*	**259**	-
Prepaid expenses	**196**	192
Income tax recoverable	**10**	-
Other current assets	**98**	146
	1,931	1,564
Property, plant and equipment	**30,292**	29,950
Less: accumulated depreciation	**8,777**	8,628
	21,515	21,322
Intangible assets	**576**	565
Less: accumulated amortization	**440**	432
	136	133
Other assets		
Nuclear fixed asset removal and nuclear waste management funds	**16,886**	16,701
Financing receivables	**1,639**	1,179
Long-term materials and supplies	**352**	355
Regulatory assets *(Note 4)*	**7,107**	7,231
Investments subject to significant influence	**307**	309
Other long-term assets	**32**	28
	26,323	25,803
	49,905	48,822

INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

(millions of dollars)	March 31 2018	December 31 2017
Liabilities		
Current liabilities		
Accounts payable and accrued charges	**1,119**	1,228
Short-term debt *(Note 6)*	**260**	260
Deferred revenue due within one year	**9**	12
Long-term debt due within one year *(Note 5)*	**263**	398
Income taxes payable	**-**	80
Regulatory liabilities *(Note 4)*	**19**	-
	1,670	1,978
Long-term debt *(Note 5)*	**6,613**	5,921
Other liabilities		
Fixed asset removal and nuclear waste management liabilities *(Note 7)*	**20,639**	20,421
Pension liabilities	**3,389**	3,423
Other post-employment benefit liabilities	**3,118**	3,092
Long-term accounts payable and accrued charges	**252**	252
Deferred revenue	**368**	351
Deferred income taxes	**917**	879
Regulatory liabilities *(Note 4)*	**574**	594
	29,257	29,012
Equity		
Common shares *(Note 12)*	**5,126**	5,126
Class A shares *(Note 12)*	**721**	519
Retained earnings	**6,632**	6,396
Accumulated other comprehensive loss *(Note 8)*	**(279)**	(295)
Equity attributable to the Shareholder	**12,200**	11,746
Equity attributable to non-controlling interest	**165**	165
Total equity	**12,365**	11,911
	49,905	48,822

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY

Three Months Ended March 31 *(millions of dollars)*	**2018**	**2017**
Common shares *(Note 12)*	**5,126**	5,126
Class A shares *(Note 12)*		
Balance at beginning of period	**519**	-
Issuance of Class A shares	**202**	-
Balance at end of period	**721**	-
Retained earnings		
Balance at beginning of period	**6,396**	5,534
Reclassification of cumulative unrealized losses on available-for-sale securities to opening retained earnings *(Note 2)*	**(9)**	-
Adjustment to recognize income tax effects of intercompany transfer of assets to opening retained earnings *(Note 2)*	**(7)**	-
	6,380	5,534
Net income attributable to the Shareholder	**535**	64
Dividend to the Province's Consolidated Revenue Fund *(Note 17)*	**(283)**	-
Balance at end of period	**6,632**	5,598
Accumulated other comprehensive loss, net of income taxes		
Balance at beginning of period	**(295)**	(295)
Other comprehensive income	**7**	12
Reclassification of cumulative unrealized losses on available-for-sale securities *(Note 2)*	**9**	-
Balance at end of period	**(279)**	(283)
Equity attributable to the Shareholder	**12,200**	10,441
Equity attributable to non-controlling interest		
Balance at beginning of period	**165**	143
Distribution to non-controlling interest	**(4)**	(4)
Income attributable to non-controlling interest	**4**	4
Balance at end of period	**165**	143
Total equity	**12,365**	10,584

See accompanying notes to the interim consolidated financial statements

NOTES TO THE INTERIM CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

For the three months ended March 31, 2018 and 2017

1. BASIS OF PRESENTATION

These interim consolidated financial statements for the three months ended March 31, 2018 and 2017 include the accounts of Ontario Power Generation Inc. (OPG or the Company) and its subsidiaries. The Company consolidates its interest in entities over which it is able to exercise control and attributes the results to its sole shareholder, the Province of Ontario (Province). Interests owned by other parties are reflected as non-controlling interest. These interim consolidated financial statements have been prepared and presented in accordance with United States generally accepted accounting principles (US GAAP). These interim consolidated financial statements do not contain all of the disclosures required by US GAAP for annual financial statements. Accordingly, they should be read in conjunction with the annual consolidated financial statements of the Company as at and for the year ended December 31, 2017. All dollar amounts are presented in Canadian dollars.

As required by *Ontario Regulation 395/11,* as amended, under the *Financial Administration Act* (Ontario), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. Since January 1, 2012, OPG also has received exemptive relief from the Ontario Securities Commission (OSC) from the requirements of section 3.2 of National Instrument 52-107, *Acceptable Accounting Policies and Auditing Standards*. The exemption allows OPG to file consolidated financial statements based on US GAAP, rather than International Financial Reporting Standards (IFRS), without becoming a US Securities and Exchange Commission registrant.

In April 2018, OPG received an extension to its previous exemptive relief from the OSC. The exemptive relief will now terminate on the earliest of the following:

- January 1, 2024
- The financial year that commences after OPG ceases to have activities subject to rate regulation
- The effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within IFRS specific to entities with rate regulated activities.

All dollar amounts are presented in Canadian dollars, unless otherwise noted. Certain 2017 comparative amounts have been reclassified from financial statements previously presented to conform to the 2018 consolidated financial statement presentation.

Use of Management Estimates

The preparation of consolidated financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the interim consolidated financial statements, and the reported amounts of revenues and expenses for the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in the period incurred. Significant estimates are included in the determination of pension and other post-employment benefit (OPEB) balances, asset retirement obligations and associated asset retirement costs capitalized as part of property, plant and equipment, income taxes (including deferred income taxes), contingencies, regulatory assets and liabilities, valuation of derivative instruments and investments in segregated funds, depreciation and amortization expenses, and inventories. Actual results may differ significantly from these estimates.

2. SIGNIFICANT ACCOUNTING POLICIES AND ESTIMATES

New Accounting Standards Effective in 2018

Revenue from Contracts with Customers

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09, *Revenue from Contracts with Customers (Topic 606)*, which supersedes nearly all existing revenue recognition guidance, including industry-specific guidance, under US GAAP. The core principle of Topic 606 is to recognize revenues when promised goods or services are transferred to customers in an amount that reflects the consideration to which an entity expects to be entitled for those goods or services.

Effective January 1, 2018, OPG adopted Topic 606, including relevant practical expedients, to recognize its revenue, utilizing the modified retrospective approach to complete the transition and identified no material differences in timing or amount of revenue recognition. The adoption of Topic 606 has required OPG to amend its accounting policy with respect to revenue recognition, as described below:

Revenue from Contracts with Customers – Regulated Generation

Energy revenue generated from OPG's regulated facilities is based on regulated prices determined by the OEB that include base regulated prices and, as applicable, rate riders for the recovery or repayment of approved variance and deferral account balances. The revenues from the regulated hydroelectric facilities are also subject to the OEB-approved hydroelectric incentive mechanism. This mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers.

All of OPG's electricity generation is offered into the real-time energy spot market administered by the IESO. For electricity generated from its regulated nuclear and regulated hydroelectric facilities, OPG receives payment from the IESO on a monthly basis. OPG has determined that its performance obligation to supply electricity generated from its regulated nuclear and regulated hydroelectric facilities is satisfied over time. The Company utilizes the output method under Topic 606 to recognize revenue by applying the relevant base regulated price and rate riders as applicable to each MWh of electricity generated and metered to the IESO. This methodology appropriately reflects the real-time nature of electricity generation and the underlying performance obligation, of which no portion remains unsatisfied at the end of the applicable reporting period. OPG's receivables in connection with electricity generated from its regulated nuclear and regulated hydroelectric facilities are part of the Company's electricity related receivables from the IESO. For further discussion, refer to Note 10.

Base regulated prices in effect during the period January 1, 2016 to May 31, 2017 were established by the OEB's November 2014 decision and December 2014 order, using a forecast cost-of-service rate-setting methodology based on the OEB-approved revenue requirements, taking into account the OEB-approved forecasts of production and operating costs for the regulated facilities for 2014 and 2015 and a return on rate base. Rate base is a regulatory construct that, for OPG, represents the average net level of investment in regulated fixed and intangible assets in-service and an allowance for working capital.

On December 28, 2017, the OEB issued its decision on OPG's May 2016 application for new regulated prices for the 2017−2021 period. The OEB set an effective date for the new regulated prices of June 1, 2017. The decision included the OEB's findings with respect to ratemaking methodologies for the prescribed facilities, the basis for inputs into the hydroelectric incentive ratemaking formula, and the elements of the nuclear revenue requirement.

Pursuant to the decision, the new base regulated prices will be determined on an incentive ratemaking methodology for the hydroelectric facilities and under a custom incentive regulation framework for the nuclear facilities. For the hydroelectric facilities, the new base regulated prices for each of the years 2017 to 2021 will be determined using a formula that annually escalates the previously approved regulated prices, subject to some adjustments, based on an

industry-specific weighted inflation factor less a stretch factor adjustment. For the nuclear facilities, the new base regulated prices will be determined under a rate smoothing approach that defers a portion of the approved nuclear revenue requirement for future collection in the Rate Smoothing Deferral Account authorized by the OEB pursuant to Ontario Regulation 53/05, with the objective of making changes in OPG's production-weighted average nuclear and hydroelectric regulated price more stable year over year. The nuclear revenue requirement for each of the years 2017 to 2021 is based on the OEB-approved forecast of operating costs as reduced by a stretch factor amount, and a return on rate base. The difference between the non-deferred portion of the nuclear revenue requirement calculated by multiplying the nuclear base regulated price determined under rate smoothing and the OEB-approved forecast of OPG's nuclear electricity production for the year, and the total approved nuclear revenue requirement for that year determines the portion of the revenue requirement deferred for future collection in the Rate Smoothing Deferral Account. Amounts recorded in the Rate Smoothing Deferral Account are recognized as adjustments to revenue.

In March 2018, the OEB issued the final payment amounts order in connection with the decision. The payment amounts order requires OPG to implement a payment amount smoothing approach whereby no additions are made to the Rate Smoothing Deferral Account in 2017 or 2018. See Note 4 for further information on the OEB's decision on OPG's May 2016 application for new regulated prices and the Rate Smoothing Deferral Account.

Revenue from Contracts with Customers – Non-regulated Generation

The electricity generation from OPG's non-regulated assets receives the Ontario electricity spot market price, except where an energy supply agreement (ESA) with the IESO or another contractual agreement is in place. The IESO is the counterparty to all ESAs that are currently entered into. As at December 31, 2017, most of OPG's operating non-regulated generating assets are subject to an ESA. As permitted by the practical expedient within Topic 606, revenue from the generating stations subject to an ESA is recognized in the amount that OPG has a right to invoice on a monthly basis to the IESO as the Company satisfies its performance obligation in accordance with the terms of the agreement to supply energy and capacity via the applicable facilities. No portion of OPG's performance obligation remains unsatisfied at the end of any applicable reporting period. OPG estimates revenues for variable or conditional amounts within each ESA using a most likely amount approach on a contract-by-contract basis. Variable consideration within each ESA is included in revenue only to the extent that it is highly probable that the amount will not be subject to significant reversal when the uncertainty is resolved. OPG's receivables in connection with electricity generated from its non-regulated assets are part of the Company's electricity related receivables from the IESO. For further discussion, refer to Note 10.

Revenue from Contracts with Customers – Non-Generation

OPG also sells into, and purchases from, interconnected markets of other provinces and the northeast and mid-west regions of the US. All contracts that are not designated as hedges are recorded on the consolidated balance sheets at market value, with gains or losses recorded in the consolidated statements of income. Gains and losses on energy trading contracts (including those to be physically settled) are recorded on a net basis in the consolidated statements of income.

OPG also derives non-energy revenue under the terms it associated, non-lease agreements with Bruce Power L.P. (Bruce Power) related to the Bruce nuclear generating stations. The associated agreements include revenue from heavy water sales, detritiation services and waste management services.

In addition, non-energy revenue includes isotope sales and other service revenues. Revenues from these activities are recognized as the respective performance obligations are satisfied, in accordance with the terms stipulated in the respective contracts.

Revenue Recognition – Lease revenue

The minimum lease payments stemming from OPG's lease arrangement with Bruce Power are recognized in revenue on a straight-line basis over the term of the lease. Similarly, revenue from real estate rentals are recognized over the term of the lease as the Company renders the requisite services outlined in the respective contracts.

Recognition and Measurement of Financial Assets and Financial Liabilities

In January 2016, the FASB issued ASU No. 2016-01, *Financial Instruments – Overall: Recognition and Measurement of Financial Assets and Financial Liabilities*. Under the updated guidance, entities are required to measure equity investments at fair value and recognize any changes in fair value in net income. Effective January 1, 2018, the available-for-sale (AFS) classification for securities is no longer available. Any unrealized gains and losses related to equity securities is now recognized in net income instead of OCI. Any unrealized gains and losses for AFS securities reported by OPG in AOCI as at December 31, 2017 was reclassified to retained earnings as of January 1, 2018.

The adoption of ASU No. 2016-01 resulted in an adjustment to transfer cumulative losses of $9 million on OPG's equity securities from AOCI to opening retained earnings on January 1, 2018. There are no other significant differences to OPG's consolidated financial statements upon adoption of the new standard, other than to replace the accounting policy for available-for-sale securities with a new policy for holdings of equity securities as described below.

Equity securities

Equity securities held by OPG are measured at fair value, with gains and losses due to changes in fair value recognized within other gains and losses in the consolidated statement of income. Related transaction costs are expensed as incurred, and dividend income is included in net income in the period in which dividends are declared. Equity securities are initially measured at the transaction price.

Restricted Cash

In November 2016, the FASB issued ASU No. 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash (a consensus of the FASB Emerging Issues Task Force)*, which clarifies how entities should present restricted cash and restricted cash equivalents in the statement of cash flows. The guidance is applied retrospectively and is effective for OPG's 2018 fiscal year, including interim periods. The changes in disclosures required under this update are reflected in the interim consolidated statements of cash flows and Note 3.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost

In March 2017, the FASB issued ASU No. 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. Under the new guidance, employers that sponsor defined benefit plans for pensions and/or other postretirement benefits are required to present the service cost component of net periodic benefit cost in the same statement of income line item as other employee compensation costs arising from services rendered during the period. The other components of the net periodic benefit cost are to be presented separately from the line item that includes the service cost and outside of any subtotal of income from operations, if such a subtotal is presented. In addition, the new guidance requires that only the service cost component of net benefit cost be eligible for capitalization.

Effective January 1, 2018, OPG adopted the provisions of Topic 715. Adoption of Topic 715 does not have a material impact on OPG's consolidated financial statements, as OPG already capitalized only the service cost component of postretirement benefits costs prior to the adoption of the new guidance. Additionally, OPG previously included the service cost component of postretirement benefit costs with other compensation costs within OM&A expenses in the consolidated statements of income, and did not show a subtotal of income from operations prior to the adoption of the new guidance. As such, the new guidance does not affect the presentation of OPG's consolidated financial

statements nor result in any significant changes in OPG's accounting policies.

Intra-Entity Transfers of Assets Other than Inventory

The FASB issued ASU 2016-16, Income Taxes (Topic 740): *Intra-Entity Transfers of Assets Other than Inventory*, in October 2016 to amend existing guidance with respect to accounting for the income tax effects of intra-entity asset transfers. Effective January 1, 2018, entities are required to recognize the income tax effects of all intra-entity asset transfers, with the exception of inventory, as soon as the transfer occurs. Previously, entities were required to defer recognition of such income tax effects until the asset was sold to a third party.

The update is effective for OPG beginning January 1, 2018 and is required to be applied on a modified retrospective basis. On adoption of the update, the Company recorded an adjustment to opening retained earnings of $7 million to reflect the associated deferred income tax liability resulting from the cumulative effect of OPG's transfer of assets, other than inventory, to the UMH Energy Limited Partnership and the Lower Mattagami Energy Limited Partnership in prior years. Adoption of this update resulted in no other material impacts to the Company's consolidated financial statements, other than an addition to OPG's accounting policy for income taxes as described below.

Income taxes – Intra-entity transfers of non-inventory assets

The income tax impact of any intra-entity transfers of non-inventory assets is recognized upon the occurrence of the transfer.

Recent Accounting Pronouncements Not Yet Adopted

Lease Accounting

In February 2016, the FASB issued ASU No. 2016-02, *Leases* (Topic 842) to replace existing lease accounting guidance under Topic 840. The update includes comprehensive changes to existing guidance, particularly for lessees, and aims to increase transparency and comparability among organizations by requiring the recognition of lease assets and lease liabilities on the balance sheet. The standard is effective for annual periods beginning after December 15, 2018, including interim periods within that year.

Under the current guidance related to the new leasing standard, entities are required to use a modified retrospective approach for leases that exist, or are entered into, after the beginning of the earliest comparative period presented in the financial statements of the period of adoption. Under this method, Topic 842 would effectively be implemented by recognizing any adjustments stemming from the transition as of the beginning of the earliest comparative period presented in the entity's financial statements. Full retrospective application is prohibited. In January 2018, the FASB issued a proposed ASU (ASU 2018-200) wherein entities would be able to utilize an additional optional transition method of recording the cumulative impact of adopting the new lease standard as an adjustment to opening balances in the initial period of adoption, with comparative periods continuing to be presented in accordance with Topic 840, including disclosures. The Company will continue to monitor the status of this proposed ASU.

The FASB also issued ASU No. 2018-01, *Land Easement Practical Expedient for Transition to Topic 842* in January 2018. The amendments therein allow an entity to choose not to evaluate under Topic 842 land easements that exist or expired before the entity's adoption of the new leasing standard and that were not previously accounted for as leases under Topic 840.

The Company has implemented a comprehensive project governance framework to oversee the transition to the new leasing guidance, comprised of a Steering Committee, Implementation & Stakeholder Committee, Project Management Office, and various working groups in order to evaluate and implement the new standard. The working groups are represented by cross functional finance and non-finance stakeholders and will support the financial and operational implementation of the standard. Management has commenced procedures to provide assurance over the completeness of the population of leasing arrangements to be assessed for impact upon adoption of the new

guidance. The Company continues to evaluate the impact of the new leasing standard on its consolidated financial statements.

3. CASH, CASH EQUIVALENTS AND RESTRICTED CASH

Cash, cash equivalents, and restricted cash include cash on deposit and money market securities with a maturity of less than 90 days on the date of purchase. All other money market securities with a maturity on the date of purchase that is greater than 90 days, but less than one year, are recorded as short-term investments and classified as current assets. These securities are valued at the lower of cost and market.

Cash, cash equivalents, and restricted cash consist of the following:

(millions of dollars)	**March 31 2018**	**December 31 2017**
Cash and cash equivalents	**315**	230
Restricted cash	**13**	4
Total cash, cash equivalents and restricted cash	**328**	234

Restricted cash represents Fair Hydro Trust's (the Trust) cash on deposit that is subject to contractual restrictions of the Trust's Master Trust Indenture. All of the Fair Hydro Trust's bank accounts are under the name of and exclusive control of its indenture trustee. Amounts on deposit are restricted in purpose and the distribution of use is subject to the order of payment priority outlined in the Fair Hydro Trust's Master Trust Indenture.

4. REGULATORY ASSETS AND LIABILITIES

Through its March 2017 approval of a partial settlement agreement reached by OPG and intervenors on a limited set of issues in OPG's May 2016 application for new regulated prices for the 2017−2021 period (Settlement Agreement) and its December 2017 decision on the application, the OEB approved OPG's request to recover amounts totalling $305 million related to previously recorded variance and deferral account balances, without adjustments. These approved amounts relate to the December 31, 2015 balances in all of the Company's OEB-authorized regulatory accounts, with the exception of the Pension & OPEB Cash Versus Accrual Differential Deferral Account, less amounts previously approved for recovery or repayment for these accounts in 2016.

The OEB issued its decision on the Draft Payment Amounts Order and Procedural Order No. 10 in EB-2016-0152 on March 12, 2018. In its decision, the OEB ordered that OPG recover the approved regulatory account balances over the period March 1, 2018 to December 31, 2020, with 15 percent of the balance to be recovered between March 1, 2018 and December 31, 2018, 50 percent of the balance to be recovered between January 1, 2019 and December 31, 2019, and 35 percent of the balance to be recovered between January 1, 2020 and December 31, 2020. This amortization was confirmed in the final Payment Amounts Order, issued by the OEB on March 29, 2018.

The final payment amount order also ordered OPG to implement a payment amount smoothing approach whereby no additions are made to the Rate Smoothing Deferral Account in 2017 and 2018. The change in smoothing approach resulted in the reversal of amounts previously recorded in the Rate Smoothing Deferral Account as at December 31, 2017, with a corresponding change in the interim Period Revenue Shortfall Account. The direction provided by the final payment amount order resulted in an immaterial financial impact.

The regulatory assets and liabilities recorded as at March 31, 2018 and December 31, 2017 are as follows:

(millions of dollars)	**March 31 2018**	**December 31 2017**
Regulatory assets		
Variance and deferral accounts authorized by the OEB		
Pension and OPEB Cost Variance Account	**712**	716
Pension & OPEB Cash Versus Accrual Differential Deferral Account	**655**	614
Hydroelectric Surplus Baseload Generation Variance Account	**387**	360
Bruce Lease Net Revenues Variance Account	**127**	121
Other variance and deferral accounts	**124**	124
	2,005	1,935
Interim Period Revenue Shortfall	**612**	544
Pension and OPEB Regulatory Asset *(Note 9)*	**3,806**	3,855
Deferred Income Taxes	**943**	897
Total regulatory assets	**7,366**	7,231
Less: current portion	**259**	-
Non current regulatory assets	**7,107**	7,231
Regulatory liabilities		
Variance and deferral accounts authorized by the OEB		
Hydroelectric Water Conditions Variance Account	**167**	150
Pension & OPEB Cash Payment Variance Account	**157**	140
Changes in Station End-of-Life Dates Deferral Account	**103**	103
Other variance and deferral accounts	**166**	201
Total regulatory liabilities	**593**	594
Less: current portion	**19**	-
Non-current regulatory liabilities	**574**	594

As at March 31, 2018 and December 31, 2017, regulatory assets for other variance and deferral accounts included amounts for the Nuclear Deferral and Variance Over/Under Recovery Variance Account, the Nuclear Liability Deferral Account, the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account, the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account, and the Nuclear Development Variance Account. As at March 31, 2018 and December 31, 2017, regulatory liabilities for other variance and deferral accounts included the amounts for the Capacity Refurbishment Variance Account, the Ancillary Services Net Revenue Variance Account, the Income and Other Taxes Variance Account and the SR&ED ITC Variance Account.

As at December 31, 2017, regulatory assets for other variance and deferral accounts included amounts for the Rate Smoothing Deferral Account. This account is no longer included in the other variance and deferral accounts as of March 31, 2018.

In January 2018, the OEB approved the establishment of a new Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account, effective January 1, 2018 on an interim basis. The purpose of the account is to record the revenue requirement impact of changes to nuclear liabilities and depreciation and amortization expense resulting from changes to station end-of-life dates for OPG's Pickering prescribed nuclear facilities effective December 31, 2017. As of March 31, 2018, OPG recognized a regulatory liability of $31 million related to the balance in the deferral account.

As at March 31, 2018, regulatory liabilities for other variance and deferral accounts also included amounts for the Impact Resulting from Changes to Pickering End-of-Life Dates (December 31, 2017) Deferral Account.

5. LONG-TERM DEBT AND NET INTEREST EXPENSE

Long-term debt consists of the following:

(millions of dollars)	March 31 2018	December 31 2017
Senior notes payable to the Ontario Electricity Financial Corporation	**3,520**	3,195
Medium Term Note	**500**	500
UMH Energy Partnership project debt	**181**	181
PSS Generating Station Limited Partnership project debt	**245**	245
Lower Mattagami Energy Limited Partnership project debt	**1,595**	1,595
Fair Hydro Trust senior debt	**836**	601
Other	**19**	19
	6,896	6,336
Less: unamortized bond issuance fees	**(20)**	(17)
Less: amounts due within one year	**(263)**	(398)
Long-term debt	**6,613**	5,921

Commented [CEFD1]: Does this include the 5% FHT funding provided by OPG?

In the first quarter of 2018, OPG issued a total of $600 million senior notes payable to the OEFC maturing in 2048. The effective and coupon interest rates on these notes ranged from 3.87 percent to 4.00 percent.

In December 2017, the Fair Hydro Trust entered into an $800 million two-year revolving warehouse facility agreement with an expiry date of December 2019. In February 2018, the Fair Hydro Trust issued $500 million of senior notes payable with a coupon interest rate of 3.36 percent and an effective interest rate of 3.44 percent, payable semi-annually until maturity in May 2033. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility.

In March 2018, the Trust purchased an Investment Interest from the IESO in the amount of $460 million. Fifty-one percent of the funding requirement or approximately $235 million was financed by the Trust through the revolving warehouse facility ranked as senior notes, and the remaining 49 percent was funded through the issuance of short-term subordinated debt to OPG. The outstanding balance of the revolving warehouse credit facility of $336 million has been classified as long-term debt as at March 31, 2018 reflecting the contractual terms of the facility agreement.

Commented [CEFD2]: We assume this includes the junior subordinated debt?

In April 2018, the Trust issued $400 million of senior notes payable with a coupon interest rate of 3.52 percent and an effective interest rate of 3.60 percent, payable semi-annually until maturity in May 2038. The proceeds were used to repay the majority of the balance of the revolving warehouse facility outstanding after the April 2018 Investment Interest acquisition from the IESO of the $149 million, of which $76 million was funded through this facility.

The following table summarizes the net interest expense for the three months period ended March 31 :

(millions of dollars)	2018	2017
Interest on long-term debt [1]	**70**	70
Interest income	**(1)**	-
Interest capitalized to property, plant and equipment and intangible assets	**(44)**	(42)
Interest related to regulatory assets and liabilities [2]	**(6)**	(9)
Net interest expense	**19**	19

[1] Excludes interest on Fair Hydro Trust senior debt and interest costs on debt issued by OPG to fund its purchase of the Trust's subordinated debt, which have been included in the Earnings from Fair Hydro Trust line in the interim consolidated statements of income. Refer to Note 15 for interest expense incurred on the Trust's senior debt and on debt issued by OPG to fund its purchase of the Trust's subordinated debt. .

[2] Includes interest to recognize the cost of financing related to regulatory accounts, as authorized by the OEB, and interest deferred in the Bruce Lease Net Revenues Variance Account, the Capacity Refurbishment Variance Account, and the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account.

6. SHORT-TERM DEBT

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. During 2017, OPG renewed and extended the expiry date of both tranches to May 2022. There were no amounts outstanding under the bank credit facility. There was $100 million of commercial paper outstanding under OPG's commercial paper program as at March 31, 2018 (December 31, 2017 – $100 million). The commercial paper program is used to provide short-term funding for the Company, at interest rates of approximately one percent and for less than one year in duration.

As at March 31, 2018, Lower Mattagami Energy Limited Partnership (LME) maintained a $400 million bank credit facility to support the funding requirements for the Lower Mattagami River project including support for LME's commercial paper program. The facility consists of a $300 million tranche maturing in August 2022 and a $100 million tranche maturing in August 2018. As at March 31, 2018, there was $160 million of commercial paper outstanding under LME's commercial paper program (December 31, 2017 − $160 million). A letter of credit of $55 million was issued in July 2017 and remains outstanding as at March 31, 2018 under the first tranche of LME's credit facility.

As at March 31, 2018, OPG maintained $25 million of short-term, uncommitted overdraft facilities and $464 million of short-term, uncommitted credit facilities, which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other general corporate purposes. As at March 31, 2018, a total of $390 million of Letters of Credit had been issued under these facilities. This included $353 million for the supplementary pension plans, $36 million for general corporate purposes, and $1 million related to the operation of the Portland Energy Centre (PEC).

The Company's short-term, uncommitted credit facilities include an agreement to sell an undivided co-ownership interest in its current and future accounts receivable to an independent trust. The maximum amount of co-ownership interest that can be sold under this agreement is $150 million, expiring on November 30, 2018. As at March 31, 2018, there were Letters of Credit outstanding under this agreement of $150 million, which were issued in support of OPG's supplementary pension plans.

UMH Energy Partnership has entered into an $8 million short-term, uncommitted overdraft facility and $16 million of irrevocable, standby Letters of Credit facilities in support of its operations. As at March 31, 2018, total Letters of Credit of $15 million had been issued under these facilities.

7. FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT LIABILITIES

The liabilities for fixed asset removal and nuclear waste management on a present value basis as at March 31, 2018 and December 31, 2017 consist of the following:

(millions of dollars)	**March 31 2018**	**December 31 2017**
Liability for nuclear used fuel management	**12,112**	11,970
Liability for nuclear decommissioning and nuclear low and intermediate level waste management	**8,185**	8,107
Liability for non-nuclear fixed asset removal	**342**	344
Fixed asset removal and nuclear waste management liabilities	**20,639**	20,421

8. ACCUMULATED OTHER COMPREHENSIVE LOSS

The changes in the balance of each component of accumulated other comprehensive loss (AOCL), net of income taxes, are as follows:

	Three Months Ended March 31, 2018			
(millions of dollars)	**Unrealized Gains and Losses on Cash Flow Hedges**	**Pension and OPEB**	**Available-for-sale securities**	**Total**
AOCL, beginning of period	**(66)**	**(220)**	**(9)**	**(295)**
Reclassification of cumulative unrealized losses on available-for-sale securities to opening retained earnings *(Note 2)*	**-**	**-**	**9**	**9**
	(66)	**(220)**	**-**	**(286)**
Amounts reclassified from AOCL	**4**	**3**	**-**	**7**
Other comprehensive income for the period	**4**	**3**	**-**	**7**
AOCL, end of period	**(62)**	**(217)**	**-**	**(279)**

	Three Months Ended March 31, 2017			
(millions of dollars)	**Unrealized Gains and Losses on Cash Flow Hedges**	**Pension and OPEB**	**Available-for-sale securities**	**Total**
AOCL, beginning of period	(87)	(207)	(1)	(295)
Unrealized loss on available-for-sale securities	-	-	5	5
Amounts reclassified from AOCL	4	3	-	7
Other comprehensive income for the period	4	3	5	12
AOCL, end of period	(83)	(204)	4	(283)

The significant amounts reclassified out of each component of AOCL, net of income taxes, during the three months ended March 31, 2018 and 2017 are as follows:

	Amount Reclassified from AOCL		
(millions of dollars)	**2018**	**2017**	**Statement of Income Line Item**
Amortization of losses from cash flow hedges			
Losses	**5**	5	Net interest expense
Income tax recovery	**(1)**	(1)	Income tax expense
	4	4	
Amortization of amounts related to pension and OPEB			
Actuarial losses	**4**	4	See (1) below
Income tax recovery	**(1)**	(1)	Income tax expense
	3	3	
Total reclassifications for the period	**7**	7	

[1] These AOCL components are included in the computation of pension and OPEB costs (see Note 9 for additional details).

9. PENSION AND OTHER POST-EMPLOYMENT BENEFITS

OPG's pension and OPEB costs for the three months ended March 31, 2018 and 2017 are as follows:

(millions of dollars)	Registered Pension Plans 2018	Registered Pension Plans 2017	Supplementary Pension Plans 2018	Supplementary Pension Plans 2017	Other Post-Employment Benefits 2018	Other Post-Employment Benefits 2017
Components of Cost Recognized for the period						
Current service costs	**83**	68	**2**	1	**20**	17
Interest on projected benefit obligation	**142**	137	**3**	3	**26**	27
Expected return on plan assets, net of expenses	**(205)**	(191)	**-**	-	**-**	-
Amortization of net actuarial loss [1]	**49**	46	**2**	2	**2**	-
Costs recognized [2]	**69**	60	**7**	6	**48**	44

[1] The amortization of net actuarial loss is recognized as an increase to other comprehensive income. This increase for the three months ended March 31, 2018 was partially offset by a decrease in the Pension and OPEB Regulatory Asset of $49 million (three months ended March 31, 2017 − $44 million).

[2] These pension and OPEB costs for the three months ended March 31, 2018 exclude the net reduction of costs of $25 million from the recognition of changes in the regulatory assets for the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB Cash Payment Variance Account (three months ended March 31, 2017 − net addition of costs of $3 million).

10. RISK MANAGEMENT AND DERIVATIVES

OPG is exposed to risks related to changes in market interest rates on debt expected to be issued in the future and movements in foreign currency that affect the Company's assets, liabilities, and forecasted transactions. Select derivative instruments are used to manage such risks. Derivatives are used as hedging instruments, as well as for trading purposes.

Interest rate risk is the risk that the value of assets and liabilities can change due to movements in related interest rates. Interest rate risk for OPG arises with the need to refinance existing debt and/or undertake new financing. The management of these risks includes using derivatives to hedge the exposure in accordance with corporate risk management policies. OPG periodically uses interest rate swap agreements to mitigate elements of interest rate risk exposure associated with anticipated financing.

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are denominated in, or tied to, US dollars. OPG enters into foreign exchange derivatives and agreements with major financial institutions, when appropriate, in order to manage the Company's exposure to foreign currency movements.

The majority of OPG's revenues are derived from sales through the IESO administered spot market. Market participants in the IESO spot market provide collateral in accordance with the IESO prudential support requirements to cover funds that they might owe to the market. Although the credit exposure to the IESO represents a significant portion of OPG's accounts receivable, the Company's management accepts this risk due to the IESO's primary role in the Ontario electricity market. OPG's electricity related accounts receivable from the IESO constituted of $436 million as at March 31, 2018 (December 31, 2017 − $354 million). The remaining receivables exposure is to a diverse group of generally high quality counterparties. OPG's allowance for doubtful accounts as at March 31, 2018 was less than $1 million.

The fair value of the outstanding derivatives totalled a net liability of $14 million as at March 31, 2018 (December 31, 2017 − $20 million).

Existing pre-tax net losses of $19 million deferred in AOCL as at March 31, 2018 are expected to be reclassified to net income within the next 12 months.

11. FAIR VALUE MEASUREMENTS

The fair value of financial instruments traded in active markets is based on quoted market prices as at the interim consolidated balance sheet dates. A market is regarded as active if quoted prices are readily and regularly available from an exchange, dealer, broker, industry group, pricing service, or regulatory agency, and those prices represent actual and regularly occurring market transactions on an arm's-length basis. The quoted market price used for financial assets held by OPG is the current bid price. These instruments are included in Level 1 and are comprised primarily of equity investments and fund investments. The fair value hierarchy groups financial instruments into three levels, based on the significance of inputs used in measuring the fair value of the assets and liabilities.

For financial instruments for which quoted market prices are not directly available, fair values are estimated using forward price curves developed from observable market prices or rates. The estimation of fair value may include the use of valuation techniques or models, based wherever possible on assumptions supported by observable market prices or rates prevailing as at the interim consolidated balance sheet dates. This is the case for over-the-counter derivatives and securities, which include energy commodity derivatives, foreign exchange derivatives, interest rate swap derivatives, and fund investments. Pooled fund investments are valued at the unit values supplied by the pooled fund administrators. The unit values represent the underlying net assets at fair values, determined using closing market prices. Valuation models use general assumptions and market data and therefore do not reflect the specific risks and other factors that would affect a particular instrument's fair value. The methodologies used for calculating the fair value adjustments are reviewed on an ongoing basis to ensure that they remain appropriate. If all significant inputs required to fair value an instrument are observable, the instrument is included in Level 2.

The following is a summary of OPG's financial instruments and their fair value as at March 31, 2018 and December 31, 2017:

	Fair Value		Carrying Value [1]		
(millions of dollars)	**2018**	**2017**	**2018**	**2017**	**Balance Sheet Line Item**
Nuclear Segregated Funds (includes current portion) [2]	**16,909**	16,724	**16,909**	16,724	Nuclear fixed asset removal and nuclear waste management funds
Financing receivables	**1,655**	1,179	**1,639**	1,179	Financing receivables
Investment in Hydro One shares	**170**	188	**170**	188	Equity securities
Payable related to cash flow hedges	**(38)**	(40)	**(38)**	(40)	Long-term accounts payable and accrued charges
Long-term debt – OPG (includes current portion)	**(6,539)**	(6,234)	**(6,060)**	(5,735)	Long-term debt
Long-term debt – Fair Hydro Trust	**(847)**	(601)	**(836)**	(601)	Long-term debt
Other financial instruments	**(5)**	(16)	**(5)**	(16)	Various

[1] The carrying values of other financial instruments included in cash, cash equivalents and restricted cash, receivables from related parties, other current assets, short-term debt, and accounts payable and accrued charges approximate their fair values due to the immediate or short-term maturity of these financial instruments.

[2] The Nuclear Segregated Funds are comprised of the Decommissioning Segregated Fund and the Used Fuel Segregated Fund. OPG's fair value of the Nuclear Segregated Funds is set not to exceed an amount equal to the funding liability pursuant to the ONFA when the Nuclear Segregated Funds are in a surplus position.

The fair value of the Fair Hydro Trust senior warehouse facility debt, long-term senior debt, and OPG's long-term debt issued under the Medium Term Note Program are based on indicative pricing from the market. The fair value of these debt instruments would be considered Level 3 in the fair value hierarchy. All other long-term debt instruments are determined based on a conventional pricing model, which is a function of future cash flows, the current market yield curve and term to maturity. These inputs are considered Level 2 inputs.

For the financing receivables related to the Investment Interest acquired from the IESO, fair value is estimated to equal the fair value of the underlying long-term debt due to the direct relationship between the asset and the debt instruments that financed the acquisition. The financing receivables are funded by both long-term senior debt issued by the Fair Hydro Trust to third parties and subordinated debt issued by the Trust to OPG, which is eliminated on consolidation. Both sources of funding are considered Level 3 inputs. Therefore, the fair value of the financing receivables would be considered Level 3 in the fair value hierarchy.

If one or more of the significant inputs is not based on observable market data, the instrument is included in Level 3. Specific valuation techniques are used to value these instruments. Significant Level 3 inputs include: recent comparable transactions, comparable benchmark information, bid/ask spread of similar transactions, and other relevant factors.

Certain alternative investments are measured at fair value by their investment managers using net asset value (NAV). Investments measured at NAV as a practical expedient for determining their fair value are excluded from the fair value hierarchy.

Transfers into, out of, or between levels are deemed to have occurred on the date of the event or change in circumstances that caused the transfer to occur.

The following tables present financial assets and financial liabilities measured at fair value in accordance with the fair value hierarchy as at March 31, 2018 and December 31, 2017:

	March 31, 2018			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Used Fuel Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	**6,096**	**4,693**	**-**	**10,789**
Investments measured at NAV [1]				**1,378**
				12,167
Due to Province				**(2,508)**
Used Fuel Segregated Fund, net				**9,659**
Decommissioning Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	**4,567**	**3,482**	**-**	**8,049**
Investments measured at NAV [1]				**1,132**
				9,181
Due to Province				**(1,931)**
Decommissioning Segregated Fund, net				**7,250**
Investment in equity securities	**170**	**-**	**-**	**170**
Other financial assets	**5**	**-**	**10**	**15**
Liabilities				
Other financial liabilities	**(20)**	**-**	**-**	**(20)**

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to amounts presented on the interim consolidated balance sheets.

(millions of dollars)	December 31, 2017 Level 1	Level 2	Level 3	Total
Assets				
Used Fuel Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	6,090	4,705	-	10,795
Investments measured at NAV [1]				1,292
				12,087
Due to Province				(2,529)
Used Fuel Segregated Fund, net				9,558
Decommissioning Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	4,547	3,487	-	8,034
Investments measured at NAV [1]				1,065
				9,099
Due to Province				(1,933)
Decommissioning Segregated Fund, net				7,166
Investments in available-for-sale securities	188	-	-	188
Other financial assets	5	3	6	14
Liabilities				
Other financial liabilities	(28)	(2)	-	(30)

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to amounts presented on the interim consolidated balance sheets.

During the period ended March 31, 2018, there were no transfers between Level 1 and Level 2. In addition, there were no transfers into or out of Level 3.

The following table presents the changes in OPG's net assets measured at fair value that are classified as Level 3 financial instruments.

(millions of dollars)	Other financial instruments
Opening balance, January 1, 2018	**6**
Realized losses included in revenue	**(5)**
Purchases	**9**
Closing balance, March 31, 2018	**10**

Nuclear Segregated Funds

The fair value of the investments within the Nuclear Segregated Funds' real assets portfolio is determined using appropriate valuation techniques, such as recent arm's-length market transactions, references to current fair values of other instruments that are substantially the same, discounted cash flow analyses, third-party independent appraisals, valuation multiples, or other valuation methods. Any control, size, liquidity or other discount premiums on the investments are considered in the determination of fair value.

The process of valuing investments for which no published market price exists is based on inherent uncertainties and the resulting values may differ from values that would have been used had a ready market existed for these investments. The values may also differ from the prices at which the investments may be sold.

The following are the classes of investments within the Nuclear Segregated Funds that are reported on the basis of NAV as at March 31, 2018:

(millions of dollars except where noted)	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice
Real Assets				
Infrastructure	**1,412**	**805**	**n/a**	**n/a**
Real Estate	**994**	**487**	**n/a**	**n/a**
Agriculture	**104**	**91**	**n/a**	**n/a**
Pooled Funds				
Short-term Investments	**33**	**n/a**	**Daily**	**1-5 days**
Fixed Income	**461**	**n/a**	**Daily**	**1-5 days**
Equity	**972**	**n/a**	**Daily**	**1-5 days**
Total	**3,976**	**1,383**		

The fair value of the pooled funds is classified as Level 2. Infrastructure, real estate and agriculture investments are measured using NAV as a practical expedient for determining their fair value.

Infrastructure

This asset class includes investments in funds and assets with an objective to generate a combination of long-term capital appreciation and current income, generally through private investments in sectors such as energy, transportation, communication and utilities. The fair values of investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in these investments. The investments in the respective funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests/shares to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Distributions from each infrastructure fund will be received based on the operations of the underlying investments and/or as the underlying investments are liquidated. It is not possible to estimate when the underlying assets in this asset class will be liquidated.

Real Estate

This asset class includes investments in funds and assets with an objective to generate a combination of long-term capital appreciation and current income, generally through investments in institutional-grade real estate property. The fair values of the investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in these investments. The investments in the respective funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Distributions from each real estate fund will be received based on the operations of the underlying investments and/or as the underlying investments are liquidated. For investments in private real estate corporations, shares may be redeemed through a pre-established redemption process. It is not possible to estimate when the underlying assets in this asset class will be liquidated.

Agriculture

This asset class includes investments in funds and assets with an objective to provide a differentiated return source, income yield, and inflation protection, generally through private investments in global farmland and timberland. The fair values of the investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in these investments. The investments in the respective funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests/shares to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Distributions from each agriculture fund will be received based on the operations of the underlying investments and/or as the underlying investments are liquidated. It is not possible to estimate when the underlying assets in this asset class will be liquidated.

Pooled Funds

This asset class represents investments in pooled funds, which primarily include a diversified portfolio of fixed income securities, issued mainly by Canadian corporations, and diversified portfolios of Emerging Market listed equity. The investment objective of the pooled funds is to achieve capital appreciation and income through professionally managed portfolios. The fair value of the investments in this class has been estimated using NAV per share of the investments. There are no significant restrictions on the ability to sell the investments in this class.

12. SHARE CAPITAL

Common Shares

As at March 31, 2018 and December 31, 2017, OPG had 256,300,010 common shares issued and outstanding at a stated value of $5,126 million. OPG is authorized to issue an unlimited number of common shares without nominal or par value. Any issue of new shares is subject to the consent of OPG's shareholder, the Province.

Class A Shares

The Company's Articles of Amalgamation were amended effective December 1, 2017 to allow for the creation and issuance of non-voting Class A shares to the Province in exchange for equity injections in OPG. All of the outstanding shares are owned directly by the Province and OPG is authorized to issue an unlimited number of Class A shares without nominal or par value. The Class A and common shares rank equally as to entitlement to dividends, and all dividends declared by OPG must be declared in equal amounts per share on all outstanding shares without preference or distinction. Upon the liquidation, dissolution or wind-up of OPG, whether voluntary or involuntary, the holders of Class A shares and common shares are entitled to share equally, on a share for share basis, in all distributions of property and assets without preference or distinction. Any issue of new class of shares is subject to the consent of the Province. OPG is entitled to redeem outstanding Class A shares as may be approved by OPG's Board of Directors.

In March 2018 and December 2017, OPG issued 4,627,343 Class A shares at a price of $43.74 per share and 12,217,616 Class A shares at a price of $42.46 per share to the Province for its equity injections in OPG, generating proceeds of $202 million and $519 million, respectively. The proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt representing 44 percent of the total funding requirements for the Trust's acquisitions of Investment Interests from the IESO in March 2018 and December 2017 of $460 million and $1.18 billion, respectively.

As at March 31, 2018, OPG had 16,844,959 Class A shares issued and outstanding at a stated value of $721 million. (December 31, 2017 − 12,217,616 Class A shares issued and outstanding at a stated value of $519 million).

In April 2018, OPG issued 1,498,856 Class A shares at a price of $43.74 per share to the Province for its equity injection in OPG, generating proceeds of $66 million. The proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt representing 44 percent of the total funding requirements for the Trust's acquisition of Investment Interest from the IESO in April 2018 of $149 million.

13. EARNINGS PER SHARE

Basic and diluted earnings per share are calculated by dividing net income attributable to the Shareholder by the weighted average number of shares outstanding.

Class A shares are included in the weighted average number of shares outstanding. The weighted average number of shares outstanding as at March 31, 2018 was 269 million (year ended December 31, 2017 – 256.7 million). There were no dilutive securities as at March 31, 2018 and December 31, 2017.

14. COMMITMENTS AND CONTINGENCIES

Litigation

On August 9, 2006, a Notice of Action and Statement of Claim filed with the Ontario Superior Court of Justice in the amount of $500 million was served against OPG and Bruce Power L.P. (Bruce Power) by British Energy Limited and British Energy International Holdings Limited (together British Energy). The action is for contribution and indemnity of any amounts British Energy was liable for in an arbitration against it by some of the owners of Bruce Power regarding an alleged breach of British Energy's representations and warranties to the claimants when they purchased British Energy's interest in Bruce Power (the Arbitration). Both the action and the Arbitration relate to corrosion to a steam generator unit discovered after OPG leased the Bruce nuclear generating stations to Bruce Power.

In 2012, the arbitrator found that British Energy was liable to the claimants for some of the damages they claimed. The final settlement amount was valued by British Energy at $71 million. In September 2014, British Energy amended its Statement of Claim (Amended Claim) to reduce the claim amount to $100 million to reflect that the purchasers of British Energy's interest in Bruce Power did not receive the full damages they originally claimed in the Arbitration. British Energy also added an allegation to its Amended Claim that OPG breached a covenant to maintain the steam generator between the time of the initial agreement to lease and the effective date of the lease in accordance with "Good Utility Practices".

In November 2016, British Energy obtained consent from the Ontario Superior Court of Justice to a timetable for the remaining steps in the litigation, pursuant to which the matter must be set down for trial by December 31, 2018. OPG has delivered a statement of defence in accordance with an extension of the original June 30, 2017 delivery deadline set up in the timetable. [**MONITOR**]

Various other legal proceedings are pending against OPG or its subsidiaries covering a wide range of matters that arise in the ordinary course of business activities.

Each of these matters is subject to various uncertainties. Some of these matters may be resolved unfavourably. While it is not possible to determine the ultimate outcome of the various pending actions, it is the Company's belief that their resolution is not likely to have a material adverse impact on its financial position.

Guarantees

The Company and its joint venture partners have jointly guaranteed the financial performance of jointly owned entities related primarily to the payment of liabilities. As at March 31, 2018, the total amount of guarantees OPG provided to these entities was $83 million (December 31, 2017 − $82 million). OPG may terminate some of these guarantees within a short time frame by providing written notice to the counterparties at any time. Other guarantees have terms ending between 2019 and 2029. As at March 31, 2018, the potential impact of the fair value of these guarantees to income has been estimated to be negligible and OPG does not expect to make any payments associated with these guarantees.

Contractual Obligations

OPG's contractual obligations as at March 31, 2018 are as follows:

(millions of dollars)	2018 [1]	2019	2020	2021	2022	Thereafter	Total
Fuel supply agreements	141	125	115	88	68	67	604
Contributions to the OPG registered pension plan [2]	161	219	-	-	-	-	380
OPG long-term debt repayment	123	368	663	413	172	4,321	6,060
Interest on OPG long-term debt	189	249	227	199	185	3,612	4,661
Fair Hydro Trust senior debt repayment [3]	-	336	-	-	-	500	836
Interest on Fair Hydro Trust senior debt	6	25	17	17	17	177	259
Commitments related to Darlington Refurbishment project [4]	450	-	-	-	-	-	450
Commitments related to Ranney Falls GS project	22	4	-	-	-	-	26
Operating licences	30	41	24	28	28	87	238
Operating lease obligations	21	25	24	22	22	79	193
Unconditional purchase obligations	41	54	52	4	-	-	151
Accounts payable and accrued charges	859	8	-	-	-	260	1,127
Other	69	33	7	1	1	63	174
Total	2,112	1,487	1,129	772	493	9,166	15,159

[1] Represents amounts for the remainder of the year.

[2] The pension contributions include ongoing funding requirements and additional funding requirements towards the deficit, in accordance with the actuarial valuation of the OPG registered pension plan as at January 1, 2017. The next actuarial valuation of the OPG registered pension plan must have an effective date no later than January 1, 2020. The pension contributions are affected by various factors including market performance, changes in actuarial assumptions, plan experience, changes in the pension regulatory environment, and the timing of funding valuations. Funding requirements after 2019 are excluded due to significant variability in the assumptions required to project the timing of future cash flows. The amount of OPG's additional voluntary contribution, if any, is revisited from time to time.

[3] The repayment of Fair Hydro Trust senior notes includes an outstanding balance of $336 million issued under an $800 million revolving warehouse facility expiring in December 2019 and $500 million of 15-year senior notes due in May 2033.

[4] Represents estimated currently committed costs to close the project, including accruals for completed work, demobilization of project staff and cancellation of existing contracts and material orders.

Contractual and commercial commitments as noted exclude certain purchase orders, as they represent purchase authorizations rather than legally binding contracts, and are subject to change without significant penalties.

15. BUSINESS SEGMENTS

Segment Income (Loss) for the Three Months Ended March 31, 2018 *(millions of dollars)*	Regulated		Unregulated					
	Nuclear Gene-ration	Nuclear Waste Manage-ment	Hydro-Electric	Contracted Generation Portfolio	Fair Hydro Trust	Other	Elimi-nation	Total
Revenue from contracts with customers	871	-	356	149	-	10	-	1,386
Leasing revenue	9	-	-	-	-	4	-	13
Other revenue	-	33	-	-	-	7	(32)	8
Total revenue	880	33	356	149	-	21	(32)	1,407
Fuel expense	73	-	65	17	-	-	-	155
Gross margin	807	33	291	132	-	21	(32)	1,252
Operations, maintenance and administration	604	33	80	41	-	(4)	(32)	722
Depreciation and amortization	121	-	36	20	-	9	-	186
Accretion on fixed asset removal and nuclear waste management liabilities	-	243	-	2	-	2	-	247
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(210)	-	-	-	-	-	(210)
Earnings from Fair Hydro Trust	-	-	-	-	(4)	-	-	(4)
Income from investments subject to significant influence	-	-	-	(10)	-	-	-	(10)
Property taxes	7	-	-	1	-	1	-	9
Other losses (gains)	-	-	4	-	-	(263)	-	(259)
Income (loss) before interest and income taxes	75	(33)	171	78	4	276	-	571
Net interest expense								19
Income before income taxes								552
Income tax expense								13
Net income								539

Segment (Loss) Income for the Three Months Ended March 31, 2017 *(millions of dollars)*	Nuclear Gene-ration	Regulated Nuclear Waste Manage-ment	Hydro-electric	Unregulated Contracted Generation Portfolio	Other	Elimi-nation	Total
Revenue from contracts with customers	643	-	363	143	2	-	1,151
Leasing revenue	9	-	-	-	14	-	23
Other revenue	-	27	-	-	1	(26)	2
Total revenue	652	27	363	143	17	(26)	1,176
Fuel expense	68	-	73	14	-	-	155
Gross margin	584	27	290	129	17	(26)	1,021
Operations, maintenance and administration	589	29	76	39	1	(26)	708
Depreciation and amortization	107	-	34	19	7	-	167
Accretion on fixed asset removal and nuclear waste management liabilities	-	234	-	2	2	-	238
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(189)	-	-	-	-	(189)
Income from investments subject to significant influence	-	-	-	(10)	-	-	(10)
Property taxes	6	-	-	2	3	-	11
Other gains	-	-	-	-	(3)	-	(3)
(Loss) income before interest and income taxes	(118)	(47)	180	77	7	-	99
Net interest expense							19
Income before income taxes							80
Income tax expense							12
Net income							68

The earnings from Fair Hydro Trust are comprised of the following for the three months period ended March 31:

(millions of dollars)	2018	2017
Revenue	**(1)**	-
Operating expenses	**1**	-
Interest income	**(10)**	-
Interest expense	**6**	-
Earnings from Fair Hydro Trust	**(4)**	-

In December 2017, the Fair Hydro Trust was established as a separate entity to be the financing entity contemplated by the Fair Hydro Act. The majority unitholder and beneficiary of the Trust is a wholly owned subsidiary of OPG, and the Trust's financial position and results are consolidated into OPG's financial results. As a legal matter, the assets and liabilities of the Trust do not form part of the assets and liabilities of OPG, and vice versa, pursuant to section 53.1(1.4) of the *Electricity Act, 1998 (Ontario).*

16. NET CHANGES IN NON-CASH WORKING CAPITAL BALANCES

	Three Months Ended March 31	
(millions of dollars)	**2018**	**2017**
Receivables from related parties	**(83)**	67
Fuel inventory	**10**	13
Materials and supplies	**12**	9
Prepaid expenses	**(2)**	(10)
Other current assets [1]	**44**	34
Income taxes payable	**(90)**	(117)
Accounts payable and accrued charges	**(45)**	(113)
	(154)	(117)

[1] Represents other accounts receivable.

17. PAYMENT OF DIVIDEND TO SHAREHOLDER

In April 2017, OPG completed the sale of its head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street in Toronto, Ontario. The sale was undertaken pursuant to a Shareholder Declaration and a Shareholder Resolution received by OPG in December 2015. Pursuant to the Shareholder Declaration and the Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014* (Trillium Trust Act), OPG was required to transfer the proceeds from this disposition, net of prescribed deductions under the Trillium Trust Act, into the Province's Consolidated Revenue Fund. In accordance with these requirements, a special dividend of $283 million was authorized by OPG's Board of Directors and transferred into the Consolidated Revenue Fund in March 2018.

18. SALE OF LAKEVIEW SITE

In March 2018, OPG completed the sale of its former Lakeview GS site property located in Mississauga, Ontario, with an after-tax gain on sale of $205 million recognized in net income in the first quarter of 2018. The sale was undertaken pursuant to a Shareholder Declaration and a Shareholder Resolution received by OPG in June 2016. Pursuant to the Shareholder Declaration and the Shareholder Resolution, and as prescribed in the Trillium Trust Act, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Trillium Trust Act, into the Province's Consolidated Revenue Fund. OPG expects that the amount of designated proceeds to be transferred into the Consolidated Revenue Fund will be largely consistent with the after-tax gain on sale~~, and is working with the Ontario Ministry of Finance to finalize the amount~~. **[MONITOR]** In accordance with the Shareholder Resolution, approximately 67 acres of the site will be transferred to the City of Mississauga by the purchaser, for parkland, institutional, and cultural uses.

19. INCOME TAXES

Income tax expense increased by $1 million in the first quarter of 2018 as compared to the same quarter in 2017, primarily due to higher income before income taxes, largely offset by a higher amount of deferred income tax expense recorded as a regulatory asset and a reduction of tax resulting from dividend distributions.

ONTARIO POWER GENERATION

News
from Ontario Power Generation

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[DRAFT]

May 15, 2018

OPG REPORTS 2018 FIRST QUARTER FINANCIAL RESULTS

Strong results attributable to former Lakeview generating station land sale and continued strong nuclear generation performance

[Toronto]: – Ontario Power Generation Inc. (OPG or Company) today reported net income attributable to the Shareholder of $535 million for the first quarter of 2018, compared to $64 million for the same period in 2017, inclusive of a one-time gain of $205 million related to the sale of the former Lakeview generating station (GS) property. The net proceeds of the Lakeview property sale will be transferred to the ~~Government of Ontario~~Province.

"As Ontario's publically-owned electricity generator, we are pleased to report our strong first quarter results that have resulted in significant net income to our shareholder, the Province of Ontario. We remain focused on continuing to supply Ontario with safe, clean, reliable, and low cost power to help moderate customer's electricity bills, and are investing in our assets to the benefit of Ontarians for years to come," said Jeff Lyash, OPG President and CEO. "Canada's single largest investment in low-cost, clean energy, the refurbishment of the Darlington Nuclear Station, remains on time and on budget due to the hard work and dedication of our employees and partners. Refurbishing this public asset will ensure OPG remains Ontario's largest provider of low cost electricity for another 30 years while providing clean power that is over 99 per cent free of carbon emissions."

Lyash continued, "In addition to investing in the Darlington Nuclear Station, OPG has begun the relicensing process to keep the Pickering Nuclear Station operating until 2024. Running Pickering until 2024 will save electricity customers up to $600 million and benefit Ontario by contributing over $12 billion to the economy. Pickering remains a safe, efficient and reliable public asset that can continue to supply low-cost electricity for up to 1.5 million homes each day, with almost no carbon emissions."

"Major contributors to the strong financial results for the quarter include the one-time gain on the sale of OPG's former Lakeview generating station lands in Mississauga, Ontario in March, the net proceeds of which will be transferred to our shareholder, the Province, and the continued strong nuclear generation performance," added Lyash. "In the same month as the Lakeview sale, a special dividend of $283 million from the last year's sale of our head office premises was transferred to the Province."

The increase in net income in the first quarter of 2018 is also attributable to the impact

Commented [DS1]: This is consistent with government messaging, so OK with the language; however, in OPG's Q1 financial statements (p.4), it shows "Net proceeds from sale of property, plant and equipment" of $273M, representing the pre-tax gain from the sale of Lakeview, which is different from the net proceeds that would be transferred to the government (Trillium Trust).

Could consider saying "designated proceeds" per Note 17 to the Q1 financial statements.

Commented [DS2]: Minor suggestion, but trying to link more closely to the fact that the transfer would be made to the Province's Consolidated Revenue Fund.

Commented [DS3]: As above

Commented [DS4]: As above

of new regulated prices for OPG's nuclear and most of its hydroelectric generation, resulting from the Ontario Energy Board's (OEB) decision on OPG's application for new regulated prices for the 2017-2021 period issued in December 2017.

The OEB issued the final payment amounts order on the application in March 2018, allowing OPG to begin collecting revenues based on the new regulated prices. Taking into account the impact of the OEB's decision, OPG continues to provide electricity at a price that is 40 per cent less than the average of other generators. OPG is the only electricity generator in Ontario that has its prices set through a public hearing process by the OEB.

Generating and Operating Performance

Electricity generated during the three months ended March 31, 2018 increased to 18.8 terawatt hours (TWh) from 18.6 TWh for the same quarter in 2017.

Regulated – Nuclear Generation Segment

Higher nuclear generation of 0.4 TWh during three months ended March 31, 2018 was primarily due to fewer planned outage days at the Darlington GS.

For the three months ended March 31, 2018, the unit capability factor for the operating units at the Darlington GS was 96.5 per cent, compared to 85.3 per cent for the same quarter in 2017. The increase was primarily due to a lower number of planned outage days at the station.

At the Pickering GS, the unit capability factor decreased to 74.5 per cent for 2018, compared to 78.5 per cent for the same quarter in 2017, primarily due to a higher number of planned outage days in the cyclical maintenance schedule at the station in the first quarter of 2018.

Regulated – Hydroelectric Segment

Lower generation from the regulated hydroelectric stations of 0.3 TWh during three months ended March 31, 2018 compared to the same quarter in 2017, was primarily due to lower water flows on the northwestern and eastern Ontario river systems.

The availability of 87.3 per cent at these stations in 2018 was lower than 89.5 per cent for the same quarter in 2017. The decrease in the availability was primarily due to a higher number of unplanned outage days at the eastern and northeastern Ontario regions' regulated hydroelectric stations.

Contracted Generation Portfolio Segment

Generation from the Contracted Generation Portfolio during three months ended March 31, 2018 was comparable to the same quarter in 2017.

The availability of these hydroelectric stations for three months ended March 31, 2018 was 80.1 per cent, compared to 83.6 per cent for the same quarter in 2017. The decrease in the availability was primarily due to a higher number of planned outage days at the Little Long GS on the Lower Mattagami River.

Total Generating Cost

The Enterprise Total Generating Cost per megawatt hour (MWh) was $49.84 for the three months ended March 31, 2018, compared to $47.86 for the same quarter in 2017. The increase was mainly a result of higher OM&A expenses and higher sustaining capital expenditures, partially offset by higher nuclear electricity generation.

Generation Development

OPG is undertaking a number of generation development and life extension projects in support of Ontario's electricity planning initiatives. Significant developments during the first quarter of 2018 were as follows:

Darlington Refurbishment

The Darlington Refurbishment project is expected to extend the operating life of the four-unit Darlington GS by approximately 30 years. In early May 2018, OPG completed the removal of the existing reactor components, which included end fittings, pressure tubes, and calandria tubes, signifying the completion of the second major segment of the project. The refurbishment of Unit 2 has transitioned into the third major segment, the installation and reassembly of reactor components. The Darlington Refurbishment project continues to track on schedule and to the $12.8 billion budget.

In addition to the execution of refurbishment activities on Unit 2, OPG is progressing with planning activities on the refurbishment of Unit 3 and ensuring that lessons learned from the Unit 2 refurbishment are being incorporated. OPG is also entering into commitments to procure major components that require long lead times. Execution of the prerequisite activities for Unit 3 refurbishment have commenced. Unit 3 refurbishment is expected to commence upon the return to service of Unit 2. As of March 31, 2018, $137 million has been invested in planning and prerequisite activities related to the refurbishment of Unit 3. In February 2018, the Government of Ontario confirmed its commitment to proceed with the refurbishment of Unit 3.

Total life-to-date capital expenditures on the project were approximately $4.7 billion as at March 31, 2018.

Ranney Falls Hydroelectric GS

In 2017, OPG began construction work on a 10 MW single-unit powerhouse on the existing Ranney Falls GS site. The new unit will replace an existing unit that reached its end of life in 2014. Construction continues in the expanded forebay, powerhouse and spillway area. Fabrication of the sectional gates and two head gates has been completed, with assembly and site delivery in progress. Turbine and generator unit fabrication is also in progress. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget. The Ranney Falls GS is included in the Regulated – Hydroelectric segment.

Nanticoke Solar Facility

The project encompasses the construction of a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands under a contract with the IESO, through

Nanticoke Solar LP, a partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation. Significant contracts for equipment and engineering construction services were executed and site preparation commenced in the first quarter of 2018. The facility is expected to be completed in the first quarter of 2019 **[MONITOR]**, with a budget of $107 million. The project is included in the Contracted Generation Portfolio segment.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

(millions of dollars – except where noted)	Three Months Ended March 31 2018	2017
Revenue	**1,407**	1,176
Fuel expense	**155**	155
Operations, maintenance and administration	**722**	708
Depreciation and amortization	**186**	167
Other (gains) expenses, net [1]	**(227)**	47
Income before interest and income taxes	**571**	99
Net interest expense	**19**	19
Income tax expense	**13**	12
Net Income	**539**	68
Net income attributable to the Shareholder	**535**	64
Net income attributable to non-controlling interest [2]	**4**	4
Income before interest and income taxes		
Electricity generation business segments	**324**	139
Regulated – Nuclear Waste Management	**(33)**	(47)
Fair Hydro Trust	**4**	-
Other	**276**	7
Total income before interest and income taxes	**571**	99
Cash flow		
Cash flow provided by operating activities	**226**	168
Electricity generation (TWh)		
Regulated – Nuclear Generation	**10.4**	10.0
Regulated – Hydroelectric	**7.7**	8.0
Contracted Generation Portfolio [3]	**0.7**	0.6
Total electricity generation	**18.8**	18.6
Nuclear unit capability factor (per cent) [4]		
Darlington Nuclear GS	**96.5**	85.3
Pickering Nuclear GS	**74.5**	78.5
Availability (per cent)		
Regulated – Hydroelectric	**87.3**	89.5
Contracted Generation Portfolio – hydroelectric stations	**80.1**	83.6
Equivalent forced outage rate		
Contracted Generation Portfolio – thermal stations	**0.3**	1.6
Enterprise Total Generating Cost (TGC) per MWh for the three months ended March 31, 2018 and March 31, 2017 ($/MWh) [5]	**49.84**	47.86
Return on Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI) for the twelve months ended March 31, 2018 and December 31, 2017 (%) [5]	**11.5**	7.6

[1] For the three months ended March 31, 2018, includes the pre-tax gain on sale of the former Lakeview GS site.

[2] Relates to the 25 per cent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation in the Lower Mattagami Limited Partnership, the 33 per cent interest of Coral Rapids Power Corporation (CRP), a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership, and the 10 per cent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP. CRP increased its partnership interest in PSS to 33 per cent in April 2017.

[3] Includes OPG's share of generation volume from its 50 per cent ownership interests in the Portlands Energy Centre and Brighton Beach GS.

[4] Nuclear unit capability factor excludes unit(s) during the period in which they are undergoing refurbishment. Unit 2 of the Darlington GS is excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

[5] Enterprise TGC per MWh and ROE Excluding AOCI are non-GAAP financial measures and do not have any standardized meaning prescribed by US GAAP. Additional information about the non-GAAP measures is provided in OPG's Management's Discussion and Analysis for the three months ended March 31, 2018, in the sections *Highlights – Return on Equity Excluding Accumulated Other Comprehensive Income*, *Highlights – Enterprise Total Generating Cost per MWh*, and *Supplementary Non-GAAP Financial Measures*.

Ontario Power Generation Inc. is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. Our mission is providing low cost power in a safe, clean, reliable and sustainable manner for the benefit of our customers and shareholder.

Ontario Power Generation Inc.'s unaudited interim financial statements and Management's Discussion and Analysis as at and for the three months ended March 31, 2018 can be accessed on OPG's web site (www.opg.com), the Canadian Securities Administrators' web site (www.sedar.com), or can be requested from the Company.

For further information, please contact: Investor Relations 416-592-6700
webmaster@opg.com

Media Relations 416-592-4008
1-877-592-4008

- 30 -

From:	John Kim
To:	"HO Philip -FIN & C CTRL"
Cc:	MAK Ricky -FIN & C CTRL; DYKXHOORN Sandra -STAKEREL; GORE Michael -FIN & C CTRL; Ronald Kwan
Subject:	RE: OPG Q3 2017 Submission to Province
Date:	Monday, October 30, 2017 6:15:45 PM
Attachments:	Q3 2017 OPG MDA - DRAFT - PROVINCE MAILING_EFB_CommentsV4.docx

Hi Philip,

See attached with our comments on the MD&A.

These are staff level comments as Ron has not had a chance to review.

Thanks,

John

From: HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
Sent: Wednesday, October 25, 2017 12:22 PM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>; 'Montgomery, Kaitlin (MOF)' <Kaitlin.Montgomery@ontario.ca>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>
Subject: OPG Q3 2017 Submission to Province

Hi All,

Please find attached OPG's draft Q3 2017 Financial Results Press Release, Management's Discussion and Analysis (MD&A), and Financial Statements for the Province's review.

We would greatly appreciate comments on the above **no later than Monday, Oct 30th**.

These documents will be filed with the Ontario Securities Commission on **Thursday, November 9th** following OPG's Board of Directors meeting.

Kindly forward all comments directly to Philip Ho – philip.ho@opg.com.

To assist the review process, the following are the key items in the Q3 2017 MD&A:

Highlights	
Recent Developments	MD&A p.10-11
Darlington Refurbishment	MD&A p.13-15
Ontario's Fair Hydro Plan	MD&A p.10-11

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ONTARIO POWER GENERATION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

2017 THIRD QUARTER REPORT

[DRAFT]

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ONTARIO POWER GENERATION

ONTARIO POWER GENERATION INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) should be read in conjunction with the unaudited interim consolidated financial statements and accompanying notes of Ontario Power Generation Inc. (OPG or Company) as at and for the three and nine months ended September 30, 2017. OPG's unaudited interim consolidated financial statements are prepared in accordance with United States generally accepted accounting principles (US GAAP) and are presented in Canadian dollars.

For a complete description of OPG's corporate strategies, risk management, corporate governance, and the effect of critical accounting policies and estimates on OPG's results of operations and financial condition, this MD&A should also be read in conjunction with OPG's audited consolidated financial statements, accompanying notes, the Annual Information Form, and the MD&A as at and for the year ended December 31, 2016.

As required by *Ontario Regulation 395/11*, as amended, a regulation under the *Financial Administration Act* (Ontario), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. In 2014, the Ontario Securities Commission approved an exemption which allows OPG to apply US GAAP up to January 1, 2019. The term of the exemption is subject to certain conditions, which may result in the expiry of the exemption prior to January 1, 2019. For details, refer to the section, *Critical Accounting Policies and Estimates* under the heading, *Exemptive Relief for Reporting under US GAAP,* in OPG's 2016 annual MD&A. This MD&A is dated November 9, 2017.

FORWARD-LOOKING STATEMENTS

The MD&A contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could", and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

All forward-looking statements involve inherent assumptions, risks, and uncertainties, including those set out in the section, *Risk Management,* and forecasts discussed in the section, *Core Business, Strategy, and Outlook.* All forward-looking statements could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's generating station performance and availability, fuel costs, surplus baseload generation (SBG), cost of fixed asset removal and nuclear waste management, performance and earnings of investment funds, refurbishment of existing facilities, development and construction of new facilities, pension and other post-employment benefit (OPEB) obligations and funds, income taxes, proposed new legislation, the ongoing evolution of Ontario's electricity industry, environmental and other regulatory requirements, health, safety and environmental developments, business continuity events, the weather, financing and liquidity, applications to the Ontario Energy Board (OEB) for regulatory prices, the impact of regulatory decisions by the OEB, and forecasts of earnings, cash flows, Funds from Operations (FFO) Adjusted Interest Coverage, Return on Common Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI), Total Generating Cost (TGC) and capital expenditures. Accordingly, undue reliance should not be placed on any forward-looking statement. The forward-looking statements included in this MD&A are made only as of the date of this MD&A. Except as required by applicable securities laws, OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events, or otherwise.

THE COMPANY

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG was established under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (Province or Shareholder).

As at September 30, 2017, OPG's electricity generation portfolio had an in-service capacity of 16,210 megawatts (MW). OPG operates two nuclear generating stations, 66 hydroelectric generating stations, three thermal generating stations, and one wind power turbine. In addition, OPG and TransCanada Energy Ltd. co-own the 550 MW Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS). OPG and ATCO Power Canada Ltd. co-own the 560 MW Brighton Beach gas-fired combined cycle GS (Brighton Beach). OPG's 50 percent share of the in-service capacity and generation volume of these co-owned facilities is included in the generation portfolio statistics set out in this report. The income from the co-owned facilities is accounted for using the equity method of accounting, and OPG's share of income is presented as income from investments subject to significant influence in the Contracted Generation Portfolio segment.

OPG also owns two other nuclear generating stations, the Bruce A GS and the Bruce B GS, which are leased on a long-term basis to Bruce Power LP (Bruce Power). Income from these leased stations is included in revenue under the Regulated – Nuclear Generation segment. The leased stations are not included in the generation portfolio statistics set out in this report.

All of OPG's owned and co-owned generating facilities are located in Ontario. OPG does not operate PEC, Brighton Beach, the Bruce A GS and the Bruce B GS.

A description of OPG's segments is provided in OPG's 2016 annual MD&A in the section, *Business Segments*.

In-Service Generating Capacity

OPG's in-service generating capacity by business segment as at September 30, 2017 and December 31, 2016 was as follows:

	As at	
(MW)	**September 30 2017**	**December 31 2016**
Regulated – Nuclear Generation [1]	**5,728**	5,728
Regulated – Hydroelectric	**6,426**	6,421
Contracted Generation Portfolio [2]	**4,056**	4,028
Total	**16,210**	16,177

[1] The in-service generating capacity as of September 30, 2017 and December 31, 2016 excludes Unit 2 of the Darlington GS. The unit, which has a generating capacity of 878 MW, was taken offline in mid-October 2016 and is currently undergoing refurbishment.

[2] Includes OPG's share of in-service generating capacity of 275 MW for PEC and 280 MW for Brighton Beach.

During the nine months ended September 30, 2017, the total in-service capacity increased by 33 MW. The increase was primarily due to the completion of the Peter Sutherland Sr. hydroelectric GS, which was placed in-service at the end of the first quarter of 2017, and the upgrade of Unit 10 of the Sir Adam Beck 1 hydroelectric GS, which was completed in June 2017.

HIGHLIGHTS

Overview of Results

This section provides an overview of OPG's unaudited interim consolidated operating results. Significant factors which contributed to OPG's results during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, are discussed below.

(millions of dollars – except where noted) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Revenue	**1,217**	1,400	**3,539**	4,265
Fuel expense	**185**	187	**518**	541
Gross margin	**1,032**	1,213	**3,021**	3,724
Operations, maintenance and administration	**635**	666	**2,054**	2,061
Depreciation and amortization	**178**	313	**517**	941
Accretion on fixed asset removal and nuclear waste management liabilities	**235**	232	**709**	696
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(196)**	(248)	**(579)**	(620)
Income from investments subject to significant influence	**(11)**	(11)	**(29)**	(28)
Property taxes	**8**	12	**30**	35
	849	964	**2,702**	3,085
Income before other losses (gains), interest and income taxes	**183**	249	**319**	639
Other losses (gains)	**3**	1	**(380)**	(23)
Income before interest and income taxes	**180**	248	**699**	662
Net interest expense	**21**	28	**56**	92
Income before income taxes	**159**	220	**643**	570
Income tax expense	**19**	22	**128**	109
Net income	**140**	198	**515**	461
Net income attributable to the Shareholder	**131**	194	**498**	449
Net income attributable to non-controlling interest [1]	**9**	4	**17**	12
Electricity production (TWh) [2]	**19.4**	19.5	**56.0**	59.9
Cash flow provided by operating activities	**485**	530	**698**	1,211

[1] Relates to the 25 percent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in the Lower Mattagami Limited Partnership, the 33 percent interest of Coral Rapids Power Corporation, a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership, and the 10 percent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP.

[2] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

Commented [A1]:
Wondering if this should be 437?
Since:
Q3 9-mos ended – Q2 6-mos ended = 698-261 = 437

Was Q2 "6-month ended June 30" number for Cash flow provided by operating activities revised?

Third Quarter

Net income attributable to the Shareholder was $131 million for the third quarter of 2017, a decrease of $63 million compared to the same quarter in 2016. Income before interest and income taxes for the third quarter of 2017 was $180 million, a decrease of $68 million compared to the same quarter in 2016.

Significant factors that reduced income before interest and income taxes:

- Lower earnings from the nuclear base regulated price of approximately $24 million reflecting lower electricity generation of 0.4 terawatt hours (TWh) from the Regulated – Nuclear Generation segment and the continuation of existing base regulated prices set by the OEB in 2014. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS since October 2016, largely offset by an increase in generation from Pickering GS. The increase in generation from the Pickering GS was primarily due to outage optimization, favourable unit conditions and execution of planned outage work. The base regulated prices set in 2014 continue to be in effect pending the OEB's decision on OPG's current application for new regulated prices, expected later in 2017. **[MONITOR]** The existing nuclear base regulated price was set to allow the Company to recover its approved nuclear costs over a higher nuclear production volume, based on the 2014 and 2015 outage profile that did not include a refurbishment outage. OPG has requested January 1, 2017 as the effective date of the new regulated prices.
- Lower earnings on the nuclear fixed asset removal and nuclear waste management funds (Nuclear Segregated Funds) of $52 million.
- Higher depreciation and amortization expense of $16 million in the Regulated – Nuclear Generation segment, excluding amortization expense related to balances in OEB-authorized regulatory variance and deferral accounts (regulatory accounts), primarily due to new assets in service.

Commented [A2]: If approved by OEB (during Q4), would this result in a higher regulated price and a revenue/net income pick up for 2017 reported in OPG's Q4?

The expiry of rate riders for the recovery of approved balances in OEB-authorized regulatory accounts on December 31, 2016 contributed to the decrease in revenue for the three months ended September 30, 2017, compared to the same period in 2016, but was largely offset by a decrease in the amortization expense related to these balances. OPG has requested new rate riders in its current application to the OEB for new regulated prices, with a proposed effective date of January 1, 2017.

Significant factor that increased income before interest and income taxes:

- Lower operations, maintenance and administration (OM&A) expenses of $31 million, mainly in the Regulated – Nuclear Generation segment, as a result of a higher materials and supplies obsolescence charge recognized in the third quarter of 2016, Services, Trading and Other Non-Generation segment due to project expenditures incurred in the third quarter of 2016, and Regulated – Hydroelectric segment due to the timing of repairs and maintenance work in 2017 and a deferral of outages during the high water period.

Net interest expense decreased by $7 million during the third quarter of 2017, compared to the same quarter in 2016, primarily due to a higher amount of interest costs capitalized for the Darlington Refurbishment project expenditures and a higher amount of interest costs deferred in OEB-authorized regulatory accounts.

Income tax expense for the three months ended September 30, 2017 was $19 million, compared to $22 million for the same period in 2016. The decrease in income tax expense was primarily due to lower income before taxes and a higher change in reserves from the resolution of uncertainties, partially offset by a lower amount of tax expense deferred in regulatory assets.

Year-To-Date

Net income attributable to the Shareholder was $498 million for the first nine months of 2017, an increase of $49 million compared to the same period in 2016. Income before interest and income taxes for the first nine months of 2017 was $699 million, an increase of $37 million compared to the same period in 2016.

Significant factor that increased income before interest and income taxes:

- Higher earnings of $390 million from the Services, Trading, and Other Non-Generation segment, primarily reflecting the gain on sale of OPG's head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street that was recognized in the second quarter of 2017. The sale of the

assets was required by a Shareholder Declaration and a Shareholder Resolution. The gain on sale was $283 million, which is net of tax effects of $95 million.

Significant factors that reduced income before interest and income taxes:

- Lower earnings from the nuclear base regulated price of approximately $230 million, partially offset by a decrease in nuclear fuel expense of $22 million, reflecting lower electricity generation of 4.0 TWh from the Regulated – Nuclear Generation segment and the continuation of existing base regulated prices set by the OEB in 2014. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS, partially offset by an increase in generation from Pickering GS.
- Lower earnings on the Nuclear Segregated Funds of $41 million.
- Higher depreciation and amortization expense of $30 million in the Regulated – Nuclear Generation segment, excluding amortization expense related to regulatory account balances, primarily due to new assets in service.
- A gain of $22 million recorded in the first quarter of 2016 to reflect the OEB's decision on OPG's motion asking the OEB to review and vary parts of its November 2014 decision on OPG's regulated prices.

The expiry of rate riders for the recovery of approved balances in OEB-authorized regulatory accounts on December 31, 2016 contributed to the decrease in revenue for the nine months ended September 30, 2017, compared to the same period in 2016, but was primarily offset by a decrease in the amortization expense related to these balances.

Net interest expense decreased by $36 million for the nine months ended September 30, 2017, compared to the same period in 2016, primarily due to a higher amount of interest costs capitalized for the Darlington Refurbishment project expenditures and a higher amount of interest costs deferred in OEB-authorized regulatory accounts.

Commented [A3]: Does this imply there were interest costs related to Darlington Refurb previously (same quarter previous year), that were not capitalized, but were able to be capitalized this year?

Income tax expense for the nine months ended September 30, 2017 was $128 million, compared to $109 million for the same period in 2016. The increase in income tax expense was primarily due to higher income before income taxes.

Segment Results

The following table summarizes OPG's income before interest and income taxes by business segment. A detailed discussion of OPG's performance by reportable segment is included in the section, *Discussion of Operating Results by Business Segment*.

(millions of dollars)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Income (loss) before interest and income taxes				
Regulated – Nuclear Generation	**20**	47	**(267)**	17
Regulated – Hydroelectric	**122**	117	**474**	500
Contracted Generation Portfolio	**75**	74	**229**	219
Total electricity generation business segments	**217**	238	**436**	736
Regulated – Nuclear Waste Management	**(36)**	18	**(123)**	(70)
Services, Trading, and Other Non-Generation	**(1)**	(8)	**386**	(4)
	180	248	**699**	662

Electricity Generation

Electricity generation for the three and nine month periods ended September 30, 2017 and 2016 was as follows:

(TWh)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Regulated – Nuclear Generation	**11.3**	11.7	**30.6**	34.6
Regulated – Hydroelectric	**7.3**	6.9	**23.5**	22.8
Contracted Generation Portfolio [1]	**0.8**	0.9	**1.9**	2.5
Total OPG electricity generation	**19.4**	19.5	**56.0**	59.9
Total electricity generation by all other generators in Ontario [2]	**16.6**	19.5	**51.7**	53.8

[1] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.
[2] Non-OPG generation is calculated as the Ontario electricity demand plus net exports, as published by the Independent Electricity System Operator (IESO), minus OPG electricity generation.

Total OPG electricity generation decreased by 0.1 TWh during the third quarter of 2017, compared to the same quarter in 2016, and by 3.9 TWh during the nine months ended September 30, 2017, compared to the same period in 2016. As expected, the lower electricity generation from the Regulated – Nuclear Generation segment was primarily the result of the removal from service of Unit 2 at the Darlington GS for the duration of the unit's refurbishment, which began in October 2016. This decrease in electricity generation was largely offset by an increase in generation from the Pickering GS, primarily due to outage optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station, and higher hydroelectric generation from the Regulated – Hydroelectric segment.

The higher electricity generation of 0.4 TWh and 0.7 TWh from the Regulated – Hydroelectric segment for the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016, was due to higher water flows primarily on the eastern Ontario river systems, net of water spilled as a result of SBG conditions, discussed below.

The lower electricity generation of 0.6 TWh from the Contracted Generation Portfolio segment for the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to higher SBG conditions. The electricity generation from the Contracted Generation Portfolio segment for the three months ended September 30, 2017 was comparable to the same period in 2016.

OPG's operating results are impacted by changes in grid-supplied electricity demand resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. For the three and nine month periods ended September 30, 2017, Ontario's electricity demand as reported by the IESO was 33.6 TWh and 98.5 TWh, respectively, compared to 36.7 TWh and 103.8 TWh for the same periods in 2016, respectively, excluding electricity exports out of the province.

Power that is surplus to the Ontario market is managed by the IESO, mainly through generation reductions at hydroelectric, other grid-connected renewable resources and nuclear stations. Reducing hydroelectric production is the first measure used by the IESO to manage SBG conditions. Low demand conditions in Ontario continued to be prevalent in 2017, resulting in forgone hydroelectric generation for OPG of 1.1 TWh and 4.5 TWh due to SBG conditions in the three and nine month periods ended September 30, 2017, respectively, compared to 0.5 TWh and 3.9 TWh during the same periods in 2016, respectively. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions during these periods was offset by the impact of a regulatory variance account authorized by the OEB. OPG did not forgo any electricity production at its nuclear stations due to SBG conditions.

Average Sales Prices

The majority of OPG's generation is from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments. The same base regulated prices for electricity generated by these segments, authorized by the OEB effective November 1, 2014, were in effect during the first nine months of 2017 as in 2016. These prices will remain in effect until such time as the OEB approves new regulated prices based on OPG's current application. **[MONITOR]** The base regulated prices established in 2014 are discussed in OPG's 2016 annual MD&A in the section, *Revenue Mechanisms for Regulated and Non-Regulated Generation*.

The average sales price for the Regulated – Nuclear Generation segment was 5.8 cents per kilowatt hour (¢/kWh) during the three and nine month periods ended September 30, 2017, respectively, compared to 6.9 ¢/kWh during the same periods in 2016. The decrease in the average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized nuclear rate rider of $10.84 per megawatt hour (MWh) for the recovery of variance and deferral account balances. The average sales price for the Regulated – Hydroelectric segment was 4.1 ¢/kWh during the three and nine month periods ended September 30, 2017, respectively, compared to 4.4 ¢/kWh during the same periods in 2016. The decrease in the average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized regulated hydroelectric rate rider of $3.19/MWh for the recovery of variance and deferral account balances. The rate riders were established to recover approved balances recorded in the variance and deferral accounts in prior years. As such, the year-over-year changes in revenue from the rate riders were largely offset by changes in amortization expense related to these balances. There were no rate riders in effect during the nine months ended September 30, 2017 for either nuclear or regulated hydroelectric generation, pending the outcome of OPG's current application with the OEB for new regulated prices.

Cash Flow from Operations

Cash flow provided by operating activities was $485 million for the three months ended September 30, 2017 and $698 million for the nine months ended September 30, 2017, compared to $530 million and $1,211 million for the same periods in 2016, respectively. The decrease in cash flow provided by operating activities was expected and primarily due to lower generation revenue receipts reflecting lower generation from the Regulated – Nuclear Generation segment as a result of the ongoing refurbishment of Unit 2 at the Darlington GS and the expiry, on December 31, 2016, of the OEB-authorized rate riders for nuclear and regulated hydroelectric generation. The decrease in cash flow during the nine months ended September 30, 2017 was also due to higher income tax instalments.

The decrease in cash flow provided by operating activities for the three and nine month periods ended September 30, 2017 was partly offset by lower OM&A expenditures and lower contributions to the Used Fuel Segregated Fund in 2017. Both the Used Fuel Segregated Fund and the Decommissioning Segregated Fund were determined to be fully funded based on an updated estimate of OPG's nuclear waste management and nuclear facilities decommissioning obligations pursuant to a reference plan approved by the Province, for years 2017 to 2021, under the Ontario Nuclear Funds Agreement (ONFA), effective January 1, 2017. Pursuant to the ONFA, the reference plan is required to be updated at least once every five years. Contributions to either or both of the Nuclear Segregated Funds may be required in the future should the funds be in an underfunded position at the time of the next ONFA reference plan update. The year-over-year decrease in cash flow also was partially offset by the payment of a supplemental rent rebate to Bruce Power in the first quarter of 2016 in relation to a period in 2015. The lease agreement for the Bruce nuclear generating stations was amended in late 2015 to eliminate this rebate provision going forward.

Return on Common Equity Excluding Accumulated Other Comprehensive Income

ROE Excluding AOCI is an indicator of OPG's performance consistent with the Company's strategy to provide value to the Shareholder. ROE Excluding AOCI is measured over a 12-month period.

ROE Excluding AOCI was 4.4 percent for the 12 months ended September 30, 2017, compared to 4.2 percent for the 12 months ended December 31, 2016. The increase was primarily due to higher net income attributable to the Shareholder for the 12 months ended September 30, 2017, which reflected the gain on sale of OPG's head office premises and associated parking facility recorded in the second quarter of 2017, partially offset by the lower earnings from the decrease in nuclear electricity generation reflecting the Unit 2 refurbishment outage at the Darlington GS without a corresponding increase in the nuclear base regulated price, as expected. The lower nuclear generation as a result of the refurbishment outage will continue to negatively affect OPG's ROE Excluding AOCI until such time as new regulated prices are approved by the OEB, anticipated in the fourth quarter of 2017. **[MONITOR]**

Funds from Operations Adjusted Interest Coverage

FFO Adjusted Interest Coverage is an indicator of OPG's ability to meet interest obligations from operating cash flows. The indicator is measured over a 12-month period. FFO Adjusted Interest Coverage for the 12 months ended September 30, 2017 was 4.2 times, compared to 5.1 times for the 12 months ended December 31, 2016. FFO Adjusted Interest Coverage in 2017 reflected a year-over-year decrease in FFO before interest due to lower cash flow provided by operating activities, partially offset by the impact of a lower adjusted interest expense due to a decrease in the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets.

The decrease in the excess of interest on pension and OPEB benefit obligations over expected return on pension plan assets in the nine months of 2017 was primarily due to the change in the method used to estimate the interest cost and service cost components of pension and OPEB costs. Effective January 1, 2017, OPG adopted a full yield curve approach to the estimation of these cost components, by applying the specific spot rates along the yield curve used in the determination of the projected benefit obligations to the relevant projected cash flows. Under the previous method, these components of pension and OPEB costs were calculated using the same single weighted-average discount rates as reflected in the calculation of the benefit obligations. This change in the method was accounted for prospectively, as a change in estimate. The resulting reduction in pension and OPEB costs for the three and nine month periods ended September 30, 2017 did not have a material impact on net income as it was largely offset by the impact of OEB-authorized variance and deferral accounts in the regulated business segments. Further details on the full yield curve approach can be found in the 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Pension and Other Post-Employment Benefits*.

Enterprise Total Generating Cost per MWh

The Enterprise TGC per MWh decreased to $46.65 for the three months ended September 30, 2017, compared to $50.72 for the same quarter in 2016. The decrease was mainly due to lower OM&A expenses before the impact of regulatory accounts and higher SBG-adjusted hydroelectric generation reflecting higher water flows.

The Enterprise TGC per MWh was $47.77 for the nine months ended September 30, 2017, an increase compared to $46.74 for the same period in 2016. The increase was expected and mainly a result of lower electricity generation due to the Unit 2 refurbishment outage at the Darlington GS, largely offset by lower OM&A expenses before the impact of regulatory accounts and higher SBG-adjusted hydroelectric generation reflecting higher water flows.

If Unit 2 at the Darlington GS was not currently undergoing refurbishment and had continued to operate in a manner consistent with the performance of the remaining units at the Darlington GS, adjusting for generation constraints on these units related to the transition of the station toward refurbishment, the Enterprise TGC would have been approximately $4 per MWh lower for both the three and nine month periods ended September 30, 2017. This sensitivity was calculated using the estimated incremental electricity and associated fuel cost that are expected to have resulted in the absence of the refurbishment.

Nuclear Total Generating Cost per MWh

The Nuclear TGC per MWh was $58.75 for the three months ended September 30, 2017, which was comparable to $58.55 for the same quarter in 2016. For the three months ended September 30, 2017, the higher generation at the Pickering GS and the impact of lower OM&A expenses before the impact of regulatory accounts was mostly offset by the expected decrease in nuclear electricity generation reflecting the Unit 2 refurbishment outage at the Darlington GS and higher sustaining capital expenditures. The Nuclear TGC per MWh was $67.87 for the nine months ended September 30, 2017, compared to $61.07 for the same period in 2016. The increase in the Nuclear TGC per MWh for the nine months ended September 30, 2017 was expected and primarily due to the decrease in nuclear electricity generation, partially offset by lower OM&A expenses before the impact of regulatory accounts.

Hydroelectric Total Generating Cost per MWh

The Hydroelectric TGC per MWh was $26.20 for the three months ended September 30, 2017, compared to $31.01 for the same quarter in 2016. The decrease was primarily due to higher SBG-adjusted hydroelectric electricity generation reflecting higher water flows. The Hydroelectric TGC per MWh was $21.74 for the nine months ended September 30, 2017, compared to $23.99 for the same period in 2016. The decrease was primarily due to lower OM&A expenses before the impact of regulatory accounts and lower sustaining capital expenditures.

ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are not measurements in accordance with US GAAP and should not be considered alternative measures to net income, cash flow provided by operating activities, or any other performance measure under US GAAP. OPG believes that these non-GAAP financial measures are effective indicators of its performance and are consistent with the Company's strategic imperatives and related objectives. The definition and calculation of ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are found in the section, *Supplementary Non-GAAP Financial Measures*.

Recent Developments

Ontario's 2017 Long Term Energy Plan

On October 26, 2017, Ontario's Ministry of Energy issued the 2017 Long Term Energy Plan. The Plan is currently being analyzed by OPG but is not expected to significantly impact OPG's business. There are no fundamental changes from the principles in the 2013 Long Term Energy Plan, which include cost effectiveness, reliability, clean energy and community engagement. The 2017 Long Term Energy Plan fully supports nuclear refurbishment projects in Ontario and the extension of commercial operation of all Pickering units to 2024. **[MONITOR & UPDATE DETAILS FOLLOWING RELEASE]**

OEB's Decision on New Regulated Prices **[MONITOR]**

Ontario's Fair Hydro Plan

OPG continues to prepare for its involvement as the Financial Services Manager for Ontario's Fair Hydro Plan (the Fair Hydro Plan) on a commercial basis. Accordingly, the financing entity was established in XX 2017 as the Fair Hydro Trust (the Trust), following the execution of its constating documents. The majority unitholder and beneficiary of the Trust is a wholly-owned subsidiary of OPG. Through this ownership and OPG's control over the key activities of the Trust, the Company will consolidate the Trust for accounting purposes commencing in the fourth quarter of 2017. **[MONITOR]**

In order for the Trust to provide financing for the deferred Global Adjustment costs, the Trust will incur senior debt from capital markets and subordinated debt from OPG. The Trust is structured to be bankruptcy remote and ring fenced from OPG to protect the Company's assets and operations. In support of the Fair Hydro Plan, the following developments have transpired:

- In October 2017, *Ontario Regulation 206/17 General* was amended to establish details of the recovery mechanism for the monthly carrying costs incurred by the Trust from June 1, 2017 to July 31, 2021 payable by the IESO to the Trust. Originally established in June 2017, this regulation provides more details on the funding obligations incurred by the Trust and the fair allocation amount, the determination and collection of clean energy adjustments, the determination of the finance amount, the true up amount, and the regulatory asset, as well as principles and assumptions relating to the financing plan.
- A plan to amend the Company's Articles of Amalgamation to allow for the creation and issuance of Class A shares to be issued to the Province for its equity investment through OPG in the Fair Hydro Plan is in progress. The Province is expected to provide 44 percent of the total funding requirement related to the deferred Global Adjustment costs, which OPG will invest as subordinated debt into the Trust. OPG's Board approval and a Shareholder Resolution are expected later in the year to authorize the amendment.
- OPG is expected to provide five percent of the total funding requirement of the Trust related to the deferred Global Adjustment costs of the Fair Hydro Plan. OPG issued senior notes payable in October 2017 under a short form base shelf prospectus for general corporate purposes and to fund OPG's subordinated debt investment in the Trust. Further details of the debt offering can be found in the section, *Liquidity and Capital Resources* under the heading, *Financing Activities*.

Commented [A4]: Are any other details available to be released at this time?

The first set of transactions of the Trust are expected to take place in the fourth quarter of 2017.

Canadian Nuclear Safety Commission Safety Rating for the Darlington GS and the Pickering GS

The Canadian Nuclear Safety Commission (CNSC) publishes an annual report on the safety performance of Canada's nuclear power plants. The report assesses how well plant operators are meeting regulatory requirements and program expectations in the areas of operational performance, safety analysis, radiation protection, waste management and conventional health and safety. On September 8, 2017, the CNSC issued an executive summary of its 2016 annual report. The CNSC gave both the Darlington GS and the Pickering GS the highest possible safety rating of "Fully Satisfactory". The Darlington GS achieved this rating for the eighth consecutive year, while the Pickering GS achieved this rating for the second consecutive year.

CORE BUSINESS, STRATEGY, AND OUTLOOK

The discussion in this section is qualified in its entirety by the cautionary statements included in the section, *Forward-Looking Statements,* at the beginning of the MD&A.

OPG's mission is to provide low cost power in a safe, clean, reliable and sustainable manner for the benefit of customers and its Shareholder. OPG also seeks to pursue, on a commercial basis, generation development projects and other business growth opportunities.

The following sections provide an update to OPG's disclosures in the 2016 annual MD&A related to its four key strategic imperatives – operational excellence, project excellence, financial strength, and social licence. A detailed discussion of these strategic imperatives is included in the 2016 annual MD&A in the section, *Core Business, Strategy, and Outlook*.

Operational Excellence

Operational excellence at OPG is accomplished by the safe and environmentally responsible generation of reliable and cost-effective electricity from the Company's generating assets through a highly trained and engaged workforce.

Electricity Generation Production and Reliability

- As part of the plan to extend Pickering operations, OPG is continuing to undertake the required technical work to confirm that the station's pressure tubes, a key life-limiting component of the station, will remain fit for service for operation to 2024. OPG is also nearing completion of component condition assessments to identify the work required to support the continued operation of the station. The accounting end of life assumptions for the Pickering GS, currently set at the end of 2020, will be reassessed based on the fuel channel analysis and safety case consistent with submissions for the CNSC approval, discussed below. The activities completed to date have had positive results, which will go towards re-confirming Pickering operations past 2020 are technically feasible. The Periodic Safety Review (PSR) is in progress and will confirm that extending operations of the Pickering units will be safe to the public, workers and the environment. The PSR consists of Safety Factor Reports (SFRs), a Global Assessment Report (GAR), and the Integration Improvement Plan (IIP). SFRs have been submitted to the CNSC and the GAR and IIP are on track for CNSC submission in October and November 2017, respectively. Other technical feasibility activities continue to progress as planned. Completion of various technical feasibility assessments are required to reach a high confidence conclusion to allow the station end of life to change for depreciation purposes. OPG's current application with the OEB for new base regulated prices, currently pending the OEB's decision, reflects OPG's plans to extend Pickering operations to 2024 and requests inclusion of the corresponding cost and generation impacts in the determination of the nuclear regulated price.
- OPG's current five-year operating licence for the Pickering GS was approved by the CNSC in 2013 and expires on August 31, 2018. This licence was issued assuming that the station would shut down in 2020. On June 28, 2017, OPG confirmed to the CNSC that it intends to cease commercial operation of all Pickering units on December 31, 2024. On August 28, 2017, OPG submitted a ten-year licence renewal application to the CNSC. The licence term spans the planned extended operations period, through to the end of commercial operation, defueling, dewatering and the start of placing the station in a safe storage state.
- Work continues on the rehabilitation of Unit 2 of the DeCew Falls hydroelectric GS and the rehabilitation and overhaul of Unit 2 of the Lower Notch hydroelectric GS.
- During the third quarter, a new control centre was opened at Saunders GS to merge its operations with Chenaux GS. The new control centre will overlook power production at ten hydroelectric stations along the Madawaska, Ottawa and St. Lawrence rivers.
- As part of the process to decommission the Nanticoke and Lambton generating stations, OPG has begun executing demolition plans that will ensure that the stations are closed safely, securely and in an environmentally responsible manner. The demolition of the Nanticoke coal yard equipment and structures is in progress, with a contract issued in July 2017 for the demolition of the Nanticoke powerhouse and associated structures. Project milestones for the Nanticoke site during the remainder of 2017 include completing the removal of coal yard equipment and structures, demolition of the ash silos, and mobilization of the contractor to prepare for removal of the stacks, powerhouse and associated structures. A competitive bidding process for the demolition of the Lambton GS has been completed, with a contract for the removal of the powerhouse and associated buildings expected to be awarded in 2018. An update of the associated asset retirement obligations related to the Nanticoke and Lambton sites is expected to be finalized in the fourth quarter of 2017.

Environmental Performance

There were no significant changes to environmental legislation affecting the Company during the third quarter of 2017. Disclosures related to the Company's environmental policy and environmental risks can be found in OPG's 2016 annual MD&A.

OPG communicates its environmental performance internally to employees and to external stakeholders, including the Ontario Ministry of the Environment and Climate Change, Environment and Climate Change Canada, the CNSC, and local communities. Details of OPG's environmental performance and initiatives to fulfill the Company's Environmental Policy can be found in OPG's 2016 Sustainability Report, available on the Company's website at www.opg.com. **[MONITOR]**

Project Excellence

OPG is pursuing a number of generation development and other major projects in support of Ontario's electricity planning initiatives. OPG remains focused on delivering projects safely, on time, on budget and with high quality. The status updates for OPG's major projects as at September 30, 2017 are outlined in the following table, with further details below.

Project	Capital expenditures		Approved budget	Expected in-service date	Current status
(millions of dollars)	**Year-to-date**	**Life-to-date**			
Darlington Refurbishment	924	4,109	12,800 [1]	First unit - 2020 Last unit - 2026	The setup of specialized tooling and equipment needed for the removal of reactor components was completed in the third quarter of 2017. All feeder tubes have been removed safely, and the pressure tubes have been severed in preparation for their removal. The Re-tube Waste Processing Building will be available for use in the fourth quarter of 2017. The project is tracking on schedule and on budget.
Peter Sutherland Sr. Hydroelectric GS	38	274	300	2017	The station was placed in-service on March 31, 2017, ahead of the originally planned schedule, and is expected to close below the approved budget. Project close-out activities are in progress.
Ranney Falls Hydroelectric GS	17	20	77	2019	Work is progressing on the expanded forebay, forebay wall concrete replacement, powerhouse and spillway areas. The project is tracking on schedule and on budget.
Nanticoke Solar Facility	1	2	107 **[MONITOR]**	2019	Project definition work is continuing, with construction planned to commence in the first quarter of 2018.
Deep Geologic Repository for low and intermediate level radioactive waste (L&ILW)	7 [2]	202 [2]			On August 21, 2017, the federal Minister of Environment and Climate Change requested further information on the project's environmental assessment (EA). OPG is reviewing the new request and will notify the Canadian Environmental Assessment Agency (CEAA) when it has a timeline for submission of that information.

[1] The total project budget of $12.8 billion is for the refurbishment of all four units at the Darlington GS.
[2] Expenditures are charged against the nuclear fixed asset removal and nuclear waste management liabilities (Nuclear Liabilities).

Commented [A5]: Does this imply that only 700M further is anticipated to be spent by the time Unit 2 gets completed? (Eg. 4.8B in Capital Expenditure)

Eg. from above:
"Once refurbished, Unit 2 is scheduled to be returned to service in the first quarter of 2020, at which time capital expenditures of approximately $4.8 billion are planned to be placed in service."

Darlington Refurbishment

The Darlington generating units are approaching their originally designed end-of-life. Refurbishment of the four generating units is expected to extend the operating life of the station by approximately 30 years. OPG commenced the planning of the refurbishment in 2010.

In 2016, the Darlington Refurbishment project transitioned from the planning phase to the execution phase, as OPG commenced the refurbishment of the first unit, Unit 2, in October 2016, as planned. The unit was taken offline on October 15, 2016. De-fuelling of the reactor, the first critical refurbishment activity undertaken once the unit is removed from service, was completed safely in January 2017, with a total of 480 fuel channels de-fuelled. Islanding of Unit 2, the physical separation of the unit under refurbishment from the three operating units, was completed in April 2017, signifying the completion of the first major segment of the project.

The second major segment includes preparatory work to support the removal of feeder tubes and fuel channel assemblies and the removal of reactor components. The preparatory work was completed in the second quarter of 2017. The Re-tube Tooling Platform for hosting the tooling for the removal, inspection, and installation activities and the setup of specialized tooling and equipment needed for the removal and replacement of the reactor components were completed in the third quarter of 2017. The disassembly of reactor components commenced in August 2017, with the removal of all 960 feeder tubes completed safely in September 2017. This was followed by the severing of pressure tubes, with the severing of bellows and the removal of end fittings expected to commence thereafter and through the end of 2017. Other key project activities executed during the second segment include the completion of the primary side steam generator layup, installation of steam generator access ports to support future inspections, continuation of the major turbine generator overhaul and continued execution of the major electrical scope. OPG is also continuing to execute work to support the requirements set out in the CNSC approved IIP for the station.

Once refurbished, Unit 2 is scheduled to be returned to service in the first quarter of 2020, at which time capital expenditures of approximately $4.8 billion are planned to be placed in service. This includes expenditures incurred during the definition and planning phase of the overall project. The project is tracking on schedule and on budget.

With the substantial completion of the Re-tube Waste Processing Building in November 2017, 17 out of 18 pre-requisite projects in support of the execution phase of the project, including construction of facilities, infrastructure upgrades and installation of safety enhancements, have been completed and placed in service. Completion of the Heavy Water Storage and Drum Handling Facility (HWSF) has been delayed due to challenges with construction. OPG suspended the project in the second quarter of 2017 to evaluate the best approach to optimize cost and schedule and complete the project. Construction activities for the HWSF recommenced in the fourth quarter of 2017 following substantial completion of the Re-tube Waste Processing Building. This plan ensures that the necessary resources are available for both projects and, through resource levelling, improves their execution and cost efficiency. The delay in the completion of the HWSF will not impact the overall Darlington Refurbishment project schedule, as the HWSF is not on the project's critical path. This also will not impact the overall project budget of $12.8 billion, as the costs of the HWSF are included in this total figure. The recovery of HWSF costs through regulated prices will be subject to a prudence review by the OEB, which OPG has proposed be conducted as part of a future OEB application.

In addition to the execution of refurbishment activities on Unit 2, OPG is continuing planning activities for the refurbishment of the second unit, Unit 3, and is entering into associated commitments to procure major components that require long lead times. As of September 30, 2017, $70 million has been invested in planning activities related to the refurbishment of the second unit, Unit 3. These planning activities are being undertaken in accordance with the refurbishment project schedule.

The Financial Accountability Office of Ontario has issued a report titled "*An Assessment of the Financial Risks of the Nuclear Refurbishment Plan*". The report assesses both OPG and Bruce Power's refurbishment activities and the method in which those refurbishments and subsequent nuclear generation is provided to the marketplace. The report

concludes that the base case of refurbishing the six units at the Bruce nuclear GS and the four units at the Darlington nuclear GS provide the most cost effective, low emission generation source available to meet Ontario's baseload electricity requirements. This report re-affirms the positive economic and societal benefits associated with a strong nuclear program in the Province. **[MONITOR]**

Commented [A6]: Not yet released.

Ranney Falls Hydroelectric GS

During the third quarter of 2017, OPG continued construction work for a 10 MW single-unit powerhouse on the existing Ranney Falls GS site, as part of the Regulated – Hydroelectric segment. The new unit will replace an existing unit that reached its end of life in 2014. The existing forebay structure demolition has been completed and the upstream cofferdam has been constructed ahead of schedule. Construction continues on the expanded forebay, powerhouse and spillway. Excavation work is substantially complete and forebay wall concrete replacement is in progress. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget.

Nanticoke Solar Facility

The construction of a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands under a Large Renewable Procurement contract with the IESO, through Nanticoke Solar LP, a partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation, is planned to commence in the first quarter of 2018. During the third quarter of 2017, the partnership continued work to obtain approvals and permits required to enable the commencement of construction, and progressed procurement activities for equipment and for engineering and construction services. The facility is expected to be completed in the first quarter of 2019.

Deep Geologic Repository for Low and Intermediate Level Waste

OPG has proposed a deep geologic repository as the preferred solution for the safe long-term management of the L&ILW produced from the continued operation of OPG-owned nuclear generating stations. Agreement has been reached with local municipalities for OPG to develop the L&ILW Deep Geologic Repository (DGR) on lands adjacent to the Western Waste Management Facility (WWMF) in Kincardine, Ontario. The environmental effects of the proposed L&ILW DGR were examined by the CNSC and CEAA-appointed Joint Review Panel (JRP) to meet the requirements of the Canadian Environmental Assessment Act. The JRP submitted its report on the EA to the federal Minister of Environment in May 2015, concluding that, given mitigation, there is unlikely to be significant environmental impact from the project and recommending that the Minister approve the EA. In December 2016, at the request of the federal Minister of Environment and Climate Change, OPG submitted additional information on certain aspects of the EA, including information related to alternate locations for the project. Following its review of OPG's submission and a period of public comment, the CEAA requested further information that OPG subsequently provided in May 2017. In June 2017, the CEAA notified OPG that it had sufficient and adequate information to proceed with the next step of the environmental assessment process and advised that a draft report and updated terms and conditions will be prepared for public review.

On August 21, 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of potential cumulative effects of the project on the Saugeen Ojibway Nations' (SON) physical and cultural heritage, including a description of the potential effects of the project on the Nation's spiritual and cultural connection to the land. OPG is assessing the request and will notify the CEAA when it has determined the timeline for developing a response. The CEAA's draft report for public review will not be issued until this update is provided. The L&ILW DGR at the WWMF site remains OPG's preferred solution for the safe long-term management of the L&ILW.

OPG continues its engagement with the SON toward securing community support for the L&ILW DGR. The in-service date of the L&ILW DGR is expected to be approximately six to seven years from the start of construction.

Financial Strength

As a commercial enterprise, OPG's financial priority is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future growth.

Increase Revenue, Reduce Costs and Achieve Appropriate Return

In May 2016, OPG filed a 5-year application with the OEB for new regulated prices for production from its regulated hydroelectric and nuclear facilities, with a proposed effective date of January 1, 2017. Consistent with the requirements of *Ontario Regulation 53/05*, the application incorporates a rate smoothing proposal that would defer, for future collection, a portion of the approved annual nuclear revenue requirement for the period from January 1, 2017 to the end of the Darlington Refurbishment project, with a view to making changes in OPG's regulated prices more stable year-over-year. The application seeks to ensure that nuclear regulated prices under the rate smoothing approach allow for sufficient cash flow to meet the Company's liquidity needs, support cost effective funding for the Darlington Refurbishment project and other expenditures, and maintain the Company's investment grade credit rating, while taking into account both near-term and future impacts on customers. OPG expects to recognize amounts deferred under rate smoothing as income in the periods to which the underlying approved revenue requirements relate.

The application will further challenge and incentivize OPG to find additional cost reductions and efficiencies within its operations, as a result of greater de-coupling of nuclear and hydroelectric regulated prices from costs and a longer rate-setting period under the OEB's incentive ratemaking framework, which forms the basis for the ratemaking methodologies reflected in the application.

The application seeks an increase in the nuclear rate base, effective in early 2020, to reflect the planned placement in service of approximately $4.8 billion of capital expenditures upon the scheduled return to service of Unit 2 at the Darlington GS as part of the Darlington Refurbishment project and, effective in 2017, an increase in the deemed capital structure applied to the total regulated rate base to 49 percent equity and 51 percent debt, from 45 percent equity and 55 percent debt reflected in the existing regulated prices. The application also requests new rate riders, effective January 1, 2017, to recover or repay the December 31, 2015 balances in all of the Company's OEB-authorized variance and deferral accounts, with the exception of the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the portion of these balances previously approved for recovery or repayment through rate riders that were in effect during 2016.

The OEB's decision on the application, including the effective date of approved new regulated prices, is expected later in 2017. **[MONITOR]**

For generation assets that do not form part of the assets regulated by the OEB, OPG's strategy has been to secure appropriate long-term revenue arrangements. In line with this strategy, virtually all of OPG's non-regulated operating facilities and assets under construction are subject to long-term Energy Supply Agreements (ESAs) or other long-term contracts with the IESO.

Ensure Availability of Cost Effective Funding

In April 2017, DBRS Limited (DBRS) re-affirmed the long-term credit rating on OPG's debt at 'A (low)' and OPG's commercial paper rating at 'R-1 (low)'. All ratings from DBRS have a stable outlook. In July 2017, S&P Global Ratings (S&P) re-affirmed OPG's long-term credit rating at 'BBB+' with a stable outlook. S&P's commercial paper rating for OPG is 'A-1 (low)'.

Social Licence

As the largest electricity generator in Ontario with diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust. OPG is committed to maintaining high standards of public safety and corporate citizenship, including environmental stewardship, transparency, community engagement, and Indigenous relations.

OPG is focused on building long-term, mutually beneficial working relationships with Indigenous communities, businesses and organizations across Ontario, and continues to support procurement, employment and educational opportunities with its Indigenous community partners. The Company seeks to establish these relationships based on a foundation of respect for the languages, customs, and political, social and cultural organizations of the Indigenous communities.

In June 2017, OPG launched an Indigenous Business Engagement (IBE) Initiative. The purpose of this initiative is to increase access to procurement opportunities for Indigenous businesses interested in supplying materials and services to OPG. The IBE Initiative is based on a strategy that will identify opportunities in contracts, scopes of work and business plans for potential Indigenous business engagement; include criteria related to suppliers' ability to engage or partner with Indigenous people or businesses in assessing procurement proposals; and invest in relationships with Indigenous communities by increasing outreach efforts to enhance understanding of how to do business with OPG. OPG has continued to engage with various Indigenous business and communities as well as its suppliers to promote the IBE Initiative. In September 2017, OPG presented the IBE to the Mohawk Council of Akwesanse (Akwesanse). As a result, Akwesanse plans to create a database of businesses in the community that will participate in contracting and supply opportunities with OPG. In September 2017, OPG also hosted a similar presentation to the Williams Treaties First Nations, located proximate to the Pickering and Darlington Nuclear Generating Stations, at the quarterly meeting for these communities.

Commented [A7]: Sp. "Akwesasne" ?

OPG is developing recruitment plans targeting Indigenous people. In October 2017, OPG participated in five Indigenous-specific career fairs to attract such talent. **[MONITOR]**

OPG has a transportation electrification strategy that will help position OPG as a leader in transportation electrification in Ontario. This strategy is intended to leverage OPG's clean electricity to support action on climate change, create growth opportunities for OPG, and enhance OPG's brand and social licence.

Commented [A8]: Does this deal with OPG owned fleet and other vehicles, or in line with the infrastructure for EV vehicles.

Can further details be provided in particular on the point of 'creating growth opportunities for OPG'.

Outlook

The financial performance of OPG's regulated operations is driven, in large part, by the outcome of applications for regulated prices to the OEB. The existing base regulated prices were established by the OEB effective November 1, 2014 based on a forecast of costs and production for the regulated facilities for the 2014 to 2015 period. The future outcome of OPG's current application for new regulated prices, currently pending the OEB's decision, is expected to provide substantial price certainty for the regulated business for the 2017 to 2021 period.

In its application, OPG has requested January 1, 2017 as the effective date for the new regulated prices. In December 2016, the OEB issued an order declaring the existing base regulated prices interim, which preserves the OEB's ability to make the new regulated prices effective as early as January 1, 2017. Considering the timing of OPG's application and OPG's procedural adherence throughout the proceeding, the Company believes that the OEB could make the new regulated prices effective January 1, 2017. This would allow OPG to recover the difference between the approved new regulated prices and the existing regulated prices for the period between January 1, 2017 and the implementation date of the new prices based on the OEB's order. The OEB's decision on the application, including the effective date of the new regulated prices, is expected in the fourth quarter of 2017. **[MONITOR]** The continuation of existing regulated prices until the issuance of the OEB's decision is expected to continue to contribute to lower income, particularly from the Regulated – Nuclear Generation segment, and, excluding the gain on sale of the Company's head office premises and associated parking facility recorded in the second quarter of 2017, lower

ROE Excluding AOCI during 2017, compared to 2016. In large part, this is due to the year-over-year reduction in nuclear electricity generation resulting from the Unit 2 refurbishment outage at the Darlington GS, given that the existing nuclear regulated prices were determined in 2014 based on a higher production forecast that reflected the operation of all four units at the station. As such, the OEB's decision on the effective date of the new regulated prices, as well as the timing of the decision issuance, could have a significant impact on OPG's financial results during 2017.

Nuclear base regulated prices resulting from OPG's current application will be subject to a rate smoothing mechanism that defers collection of a portion of OEB-approved revenues to future periods. As expected, combined with the expiry of rate riders in effect to the end of 2016, a year-over-year reduction in nuclear generation due to the Unit 2 refurbishment outage at the Darlington GS and the continuation of existing regulated prices until such time as new prices are implemented by the OEB, this will result in lower cash flow from operating activities in 2017, compared to 2016. OPG expects to continue to have the necessary financial capacity and sufficient access to cost effective financing sources to continue to fund its capital requirements and other disbursements.

Lower nuclear generation due to the Darlington Refurbishment outages will continue, as planned, to negatively impact the Enterprise TGC metric for the duration of the refurbishment project. Variability in sustaining capital investment expenditures, including major sustaining projects for the hydroelectric operations, also will impact the Enterprise TGC in future periods.

Several OEB-authorized regulatory variance and deferral accounts currently in place contribute to reducing the relative variability of the Company's income and ROE Excluding AOCI. Among others, the regulatory accounts include those related to the revenue impact of variability in water flows and forgone production due to SBG conditions at the regulated hydroelectric stations. As there are no variance or deferral accounts in place related to the impact of generation performance of the nuclear stations on revenue from base regulated prices, the Regulated – Hydroelectric segment generally is expected to produce overall more predictable earnings. OPG continues to operate and maintain its nuclear facilities with a view to optimize their performance and availability, while focusing on improving the overall reliability and predictability of the fleet.

Electricity generated from most of OPG's non-regulated assets is subject to ESAs with the IESO. Based on these agreements, OPG expects the Contracted Generation Portfolio segment to continue to contribute a generally stable level of earnings and cash flow from operations going forward.

OPG's total forecast capital expenditures for the 2017 year are approximately $2.0 billion. This includes amounts for the Darlington Refurbishment project, hydroelectric and other development projects including the completion of the Peter Sutherland Sr. GS and the expansion of the Ranney Falls GS, and sustaining capital investments across the generating fleet. OPG's major projects are discussed in the section, *Project Excellence*.

In addition to the operating and financial performance of the electricity generation business, OPG's results are affected by the earnings on the Nuclear Segregated Funds, which are reported in the Regulated – Nuclear Waste Management segment. While the Nuclear Segregated Funds are managed to achieve, in the long term, the target rate of return based on the discount rate specified in the ONFA, the rates of return earned in a given period can be subject to various external factors including financial market conditions and, for the portion of the Used Fuel Segregated Fund guaranteed by the Province under the ONFA, changes in the Ontario consumer price index (CPI). In the near term, these factors can be volatile and cause fluctuations in the Company's income. This volatility is partially mitigated by the impact of the OEB-authorized Bruce Lease Net Revenues Variance Account and, as discussed below, the funded status of the two segregated funds.

As OPG does not have the right to withdraw surplus amounts from the Nuclear Segregated Funds, OPG limits the amount of Nuclear Segregated Funds assets reported on the balance sheet to the present value of such life cycle funding liability. This reduces the volatility of earnings on the Nuclear Segregated Funds reflected in net income when the funds are in a fully funded or overfunded position. As at September 30, 2017, the Decommissioning

Segregated Fund was overfunded by approximately 23 percent, and the Used Fuel Segregated Fund was marginally overfunded, by less than one percent, based on the 2017 ONFA Reference Plan. Variability in asset performance due to volatility inherent in financial markets and changes in Ontario CPI, or changes in funding liability estimates, may result in either or both funds becoming underfunded in the future.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

Regulated – Nuclear Generation Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue	**739**	885	**2,000**	2,631
Fuel expense	**81**	79	**217**	239
Gross margin	**658**	806	**1,783**	2,392
Operations, maintenance and administration	**511**	521	**1,693**	1,665
Depreciation and amortization	**116**	230	**333**	691
Property taxes	**7**	6	**20**	19
Income (loss) before other losses, interest, and income taxes	**24**	49	**(263)**	17
Other losses	**4**	2	**4**	-
Income (loss) before interest and income taxes	**20**	47	**(267)**	17

For the three and nine month periods ended September 30, 2017, the segment earnings decreased by $27 million and $284 million, respectively, compared to the same periods in 2016. The decrease in earnings was expected and primarily due to reduced revenue from the nuclear base regulated price of approximately $24 million and $230 million, respectively. The decrease was partially offset by an associated year-over-year decrease in fuel expense. The decrease in revenue during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, reflected lower electricity generation of 0.4 TWh and 4.0 TWh, respectively, primarily due to the ongoing Unit 2 refurbishment outage at the Darlington GS that began in October 2016, without a corresponding increase in the base regulated price. The existing nuclear base regulated price set by the OEB in 2014 continues to be in effect pending the OEB's decision on OPG's application for new regulated prices, proposed to be effective on January 1, 2017. The existing price does not reflect the lower generation as a result of the Darlington Refurbishment project, as it was set to allow the Company to recover its approved nuclear costs over a higher nuclear production volume, based on the 2014 and 2015 outage profile that did not include a refurbishment outage. The reduction in nuclear electricity generation for the three months ended September 30, 2017 was largely offset by the higher electricity generation from the Pickering GS.

OM&A expenses decreased by $10 million during the third quarter of 2017, compared to the same period in 2016, as a result of a higher materials and supplies obsolescence charge recognized in 2016. OM&A expenses increased by $28 million during the nine months ended September 30, 2017, compared to the same period in 2016, due to planned maintenance activities in 2017.

Depreciation and amortization expense, excluding amortization expense related to regulatory account balances, increased by $16 million and $30 million during the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016, primarily due to new assets in service.

The expiry of an OEB-authorized nuclear rate rider on December 31, 2016 contributed to the decrease in segment revenue for the three and nine month periods ended September 30, 2017, compared to the same periods in 2016. As rate riders allow for recovery of approved balances in OEB-authorized regulatory accounts, this decrease in revenue was largely offset by a decrease in amortization expense related to these balances. There was no rate rider

in effect during the nine months ended September 30, 2017, pending the outcome of OPG's current application to the OEB for new regulated prices.

The Unit Capability Factors for the Darlington and Pickering generating stations were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Unit Capability Factor *(%)* [1]				
Darlington GS	**96.2**	89.6	**82.1**	87.6
Pickering GS	**88.7**	77.3	**83.8**	73.8

[1] The nuclear Unit Capability Factor excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS was excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

The Unit Capability Factor at the Darlington GS increased in the third quarter of 2017, compared to the same quarter in 2016, primarily due to the lower number of planned outage days during the third quarter of 2017. The lower Unit Capability Factor at the Darlington GS for the nine months ended September 30, 2017, compared to the same period in 2016, reflected the higher number of planned outage days, largely driven by constraints related to the transition of the station toward refurbishment.

The increase in Unit Capability Factor at the Pickering GS for the three and nine month periods ended September 30, 2017 was primarily due to outage optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station compared to 2016.

Regulated – Nuclear Waste Management Segment

(millions of dollars) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Revenue	**33**	36	**90**	102
Operations, maintenance and administration	**35**	38	**96**	108
Accretion on nuclear fixed asset removal and nuclear waste management liabilities	**230**	228	**696**	684
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(196)**	(248)	**(579)**	(620)
(Loss) Income before interest and income taxes	**(36)**	18	**(123)**	(70)

The segment loss before interest and income taxes was $36 million and $123 million during the three and nine months ended September 30, 2017, respectively, a decrease in earnings of $54 million and $53 million compared to the same periods in 2016. The decline in earnings was primarily due to lower earnings from the Nuclear Segregated Funds, net of the impact of the impact of the Bruce Lease Net Revenues Variance Account, reflecting higher earnings from market returns on fund assets and the CPI-adjusted rate of return guaranteed by the Province for the portion of the Used Fuel Segregated Fund related to the initial 2.23 million used fuel bundles (committed return) in the third quarter of 2016.

As both the Decommissioning Segregated Fund and the Used Fuel Fund were in an overfunded position during the three and nine months period ended September 30, 2017, compared to the underlying funding liabilities per the approved ONFA Reference Plan, the earnings on the funds during these periods reflected the growth rate in the present value of the funding liabilities and were not impacted by market returns and committed return. The higher earnings on both funds during the three and nine months periods ended September 30, 2016 reflected market returns and committed return, as the Decommissioning Segregated Fund became over 120 percent funded during the third quarter of 2016 while the Used Fuel Fund was underfunded, compared to the corresponding funding liabilities.

Higher market returns and committed return in the third quarter of 2016 in relation to the funding liabilities' growth rate reflected in fund earnings during 2017 resulted in a year-over-year decrease in the amount of earnings on the Nuclear Segregated Funds.

As of December 31, 2016, OPG recorded a decrease of approximately $1,570 million to the Nuclear Liabilities and associated asset retirement costs capitalized as part of the carrying value of the nuclear generating stations. The resulting year-over-year decreases in accretion on fixed asset removal and nuclear waste management liabilities recorded in the Regulated – Nuclear Waste Management segment and depreciation and fuel expenses recorded in the Regulated – Nuclear Generation segment during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, were offset by the impact of the Bruce Lease Net Revenues Variance Account and the Nuclear Liability Deferral Account authorized by the OEB.

Under the current OEB-approved cost recovery methodology, these changes in expenses also are not expected to materially affect OPG's income during the rest of 2017, as they are expected to continue to be largely offset by the impact of the regulatory accounts until such time as the OEB implements corresponding changes to OPG's nuclear regulated prices, and subsequently by the impact of such new regulated prices. Further details on the change in the estimate of the Nuclear Liabilities as of December 31, 2016 are described in OPG's 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Asset Retirement Obligation*. **[MONITOR]**

Regulated – Hydroelectric Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue [1]	**327**	350	**1,069**	1,148
Fuel expense	**88**	88	**258**	259
Gross margin	**239**	262	**811**	889
Operations, maintenance and administration	**81**	87	**232**	238
Depreciation and amortization	**34**	56	**103**	169
Property tax	**1**	1	**1**	1
Income before other losses (gains), interest and income taxes	**123**	118	**475**	481
Other losses (gains)	**1**	1	**1**	(19)
Income before interest and income taxes	**122**	117	**474**	500

[1] During the three and nine month periods ended September 30, 2017, the Regulated – Hydroelectric segment revenue included incentive payments of $4 million and $9 million, respectively, related to the OEB-approved hydroelectric incentive mechanism (three and nine month periods ended September 30, 2016 – incentive payments of $6 million and $8 million, respectively). The mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers. The incentive payments are reduced to remove incentive revenues arising in connection with SBG conditions.

The increase in segment income before interest and income taxes of $5 million during the third quarter of 2017, compared to the same quarter in 2016, was primarily the result of a decrease in OM&A expenses, mainly due to the timing of repairs and maintenance work in 2017 and a deferral of outages during the high water period.

The decrease in segment income before interest and income taxes of $26 million during the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to a gain of $22 million recognized during the first quarter of 2016 to reflect the OEB's January 2016 decision to reverse a portion of an earlier capital cost disallowance related to the Niagara Tunnel project expenditures, in response to a motion by OPG. The income impact of OEB-approved variance accounts also contributed to the year-over-year decrease in income for the period. These factors were partially offset by the decrease in OM&A expenses related to the timing of repairs and maintenance work in 2017 and a deferral of outages during the high water period.

The decrease in revenue from the segment for the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was largely due to the expiry of an OEB-authorized rate rider on

December 31, 2016. As the rider allowed for the recovery of approved balances in OEB-authorized regulatory accounts, the resulting reduction in revenue was largely offset by lower amortization expense related to these balances. There was no rate rider in effect during the first nine months of 2017 pending the outcome of OPG's current application to the OEB for new regulated prices.

The Hydroelectric Availability for the stations included in the Regulated – Hydroelectric segment was as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Hydroelectric Availability *(%)*	**87.6**	84.1	**89.0**	89.8

The Hydroelectric Availability in the third quarter of 2017 was higher compared to the same period in 2016, primarily due to a higher number of planned outages in 2016 as a result of the refurbishment of the Sir Adam Beck Pump GS reservoir between April 2016 and February 2017. The marginal decrease in Hydroelectric Availability during the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to a higher number of unplanned outage days at the Northwestern Ontario and Niagara region hydroelectric stations, partially offset by higher availability from the Sir Adam Beck Pump GS.

Contracted Generation Portfolio Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue	**141**	149	**431**	431
Fuel expense	**15**	19	**42**	42
Gross margin	**126**	130	**389**	389
Operations, maintenance and administration	**39**	44	**118**	129
Depreciation and amortization	**20**	19	**59**	56
Accretion on fixed asset removal liabilities	**3**	2	**7**	6
Property taxes	**-**	1	**5**	6
Income from investments subject to significant influence	**(11)**	(11)	**(29)**	(28)
Income before other loss, interest and income taxes	**75**	75	**229**	220
Other loss	**-**	1	**-**	1
Income before interest and income taxes	**75**	74	**229**	219

Income before interest and income taxes from the segment increased by $1 million and $10 million during the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016. The increase in earnings for the three months ended September 30, 2017 mainly resulted from revenues from the Peter Sutherland Sr. GS that was placed in-service at the end of the first quarter of 2017 and lower OM&A expenses, partially offset by lower revenue from the Atikokan GS. The decrease in revenue from the Atikokan GS was primarily due to higher revenues in 2016, when the station was called upon to provide the needed support to the electricity system in Northwestern Ontario as a result of an outage at a local transformer station. For the nine months ended September 30, 2017, the increase in earnings was primarily due to lower OM&A expenses. The lower OM&A expenses for the three and nine month periods ended September 30, 2017 were mainly due to the prospective adoption of the full yield curve approach to the estimation of the service and interest cost components of pension and OPEB costs starting in 2017.

The Hydroelectric Availability and the Thermal Equivalent Forced Outage Rate (EFOR) for the Contracted Generation Portfolio segment were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Hydroelectric Availability *(%)*	**66.1**	68.2	**76.9**	79.6
Thermal EFOR *(%)*	**2.6**	2.1	**6.0**	1.3

Lower Hydroelectric Availability during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was primarily due to an increase in the number of planned outage days at the Lower Mattagami River hydroelectric generating stations.

The higher Thermal EFOR during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was primarily due to a higher number of unplanned outage days at a Lennox GS unit as a result of a transmission outage and a generator cooling water system outage in 2017.

Services, Trading, and Other Non-Generation Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue	**9**	15	**36**	52
Fuel expense	**1**	1	**1**	1
Gross margin	**8**	14	**35**	51
Operations, maintenance and administration	**1**	11	**2**	20
Depreciation and amortization	**8**	8	**22**	25
Accretion on fixed asset removal liabilities	**2**	2	**6**	6
Property taxes	**-**	4	**4**	9
(Loss) income before other gains, interest, and income taxes	**(3)**	(11)	**1**	(9)
Other gains	**(2)**	(3)	**(385)**	(5)
Income (loss) before interest and income taxes	**(1)**	(8)	**386**	(4)

Segment earnings improved by $7 million during the third quarter of 2017, compared to the same quarter in 2016. The improvement in earnings was primarily due to lower OM&A expenses reflecting project expenditures incurred in the third quarter of 2016, and OPG's decision, in the fourth quarter of 2016, to proceed with the decommissioning of Lambton GS.

Segment income before interest and income taxes increased by $390 million for the nine months ended September 30, 2017, compared to the same period in 2016. The increase in earnings mainly reflected the gain on the sale of OPG's head office premises and associated parking facility recorded during the second quarter of 2017.

LIQUIDITY AND CAPITAL RESOURCES

OPG's primary sources of liquidity and capital are funds generated from operations, bank financing, credit facilities provided by the Ontario Electricity Financial Corporation (OEFC), long-term corporate debt, and capital market financing. These sources are used for multiple purposes including: to invest in plants and technologies, to undertake major projects, to fund long-term obligations such as contributions to the pension fund and the Nuclear Segregated Funds, to make payments under the OPEB plans, to fund expenditures on Nuclear Liabilities not reimbursable from the Nuclear Segregated Funds, to service and repay long-term debt, to provide general working capital, and to fund OPG's investment in the Fair Hydro Plan.

Changes in cash and cash equivalents for the three and nine month periods ended September 30 are as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Cash and cash equivalents, beginning of period	**242**	295	**186**	464
Cash flow provided by operating activities	**485**	530	**698**	1,211
Cash flow used in investing activities	**(463)**	(390)	**(720)**	(1,253)
Cash flow provided by (used in) financing activities	**16**	(9)	**116**	4
Net increase (decrease)	**38**	131	**94**	(38)
Cash and cash equivalents, end of period	**280**	426	**280**	426

For a discussion of cash flow provided by operating activities and the FFO Adjusted Interest Coverage ratio, refer to the details in the section, *Highlights* under the heading, *Overview of Results*.

Investing Activities

Electricity generation is a capital-intensive business. It requires continued investment in plants and technologies to maintain and improve operating performance including asset reliability, safety and environmental performance, to increase the generating capacity of existing stations, and to invest in the development of new generating stations, emerging technologies and other business growth opportunities.

Cash flow used in investing activities during the third quarter of 2017 was $463 million, compared to $390 million for the same period in 2016. The increase in cash flow used for investing activities mainly resulted from higher expenditures on the Darlington Refurbishment project in the third quarter of 2017.

Cash flow used in investing activities decreased by $533 million for the nine months ended September 30, 2017, compared to the same period in 2016. The decrease in net cash flow used in investing activities was primarily due to the receipt of proceeds from the sale of OPG's head office premises and associated parking facility in the second quarter of 2017 pursuant to a Shareholder Declaration and Shareholder Resolution, and the acquisition of nine million common shares of Hydro One Limited (Hydro One) in the second quarter of 2016, partially offset by higher expenditures on the Darlington Refurbishment project in 2017. OPG acquired the Hydro One shares for investment purposes, to mitigate the risk of future price volatility related to the Company's future share delivery obligations under the collective agreements with the Power Workers' Union and The Society of Energy Professionals.

Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from the sale of head office premises and associated parking facility, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. OPG expects that the amount of designated proceeds to be transferred into the Consolidated Revenue Fund will be largely consistent with the after-tax gain on sale. The transfer is expected to take place later in 2017.

Financing Activities

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. In the second quarter of 2017, OPG renewed and extended the expiry date of both tranches from May 2021 to May 2022. There were no amounts outstanding under the bank credit facility as at September 30, 2017.

There was $160 million of commercial paper outstanding under OPG's commercial paper program as at September 30, 2017.

As at September 30, 2017, OPG also maintained $25 million of short-term, uncommitted overdraft facilities, and a further $463 million of short-term, uncommitted credit facilities, which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other general corporate purposes. As at September 30, 2017, a total of $388 million of Letters of Credit had been issued under these facilities. This included $349 million for the supplementary pension plans, $38 million for general corporate purposes, and $1 million related to the operation of the PEC.

The Company has an agreement to sell an undivided co-ownership interest in its current and future accounts receivable to an independent trust, expiring on November 30, 2018. The maximum amount of co-ownership interest that can be sold under this agreement is $150 million. As at September 30, 2017, no borrowings were issued under this agreement and there were Letters of Credit outstanding under this agreement of $150 million, which were issued in support of OPG's supplementary pension plans.

As at September 30, 2017, Lower Mattagami Energy Limited Partnership (LME) maintained a $400 million bank credit facility to support the funding requirements for the Lower Mattagami River project including support for LME's commercial paper program and the issuance of the Letters of Credit. The facility consists of a $300 million tranche which, in the third quarter of 2017, was extended to mature in August 2022 and a $100 million tranche which, in the third quarter of 2017, was reduced from $200 million and extended to mature in August 2018. As at September 30, 2017, there was no external commercial paper outstanding under LME's commercial paper program. A letter of credit of $55 million was issued in July 2017 and remains outstanding as at September 30, 2017 under the $300 million tranche of the credit facility.

In June 2016, OPG entered into a $700 million general corporate credit facility agreement with the OEFC, which expires on December 31, 2017. In the third quarter of 2017, the agreement was amended to increase the credit facility to $2,350 million and to extend its expiry date to December 31, 2018.

In February 2017, OPG issued senior notes payable to the OEFC totalling $200 million and maturing in February 2047. The effective interest rate and coupon interest rate of these notes was 4.12 percent. In June 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in June 2047. The effective interest rate and coupon interest rate of these notes was 3.65 percent. In August 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in August 2047. The effective interest rate and coupon interest rate of these notes was 3.86 percent. In September 2017, OPG issued senior notes payable to the OEFC totalling $400 million and maturing in September 2047. The effective interest rate and coupon interest rate of these notes was 4.07 percent. As at September 30, 2017, there were outstanding long-term borrowings of $800 million under this credit facility.

In October 2017, OPG issued $500 million of senior notes payable under a Medium Term Note Program. The notes bear a coupon interest rate of 3.32 percent and an effective rate of 3.43 percent, payable semi-annually until maturity on October 4, 2027. The offering was made under OPG's $2 billion short form base shelf prospectus dated September 12, 2017. The net proceeds will be used for general corporate purposes, including the financing of OPG's subordinated debt investment in the Fair Hydro Plan.

As at September 30, 2017, OPG's long-term debt outstanding was $5,482 million, including $628 million due within one year.

OPG continues to evaluate arrangements that would appropriately support the Company's financing needs and capital expenditure programs.

Contractual and Commercial Commitments

Pension Plan Actuarial Valuation

A new actuarial valuation of the OPG registered pension plan was filed with the Financial Services Commission of Ontario in September 2017 with an effective date of January 1, 2017. The annual funding requirements in accordance with the new actuarial valuation are $212 million for 2017, $215 million for 2018, and $219 million for 2019. The next actuarial valuation must have an effective date no later than January 1, 2020.

BALANCE SHEET HIGHLIGHTS

The following section provides highlights of OPG's unaudited interim consolidated financial position using selected balance sheet data:

(millions of dollars) (unaudited)	As At September 30 2017	As At December 31 2016
Property, plant and equipment - net	**20,801**	19,998
The increase was primarily due to capital expenditures on the Darlington Refurbishment project, partially offset by depreciation expense.		
Nuclear fixed asset removal and nuclear waste management funds *(current and non-current portions)*	**16,534**	15,984
The increase was primarily due to earnings on the Nuclear Segregated Funds, partially offset by reimbursements of eligible expenditures on nuclear fixed asset removal and nuclear waste management activities.		
Short-term debt	**160**	2
The increase was due to commercial paper issued under OPG's commercial paper program during the third quarter of 2017.		
Fixed asset removal and nuclear waste management liabilities	**20,075**	19,484
The increase was primarily a result of accretion expense representing the increase in the liabilities due to the passage of time, partially offset by expenditures on nuclear fixed asset removal and waste management activities.		

Off-Balance Sheet Arrangements

In the normal course of operations, OPG engages in a variety of transactions that, under US GAAP, are either not recorded in the Company's interim consolidated financial statements or are recorded in the Company's interim consolidated financial statements using amounts that differ from the full contract amounts. Principal off-balance sheet activities for OPG include guarantees and long-term contracts.

CHANGES IN ACCOUNTING POLICIES AND ESTIMATES

OPG's significant accounting policies are outlined in Note 3 to the audited consolidated financial statements as at and for the year ended December 31, 2016. A discussion of recent accounting pronouncements and change in accounting estimate are included in Note 2 to OPG's unaudited interim consolidated financial statements as at and for the three and nine month periods ended September 30, 2017 under the heading, *Significant Accounting Policies and Estimates*. Disclosure regarding OPG's critical accounting policies is included in OPG's 2016 annual MD&A.

RISK MANAGEMENT

The following provides an update to the discussion of the Company's risks and risk management activities included in OPG's 2016 annual MD&A. As such, the disclosure in this section should be read in conjunction with the *Risk Management* section included in the annual MD&A.

Risks to Achieving Project Excellence

Deep Geologic Repository for Low and Intermediate Level Waste

In August 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of the potential cumulative effects of the DGR project on the physical and cultural heritage of the SON, taking into account the results of the SON Community Process. OPG continues to work with the SON, however the timing and outcome of the SON Community Process and the EA decision by the Minister are uncertain.

Risks to Maintaining Financial Strength

Commodity Markets

Changes in the market price of fuels used to produce electricity can adversely impact OPG's earnings and cash flow from operations.

To manage the risk of unpredictable increases in the price of fuels, the Company has fuel hedging programs, which include fixed price and indexed contracts.

The percentages hedged of OPG's fuel requirements are shown in the following table. These amounts are based on yearly forecasts of generation and supply mix, and as such, are subject to change as these forecasts are updated.

	2017 [1]	2018	2019
Estimated fuel requirements hedged [2]	73%	73%	69%

[1] Based on actual fuel requirements hedged for the nine months ended September 30, 2017 and forecast for the remainder of the year.

[2] Represents the approximate portion of megawatt-hours of expected generation production (and year-end inventory targets) from each type of OPG-operated facility (nuclear, hydroelectric and thermal) for which the Company has entered into contractual arrangements or obligations in order to secure the price of fuel, or which is subject to regulation. In the case of hydroelectric generation, this represents the gross revenue charge and water rental charges. Excess fuel inventories (nuclear and thermal) in a given year are attributed to the next year for the purpose of measuring hedge ratios.

Foreign Exchange

OPG's earnings and cash flow can be affected by movements in the United States dollar (USD) relative to the Canadian dollar.

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are denominated in, or tied to, USD. To manage this risk, OPG periodically employs various financial instruments such as forwards and other

derivative contracts, in accordance with approved risk management policies. As at September 30, 2017, OPG had no foreign exchange contracts outstanding.

Trading

OPG's financial performance can be affected by its trading activities.

OPG's electricity trading operations are closely monitored, with total exposures measured and reported to senior management on a daily basis. The main metric used to measure the financial risk of trading activity is Value at Risk (VaR). VaR is defined as a probabilistic maximum potential future loss expressed in monetary terms for a portfolio based on normal market conditions over a set period of time. For the third quarter of 2017, the VaR utilization ranged between $0.2 million and $0.3 million.

Credit

Deterioration in energy markets counterparty credit and non-performance by suppliers and contractors can adversely impact OPG's earnings and cash flow from operations.

OPG manages its exposure to suppliers or counterparties by evaluating their financial condition and negotiating appropriate collateral or other forms of security. OPG's credit exposure relating to energy markets transactions as at September 30, 2017 was $356 million, including $346 million with the IESO. Management considers the Company's risk exposure relating to electricity sales through the IESO-administered spot market to be low as the IESO oversees the credit worthiness of all market participants. In accordance with the IESO's prudential support requirements, market participants are required to provide collateral to cover funds that they might owe to the market. Of the $10 million remaining exposure as at September 30, 2017, over 95 percent was related to investment grade counterparties.

Fair Hydro Plan

OPG's role in connection with the Fair Hydro Plan could have reputational impacts on the Company.

The *Ontario Fair Hydro Plan Act, 2017* received Royal Assent on June 1, 2017 and its attendant regulations came into force in June, July, and October 2017. **[UPDATE]** The regulations clarify aspects of the structure and program logistics required for OPG, as the Financial Services Manager of the Fair Hydro Plan, to refinance a portion of the Global Adjustment through the Trust. OPG's reputation could potentially be adversely impacted through its involvement with the Fair Hydro Plan and through stakeholder opinions related to this involvement.

Recovery of Pension and OPEB Costs

On September 14, 2017, the OEB issued its final report on the guiding principles and the policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the electricity and natural gas sectors. The report reaffirmed the conclusions of the initial report issued in May 2017, including the establishment of the accrual basis of accounting as the default rate-setting method and the establishment of a variance account to record asymmetric carrying charges in favour of ratepayers on the differences between the accrual costs recovered and cash payments made by a utility for pension and OPEB plans. The report requires OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the Pension & OPEB Cash Versus Accrual Differential Deferral Account that has been in effect since November 1, 2014, until such time as the OEB approves the resumption of the accrual basis of recovery. The future recovery of amounts recorded in the account will be subject to this approval. The report confirmed that OPG would become subject to the carrying charges on the differences between accrual costs and cash payments going back to November 1, 2014, with the charges calculated on the portion of such differences that have been recovered through regulated prices. The carrying charges will be determined at prescribed interest rate set quarterly by the OEB based on the quarterly return of a mid-term corporate bond index yield. This outcome has reduced OPG's risk related to the recovery of actual pension and OPEB accrual costs and the recovery of the balance in the Pension & OPEB Cash Versus Accrual Differential Deferral Account.

The account had a balance of $552 million as at September 30, 2017 and is recognized on the Company's consolidated balance sheet as a regulatory asset. OPG's financial results for the three and nine month periods ended September 30, 2017 were not impacted by the issuance of the OEB's report.

RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One, the IESO and the OEFC. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions are summarized below:

	Three Months Ended September 30			
	2017		2016	
(millions of dollars) (unaudited)	**Revenue**	**Expense**	**Revenue**	**Expense**
Hydro One				
Electricity sales	**2**	**-**	1	-
Services	**-**	**3**	-	3
Dividends	**2**	**-**	-	2
Province of Ontario				
Decommissioning Fund excess funding [1]	**-**	**(44)**	-	201
Used Fuel Fund rate of return guarantee and excess funding [1]	**-**	**(39)**	-	295
Gross revenue charges	**-**	**27**	-	28
ONFA guarantee fee	**-**	**2**	-	2
Other	**-**	**2**	-	-
OEFC				
Gross revenue charges	**-**	**62**	-	57
Interest expense on long-term notes	**-**	**40**	-	42
Income taxes, net of investment tax credits	**-**	**23**	-	28
IESO				
Electricity related revenue	**1,126**	**4**	1,293	7
	1,130	**80**	1,294	665

(millions of dollars) (unaudited)	Nine Months Ended September 30 2017 Revenue	2017 Expense	2016 Revenue	2016 Expense
Hydro One				
Electricity sales	**7**	**-**	4	-
Services	**1**	**8**	1	12
Dividends	**6**	**-**	-	4
Province of Ontario				
Decommissioning Fund excess funding [1]	**-**	**164**	-	137
Used Fuel Fund rate of return guarantee and excess funding [1]	**-**	**217**	-	190
Gross revenue charges	**-**	**84**	-	91
ONFA guarantee fee	**-**	**6**	-	6
Other	**-**	**3**	-	-
OEFC				
Gross revenue charges	**-**	**156**	-	147
Interest expense on long-term notes	**-**	**122**	-	127
Income taxes, net of investment tax credits	**-**	**132**	-	112
IESO				
Electricity related revenue	**3,228**	**11**	3,894	22
	3,242	**903**	3,899	848

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at September 30, 2017 and December 31, 2016, the Nuclear Segregated Funds were reported net of amounts due to the Province of $3,796 million and $3,415 million, respectively. The details of accounting for the Nuclear Segregated Funds are described in OPG's 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

The receivable, available-for-sale securities, payable and long-term debt balances between OPG and its related parties are summarized below:

(millions of dollars) (unaudited)	September 30 2017	December 31 2016
Receivables from related parties		
Hydro One	**1**	1
IESO	**346**	421
OEFC	**3**	1
PEC	**2**	4
Province of Ontario	**5**	2
Available-for-sale securities		
Hydro One shares	**190**	212
Accounts payable and accrued charges		
OEFC	**37**	61
Province of Ontario	**6**	2
IESO	**2**	2
Long-term debt (including current portion)		
Notes payable to OEFC	**3,245**	3,295

OPG holds interest-bearing Province of Ontario bonds in the Nuclear Segregated Funds and the OPG registered pension fund. As at September 30, 2017, the Nuclear Segregated Funds held $1,498 million of interest-bearing Province of Ontario bonds, while the registered pension fund had no such holdings. As at December 31, 2016, the Nuclear Segregated Funds and the registered pension fund held $1,652 million and $284 million of interest-bearing Province of Ontario bonds, respectively. These bonds are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

There have been no related party transactions related to the Fair Hydro Plan and associated financing activities. The first transaction between the Trust and the IESO is expected later in 2017.

INTERNAL CONTROLS OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

The Company maintains a comprehensive system of policies, procedures, and processes that represents its framework for internal controls over financial reporting and for its disclosure controls and procedures (together, ICOFR). There were no changes in the Company's internal control system during the current interim period that has or is reasonably likely to have a material impact to the ICOFR.

QUARTERLY FINANCIAL HIGHLIGHTS

The following tables set out selected financial information from OPG's unaudited interim consolidated financial statements for each of the eight most recently completed quarters.

(millions of dollars - except where noted) (unaudited)	**September 30 2017**	**June 30 2017**	**March 31 2017**	**December 31 2016**
Revenue	**1,217**	1,146	1,176	1,388
Net income (loss)	**140**	307	68	(8)
Less: Net income attributable to non-controlling interest	**9**	4	4	5
Net income (loss) attributable to the Shareholder	**131**	303	64	(13)
Per common share, attributable to the Shareholder *(dollars)*	**$0.51**	$1.18	$0.25	($0.05)

(millions of dollars - except where noted) (unaudited)	**September 30 2016**	**June 30 2016**	**March 31 2016**	**December 31 2015**
Revenue	1,400	1,387	1,478	1,312
Net income (loss)	198	135	128	(100)
Less: Net income attribute to the non-controlling interest	4	3	5	1
Net income (loss) attributable to the Shareholder	194	132	123	(101)
Per common share, attributable to the Shareholder *(dollars)*	$0.76	$0.51	$0.48	($0.39)

Trends

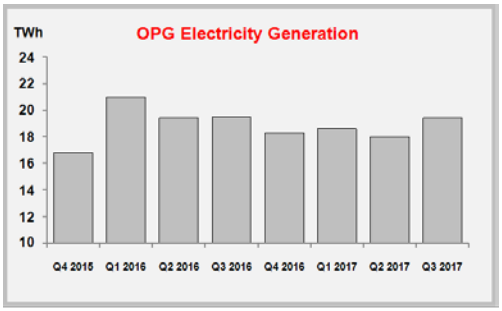
OPG's quarterly results are affected by changes in grid-supplied electricity demand, primarily resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. Weather conditions affect water flows, electricity demand, and prevalence of SBG conditions. Historically, OPG's revenues have been higher in the first

quarter of a fiscal year as a result of winter heating demands and in the third quarter due to air conditioning and cooling demands. The financial impact of forgone production due to SBG conditions at the regulated hydroelectric stations and the financial impact of differences between forecast water flows reflected in OEB-approved regulated prices and the actual water flows are mitigated by regulatory variance accounts authorized by the OEB.

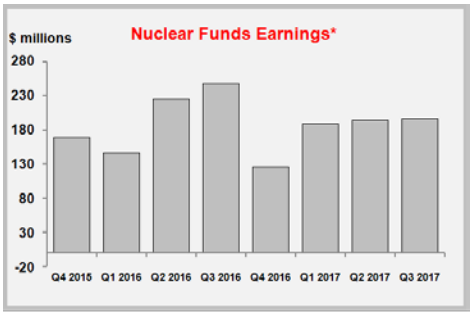
The timing of planned outages at a nuclear generating station during the year can cause variability in year-over-year operating results for partial periods of a fiscal year, including the impact on revenue and OM&A expenses, but is not a significant driver of variability for full fiscal year results.

OPG's electricity generation was reduced as a result of the Unit 2 refurbishment outage at the Darlington GS, which began in October 2016 and is expected to continue until early 2020.

OPG's financial results are also affected by the earnings on the Nuclear Segregated Funds, net of the impact of the Bruce Lease Net Revenues Variance Account.



Additional items that affected net income in certain quarters above are described in OPG's 2016 annual MD&A under



*net of regulatory variance account

the section, *Quarterly Financial Highlights*.

SUPPLEMENTARY NON-GAAP FINANCIAL MEASURES

In addition to providing net income and other financial information in accordance with US GAAP, certain non-GAAP financial measures are also presented in OPG's MD&A. These non-GAAP measures do not have any standardized meaning prescribed by US GAAP and, therefore, may not be comparable to similar measures presented by other issuers. OPG utilizes these measures to make operating decisions and assess performance. Readers of the MD&A would utilize these measures in assessing the Company's financial performance from ongoing operations. The Company believes that these indicators are important since they provide additional information about OPG's performance, facilitate comparison of results over different periods, and present measures consistent with the Company's strategies to provide value to the Shareholder, improve cost performance, and ensure availability of cost effective funding. These non-GAAP financial measures have not been presented as an alternative to net income, cash flow provided by operating activities, or any other measure in accordance with US GAAP, but as indicators of operating performance.

The definitions of the non-GAAP financial measures are as follows:

(1) **ROE Excluding AOCI** is defined as net income attributable to the Shareholder divided by average equity attributable to the Shareholder excluding AOCI, for the period. ROE Excluding AOCI is measured over a 12-month period and is calculated as follows:

	Twelve Months Ended	
(millions of dollars – except where noted) (unaudited)	**September 30 2017**	**December 31 2016**
ROE Excluding AOCI		
Net income attributable to the Shareholder	**485**	436
Divided by: Average equity attributable to the Shareholder, excluding AOCI	**11,055**	10,442
ROE Excluding AOCI *(percent)*	**4.4**	4.2

(2) **FFO Adjusted Interest Coverage** is defined as FFO before interest divided by adjusted interest expense. FFO before interest is defined as cash flow provided by operating activities adjusted for interest paid, interest capitalized to fixed and intangible assets, and changes to non-cash working capital balances for the period. Adjusted interest expense is calculated as net interest expense plus interest income, interest capitalized to fixed and intangible assets, interest related to regulatory assets and liabilities, and the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets, for the period.

FFO Adjusted Interest Coverage is measured over a 12-month period and is calculated as follows:

	Twelve Months Ended	
(millions of dollars – except where noted) (unaudited)	**September 30 2017**	**December 31 2016**
FFO before interest		
Cash flow provided by operating activities	**1,082**	1,595
Add: Interest paid	**270**	269
Less: Interest capitalized to fixed and intangible assets	**(161)**	(141)
Less: Changes to non-cash working capital balances	**38**	42
FFO before interest	**1,229**	1,765
Adjusted interest expense		
Net interest expense	**84**	120
Add: Interest income	**8**	7
Add: Interest capitalized to fixed and intangible assets	**161**	141
Add: Interest related to regulatory assets and liabilities	**43**	30
Add: Excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets [1]	**-**	45
Adjusted interest expense	**296**	343
FFO Adjusted Interest Coverage *(times)*	**4.2**	5.1

[1] A value of nil is used in the calculation when interest on pension and OPEB projected benefit obligations is equal to, or lower than, expected return on pension plan assets.

(3) **Enterprise Total Generating Cost per MWh** is used to measure OPG's overall organizational cost performance. Enterprise TGC per MWh is defined as OM&A expenses (excluding the Darlington Refurbishment project and other generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to OPG's electricity generation business), fuel expense for OPG-operated stations including hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures (excluding the Darlington Refurbishment project and other generation development projects) incurred during the period, divided by total electricity generation from OPG-operated generating stations plus electricity generation forgone due to SBG conditions during the period.

(millions of dollars – except where noted) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Enterprise TGC				
Total OM&A expenses	**635**	666	**2,054**	2,061
Total fuel expense	**185**	187	**518**	541
Total capital expenditures	**476**	444	**1,335**	1,162
Less: Darlington Refurbishment capital and OM&A costs	**(328)**	(269)	**(943)**	(717)
Less: Other generation development project capital and OM&A costs	**(17)**	(42)	**(53)**	(121)
Add (Less): OM&A and fuel expenses (refundable through) deferred in regulatory variance and deferral accounts	**4**	35	**(19)**	76
Less: Nuclear fuel expense for non OPG-operated stations	**(13)**	(18)	**(42)**	(50)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**13**	5	**47**	38
Less: OM&A expenses ancillary to electricity generation business	**(4)**	(5)	**(13)**	(17)
Other adjustments	**(3)**	(12)	**(7)**	(15)
	948	991	**2,877**	2,958
Adjusted electricity generation *(TWh)*				
Total OPG electricity generation	**19.4**	19.5	**56.0**	59.9
Adjust for electricity generation forgone due to SBG conditions and OPG's share of electricity generation from co-owned facilities	**0.9**	0.1	**4.2**	3.4
	20.3	19.6	**60.2**	63.3
Enterprise TGC per MWh *($/MWh)* [1]	**46.65**	50.72	**47.77**	46.74

[1] Amounts may not calculate due to rounding.

(4) **Nuclear Total Generating Cost per MWh** is used to measure the cost performance of OPG's nuclear generating assets. Nuclear TGC per MWh is defined as OM&A expenses of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the nuclear electricity generation business), nuclear fuel expense for OPG-operated stations (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs) incurred during the period, divided by nuclear electricity generation for the period.

(millions of dollars – except where noted) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Nuclear TGC				
Regulated – Nuclear Generation OM&A expenses	**511**	521	**1,693**	1,665
Regulated – Nuclear Generation fuel expense	**81**	79	**217**	239
Regulated – Nuclear Generation capital expenditures	**409**	339	**1,150**	896
Less: Darlington Refurbishment capital and OM&A costs	**(328)**	(269)	**(943)**	(717)
Add: Regulated – Nuclear Generation OM&A and fuel expenses deferred in regulatory variance and deferral accounts	**5**	31	**6**	84
Less: Nuclear fuel expense for non OPG-operated stations	**(13)**	(18)	**(42)**	(50)
Less: Regulated - Nuclear Generation OM&A expenses ancillary to nuclear electricity generation business	**(1)**	(1)	**(3)**	(4)
Other adjustments	**1**	3	**(1)**	(1)
	665	685	**2,077**	2,112
Nuclear electricity generation (TWh)	**11.3**	11.7	**30.6**	34.6
Nuclear TGC per MWh (*$/MWh*) [1]	**58.75**	58.55	**67.87**	61.07

[1] Amounts may not calculate due to rounding.

(5) **Hydroelectric Total Generating Cost per MWh** is used to measure the cost performance of OPG's hydroelectric generating assets. Hydroelectric TGC per MWh is defined as OM&A expenses of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the hydroelectric electricity generation business), hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding expenditures related to the Peter Sutherland Sr. GS, Ranney Falls GS, and other hydroelectric generation development projects) incurred during the period, divided by total hydroelectric electricity generation plus hydroelectric electricity generation forgone due to SBG conditions during the period. OPG reports hydroelectric gross revenue charge and water rental payments as fuel expense.

(millions of dollars – except where noted) (unaudited)	**Three Months Ended September 30**		**Nine Months Ended September 30**	
	2017	**2016**	**2017**	**2016**
Hydroelectric TGC				
Regulated – Hydroelectric OM&A expenses	**81**	87	**232**	238
Regulated – Hydroelectric fuel expense	**88**	88	**258**	259
Contracted Generation Portfolio OM&A expenses	**39**	44	**118**	129
Contracted Generation Portfolio fuel expense	**15**	19	**42**	42
Regulated – Hydroelectric and Contracted Generation Portfolio capital expenditures	**56**	92	**141**	231
Less: Regulated – Hydroelectric and Contracted Generation Portfolio generation development project capital and OM&A costs	**(17)**	(41)	**(52)**	(117)
Less: Thermal OM&A and fuel expenses and capital expenditures in the Contracted Generation Portfolio	**(39)**	(51)	**(119)**	(126)
(Less) Add: Regulated – Hydroelectric OM&A and fuel expenses refundable through regulatory variance and deferral accounts	**(1)**	4	**(25)**	(8)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**13**	5	**47**	38
Other adjustments	**(1)**	(1)	**-**	(1)
	234	246	**642**	685
Adjusted hydroelectric electricity generation *(TWh)*				
Regulated – Hydroelectric electricity generation	**7.3**	6.9	**23.5**	22.8
Contracted Generation Portfolio electricity generation	**0.8**	0.9	**1.9**	2.5
Adjust for hydroelectric electricity generation forgone due to SBG conditions and non-hydroelectric electricity generation of the Contracted Generation Portfolio, including OPG's share of electricity generation from co-owned facilities	**0.8**	0.1	**4.1**	3.4
	8.9	7.9	**29.5**	28.7
Hydroelectric TGC per MWh *($/MWh)* [1]	**26.20**	31.01	**21.74**	23.99

[1] Amounts may not calculate due to rounding.

(6) **Gross margin** is defined as revenue less fuel expense.

For further information, please contact: Investor Relations 416-592-6700

webmaster@opg.com

Media Relations 416-592-4008

1-877-592-4008

www.opg.com
www.sedar.com

From: John Kim
To: Ronald Kwan
Cc: Usman Zahid
Subject: RE: OPG Q4 2017 Submission to Province
Date: Monday, February 26, 2018 6:36:04 PM

Thanks Ron….done and also FYI'ed Energy on Energy-related comments.

John

From: Ronald Kwan
Sent: Monday, February 26, 2018 5:53 PM
To: John Kim <John.Kim@ofina.on.ca>
Cc: Usman Zahid <Usman.Zahid@ofina.on.ca>
Subject: RE: OPG Q4 2017 Submission to Province

Hi John,

Go ahead and consolidate my comments with the other ones. I won't have time to review the F/S and AIF documents today, so please get back to OPG ASAP.

Thanks,
Ron

From: John Kim
Sent: February-26-18 17:38
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Usman Zahid <Usman.Zahid@ofina.on.ca>
Subject: FW: OPG Q4 2017 Submission to Province

Hi Ron,

Would you have any issues adding these edits to your comments (or vice versa)?

Thanks,

John

From: John Kim
Sent: Saturday, February 24, 2018 11:31 AM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Usman Zahid <Usman.Zahid@ofina.on.ca>; Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>; Darren Scanlan <Darren.Scanlan@ofina.on.ca>
Subject: RE: OPG Q4 2017 Submission to Province

Hi Ron,

Pls. see attached. No issue on the NR.

Thanks,

John

Z:\Users\CEF\Hydro 2018\OPG\Financials\Q4 2017

From: HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
Sent: February-16-18 5:11 PM
To: Shruti.Talwar@ontario.ca; Manu.Sud@ontario.ca; John Kim <John.Kim@ofina.on.ca>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: GORE Michael -FIN & C CTRL <michael.gore@opg.com>; PAN Rebecca -FIN & C CTRL <rebecca.pan@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>
Subject: OPG Q4 2017 Submission to Province

Hi All,

Please find attached OPG's draft Q4 2017 Financial Results Press Release, Management's Discussion and Analysis (MD&A), Annual Information Form (AIF) and Financial Statements for the Province's review.

We would greatly appreciate comments on the above **no later than Thursday, Feb 22nd**.

These documents will be filed with the Ontario Securities Commission on **Thursday, March 8th** following OPG's Board of Directors meeting.

Kindly forward all comments directly to Philip Ho – philip.ho@opg.com.

To assist the review process, the following are the key items in the Q4 2017 MD&A:

Highlights	
Recent Developments	MD&A p.13-19
OEB's Decision on OPG's Application for New Regulated Prices	MD&A p.13-15
Darlington Refurbishment	MD&A p.16-17; 28-30
Ontario's Fair Hydro Plan	MD&A p.17-18

Philip Ho, CPA, CA | Senior Manager, External Reporting & Accounting Policy | Ontario Power Generation
700 University Avenue, Toronto ON M5G 1X6 | Phone: (416) 592-3320| E-mail: philip.ho@opg.com

From:	John Kim
To:	"HO Philip -FIN & C CTRL"
Cc:	Ronald Kwan; GORE Michael -FIN & C CTRL; PAN Rebecca -FIN & C CTRL; DYKXHOORN Sandra -STAKEREL; LAURETA LAPIRA May -TREASURY; LADAK Lubna -TREASURY; MAK Ricky -TREASURY
Subject:	RE: OPG Q4 2017 Submission to Province
Date:	Monday, February 26, 2018 6:26:14 PM
Attachments:	Q4 2017 OPG FS Feb 25_230PM_RPT excerpt for Prov(TPW Comments).docx Q4 2017 OPG MDA - DRAFT - Feb 25_230PM_RPT excerpt for Prov (TPW Comments).docx 2017 AIF - DRAFT - Feb 16 - PROVINCE MAILING_EFB_v4 Sent.docx Q4 2017 MD&A - DRAFT - Feb 16 - PROVINCE MAILING_EFB_v4 Sent.docx Q4 2017 Press Release - PROVINCE MAILING_Markup v Sent.docx Q4 2017 OPG FS PROVINCE MAILING Feb 16_EFB_v4 Sent.docx

Hi Pilip,

Pls. see attached. Two separate files on your inquiry from Sunday are attached with comments from our Legal (the first two attachments). The draft documents with our comments are also attached (the next four).

Thanks,

John

From: HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
Sent: Sunday, February 25, 2018 3:09 PM
To: Shruti.Talwar@ontario.ca; Manu.Sud@ontario.ca; John Kim <John.Kim@ofina.on.ca>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: GORE Michael -FIN & C CTRL <michael.gore@opg.com>; PAN Rebecca -FIN & C CTRL <rebecca.pan@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; LAURETA LAPIRA May -TREASURY <may.lapira@opg.com>; LADAK Lubna -TREASURY <lubna.ladak@opg.com>; MAK Ricky -TREASURY <ricky.mak@opg.com>
Subject: RE: OPG Q4 2017 Submission to Province

Hi All,

We have added disclosure in the Financial Statements and the Management's Discussion and Analysis, specifically in the Related Party Transactions section (attached below), as it relates to the limited guarantee provided by the Province to the creditors of the Fair Hydro Trust, established as the financing entity contemplated by the *Ontario Fair Hydro Plan Act, 2017*, of which OPG is the Financial Services Manager.

This is broadly consistent with the wording used in the Financing Plan. Please let us know if you have comments.

Our external reporting timeline remains the same as previously communicated. Please let us know if you have any other comments.

Thank you.

Regards,

Philip

From: HO Philip -FIN & C CTRL
Sent: Friday, February 16, 2018 5:11 PM
To: 'Shruti.Talwar@ontario.ca' <Shruti.Talwar@ontario.ca>; 'Manu.Sud@ontario.ca' <Manu.Sud@ontario.ca>; 'John.Kim@ofina.on.ca' <John.Kim@ofina.on.ca>; 'Ronald.Kwan@ofina.on.ca' <Ronald.Kwan@ofina.on.ca>
Cc: GORE Michael -FIN & C CTRL <michael.gore@opg.com>; PAN Rebecca -FIN & C CTRL <rebecca.pan@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>
Subject: OPG Q4 2017 Submission to Province

Hi All,

Please find attached OPG's draft Q4 2017 Financial Results Press Release, Management's Discussion and Analysis (MD&A), Annual Information Form (AIF) and Financial Statements for the Province's review.

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To assist the review process, the following are the key items in the Q4 2017 MD&A:

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Ontario's Fair Hydro Plan	MD&A p.17-18

<< File: Q4 2017 Press Release - PROVINCE MAILING.docx >> << File: Q4 2017 MD&A - DRAFT - Feb 16 - PROVINCE MAILING.docx >> << File: 2017 AIF - DRAFT - Feb 16 - PROVINCE MAILING.docx >> << File: Q4 2017 OPG FS PROVINCE MAILING Feb 16.docx >>

Philip Ho, CPA, CA | Senior Manager, External Reporting & Accounting Policy | Ontario Power Generation
700 University Avenue, Toronto ON M5G 1X6 | Phone: (416) 592-3320| E-mail: philip.ho@opg.com

ONTARIO POWER GENERATION INC.

CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2017

[DRAFT]

19. RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One, the IESO and the OEFC. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly-owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions for the years ended December 31 are summarized below:

	2017		2016	
(millions of dollars)	**Income**	**Expense**	**Income**	**Expense**
Hydro One				
Electricity sales	**8**	**-**	6	-
Services	**1**	**10**	1	5
Dividends	**7**	**-**	6	-
Province of Ontario				
Change in Decommissioning Segregated Fund amount due to Province [1]	**-**	**456**	-	192
Change in Used Fuel Segregated Fund amount due to Province [1]	**-**	**591**	-	235
Hydroelectric gross revenue charge	**-**	**110**	-	120
ONFA guarantee fee	**-**	**8**	-	8
Other	**-**	**2**	-	-
OEFC				
Hydroelectric gross revenue charge	**-**	**216**	-	203
Interest expense on long-term notes	**-**	**158**	-	169
Income taxes, net of investment tax credits	**-**	**246**	-	104
IESO				
Electricity related revenue	**4,802**	**-**	5,082	-
Earnings from Fair Hydro Trust	**1**	**-**	-	-
	4,819	**1,797**	5,095	1,036

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at December 31, 2017 and December 31, 2016, the Nuclear Segregated Funds were reported net of amounts due to the Province of $4,462 million and $3,415 million, respectively.

The receivable, AFS securities, payable and long-term debt balances between OPG and its related parties are summarized below:

(millions of dollars)	**December 31 2017**	**December 31 2016**
Receivables from related parties		
Hydro One	**1**	1
IESO − Electricity related receivables	**354**	421
IESO − Fair Hydro Trust [1]	**7**	-
OEFC	**-**	1
PEC	**4**	4
Province of Ontario	**3**	2
Financing receivables		
IESO − Fair Hydro Trust	**1,179**	-
Available-for-sale securities		
Hydro One shares	**188**	212
Accounts payable and accrued charges		
Hydro One	**1**	-
OEFC	**52**	61
Province of Ontario	**9**	2
IESO − Electricity-related payables	**5**	2
IESO − Fair Hydro Trust	**3**	-
Long-term debt (including current portion)		
Notes payable to OEFC	**3,195**	3,295

[1] Balance consists of unbilled revenue.

OPG holds interest-bearing Province of Ontario bonds in the Nuclear Segregated Funds and the OPG registered pension fund. As at December 31, 2017, the Nuclear Segregated Funds held $1,503 million of interest-bearing Province of Ontario bonds, while the registered pension fund had no such holdings. As at December 31, 2016, the Nuclear Segregated Funds and the registered pension fund held $1,652 million and $284 million of interest-bearing Province of Ontario bonds, respectively. These bonds are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

In December 2017, the Fair Hydro Trust purchased its first tranche of Investment Interest from the IESO for an exchange amount of $1.18 billion, which has been classified as a financing receivable on OPG's consolidated balance sheet. The transaction was settled in cash using proceeds from the Trust's issuance of senior and subordinated debt. Pursuant to the general regulation of the Fair Hydro Act, the IESO is required to pay and remit carrying costs of the Trust, excluding repayment of principal on any debt obligations, up to July 31, 2021. Commencing May 1, 2021, Specified Consumers will be invoiced by their local distribution company for the Clean Energy Adjustment to pay the carrying costs of the Trust. These funds will be remitted to the Trust through the IESO and will be used to settle all funding and other related expenses of the Trust that underlie the financing receivable.

As at December 31, 2017, OPG's consolidated balance sheet included approximately $7 million of unbilled revenue from the IESO, primarily for OPG's general fee for 2017 as the Financial Services Manager under the Act relating to incurred third-party and certain direct labour costs.

~~Under one of the Trust's program agreements, the~~The Province has provided a limited guarantee to specified creditors of the Fair Hydro Trust. The limited guarantee would be triggered in the event that the Trust's ability to receive amounts in respect of its Investment Interest to pay for certain funding obligations is adversely affected due to the occurrence of any one of the following: the Province changes the Fair Hydro Act or any other legislation or

regulation; Ontario's electricity market significantly changes due to actions undertaken by the Province; or a court declares that the Act is ~~declared~~ invalid or unconstitutional.

ONTARIO POWER GENERATION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

DECEMBER 31, 2017

[DRAFT]

RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One, the IESO and the OEFC. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly-owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions for the years ended December 31 are summarized below:

	2017		2016	
(millions of dollars)	**Income**	**Expense**	**Income**	**Expense**
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Electricity sales	**8**	**-**	6	-
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Interest expense on long-term notes	**-**	**158**	-	169
Income taxes, net of investment tax credits	**-**	**246**	-	104
IESO				
Electricity related revenue	**4,802**	**-**	5,082	-
Earnings from Fair Hydro Trust	**1**	**-**	-	-
	4,819	**1,797**	5,095	1,036

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at December 31, 2017 and December 31, 2016, the Nuclear Segregated Funds were reported net of amounts due to the Province of $4,462 million and $3,415 million, respectively.

The receivable, AFS securities, payable and long-term debt balances between OPG and its related parties are summarized below:

(millions of dollars)	December 31 2017	December 31 2016
Receivables from related parties		
Hydro One	**1**	1
IESO – Electricity related receivables	**354**	421
IESO – Fair Hydro Trust [1]	**7**	-
OEFC	**-**	1
PEC	**4**	4
Province of Ontario	**3**	2
Financing receivables		
IESO – Fair Hydro Trust	**1,179**	-
Available-for-sale securities		
Hydro One shares	**188**	212
Accounts payable and accrued charges		
Hydro One	**1**	-
OEFC	**52**	61
Province of Ontario	**9**	2
IESO – Electricity-related payables	**5**	2
IESO – Fair Hydro Trust	**3**	-
Long-term debt (including current portion)		
Notes payable to OEFC	**3,195**	3,295

[1] Balance consists of unbilled revenue.

OPG holds interest-bearing Province of Ontario bonds in the Nuclear Segregated Funds and the OPG registered pension fund. As at December 31, 2017, the Nuclear Segregated Funds held $1,503 million of interest-bearing Province of Ontario bonds, while the registered pension fund had no such holdings. As at December 31, 2016, the Nuclear Segregated Funds and the registered pension fund held $1,652 million and $284 million of interest-bearing Province of Ontario bonds, respectively. These bonds are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

In December 2017, the Fair Hydro Trust purchased its first tranche of Investment Interest from the IESO for an exchange amount of $1.18 billion, which has been classified as a financing receivable on OPG's consolidated balance sheet. The transaction was settled in cash using proceeds from the Trust's issuance of senior and subordinated debt. Pursuant to the general regulation of the Fair Hydro Act, the IESO is required to pay and remit carrying costs of the Trust, excluding repayment of principal on any debt obligations, up to July 31, 2021. Commencing May 1, 2021, Specified Consumers will be invoiced by their local distribution company for the Clean Energy Adjustment to pay the carrying costs of the Trust. These funds will be remitted to the Trust through the IESO and will be used to settle all funding and other related expenses of the Trust that underlie the financing receivable.

As at December 31, 2017, OPG's consolidated balance sheet included approximately $7 million of unbilled revenue from the IESO, primarily for OPG's general fee for 2017 as the Financial Services Manager under the Act relating to incurred third-party and certain direct labour costs.

~~Under one of the Trust's program agreements,~~ The~~the~~ Province has provided a limited guarantee to specified creditors of the Fair Hydro Trust. The limited guarantee would be triggered in the event that the Trust's ability to receive amounts in respect of its Investment Interest to pay for certain funding obligations is adversely affected due to the occurrence of any one of the following: the Province changes the Fair Hydro Act or any other legislation or

regulation; Ontario's electricity market significantly changes due to actions undertaken by the Province; or a court declares that the Act is ~~declared~~ invalid or unconstitutional.

ONTARIO POWER GENERATION INC.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2017

[DRAFT]

March 8, 2018

ANNUAL INFORMATION FORM
FOR THE YEAR ENDED DECEMBER 31, 2017

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PRESENTATION OF INFORMATION

References in this Annual Information Form (AIF) to the "Company", the "Corporation" or "OPG" are made to Ontario Power Generation Inc. Unless otherwise noted, the information contained in this AIF is as at or for the year ended December 31, 2017. Amounts are expressed in Canadian dollars unless otherwise indicated. Financial information is presented in accordance with United States generally accepted accounting principles (US GAAP). This AIF is dated March 8, 2018.

ADDITIONAL INFORMATION

Additional information relating to the Company may be found on SEDAR at www.sedar.com. Additional financial information relating to the Company is provided in the Company's annual Management's Discussion and Analysis (MD&A) and audited consolidated financial statements as at and for the year ended December 31, 2017, which is available on SEDAR at www.sedar.com or on the Company's website at www.opg.com. ***The above information is made available in accordance with legal requirements of an AIF and is not, unless otherwise specifically stated, incorporated by reference into this AIF.***

Details regarding compensation paid to directors and executive officers of the Company during the financial year ended December 31, 2017 is included in OPG's Statement of Executive Compensation (Form 51-102F6), which is available on SEDAR at www.sedar.com and is incorporated by reference herein.

FORWARD-LOOKING INFORMATION

This AIF contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could", and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

All forward-looking statements involve inherent assumptions, risks, and uncertainties. All forward-looking statements could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's generating station performance and availability, fuel costs, surplus baseload generation (SBG), cost of fixed asset removal and nuclear waste management, performance and earnings of investment funds, refurbishment of existing facilities, development and construction of new facilities, pension and other post-employment benefit (OPEB) obligations and funds, income taxes, proposed new legislation, the ongoing evolution of Ontario's electricity industry, environmental and other regulatory requirements, health, safety and environmental developments, business continuity events, the weather, financing and liquidity, applications to the Ontario Energy Board (OEB) for regulatory prices, the impact of regulatory decisions by the OEB, Ontario's Fair Hydro Plan (Fair Hydro Plan or the Plan), OM&A expenditures, retention of critical talent, supplier and third party performance, and project expenditures. Accordingly, undue reliance should not be placed on any forward-looking statement. The forward-looking statements included in this AIF are made only as of the date of this AIF. Except as required by applicable securities laws, OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events, or otherwise.

OPG faces various risks that could have a material adverse effect on its business, strategy, generating stations, reputation, financial condition, operating results, generation development and other projects. There may be further risks and uncertainties that are not presently known, or that are not currently believed to be material, that may in the future adversely affect the Company's performance or financial condition. OPG may be exposed to a significant event that it is not fully insured or indemnified against, or to a party that fails to meet its indemnification obligations. For details on risks faced by OPG, refer to the section, *Risk Management*, in the Company's 2017 year-end MD&A.

CORPORATE STRUCTURE

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG was formed in April 1999 through the restructuring of Ontario Hydro's integrated electricity business. OPG was established under the *Business Corporations Act* (Ontario) (OBCA) and is wholly owned by the Province of Ontario (Province or Shareholder). OPG and the Province are parties to a Memorandum of Agreement (MOA) that sets out OPG's role and responsibilities. The current MOA was executed in July 2015 and reaffirmed for continuance by both the Ontario Minster of Energy and the OPG Board of Directors' Chair in the fourth quarter of 2016, as required by the MOA following a change in the Minister of Energy. Further details on the MOA are discussed in the section, *Interest of Management and Others in Material Transactions* under the heading, *Relationship with the Province and the OEFC*.

OPG's registered head office is located at 700 University Avenue, Toronto, Ontario, M5G 1X6, Canada.

OVERVIEW OF OPG

OPG is Ontario's largest clean energy generator. As at December 31, 2017, OPG operated two nuclear generating stations, three thermal generating stations, 66 hydroelectric generating stations, and one wind power turbine. The majority of OPG's generation is from its rate-regulated nuclear and rate-regulated hydroelectric stations. In addition, OPG and TransCanada Energy Ltd. co-own the 550 megawatt (MW) Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS). OPG and ATCO Power Canada Ltd. co-own the 560 MW Brighton Beach gas-fired combined cycle GS (Brighton Beach). Including its share of the co-owned facilities, OPG's total in-service generating capacity was 16,210 MW as at December 31, 2017, which represented approximately 45 percent of installed generation capacity in Ontario's electricity grid as reported by the Independent Electricity System Operator (IESO). OPG's in-service generating capacity as of December 31, 2017 excludes Unit 2 of the Darlington Nuclear GS. The unit, which has a generating capacity of 878 MW, was taken offline in mid-October 2016 and is currently undergoing refurbishment. OPG operates under an electricity generation licence issued by the OEB, which is valid until October 30, 2023. OPG expects the licence to be renewed in the future.

OPG also owns two other nuclear generating stations, the Bruce A GS and the Bruce B GS, which are leased on a long-term basis to Bruce Power L.P. (Bruce Power) and are not included in the generation and other operating statistics set out in this AIF.

All of OPG's owned and co-owned generating facilities are located in Ontario.

Effective in the fourth quarter of 2017, following the establishment of the Fair Hydro Trust (the Trust) as the financing entity to implement the Fair Hydro Plan under the *Ontario Fair Hydro Plan Act, 2017* (the Fair Hydro Act or the Act), OPG has modified its reportable business segments to include the Fair Hydro Trust segment. Through its control over the key activities of the Trust and its obligation to absorb losses through ownership of the Trust's subordinated debt, the Company consolidates the financial results of the Trust in accordance with US GAAP. The Fair Hydro Trust segment reports the income related to OPG's role as Financial Services Manager under the Act and holder of subordinated debt issued by the Trust, including the financial results of the Trust. The Fair Hydro Plan and the Fair Hydro Trust are discussed in the section, *General Development of the Business* under the heading, *General Development* and in the section, *Description of the Business* under the heading, *Fair Hydro Trust Segment*.

OPG's business operations are divided into six business segments and are discussed under the heading, *General Development* and in their respective sections. The six business segments are as follows:

- Regulated – Nuclear Generation
- Regulated – Nuclear Waste Management
- Regulated – Hydroelectric
- Contracted Generation Portfolio
- Services, Trading, and Other Non-Generation
- Fair Hydro Trust

Pursuant to the *Ontario Energy Board Act, 1998* and *Ontario Regulation 53/05,* OPG receives OEB-authorized regulated prices for electricity generated from the Pickering and Darlington nuclear generating stations and the 54 hydroelectric facilities prescribed for rate regulation (collectively, prescribed facilities or regulated facilities). The OEB is an independent, quasi-judicial tribunal that regulates market participants in Ontario's natural gas and electricity industries, and reports to the Legislature of the Province through the Ontario Ministry of Energy. OPG is Ontario's only electricity generator subject to rate regulation by the OEB.

Of OPG's 54 regulated hydroelectric facilities, 48 facilities were prescribed for rate regulation effective July 1, 2014 pursuant to a November 2013 amendment to *Ontario Regulation 53/05*. The remaining six regulated hydroelectric facilities and the Pickering and Darlington nuclear generating stations have been subject to rate regulation by the OEB since 2008.

Electricity generated from most of OPG's non-regulated assets is subject to Energy Supply Agreements (ESAs) with the IESO. The IESO is a non-profit corporate entity governed by an independent Board of Directors appointed by the Province and is responsible for operating the electricity market and directing the operation of the bulk electrical system in Ontario. Effective January 1, 2015, the Ontario Power Authority (OPA), an organization previously established by the Province with a mandate to contribute to the development of a reliable and sustainable electricity system in Ontario, merged with the IESO. The new entity continued under the name IESO. The IESO is the counterparty to the ESAs and other agreements that were previously executed with the OPA.

ESAs are in effect for the capacity and production from OPG's three operating thermal generating stations – the oil/gas dual-fuelled Lennox GS, the biomass powered Atikokan GS and the advanced biomass fuelled unit at the Thunder Bay GS. The results of these stations are reported under the Contracted Generation Portfolio segment. The expiry dates of these ESAs range from January 2020 to July 2024. In addition, 50-year ESAs are in place for the hydroelectric facilities reported under the Contracted Generation Portfolio segment. The hydroelectric ESAs for the operating stations have expiry dates ranging from February 2059 to March 2067. The ESAs for the contracted generating stations result in a relatively stable stream of revenues from the Contracted Generation Segment.

OPG's revenue and electricity generation by business segment for the years ended December 31, 2017, 2016 and 2015 and OPG's in-service generating capacity as at December 31, 2017, 2016 and 2015 are summarized in the table below.

		Regulated – Nuclear Generation	Regulated – Nuclear Waste Management	Regulated – Hydroelectric	Contracted Generation Portfolio [1]	Services, Trading, and Other Non-Generation	Fair Hydro Trust
2017	Revenue *(millions of dollars)* [2]	**3,095**	**121**	**1,436**	**579**	**43**	**1** [4]
	Electricity Generation *(terawatt hours)*	**40.7**	**N/A**	**30.7**	**2.7**	**N/A**	**N/A**
	In-service Generating Capacity *(MW)* [3]	**5,728**	**N/A**	**6,426**	**4,056**	**N/A**	**N/A**
2016	Revenue *(millions of dollars)* [2]	3,481	138	1,527	573	68	N/A
	Electricity Generation *(terawatt hours)*	45.6	N/A	29.5	3.1	N/A	N/A
	In-service Generating Capacity *(MW)* [3]	5,728	N/A	6,421	4,028	N/A	N/A
2015	Revenue *(millions of dollars)* [2]	3,245	122	1,619	535	73	N/A
	Electricity Generation *(terawatt hours)*	44.5	N/A	30.4	3.1	N/A	N/A
	In-service Generating Capacity *(MW)*	6,606	N/A	6,428	4,021	N/A	N/A

[1] The in-service generating capacity includes OPG's share of 275 MW for PEC and 280 MW for Brighton Beach, and the electricity generation includes OPG's share of its 50 percent ownership in these stations.
[2] Revenue for each segment is shown before inter-segment elimination.
[3] Regulated – Nuclear Generation segment excludes the generating capacity of 878 MW from Unit 2 of the Darlington GS, which has been undergoing refurbishment since mid-October 2016.
[4] This represents OPG's earnings from the Fair Hydro Trust, which consist of income related to OPG's role as Financial Services Manager under the Act and holder of subordinated debt issued by the Trust, including the financial results of the Trust.

For the year ended December 31, 2017, OPG's electricity generation accounted for over 50 percent of the total energy generated on Ontario's electricity grid, as reported by the IESO.

OPG is subject to a number of provincial and federal legislation and regulations, including the decisions of administrative tribunals or other regulatory bodies, and to Canada's international obligations under certain international treaties. Collectively, these sources dictate many of the constraints within which OPG is permitted to operate its facilities and manage its business.

Strategic Imperatives

OPG's mission is to provide low cost power in a safe, clean, reliable and sustainable manner for the benefit of its customers and its Shareholder. OPG also seeks to pursue, on a commercial basis, generation development projects and other business growth opportunities to the benefit of the Shareholder. The four strategic imperatives of OPG are briefly described below.

Operational Excellence

Operational excellence at OPG is accomplished by the safe and environmentally responsible generation of reliable and cost-effective electricity from the Company's generating assets through a highly trained and engaged workforce. Workplace safety and public safety are overriding priorities in all activities performed at OPG.

Project Excellence

OPG is pursuing a number of generation development and other projects in support of Ontario's electricity planning initiatives. OPG's major generation projects include the refurbishment of the Darlington GS, the expansion of the Ranney Falls hydroelectric GS, and the construction of a solar facility at the Nanticoke GS site. OPG aims to be an industry leader in project management capability and performance.

Financial Strength

As a commercial enterprise, OPG's financial priority is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future growth. Inherent in this priority are the following objectives:

- Increasing revenue, reducing costs and achieving appropriate return;
- Ensuring availability of cost effective funding for operational needs, generation development projects and other business opportunities, and long-term obligations;
- Pursuing opportunities to expand the existing core business and capitalize on new growth paths including emerging renewable energy opportunities; and
- Managing risks. Refer to the section, *Risk Management*, in the Company's 2017 year-end MD&A for more details.

Social Licence

As the largest, publicly-owned electricity generator in Ontario with geographically diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust. OPG is committed to maintaining high standards of public safety and corporate citizenship, including environmental stewardship, transparency, community engagement, and Indigenous relations.

OPG has in place a Code of Business Conduct that establishes the standards, expectations, and accountabilities for ethical behaviour. All employees and all parties with whom the Company does business are expected to abide by OPG's Code of Business Conduct. A copy of the Code of Business Conduct can be found on SEDAR at www.sedar.com and also is available on the Company's website at www.opg.com.

Further details on OPG's strategic imperatives can be found in the corresponding sections of the Company's 2017 year-end MD&A in the section, *Core Business, Strategy, and Outlook.*

GENERAL DEVELOPMENT OF THE BUSINESS

The following is a summary of key developments in OPG's business since January 2015.

General Development

OPG's Regulated Prices and Other OEB-Related Developments

Energy revenue generated from the Company's regulated nuclear and regulated hydroelectric facilities is based on regulated prices determined by the OEB through public proceedings. To date, the regulated prices have included a volumetric base regulated price, and volumetric rate riders for the recovery or repayment of approved variance and deferral account balances. As the regulated operations account for the majority of the Company's electricity generation, the outcomes of OPG's applications for regulated prices to the OEB determine a large portion of the Company's revenues and can have a significant impact on the Company's financial performance.

The following are the OEB-authorized regulated prices for electricity generated from the Company's regulated facilities in effect during the years ended December 31:

	2017		2016	2015	
($/megawatt hour)	**January 1 to May 31**	**June 1 to December 31** [1]		**January 1 to June 30**	**July 1 to December 31**
Regulated – Nuclear Generation					
Base regulated price	**59.29**	**80.65**	59.29	59.29	59.29
Variance and deferral account rate riders	**-**	**-**	10.84 [2]	1.33	12.17 [2]
	59.29	**80.65**	70.13	60.62	71.46
Regulated – Hydroelectric					
Hydroelectric generating stations prescribed for rate regulation prior to 2014					
Base regulated price	**40.20**	**41.67**	40.20	40.20	40.20
Variance and deferral account rate riders	**-**	**-**	3.19 [2]	6.04	9.23 [2]
	40.20	**41.65**	43.39	46.24	49.43
Hydroelectric generating stations prescribed for rate regulation effective in 2014					
Base regulated price	**41.93**	**41.67**	41.93	41.93	41.93
Variance and deferral account rate riders	**-**	**-**	3.19 [2]	-	3.19 [2]
	41.93	**41.67**	45.12	41.93	45.12

[1] Regulated prices for the June 1, 2017 to December 31, 2017 period were calculated and submitted to the OEB by OPG in January 2018 based on the OEB's December 28, 2017 decision on OPG's 2017-2021 application for new regulated prices. The final regulated prices will be determined by the OEB as part of the final payment amounts order process, which is expected to be completed in the first half of 2018. As part of the process, the OEB is expected to authorize separate rate riders to allow for the recovery of the shortfall between the new regulated prices and the previous regulated prices that OPG continues to receive during the period between June 1, 2017 and the implementation date of the new regulated prices pending the issuance of the final payment amounts order. The incremental revenue for the period between June 1, 2017 and December 31, 2017 arising from this retrospective application of new regulated prices was accrued in 2017. **[MONITOR]**

[2] The OEB authorized interim period rate riders for the period from October 1, 2015 to December 31, 2016 to allow for the recovery of the riders effective July 1, 2015 for the period from July 1, 2015 to September 30, 2015. The nuclear interim period rate rider was $2.17 per megawatt hour (MWh) and the regulated hydroelectric interim period rate rider was $0.64/MWh. These interim period rate riders have not been included in the above table. All rate riders in effect during 2016 expired on December 31, 2016.

Base Regulated Prices

The OEB's decision on OPG's May 2016 five-year application for new regulated prices for its nuclear and regulated hydroelectric generation was issued on December 28, 2017, following a public hearing process. Based on the OEB's December 2017 decision, the new base regulated prices are determined on an incentive ratemaking methodology for the hydroelectric operations and under a custom incentive regulation framework for the nuclear operations. For the hydroelectric facilities, the new base regulated price is determined using a formula that annually escalates the previous regulated prices, subject to some adjustments, based on inflation less a stretch factor to incent additional innovation and efficiency. For the nuclear facilities, the new regulated price is determined under a rate smoothing approach that defers a portion of the approved nuclear revenue requirement for future collection, with the aim of making more stable changes in OPG's production-weighted regulated prices year over year. The nuclear revenue requirement is based on the OEB-approved forecasts of operating costs as reduced by a stretch factor and a return on rate base. Rate base for OPG represents the average net level of investment in regulated fixed and intangible assets in service and an allowance for working capital.

For the first time since OPG's prescribed facilities became subject to rate regulation, the new prices have been determined on an incentive ratemaking methodology for the hydroelectric operations and a custom incentive regulation framework for the nuclear operations.

For the hydroelectric facilities, effective June 1, 2017, the base regulated prices in effect prior to June 1, 2017, with some adjustments, will be escalated for each of years 2017 to 2021 using a formula equal to an industry-specific weighted inflation factor based on indices published annually by the OEB for use in incentive regulation formulas, less a stretch factor adjustment. The OEB accepted OPG's proposal to set the annual stretch factor adjustment at 0.3 percent. Based on the approved formula, the 2017 increase in the base regulated price for the regulated hydroelectric facilities is 1.4 percent as of June 1, 2017 and the 2018 increase is 0.9 percent as of January 1, 2018. For the 2019-2021 period, the base regulated price for the regulated hydroelectric facilities will be determined annually before the beginning of each year using the approved formula and inflation indices published by the OEB.

For the nuclear operations, a revenue requirement is determined for each of the years 2017 to 2021 based on the OEB-allowed level of OPG's forecast operating costs, reduced by a stretch factor amount, as well as a return on rate base determined using OEB's generic prescribed rate of return and an OPG-specific deemed capital structure. OPG has calculated that the findings of the OEB's December 2017 decision with respect to the forecast operating costs, rate base and deemed capital structure for the nuclear generating facilities will result in nuclear revenue requirements totalling $15.9 billion over the five years.

The OEB's findings with respect to the nuclear revenue requirement include approval for inclusion in rate base of in-service amounts related to the Darlington Refurbishment of $5.5 billion by 2021, including $4.8 billion forecast in the first quarter of 2020 upon return to service of Unit 2, $0.4 billion forecast for pre-requisite projects excluding the construction of the Heavy Water Storage and Drum Handling Facility (HWSF) over the 2016-2021 period and $0.3 billion for pre-requisite projects placed in service prior to 2016. The OEB is expected to review the HWSF project as part of a future application. In the decision, the OEB concluded that it is appropriate to evaluate OPG's performance on the Darlington Refurbishment project at an overall level rather by individual cost component, with recovery of any increases over the approved in-service amounts subject to a future prudence review. The revenue requirement impact of differences between the approved in-service additions and the actual in-service additions will be recorded in the Capacity Refurbishment Variance Account authorized by the OEB pursuant to *Ontario Regulation 53/05*. The $4.8 billion forecast in-service amount upon return to service of Unit 2 includes expenditures incurred during the definition and planning phase of the project.

The OEB also approved OPG's requested forecast costs of approximately $292 million for activities to enable Pickering commercial operations beyond 2020 and agreed to inclusion of operating cost and generation impacts associated with continued operation of Pickering in 2021 in nuclear regulated prices. The differences between approved forecast enabling costs for continued Pickering operations and the actual amounts will be recorded in the Capacity Refurbishment Variance Account for future review and disposition by the OEB.

Excluding amounts that otherwise would have been recorded in OEB-authorized regulatory accounts for repayment to, or recovery from, customers in the future, the OEB's decision reduced OPG's proposed five-year nuclear revenue requirement by $0.6 billion. The main adjustments made by the OEB included a reduction of $100 million per year to requested OM&A costs , a reduction of 10 percent per year to forecast non-Darlington refurbishment capital in-service additions entering rate base over the 2017-2021 period, an increase and expansion of the scope of the stretch factor for nuclear costs that further reduced the revenue requirement, and a rejection of OPG's request to increase the equity component of the existing deemed capital structure of 45 percent equity and 55 percent debt. The OEB increased and expanded the annual stretch factor to 0.6 percent to most of OPG's OM&A expenses incurred directly for, or allocated to, the nuclear facilities, as well as to non-Darlington refurbishment capital in-service additions. The stretch factor is applied starting in 2018 and compounds in each year to 2021.

In accordance with *Ontario Regulation 53/05*, the nuclear revenue requirement continues to be adjusted by the amount of OPG's revenues, net of costs, from leasing the Bruce nuclear generating stations to Bruce Power. As directed by the OEB, OPG's revenues and costs related to the Bruce nuclear generating stations continue to be determined in accordance with US GAAP for the purposes of establishing the nuclear revenue requirement and are subject to the Bruce Lease Net Revenues Variance Account in accordance with *Ontario Regulation 53/05*. This includes costs related to the portion of the Nuclear Liabilities associated with the Bruce nuclear generating stations. The OEB's decision maintained the previously approved cost recovery methodology for the costs of the Nuclear Liabilities for the prescribed facilities and for the Bruce facilities, directing OPG to file a future study examining such methodologies jurisdictionally and for OPG's assets specifically. The decision fully incorporated the impacts of the updated estimate of OPG's obligations for nuclear waste management and nuclear facilities decommissioning as at December 31, 2016, including through a new ONFA reference plan effective January 1, 2017 and the change in the Nuclear Liabilities recorded on December 31, 2016.

As proposed by OPG, the OEB set recovery of pension and OPEB costs in the nuclear revenue requirement on the basis of OPG's cash payments for pension and OPEB plans, with differences between pension and OPEB accrual costs and cash payments continuing to be recorded in the Pension & OPEB Cash to Accrual Differential Deferral Account. The regulatory treatment of pension and OPEB costs is discussed further under the heading, *Pension and OPEB Cost Recovery Methodology*.

To reflect the OEB's decision, in the fourth quarter of 2017, OPG recorded incremental revenue of approximately $480 million for the period June 1, 2017 to December 31, 2017 based on the draft payment amounts order. The revenue was recorded as an increase in regulatory assets for the June 1, 2017 to December 31, 2017 revenue shortfall based on proposed new regulated prices for nuclear facilities and regulated hydroelectric facilities, net of a regulatory liability recognized in relation to OPG's rate smoothing proposal. The OEB's approval of the final payment amounts order, including the allocation of the approved revenue requirement between nuclear regulated prices and rate smoothing deferrals, is not expected to have a material impact on the net revenue increase recorded in the fourth quarter of 2017. The OEB is expected to issue the final payment amounts order and implement new regulated prices in the first half of 2018. **[MONITOR]**

The base regulated prices in effect from January 2015 through May 2017 were established by the OEB's November 2014 decision and December 2014 order on OPG's September 2013 rate application. This included regulated prices effective November 1, 2014 for the 48 hydroelectric facilities that were prescribed for rate regulation effective July 1, 2014. Prior to November 1, 2014, the generation revenue for these hydroelectric facilities was based on the Ontario electricity spot market price, including for the period from

July 1, 2014 to November 1, 2014 as determined by the OEB. The base regulated prices effective November 1, 2014 remained in effect until May 31, 2017.

The regulated prices in effect from January 2015 through May 2017 for the nuclear facilities and the hydroelectric facilities prescribed for rate regulation prior to 2014 were determined by the OEB based on approved 24-month revenue requirements for the 2014 to 2015 period totaling approximately $7.3 billion. This reflected a reduction of $833 million from the revenue requirements submitted by OPG. The regulated price for the 48 hydroelectric facilities prescribed for rate regulation beginning in 2014 was established based on an approved 18-month revenue requirement for the period from July 1, 2014 to December 31, 2015 of approximately $750 million, a reduction of $101 million from OPG's submission. The most significant adjustments made by the OEB to OPG's September 2013 rate request included the following:

- Allowed pension and OPEB costs were limited to the forecast 2014 and 2015 cash expenditures for these plans, which were approximately $600 million lower, including related tax impacts, than the forecast accrual costs submitted by OPG. The difference between accrual costs and cash expenditures is being recorded in a deferral account authorized by the OEB. For further details, see *Pension and OPEB Cost Recovery Methodology* in this section. **[CONFIRM]**
- A reduction in overall forecast compensation costs of $100 million in each of 2014 and 2015 across all of OPG's regulated facilities.
- An increase in the forecast nuclear production of 0.5 terawatt hours (TWh) annually used to set the nuclear regulated prices, which had the effect of reducing the approved nuclear regulated price.
- The rate base addition for the Niagara Tunnel project to construct a third tunnel to divert additional water to OPG's generating stations on the Niagara River was limited to $1,365 million, which resulted in a write-off of $77 million being charged to operations in 2014.
- A reduction in the 2014 income tax expense included in the regulated prices by the amount of the regulatory tax loss calculated for 2013, which reduced the 2014/2015 revenue requirement by approximately $70 million.

In December 2014, OPG filed a motion with the OEB asking it to review and vary the parts of its November 2014 decision related to the disallowance of the Niagara Tunnel project expenditures and the application of the 2013 regulatory tax loss against the 2014/2015 revenue requirement. In its January 2016 decision on the motion, the OEB reversed a portion of the Niagara Tunnel project disallowance and upheld the original tax loss decision. In the first quarter of 2016, OPG recorded a gain of $22 million to recognize the expected future recovery from customers of the reversed portion of the Niagara Tunnel project disallowance.

In its November 2014 decision, the OEB adjusted the deemed capital structure applied to OPG's total regulated rate base to 45 percent equity and 55 percent debt, from 47 percent equity and 53 percent debt used previously. In making this adjustment, the OEB found that there had been an overall improvement in the risk profile of OPG's regulated operations, based on the increased proportionate share of rate base related to hydroelectric facilities. This reduced the 2014/2015 revenue requirements. In general, OPG's actual capital structure contains a significantly higher proportion of equity than has been reflected in the OEB-approved deemed capital structure, which has had the effect of reducing OPG's return on shareholder's equity.

Variance and Deferral Accounts and Rate Riders

Consistent with the requirements of *Ontario Regulation 53/05*, OPG's overall production-weighted regulated prices will be smoothed, with a resulting portion of the approved annual nuclear revenue requirements for the 2017-2021 period deferred in the Rate Smoothing Deferral Account for future collection. The non-deferred portion of each year's nuclear revenue requirement is divided by the OEB-approved forecast of OPG's nuclear electricity generation for the corresponding year to determine the base nuclear regulated price. The OEB approved the nuclear electricity generation forecast as requested by OPG.
As amended in March 2017, *Ontario Regulation 53/05* requires rate smoothing to be applied in a manner that makes changes in OPG's weighted-average nuclear and hydroelectric regulated prices more stable year over year. Previously, the regulation required that rate smoothing be applied with a view of making

more stable year-over-year changes in OPG's nuclear regulated prices only. Per the regulation, the deferral account records interest at a long-term debt rate reflecting OPG's cost of long-term borrowing approved by the OEB, compounded annually. The regulation requires the OEB to authorize recovery of the balance in the account on a straight line basis over a period not to exceed 10 years following the end of the Darlington Refurbishment project. OPG recognizes positive amounts deferred under rate smoothing as an increase in net regulatory assets and an increase in revenue in the period to which the underlying approved revenue requirement relates. Negative amounts determined under rate smoothing are correspondingly recorded as a decrease in net regulatory assets and a decrease to revenue.

On January 17, 2018, OPG submitted a draft payment amounts order to the OEB that proposed nuclear base regulated prices for each year of the 2017-2021 period, including a rate smoothing proposal, based on the December 2017 decision's findings. The rate smoothing proposal takes into account the near-term and future impacts on customers, while seeking to ensure that resulting nuclear regulated prices allow for sufficient cash flow to maintain the Company's investment grade credit rating and support availability of cost effective funding, while taking into account both near-term and future impacts on customers. Based on the OEB's direction, the draft payment amounts order also included proposed periods for recovery, through interim period shortfall rate riders, of the retrospective revenue shortfall for the period between June 1, 2017 and the implementation date of the new regulated prices based on proposed new regulated prices that would have been in effect during that period. The draft payment amounts also included proposed recovery periods, through variance and deferral account rate riders, for regulatory account balances approved for recovery in this application. **[MONITOR]**

Variance and deferral accounts are typically established by the OEB to capture, for subsequent review and approval, differences between actual costs and revenues and the corresponding forecast amounts approved by the OEB in setting regulated prices, or to record the impact of items not reflected in the approved regulated prices. Such accounts generally help to mitigate risks and uncertainties to the regulated entity and its customers.

The OEB has authorized several variance and deferral accounts for OPG, including those required by *Ontario Regulation 53/05*. The authorized accounts include, among others, those related to the gross margin impact of variability in regulated hydroelectric electricity production due to differences between the forecast and actual water conditions and due to the effect of SBG conditions, changes in liabilities for nuclear waste management and nuclear facilities decommissioning, changes in revenues and costs related to the lease and related agreements with Bruce Power for the Bruce nuclear generating stations, and variances in the revenue requirement impact of capital and non-capital costs incurred to increase the output of, refurbish, or add operating capacity to the regulated facilities, including the Darlington Refurbishment project. A number of these accounts are subject to an OEB prudence review. There is currently no regulatory variance or deferral account related to the impact of generation performance of OPG's nuclear stations on revenue from the base regulated prices. The Darlington Refurbishment project is discussed in the section, *General Development of the Business* under the heading, *Nuclear Business Development – Darlington Refurbishment*.

Approved balances in the regulatory variance and deferral accounts authorized by OPG are recovered or refunded through volumetric rate riders. The additional revenue from the riders is largely offset by a corresponding increase in amortization expense related to the variance and deferral account balances, which are typically recognized as assets (amounts recoverable from customers) or liabilities (amounts payable to customers) on the Company's balance sheet. Differences in amounts recovered or repaid through rate riders due to differences between actual and forecast production volumes are recorded in separate variance accounts for future disposition. **[MONITOR]**

The OEB accepted all variance and deferral account balances proposed for recovery that were not already accepted as part of the Settlement Agreement, resulting in approval of recovery of $305 million recorded in variance and deferral variance accounts as at December 31, 2015, without adjustments. The Settlement Agreement provided for the continuation of all applicable existing variance and deferral accounts. In addition to the Rate Smoothing Deferral Account, the OEB established, as of the effective date of the new regulated prices, new variance and deferral accounts to record costs related to implementing the Canadian

Nuclear Safety Commission's (CNSC) Fitness for Duty program and to record differences between forecast and actual amount of Scientific Research & Experimental Development investment tax credits attributable to the nuclear facilities. In January 2018, OPG filed a motion asking the OEB to review and vary the effective date of the new regulated prices to January 1, 2017. The motion did not impact OPG's financial results for the year ended December 31, 2017.

Consistent with the effective date of the OEB's December 2017 decision, for the period from January 1, 2017 to May 31, 2017, OPG continued to record additions to the existing variance and deferral accounts for the nuclear and regulated hydroelectric facilities pursuant to the OEB's previous decisions and orders. These additions reflected differences between actual and forecast amounts embedded in the regulated prices in effect prior to the June 1, 2017 effective date.

The rate riders in effect in 2015 and 2016 included those authorized by the OEB's October 2015 order on OPG's application in 2014 to recover or repay most of the December 31, 2014 variance and deferral account balances, discussed below. The 2015 rate riders also included those established by the OEB's December 2014 order on OPG's September 2013 rate application for the period January 1, 2015 to December 31, 2015. The December 2014 order allowed for recovery of $189 million recorded in certain variance and deferral accounts as at December 31, 2013, without adjustments.

The total balances approved for recovery by the OEB's October 2015 order were approximately $1.8 billion, of which approximately $1.5 billion was the subject of an OEB-approved partial settlement agreement reached by OPG and intervenors. The remaining balances of $263 million were approved by the OEB's September 2015 decision, without adjustments. The rate riders authorized by the October 2015 order were in effect from July 1, 2015 to December 31, 2016 and allowed for recovery of $933 million of the total approved balances.

Amendments to Ontario Regulation 53/05

In November 2015, the Province amended *Ontario Regulation 53/05* to establish a deferral account, effective January 1, 2017, that will record, for future recovery, a portion of the annual OEB-approved revenue requirements for OPG's regulated nuclear facilities during the period from January 1, 2017 to the end of the Darlington Refurbishment project. The amended regulation requires the OEB to determine the revenue requirements for OPG's nuclear facilities on a five-year basis for the ten-year period beginning on January 1, 2017. The portion of the approved revenue requirement deferred in the new account each year also will be determined by the OEB on a five-year basis during this ten-year period. The regulation stipulates that the deferral account will record interest at a long-term debt rate reflecting OPG's cost of long-term borrowing approved by the OEB, compounded annually, and that the OEB shall authorize recovery of the balance in the account on a straight line basis over a period not to exceed 10 years following the end of the Darlington Refurbishment project. OPG expects to recognize the deferred amounts as income in the period to which the underlying approved revenue requirements relate.

The November 2015 amendment required the portion of the approved annual nuclear revenue requirements deferred for future recovery to be determined with a view of making more stable year-over-year changes in OPG's nuclear regulated prices only. In March 2017, the Province amended *Ontario Regulation 53/05* to require that the deferred portion of the approved annual nuclear revenue requirements be determined with a view of making more stable year-over-year changes in OPG's weighted-average nuclear and hydroelectric regulated prices, including rate riders. The amendment is intended to make more predictable the impact on customer bills resulting from changes in OPG's overall regulated prices, reducing the average year-over-year change in customer bills over the term of OPG's May 2016 application for new regulated prices.

The regulation was also amended in November 2015 to require the OEB to accept the need for the Darlington Refurbishment project in light of Ontario's 2013 Long-Term Energy Plan (LTEP) and the related policy of the Province endorsing the need for nuclear refurbishment. Furthermore, the 2017 LTEP reaffirms the Province's support for nuclear refurbishment. The 2017 LTEP is discussed in the section, *General*

Development of the Business under the heading, *General Development – Ontario's Long-Term Energy Plan*.

Pension and OPEB Cost Recovery Methodology

Using the methodology previously applied by the OEB in setting OPG's regulated prices, the revenue requirements submitted by OPG in its September 2013 rate application included a forecast of 2014 and 2015 pension and OPEB costs determined on an accrual basis in accordance with US GAAP. In its November 2014 decision and December 2014 order on the application, the OEB approved revenue requirements based on OPG's estimated minimum required contributions to its registered pension plan, and a forecast of OPG's expenditures on the OPEB and supplementary pension plans. In directing this reduction in the revenue requirement, the OEB agreed with OPG and certain other parties that a generic proceeding on the regulatory treatment and recovery of pension and OPEB costs would be beneficial. The OEB also indicated that a change in the recovery methodology for OPG's pension and OPEB amounts from the accrual basis, if required, would be addressed in a future OPG rate proceeding, informed by the outcome of the generic proceeding.

Pending the generic proceeding, the OEB established the Pension & OPEB Cash Versus Accrual Differential Deferral Account. Effective November 1, 2014, this deferral account records the difference between OPG's actual pension and OPEB costs for the regulated business determined on an accrual basis and the corresponding actual cash expenditures for these plans. The OEB's November 2014 decision indicated that the future recovery, if any, of amounts recorded in the deferral account would be subject to the outcome of a future generic OEB proceeding on the regulatory treatment and recovery of pension and OPEB costs. The balance in the account is recognized as a regulatory asset on OPG's balance sheet.

On September 14, 2017, the OEB issued its final report on the guiding principles and policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the Ontario electricity and natural gas sectors. The report establishes the accrual basis of accounting as the method of determining pension and OPEB amounts for rate-setting purposes, unless the OEB finds that this method does not result in just and reasonable rates in the circumstances of a particular utility. The report also provides for the establishment of a generic variance account to record asymmetric carrying charges in favour of ratepayers on the differences between the accrual costs recovered and cash payments made by a utility in respect of pension and OPEB plans. Carrying charges on this differential are to be assessed at the OEB's prescribed interest rate, on a prospective basis from the effective date of the new variance account. For OPG, this differential will include amounts going back to November 1, 2014, with the charges calculated on the portion of the differential that has been recovered through regulated prices. None of this differential has been recovered to date. The prescribed interest rate is set quarterly by the OEB based on the quarterly return of a mid-term corporate bond index yield.

The OEB's September 2017 report and the OEB's December 2017 decision on OPG's application for new regulated prices require OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the Pension & OPEB Cash to Accrual Differential Deferral Account in effect since November 1, 2014, until such time as the OEB approves resumption of the accrual basis of recovery for OPG. The future recovery of amounts recorded in the account will be subject to this approval. The OEB's report did not impact OPG's financial results for the year ended December 31, 2017.

The Company recognizes the amount set aside in the Pension & OPEB Cash Versus Accrual Differential Deferral Account as a regulatory asset. As at December 31, 2017, the regulatory asset had a balance of $614 million. Consistent with the expectations set out in the OEB's December 2017 decision, in 2018, OPG plans to file an application with the OEB requesting disposition of the Pension & OPEB Cash Versus Accrual Differential Deferral Account balance as well as balances accumulated since December 31, 2015 in other regulatory accounts.

Supreme Court of Canada's Decision on 2011 OEB Ruling

In September 2015, the Supreme Court of Canada (Supreme Court) issued its decision upholding the OEB's disallowance of $145 million of OPG's forecast nuclear compensation costs for the 2011 to 2012 period. The majority of these costs were based on previously negotiated collective bargaining agreements. This disallowance was part of the OEB's March 2011 decision on OPG's application for regulated prices effective March 1, 2011. The Supreme Court decision underscores that OPG must continue to establish the reasonableness of both committed and future costs as part of the rate-setting process.

Ontario's Fair Hydro Plan

On March 2, 2017, the Province announced the Fair Hydro Plan aimed at reducing electricity bills for eligible residential, farm, small businesses ~~and other eligible~~ consumers (Specified Consumers) in the province by refinancing a portion of the Global Adjustment costs over a longer period of time. The Global Adjustment includes the difference between Ontario's electricity market clearing price used to dispatch generation and the prices paid to contracted and regulated generators in the province, and the cost of conservation and demand management programs. On June 1, 2017, the Fair Hydro Act received Royal Assent and the associated general regulation came into force in June 2017. The Act established a framework under which the costs and benefits associated with the Government of Ontario's clean energy initiatives are to be allocated between present and future consumers of electricity under the Fair Hydro Plan. The general regulation provides details on the structural, operational and financial elements required to implement the Fair Hydro Plan.

Pursuant to the Act, effective May 1, 2017, the IESO began to defer a portion of the Global Adjustment costs. The Act allows the IESO to transfer a portion of the deferred balance to a financing entity that would fund the deferral in exchange for an irrevocable right to recover the balance and associated financing and other costs from Specified Consumers in the future (Investment Interest). The legislation appointed OPG as the Financial Services Manager under the Act and conveyed upon the Financial Services Manager statutory obligations, including the creation of one or more financing entities that may acquire Investment Interests from the IESO.

In November 2017, OPG's Board of Directors provided its final approval regarding OPG's involvement with the Trust on commercial terms following the fulfilment of all conditions it established in May 2017. Accordingly, the Fair Hydro Trust was established as the financing entity contemplated by the Act in December 2017. The majority unitholder and beneficiary of the Trust is a wholly-owned subsidiary of OPG. The Trust is structured to be bankruptcy remote and ring fenced from OPG in order to protect the Company's assets and operations.

In order for the Trust to finance the Investment Interest acquired from the IESO, it will incur senior debt from capital markets and subordinated debt from OPG. The Trust's investment will attract financing amounts and other related fees, which, under the general regulation, will be payable by the IESO as carrying costs until July 2021 and by Specified Consumers through the Clean Energy Adjustment to be invoiced by local distribution companies commencing in May 2021, with the three-month lag in 2021 intended to cover the billing and collection lag from the introduction of the Clean Energy Adjustment. The carrying costs include all financing and third-party costs other than payment of principal on debt.

Concurrent with every issuance of the Trust's senior notes, it is expected that OPG will purchase subordinated debt of the Trust in an aggregate amount not to exceed 49 percent of the Trust's total outstanding debt, with 44 percent of the funding to be provided by the Province through equity injections and five percent to be provided by OPG. The subordination level may vary over time, but must at least equal to, or be greater than 35 percent of all outstanding debt. Through OPG's control over the key activities of the Trust and its obligation to absorb losses through ownership of the Trust's subordinated debt, the Company consolidates the financial results of the Trust in accordance with US GAAP.

On December 21, 2017, the Trust purchased its first tranche of Investment Interest from the IESO in the amount of approximately $1.18 billion. Fifty-one percent of the funding requirement or $601 million was financed by the Trust through a revolving warehouse facility ranked as senior notes, and the remaining 49

percent was funded through the issuance of short-term subordinated debt to OPG. The Investment Interest has been classified as a financing receivable on OPG's consolidated balance sheet.

OPG's subordinated debt investment in the Trust was funded through the following sources:

- The Province provided 44 percent of the total funding requirement or $519 million, through an equity injection in OPG in exchange for approximately 12.2 million non-voting Class A common shares at a price of $42.46 per share. The Company's Articles of Amalgamation were amended effective December 1, 2017 to allow for the creation and issuance of Class A shares. Refer to Note 14 to the Company's audited annual financial statements as at and for the year ended December 31, 2017 for further details; and
- OPG provided five percent of the total funding requirement or approximately $60 million.

In February 2018, the Trust issued $500 million of senior notes payable with a coupon interest rate of 3.36 percent and an effective interest rate of 3.42 percent, payable semi-annually until maturity on May 15, 2033. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility issued in December 2017. By the end of the first quarter of 2018, the Trust is expected to acquire another tranche of Investment Interest from the IESO, which is expects to fund using its revolving warehouse facility.

Refer to the section, *Liquidity and Capital Resources* under the heading, *Financing Activities* for further details on the Trust's financing arrangements and OPG's public debt offering in the Company's 2017 year-end MD&A.

Ontario's Long-Term Energy Plan

On October 26, 2017, Ontario's Ministry of Energy issued the 2017 LTEP that outlines the Province's plans for the future development of Ontario's electricity system. The 2017 LTEP focuses on the affordability, reliability and flexibility of a clean energy supply in the province. The 2017 LTEP replaces the previous LTEP issued in 2013.

As it relates to the supply of electricity, the 2017 LTEP recognizes the refurbishment of Ontario's nuclear generating stations as the most cost-effective option for producing emission-free baseload generation to meet Ontario's needs and reaffirms the Province's support for the refurbishment of the four units at the Darlington GS and the six units at the Bruce generating stations, subject to the principles established in the 2013 Long-Term Energy Plan. The 2017 LTEP also recognizes the value to customers of continuing to operate the Pickering GS until 2024, as planned. With respect to hydroelectric electricity generation, the 2017 LTEP highlights the opportunity to continue to invest in optimizing existing hydroelectric facilities, noting that pumped hydroelectric storage could play an important role in the reliability of the electricity system.

Additionally, the 2017 LTEP discusses the potential impact of a number of innovative technologies on the future of the electricity system. Among others, these include the increased electrification of the transportation sector, the emergence of energy storage, and the opportunity for Ontario to foster nuclear innovation technologies. OPG continues to assess how best to capitalize on potential business opportunities in these and other areas. The 2017 LTEP also recognizes the importance of Indigenous peoples' continuing role in shaping Ontario's energy planning, projects and policies.

Renewal of Collective Agreements and Acquisition of Hydro One Limited Shares

Most of OPG's regular employees are represented by one of two unions: the Power Workers' Union (PWU) and The Society of Energy Professionals (The Society). As at December 31, 2017, the PWU represented approximately 53 percent of OPG's regular workforce, while The Society represented approximately 35 percent of the regular workforce.

The previous collective agreement between OPG and the PWU expired on March 31, 2015. In May 2015, the parties agreed to renew the collective agreement for a three-year term, expiring on March 31, 2018.

The changes to the collective agreement included increases to employee pension plan contributions in each year of the agreement. Negotiations for a new labour agreement with the PWU are underway. **[MONITOR]** The previous collective agreement between OPG and The Society expired on December 31, 2015. In November 2015, the parties agreed to renew the collective agreement for a three-year term, expiring on December 31, 2018. Changes to the collective agreement included increases to employee pension plan contributions in each of the first two years of the agreement. The changes in pension plan contributions apply to current employees and future employees of both unions, and do not have an end date.

The changes to both collective agreements provided existing employees with lump sum payments for each of the first two years of the respective contract and eligibility to annually receive shares in Hydro One Limited (Hydro One) for up to 15 years starting in the third year of the contract, as long as these employees continue to make contributions to the OPG pension plan and have less than 35 years of pensionable service. The lump sum payments and future share awards are intended to compensate current eligible employees, over a defined period, for their increased pension plan contributions.

In April 2016, OPG acquired nine million common shares of Hydro One at $23.65 per share as part of a secondary share offering by the Province through a syndicate of underwriters. The acquisition, totaling $213 million, was made for investment purposes to mitigate the risk of future price volatility related to OPG's future share delivery obligations under the collective agreements. The shares acquired in this transaction represent the substantial majority of OPG's currently anticipated purchases of Hydro One shares.

In addition to the regular workforce, construction work is performed through 19 craft unions with established bargaining rights at OPG facilities. These bargaining rights are established either through the Electrical Power Systems Construction Association (EPSCA) or directly with OPG. Collective agreements between the Company and its construction unions are negotiated either directly or through EPSCA. All of these collective agreements currently have multi-year terms, expiring on April 30, 2020.

Shareholder Declarations and Shareholder Resolutions to Sell Certain Non-Core Real Estate Properties

In December 2015, OPG received a Shareholder Declaration and a Shareholder Resolution requiring the Company to sell its head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street in Toronto, Ontario. The sale was completed in April 2017, with a gain on sale of $283 million, which is net of tax effects of $95 million, recognized in net income in the second quarter of 2017. The pre-tax gain on sale was recorded as an item of Other gains in the consolidated statement of income in the Services, Trading and Other Non-Generation segment. Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. The amount of designated proceeds transferred into the Consolidated Revenue Fund are expected to approximate ~~will be equal to~~ the after-tax gain on sale. **[MONITOR]** The transfer is expected to take place in the first quarter of 2018, through a special dividend authorized by OPG's Board of Directors in March 2018. **[MONITOR]**

Commented [DS1]: The amount of designated proceeds will be determined by regulation and therefore uncertain until the regulation is filed and made public.

In June 2016, OPG received a Shareholder Declaration and a Shareholder Resolution that requires the Company to sell its former Lakeview GS site located in Mississauga, Ontario. OPG has entered into a purchase and sale agreement with a purchaser with the sale scheduled to close in March 2018. An estimated after-tax gain on sale of approximately $200 million is expected to be recognized in net income upon completion of the transaction in the first quarter of 2018. **[MONITOR]** Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. OPG anticipates the amount of designated proceeds transferred into the Consolidated Revenue Fund to approximate the after-tax gain on the sale. In accordance with the Shareholder Resolution, approximately one-third of the site is to be transferred to the City of Mississauga, by the purchaser, for parkland, institutional, and cultural uses.

Neither the former Lakeview GS site nor the Company's head office premises and associated parking facility are considered core assets to OPG's business.

For a complete list of Shareholder directives, refer to the section, *Interest of Management and Others in Material Transactions* under the heading, *Relationship with the Province and the OEFC – Shareholder Directives*.

Business Transformation **[UPDATE]**

OPG has completed a multi-year initiative with the objective of transforming itself into a more streamlined, agile and efficient organization. The business transformation initiative was intended to drive sustainable change across the Company, while ensuring that there is no adverse impact on the safety, reliability and environmental sustainability of OPG's operations. OPG's cumulative savings from reductions in regular headcount from ongoing operations, through the business transformation and other initiatives, since the beginning of 2011, reached $1 billion in 2016.

The business transformation initiative involved aggressively pursuing cost control and efficiency improvements at the enterprise and business unit level, including realignment of work, streamlining of processes and leveraging workforce attrition. As part of the initiative, OPG implemented a centre-led organizational model intended to more efficiently utilize resources. In 2015, OPG successfully completed a large-scale initiative, the Enterprise System Consolidation Project, to streamline the company's software systems and improve business processes by implementing a common enterprise software platform.

Although business transformation has concluded as a discrete initiative, improving organizational performance and building on efficiency gains achieved to date remains a key priority for the Company. OPG continues to review its cost structure, identify cost improvement strategies and embed an outcomes-driven culture that reinforces low cost, efficiency, and organizational agility as part of business decision-making.

Nuclear Business Development

Darlington Refurbishment

Government's Endorsement and Execution Phase

The Darlington generating units are approaching their originally designed end-of-life. Refurbishment of the four generating units to extend the operating life of the station by approximately 30 years, into the 2050s. In January 2016, the Government of Ontario's support for the Darlington Refurbishment project was affirmed through the Ontario Minister of Energy's announcement endorsing OPG's plan to refurbish the four Darlington units at a total project budget of $12.8 billion, including capitalized interest and escalation. The Province's announcement followed the approval of the project budget and schedule by OPG's Board of Directors in November 2015. The refurbishment of the last unit is scheduled to be completed by 2026. *Ontario Regulation 53/05* requires the OEB to ensure that OPG recovers capital and non-capital costs and firm financial commitments in respect of the Darlington Refurbishment project, if the OEB is satisfied that the costs were prudently incurred and that the firm financial commitments were prudently made.

The refurbishment project is a multi-phase program comprising several sub-projects. The major work streams include: de-fuelling of reactors and refurbishment of the fuel handling equipment; removal and replacement of feeder tubes and fuel channel assemblies in each reactor (Retube and Feeder Replacement or RFR); inspections and repairs of turbine generator sets and replacement of associated control systems; mechanical cleaning, water lancing, and inspection and maintenance work on steam generators; and replacement or repairs of certain other station components referred to as balance of plant. The RFR is the largest sub-project and represents a majority of the critical path schedule.

In 2016, the Darlington Refurbishment project transitioned from the planning phase to the execution phase, as OPG commenced the refurbishment of the first unit, Unit 2, in October 2016 as planned. The unit was

taken offline on October 15, 2016. De-fuelling of the reactor was completed in January 2017, with a total of 480 fuel channels de-fuelled. Islanding of Unit 2, the physical separation of the unit under refurbishment from the three operating units, was completed in April 2017, signifying the completion of the first major segment of the project.

The second major segment includes preparatory work to support the removal of feeder tubes and fuel channel assemblies, followed by the removal of reactor components. The preparatory work was completed in the second quarter of 2017. The Re-tube Tooling Platform for hosting the tooling for the removal, inspection and installation activities, and the setup of specialized tooling and equipment needed for the removal and replacement of the reactor components were completed in the third quarter of 2017. The disassembly of reactor components commenced in August 2017, with the removal of all 960 feeder tubes completed safely in September 2017. The removal of fuel channel assemblies commenced in October 2017. As part of the fuel channel assemblies, the removal of pressure tubes is in progress and will be followed by the removal of calandria tubes. The second major segment and the removal of all reactor components is expected to be completed by mid-2018. Key projects in the second major segment finished in 2018 include the completion of the primary side steam generator layup and installation of steam generator access ports to support future inspections. Other key project activities being executed during the second segment include the continuation of the major turbine generator overhaul, which will be completed in the second quarter of 2018, and continued execution of the major electrical scope. OPG is also continuing to execute work to support the requirements set out in the CNSC-approved Integrated Implementation Plan (IIP) for the station.

Most of the pre-requisite projects, including construction of facilities, infrastructure upgrades and installation of safety enhancements, have been completed and placed in-service. The Re-tube Waste Processing Building was completed in November 2017. Completion of the HWSF has been delayed due to challenges with construction. OPG suspended the project in the second quarter of 2017 to evaluate the best approach to optimize cost and schedule and complete the project. Construction to complete the facility recommenced in the fourth quarter of 2017. The HWSF is expected to be completed by the second quarter of 2019 and is not on the critical path for the Darlington Refurbishment project, which continues to track on schedule. The increase in the cost estimate for the HWSF will be accommodated within the overall Darlington Refurbishment budget of $12.8 billion. Taking into account the execution performance of the Unit 2 refurbishment, the overall Darlington Refurbishment project continues to track on budget.

The OEB accepted OPG's rate application with respect to the refurbishment of the Darlington units including an increase in the nuclear rate base, effective in the first quarter of 2020, to reflect the planned in service of $4.8 billion in capital expenditures upon the return to service of Unit 2, which includes expenditures incurred during the definition and planning phase of the project. Based on OPG's proposal in the application, the revenue requirement impact of the differences between the forecast Unit 2 in-service amount included in the regulated prices and the actual amounts placed in service would be subject to true up via the Capacity Refurbishment Variance Account established by the OEB pursuant to *Ontario Regulation 53/05*.

In addition to the execution of refurbishment activities on Unit 2, OPG is continuing planning activities for the refurbishment of the second unit, Unit 3, and is entering into associated commitments to procure major components that require long lead times. These planning activities are being undertaken in accordance with the refurbishment project schedule. In February 2018, the Province confirmed its commitment to proceed with Darlington's Unit 3 refurbishment in 2020. **[MONITOR]**

On November 21, 2017, the Financial Accountability Office of Ontario issued a report, "*An Assessment of the Financial Risks of the Nuclear Refurbishment Plan*". The report assesses the impact of OPG and Bruce Power's nuclear refurbishments on customers and the Province based on mechanisms in place for the recovery of the costs to refurbish and subsequently operate the nuclear stations. The report concludes that refurbishment of the four units at the Darlington GS and the six units at the Bruce nuclear generating stations provides the most cost effective, low emission generation source available to meet Ontario's baseload electricity requirements.

CNSC Regulatory Approvals

In December 2013, OPG submitted an application to the CNSC for the operating licence renewal for the Darlington GS. The CNSC granted the Darlington GS a ten-year operating licence in December 2015, which is the longest licence ever granted by the CNSC to a Canadian nuclear power plant. The new licence, which is effective from January 1, 2016 to November 30, 2025, spans most of the planned duration of the Darlington Refurbishment project.

In line with the CNSC's regulatory requirements related to life extensions of nuclear power plants in effect at the time that OPG began to undertake the Darlington Refurbishment project, OPG completed a series of assessments, including an environmental assessment (EA), an Integrated Safety Review, and a Global Assessment Report (GAR). The EA decision, issued by the CNSC and Fisheries and Oceans Canada in March 2013 following public hearings, confirmed that, taking into account identified mitigation measures, the project was not likely to cause significant adverse environmental effects. In April 2014, the CNSC accepted the GAR as meeting all regulatory requirements related to life extensions of nuclear power plants. In November 2014 and April 2016, respectively, certain intervenors' request for a judicial review and subsequent appeal to the Federal Court of Appeal related to the EA decision were dismissed by the courts.

Actions identified as part of the above assessments to meet updated codes, standards and practices, and to ensure that the operation of the station continues to pose minimal risk to health, safety, security and the environment, were integrated into the IIP. As part of the Darlington operating licence renewal in December 2015, the CNSC approved the regulatory scope defined in the IIP. OPG has been undertaking activities in support of the IIP requirements, including the commissioning of two safety enhancements at the station, the Third Emergency Power Generator and the Containment Filtered Venting System, which were placed in-service in April 2017. There were 17 IIP commitments scheduled and completed for 2017.

Extension of Commercial Operations at Pickering to 2024

In 2015, OPG completed the necessary work to demonstrate with sufficient confidence that the Pickering fuel channel life, a key life-limiting component of the station, will allow all six operating units of the station to operate to the end of 2020. OPG's early technical work at that time also showed that the Pickering GS can be operated safely beyond 2020. OPG's objective is to maximize the safe and reliable operating life of the Pickering units. As announced in 2016 and approved by the Province, OPG is continuing to execute on a plan to extend safe and reliable operation of the Pickering GS to 2024. Extending operations at the Pickering GS will provide Ontario with a clean, reliable source of baseload electricity during the Darlington GS and initial Bruce nuclear unit refurbishments, providing continued employment for up to 4,000 full-time employees at OPG.

OPG's current five-year operating licence for the Pickering GS was approved by the CNSC in 2013 and expires on August 31, 2018. This current licence was issued assuming that the station would shut down in 2020. On June 28, 2017, OPG confirmed to the CNSC that it intends to cease commercial operation of all Pickering units on December 31, 2024. On August 28, 2017, OPG submitted a ten-year licence renewal application to the CNSC. The requested licence term spans the planned extended commercial operations period, through to the planned period of de-fuelling, de-watering and beginning to place the station in a safe storage state in 2028. In support of the licence renewal, OPG undertook a Periodic Safety Review (PSR), a comprehensive assessment of the station's design and operation to confirm that there is a high level of safety throughout the operating life and to determine what reasonable and practical enhancements can be made to further improve safety. The PSR also includes a component condition assessment of the station to identify the work required to support the station's continued operation. The PSR has confirmed that extending operations of the Pickering units will continue to pose minimal risk to the health, safety and security of workers, the public and the environment. The final major component of the PSR was submitted to the CNSC in November 2017. The CNSC's review of the PSR submission and licence application is in progress. Based on the evidence and documentation submitted to the CNSC, OPG is confident in obtaining a licence renewal that would support our extended operations plan for Pickering GS.

As part of the plan to extend Pickering operations, OPG has been continuing to undertake the required technical work to confirm that the station's pressure tubes, a key life-limiting component of the station, will remain fit for service for operation to 2024. In the fourth quarter of 2017, OPG has confirmed that technical assessments completed to date provide sufficient confidence in the programs and provisions in place to assure fitness-for-service of fuel channel components in line with the planned extended operations period. This evaluation is consistent with the safety case reflected in OPG's operating licence renewal application for the Pickering GS submitted to the CNSC in 2017, discussed above. Taking these factors into account, OPG revised the accounting end-of-life assumptions for the Pickering GS from December 31, 2020 for all units to December 31, 2022 for Units 1 and 4 and December 31, 2024 for Units 5 to 8, effective December 31, 2017.

The change in the Pickering GS accounting end-of-life assumptions did not impact OPG's net income in 2017. The change is expected to decrease depreciation expense by $77 million in 2018, including the associated impact on the nuclear asset retirement obligation recorded as of December 31, 2017 but before the impact of regulatory accounts. Regulatory accounts, including a new deferral account proposed by OPG in a December 2017 application to the OEB, are expected to largely offset the decrease in depreciation expense. As of December 31, 2017, OPG recorded an increase of $188 million in the Nuclear Liabilities and associated asset retirement costs capitalized as part of carrying value of property, plant and equipment reflecting the change in the Pickering GS accounting end-of-life assumptions from December 31, 2020 for all operating units to December 31, 2022 for Units 1 and 4 and December 31, 2024 for Units 5 to 8. The increase in the liabilities is primarily due to higher fixed costs associated with the Used Fuel Disposal and L&ILW Storage programs, discounted using the current credit-adjusted risk-free rate of 2.94 percent. The adjustment did not impact net income for 2017. The adjustment is not expected to have a material impact on net income in 2018 as the associated impact on expenses is expected to be largely offset by OEB-authorized regulatory accounts. On December 29, 2017, OPG applied for an accounting order to establish a variance account to record, from January 1, 2018 until the effective date of the OEB's next payment amounts order, the revenue requirement impact of changes to nuclear liabilities and depreciation and amortization expense resulting from changes to station end-of-life dates for OPG's Pickering prescribed nuclear facilities that will be effective December 31, 2017. Pending the OEB's review of the application, an interim order was issued January 31, 2018 establishing the proposed variance account effective January 1, 2018. The OEB's final decision in the account is expected later in 2018.

The income statement impacts associated with the changes to the Nuclear Liabilities are offset by the Bruce Lease Net Revenues Variance Account and the Nuclear Liability Deferral Account authorized by the OEB or new variance account to be authorized by OEB for the prescribed facilities.

Bruce Power Refurbishment and Bruce Lease Agreement

OPG leases the four-unit Bruce A (Units 1 to 4) and the four-unit Bruce B (Units 5 to 8) nuclear generating stations and associated lands and facilities to Bruce Power on a long-term basis. Bruce Units 1 and 2 were refurbished by Bruce Power under a refurbishment agreement with the IESO and returned to service in 2012. While Bruce Power is responsible for operating all of the leased units, OPG is primarily responsible for the management of the nuclear used fuel and other nuclear waste associated with the Bruce nuclear generating facilities, as well as the decommissioning of the facilities at the Bruce site. Under the lease agreement between Bruce Power and OPG (Bruce Lease) and related agreements, OPG receives base rent and supplemental rent payments from Bruce Power, fees for nuclear waste management other than used fuel, and fees for certain other services. The output from the Bruce nuclear generating stations is not subject to rate regulation by the OEB.

In December 2015, the Province announced that the refurbishment agreement between the IESO and Bruce Power had been updated and that Bruce Power will proceed with the refurbishment of the six un-refurbished units of the Bruce nuclear generating stations. In order to facilitate Bruce Power's refurbishment plans, the Bruce Lease and related agreements were amended in December 2015 to extend Bruce Power's future options to renew the lease up to the end of 2064. To achieve better alignment with OPG's costs, the agreements were also amended to revise, starting in 2016, the approach for calculating supplemental rent payments and fees for nuclear waste management other than used fuel, and to modify the fee structure for

OPG's heavy water detritiation services starting in 2017. Beginning in 2016, supplemental rent payments wholly represent fees for nuclear used fuel management. Amendments were also made to enable certain adjustments to future base rent, supplemental rent and other fees for potential future changes in OPG's decommissioning and nuclear waste management cost estimates related to the Bruce facilities, and to remove a conditional supplemental rent rebate provision effective December 4, 2015. Certain of the above amendments were executed by OPG pursuant to a Shareholder Declaration and Shareholder Resolutions issued in November 2015. For a complete list of Shareholder directives, refer to the section, *Interest of Management and Others in Material Transactions* under the heading, *Relationship with the Province and the OEFC – Shareholder Directives*.

The refurbishment of Bruce Power's Unit 6 is scheduled to commence on January 1, 2020. As part of the preparation activities, OPG is working with Bruce Power to develop a fixed price cost estimate for the non-routine nuclear waste that will be generated from the Unit 6 refurbishment. The parties will execute a separate agreement that sets out the terms and conditions that will apply to this refurbishment waste. Pursuant to a Memorandum of Understanding dated November 12, 2015, OPG and Bruce Power have committed to ongoing collaboration to improve their respective refurbishment programs.

Ontario Nuclear Funds Agreement Reference Plan Update

OPG is responsible for the management of radioactive used nuclear fuel and low and intermediate level radioactive waste material (L&ILW) and the decommissioning of its nuclear stations and waste management facilities. Pursuant to the Ontario Nuclear Funds Agreement (ONFA), OPG is required to set aside monies into two segregated funds, the Used Fuel Segregated Fund and the Decommissioning Segregated Fund, to fund the future life cycle costs of long-term nuclear used fuel and L&ILW management and nuclear facilities decommissioning. OPG's required contributions to the Nuclear Segregated Funds are determined based on periodically updated reference plans approved by the Province under the ONFA, at least once every five years. As part of the reference plan update process, OPG estimates the total funding liabilities for future nuclear waste management and nuclear decommissioning based on life cycle cost estimates and a set of underpinning assumptions, including remaining useful lives of the nuclear stations, proposed methods and timing of nuclear waste disposal, and economic indicators. In accordance with US GAAP, OPG carries a present value asset retirement obligation on the balance sheet related to its nuclear waste management and nuclear decommissioning liabilities. In accordance with *Ontario Regulation 53/05*, the OEB is required to ensure that OPG recovers the revenue requirement impact of its nuclear waste management and nuclear decommissioning liabilities arising from the current approved ONFA reference plan. The current methodology applied by the OEB for including OPG's costs associated with these liabilities in the regulated prices was established by the OEB in its 2008 decision on OPG's first application for new regulated prices.

In 2016, OPG completed a comprehensive update of the estimate for its obligations for nuclear waste management and nuclear facilities decommissioning, in line with the required ONFA reference plan update process. The results of the update were reflected in a new ONFA reference plan as well as a downward adjustment in the asset retirement obligation carried on OPG's balance sheet as at December 31, 2017. The new ONFA reference plan was approved by the Province in December 2016, with an effective date of January 1, 2017 (the 2017 ONFA Reference Plan). Reflecting the funded status of the Used Fuel Segregated Fund and the Decommissioning Segregated Fund based on the revised lower life cycle liability estimates per the 2017 ONFA Reference Plan, no overall contributions to either the Used Fuel Segregated Fund or the Decommissioning Segregated Fund are currently required starting in 2017. Contributions may be required in the future should either or both of the funds be in an underfunded position when a new reference plan is approved. Such may be the case as a result of future variability in asset performance due to volatility inherent in financial markets and economic conditions. Future contribution levels also are dependent on changes in baseline cost estimates and underpinning planning assumptions used to establish the funding obligations in subsequent ONFA reference plans.

The overall reduction in OPG's nuclear waste management and nuclear decommissioning liabilities resulting from the comprehensive update was mainly due to a decrease in cost estimates to reflect a proposed new, more cost effective container design and engineered barrier concept to house used nuclear fuel for disposal, updated cost escalation rates, and a later expected in-service date for Nuclear Waste Management Organization's (NWMO) planned deep geologic repository for the long-term permanent disposal of Canada's used nuclear fuel. These decreases were partly offset by higher cost estimates related to station decommissioning, primarily due to a better definition of work required during the preparation for safe storage after station shutdown and a higher volume of waste expected to be generated during the decommissioning.

Further details on OPG's nuclear waste management and nuclear decommissioning obligations, the ONFA and proposed methods for long-term used fuel and L&ILW disposal are discussed in the section, *Description of the Business* under the heading, *Regulated – Nuclear Waste Management Segment.*

Hydroelectric Business Development

Peter Sutherland Sr. Hydroelectric Generating Station

In March 2015, OPG's Board of Directors approved a project to construct the Peter Sutherland Sr. GS, a new 28 MW hydroelectric station on the New Post Creek near its outlet to the Abitibi River, with a budget of $300 million. The station was constructed through PSS Generating Station LP, a partnership between OPG and Coral Rapids L.P., a wholly owned subsidiary of the Taykwa Tagamou Nation.

In March 2017, final testing and commissioning of the turbine and generator units were successfully completed and both units were declared substantially complete. On March 31, 2017, the project received a permit from the Ontario Ministry of the Environment and Climate Change (MOECC) to take water for operations to allow the station to operate commercially. The project is expected to close below the approved budget of $300 million. Project close-out activities are in progress. OPG began to receive contracted revenue for the project following the IESO's confirmation of the station's commercial operations as of March 31, 2017, under a 50-year hydroelectric ESA.

In April 2017, Coral Rapids Power Corporation (CRP) exercised its right under the partnership agreement to increase its interest in PSS to 33 percent.

Sir Adam Beck Pump Generating Station Reservoir Refurbishment

In August 2015, OPG's Board of Directors approved a project to refurbish the 300-hectare storage reservoir at the Sir Adam Beck Pump GS. The Sir Adam Beck Pump GS facility allows OPG to pump and store water diverted from the Sir Adam Beck generating complex during periods of low electricity demand to be used to generate up to 600 MW of electricity during subsequent periods of high electricity demand.

The refurbishment construction began in April 2016 and was completed in February 2017, ahead of the originally planned schedule date of April 2017 and below the approved budget of $58 million. The reservoir refurbishment work included the installation of a partial new reservoir liner and construction of a grout curtain in the bedrock foundation of the reservoir dyke. The refurbishment is expected to add approximately 50 more years to the reservoir's life. The Sir Adam Beck Pump GS is reported in the Regulated – Hydroelectric segment.

Ranney Falls Hydroelectric Generating Station

In 2017, OPG began construction work on a 10 MW single-unit powerhouse on the existing Ranney Falls GS site, as part of the Regulated – Hydroelectric segment. The new unit will replace an existing unit that reached its end of life in 2014. The existing forebay structure has been demolished and the new concrete structure has been completed. Excavation has been completed and construction continues in the expanded forebay, powerhouse and spillway area. The new forebay concrete wall has been completed, and concrete placement of the new powerhouse and the spillway integrated structure is in progress. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget.

Thermal and Solar Business Development

Nanticoke Solar Facility

In March 2016, Nanticoke Solar LP, then a partnership between OPG, SunEdison Canadian Construction LP (SECCLP) and a subsidiary of Six Nations of the Grand River Development Corporation, was selected through the first phase of IESO's Large Renewable Procurement (LRP) program to develop a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands in Haldimand County, Ontario. The LRP program was a competitive bidding process for procuring large renewable energy projects in Ontario. In March 2016, Nanticoke Solar LP and the IESO executed a 20-year LRP contract, which formalized the terms and conditions for the development and operation of the new solar facility. In the first quarter of 2017, OPG purchased SECCLP's interests in Nanticoke Solar LP and is working to obtain approvals and permits required to enable the commencement of construction planned for the first quarter of 2018. Significant contracts for equipment and engineering construction services were executed in the first quarter of 2018. The 20-year term of the LRP contract takes effect once the station achieves commercial operation, which is expected in the first quarter of 2019. The facility is expected to be completed in the first quarter of 2019, with a budget of $107 million. **[MONITOR]**

Decommissioning of Lambton and Nanticoke Coal-Fired Generating Stations

OPG ceased coal-fired generation at the Lambton and Nanticoke generating stations in September 2013 and December 2013, respectively. In November 2016 and July 2015, respectively, OPG announced that it would decommission the Lambton and Nanticoke generating stations as it could not commercially support continued preservation of these sites in light of the outlook for long-term electricity demand in the province that does not support the need for their future conversion. OPG has begun executing decommissioning plans for these two stations, which will ensure that they are closed safely, securely, and in an environmentally responsible manner. The decommissioning of the Nanticoke GS will accommodate the construction and operation of the Nanticoke solar facility.

During 2017, OPG substantially completed the demolition of the Nanticoke coal yard equipment and structures and issued a contract for the demolition of the Nanticoke powerhouse and associated structures. In the fourth quarter of 2017, the demolition contractor had been mobilized to prepare for the removal of the powerhouse and associated structures and initiated the preparatory work for the demolition of the stacks. The demolition of the stacks took place in February 2018. **[MONITOR]** A competitive bidding process for the demolition of the Lambton GS is in progress, with a contract for the removal of the powerhouse and associated structures expected to be issued during 2018. An update of the associated asset retirement obligations related to the Nanticoke and Lambton sites has been completed. For a discussion of the revaluation of this liability for non-nuclear fixed asset removal as at December 31, 2017, refer to the section, *Critical Accounting Policies and Estimates* under the heading, *Asset Retirement Obligations* in the Company's 2017 year-end MD&A.

DESCRIPTION OF THE BUSINESS

The Electricity Industry

The electricity industry is principally comprised of four components: generation, transmission, distribution, and marketing of energy and other services in wholesale and retail markets.

Generation is the production of electricity. Transmission is the transfer of electricity across high-voltage power lines from generating facilities to local areas. Distribution is the delivery of electricity within local areas to homes and businesses using relatively low-voltage power lines. Energy marketing relates to the purchase of large amounts of electricity or equivalent financial products, and the subsequent re-selling in smaller quantities to third parties in either the wholesale or retail markets.

Electricity has traditionally been generated in large, multi-unit, centralized facilities. These facilities are usually classified by: (i) the type of fuel used; (ii) capacity, typically expressed in MW; and (iii) dispatch mode (being whether or not the electricity generated by a particular facility is dispatched to meet peak, intermediate or baseload demand). The energy produced by a facility is generally expressed as its output over the time the facility operates, typically in terms of MWh. New supply from smaller scale, largely intermittent, renewable sources such as wind, solar, and bio-energy is being integrated into the power system, connected either directly to the transmission system or embedded in distribution networks. Distributed generation involves production of electricity closer to end users and away from large scale production facilities that require more transmission. Electricity systems typically require new capital expenditures and processes in order to accommodate intermittent generators.

Electricity is an essential commodity that cannot be stored without converting to other forms, a process that is more difficult in large volumes. Therefore, electricity supply must instantaneously match demand to maintain the stability and reliability of the electrical power system. This is accomplished by coordinating the supply of and demand for electricity, a responsibility typically assigned to regulated regional system operators. Electricity systems have evolved on a regional basis and are connected to neighbouring regional power grids. Such connections enhance system reliability and permit the economic purchase and sale of electricity between electricity markets.

Ontario's Electricity Industry

OPG's predecessor, Ontario Hydro, served as a vertically integrated electric utility in Ontario. Following the adoption of a restructuring plan for Ontario's electricity industry pursuant to the *Energy Competition Act, 1998,* five principal successors to Ontario Hydro's integrated electricity business began operating as separate entities on April 1, 1999:

- OPG, which purchased and assumed the electricity generation, wholesale energy, and ancillary services businesses of Ontario Hydro;
- Hydro One, which purchased and assumed the transmission, distribution, and retail energy services businesses of Ontario Hydro;
- the Independent Electricity Market Operator (later renamed the IESO), which was formed to act as both the independent electricity system operator and the market operator. The IESO is responsible for the dispatch of generation to meet demand, the control of the Ontario transmission grid, and the operation of energy and ancillary markets;
- the Electrical Safety Authority, which was established to carry out electrical equipment and electrical wiring safety and inspection functions; and
- the Ontario Electricity Financial Corporation (OEFC), which is the legal continuation of the former Ontario Hydro and is responsible for managing the debt and certain other obligations not transferred to other successor companies of Ontario Hydro.

OPG purchased and assumed all of the interest of Ontario Hydro in and to all officers, employees, assets, liabilities, rights and obligations of Ontario Hydro directly or indirectly relating in any manner to the applicable activities carried on by Ontario Hydro as of April 1, 1999, pursuant to the transfer orders made

by Order-in-Council under the *Electricity Act, 1998*. The transfer orders provide that if they fail for any reason to fully and effectively in law transfer any such asset, right, liability or obligation or that if such transfer would constitute a breach of the terms of the asset, right, liability or obligation or of any applicable law, such assets, rights, liabilities or obligations are not transferred, but are held by the OEFC for the benefit of OPG.

Ontario's competitive electricity market was opened by the IESO in 2002. The market is used to manage the purchase and sale of wholesale electricity in the province.

Since the opening of the competitive market, Ontario's power supply mix has experienced significant change. A significant amount of new capacity has been added, while coal-fired generation, which at its peak accounted for approximately 6,500 MW of capacity, has been eliminated. New natural gas powered capacity of approximately 5,000 MW as of the end of 2017 has largely replaced the peaking capacity previously provided by coal-fired generation, while the return to service of Units 1 and 2 at the Bruce A GS in 2012 added approximately 1,500 MW of baseload nuclear generation. New wind and solar capacity of over 7,000 MW has also been added as of the end of 2017, toward Ontario's longer-term target for total wind and solar capacity of about 10,000 MW.

While electricity supply in Ontario has increased, the province's electricity demand as reported by the IESO has fallen, by approximately 13 percent over the last decade, largely due to changes in economic conditions and conservation measures, and also in part due to the addition of small scale solar generation embedded in the distribution system. Embedded generation reduces the demand supplied by grid-connected generation. Reducing electricity demand by encouraging conservation and demand management has been a key part of the Government of Ontario's plan to reduce greenhouse gas (GHG) emissions from the province's electricity sector. Shorter-term fluctuations in electricity demand are impacted by variations in seasonal weather conditions. Ontario's electricity demand as reported by the IESO was 132 TWh in 2017, which excludes electricity exports out of the province.

In October 2017, Ontario's Ministry of Energy issued the 2017 LTEP that outlines the Province's plans for the future development of Ontario's electricity system. The 2017 LTEP focuses on the affordability, reliability and flexibility of a clean energy supply in the province. For further details on the LTEP, refer to the section, *General Development of the Business* under the heading, *General Development – Ontario's Long-Term Energy Plan.*

Ontario Electricity Market Activities

Real-time energy supply needs are met through the wholesale electricity market administered by the IESO, with the market clearing price, the Hourly Ontario Energy Price, set by offers or bids into the market. OPG offers its generation into this real-time energy market, or spot market, to be dispatched by the IESO. The IESO receives hourly offers from electricity generators and importers to provide energy, along with bids to withdraw energy from a few flexible loads and exporters, and then schedules the lowest-cost offers and bids needed to meet demand every five minutes.

Virtually all non-OPG generators in Ontario have bilateral contracts with the IESO that provide for payments that are different from the market price of electricity. In addition, the prices for all of OPG's nuclear and most of its hydroelectric stations are set by the OEB. The difference between the market price and the prices paid for regulated and contracted generation, as well the cost of conservation and demand management programs, are charged to Ontario electricity consumers through the Global Adjustment portion of the total price of electricity.

Maintaining power system reliability requires a continuous balance of supply and demand. Some generators are needed to produce a constant supply of energy to meet basic energy needs (baseload generation), while others are needed to adjust energy output to match changes in demand (peaking and intermediate generation). OPG's nuclear generating stations operate as baseload facilities, whereas its hydroelectric stations operate as baseload, intermediate or peaking stations, depending on their physical characteristics and hydrological conditions. OPG's thermal stations operate as peaking facilities.

SBG occurs when electricity production from the baseload facilities is greater than the market demand for electricity. Baseload generation supply surplus in Ontario is managed by the IESO, mainly through generation reductions at hydroelectric and certain nuclear stations and other grid-connected renewable resources. The prevalence of SBG conditions is impacted by weather conditions which affect electricity demand, wind and solar generation quantities, and through the impact on water flows, the availability of hydroelectric power. In 2017, OPG lost 5.9 TWh of hydroelectric generation due to SBG conditions. In each of 2016 and 2015, OPG lost 4.7 TWh and 3.2 TWh of hydroelectric generation due to SBG conditions. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions, which represents the majority of such production forgone by OPG to date, has been offset by a regulatory variance account authorized by the OEB. During 2017, 2016 and 2015, generation losses at OPG's regulated hydroelectric stations due to SBG conditions were 5.2 TWh, 4.3 TWh and 2.8 TWh, respectively.

The OEB has authorized an additional pricing mechanism for OPG's regulated hydroelectric generation that provides a financial incentive to OPG to shift hydroelectric generation from lower market price periods to higher market price periods. This is intended to benefit customers through the displacement of generation from the relatively higher cost sources such as natural gas. The time-shifting is made possible by the ability to store water in reservoirs located at a number of OPG's hydroelectric facilities, including the Sir Adam Beck Pump GS.

The IESO also administers the operating reserve market and a market for ancillary services. The objective of the operating reserve market is to ensure that additional supplies of energy are available to maintain power system reliability following an unforeseen event. Ancillary services include regulation service, reactive support, black start capacity, and other services required to maintain the reliability of the Ontario electricity system. OPG participates in these markets. Revenues earned by OPG's regulated facilities from providing services into these markets are applied by the OEB to reduce regulated prices for electricity generated from these facilities.

OPG and other Ontario electricity market participants are required to comply with market rules issued by the IESO. As an owner and operator of generating stations, OPG is also subject to reliability standards as set out by the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC) and the IESO. NERC, NPCC and IESO are standards authorities with the ability to create or modify reliability standards. Such standards are binding on OPG pursuant to the OEB-issued electricity generating license and the IESO market rules. The IESO monitors compliance with and enforces the market rules and coordinates with system operators and reliability agencies in other jurisdictions to ensure energy adequacy and security across the interconnected bulk electricity market in North America.

Interconnected Markets

The interconnected markets are electricity markets in neighbouring provinces and states whose transmission systems are connected to the Ontario power grid, either directly or through other contiguous interconnected markets. Ontario's market is interconnected with New York, Michigan, Minnesota, Manitoba, and Québec. Market intermediaries wishing to import or export electricity between Ontario and the interconnected markets are required to schedule these transactions through the Ontario spot market. OPG and its wholly owned subsidiary, OPG Energy Trading (OPGET), participate in the interconnected markets. Further details on OPGET are discussed under the heading, *Services, Trading, and Other Non-Generation Segment.*

Interconnection transmission capabilities between Ontario and the interconnected markets are subject to physical and weather dependent limitations. These limitations include planned or forced outages to transmission lines and other equipment that reduce transmission capacity. They also include wind and temperature conditions that affect the transfer capability of all transmission lines on the electrical system. For example, higher ambient air temperature lowers capacity, while higher wind speeds increase capacity. Overall power system parameters and conditions also can result in limitations on particular interties, being one or more transmission lines that connect Ontario to a neighbouring region. For example, high flow on one intertie may result in a reduction in the limit on another intertie.

Water Rights

OPG's management of available water resources directly affects the generation output, efficiency, and ultimately return on investment for the Company's hydroelectric assets. The watersheds on which OPG's hydroelectric generating facilities are located are shared by many users and are subject to various governance requirements, such as international, federal and provincial agreements, water power leases, and regulations. Accordingly, OPG must balance the economic, environmental, social and legal requirements associated with the watersheds when utilizing water to optimize electricity generation.

International Rivers

The six OPG hydroelectric generating stations subject to OEB rate regulation since 2008 are directly or indirectly supplied by two major international waterways, the Niagara River and the St. Lawrence River, and are subject to treaties with the U.S. relating to water use. These stations represent approximately 45 percent of OPG's total in-service hydroelectric capacity.

Through a series of agreements between the Government of Canada and the Province, and certain federal and provincial laws, OPG has been granted the right to exercise Canada's rights with respect to the construction, maintenance, and operation of generating facilities under the *Boundary Waters Treaty of 1909* and the *Niagara Diversion Treaty of 1950* between Canada and the U.S. Both of these treaties continue in perpetuity but are terminable by either party with 12 months prior written notice. Given the significance of these treaties, OPG does not expect either party to exercise their respective termination rights in the foreseeable future.

The *Boundary Waters Treaty of 1909* established the International Joint Commission with the mandate of regulating shared water uses and preventing and resolving disputes between U.S. and Canada. In December 2016, the International Joint Commission issued an order implementing a new plan to manage water levels and flows in Lake Ontario and the St. Lawrence River, effective January 7, 2017. The new plan, which replaced the existing plan in use since 1963, is intended to allow for more natural water levels, while minimizing impacts to other users, including hydroelectric power production. No significant changes in OPG's operations are expected as a result of the new plan.

The *Niagara Parks Act* (Ontario) gives the Niagara Parks Commission the authority to grant certain rights for the use of the waters of the Niagara River for purposes of power generation. By agreement with OPG, the Niagara Parks Commission has agreed not to grant any rights to third parties until after 2056.

Under an agreement between OPG and the St. Lawrence Seaway Management Corporation, a federal agency, the DeCew Falls generating stations use water that is transported along the Welland Canal from Lake Erie. The agreement has been renewed through June 30, 2038.

The Province has granted OPG the right to use water from the International Rapids section of the St. Lawrence River for power generation at the R.H. Saunders GS, subject to an agreement between the Government of Canada and the Province. The Government of Canada has the right, upon notice and after unsuccessful arbitration, to take over the operation of and title to the R.H. Saunders GS in the unlikely event of a breach of the agreement by the Province.

Interprovincial Rivers

Four of OPG's hydroelectric stations are located on the Ottawa River, which forms part of the Ontario-Québec border. These stations represent approximately 12 percent of OPG's total in-service hydroelectric capacity. Three of these stations are subject to 999-year leases with each of the Provinces of Ontario and Québec. The fourth station is subject to a water power lease with the Province of Ontario, which is renewable to 2031, subject to certain conditions. OPG's use of water from the Ottawa River basin is subject to guidelines established by the Ottawa River Regulation Planning Board, comprised of government and industry representatives.

Interior Rivers

Fifty-six of OPG's hydroelectric stations, representing approximately 43 percent of OPG's total in-service hydroelectric capacity, are located on 20 other Ontario river systems. OPG holds water power leases, Crown leases and licences with the Province on the river systems that supply 37 of these stations. A land use permit, issued for the Peter Sutherland Sr. GS, remains in effect while a water power lease for the site is prepared by the Ontario Ministry of Natural Resources and Forestry (MNRF). These leases and licences have expiry dates, including renewal periods, ranging between 2023 and 2075. Certain of these leases provide that the leased property and any fixed improvements, including generating stations and dams, will revert to the Province on the expiry of the lease. OPG intends to work towards new leases and licenses for these stations. OPG's use of Ontario's interior watersheds is constrained by restrictions contained in certain of the water power leases and licences. Eight of the 56 stations are located on the Trent and Rideau Waterways and are operated pursuant to licences from the federal government. These licences expire in February 2020. The process to renew the licences is currently underway with Parks Canada. Ten of the 56 stations are not subject to leases or licences.

The current provincial regulatory framework requires the development of Operational Plans for new storage dams and generating stations in Ontario, except for those on international rivers, interprovincial rivers, or rivers under federal jurisdiction. These plans include any limitations on water flows and elevations, and historically have been a component of formal Water Management Plans (WMPs). WMPs were established under the *Lakes and Rivers Improvement Act* (Ontario) and *Water Management Planning Guidelines for Waterpower (2002)*, on a watershed basis, in consultation with the Ontario Ministry of Natural Resources and Forestry, federal fisheries authorities, stakeholders, such as recreational and commercial users, local communities, environmental groups, and partners, such as Indigenous groups. In October 2016, the MNRF published a Technical Bulletin, *Maintaining Water Management Plans (2016),* eliminating the need for WMPs where they are not already in place, removing the expiry date from existing WMPs, and outlining the requirements for Operational Plans for new waterpower works going forward. Existing WMPs continue to be in effect. WMPs and Operational Plans may be amended as certain conditions change or new data becomes available. OPG operates in compliance with WMPs and Operational Plans.

The operations of certain OPG stations in northwestern Ontario can impact users in Manitoba and are subject to guidelines and directions provided by the Lake of the Woods Control Board, which is comprised of Ontario, Manitoba and federal government representatives.

Dams and Waterways

In Canada, dams fall under provincial jurisdiction, with the exception of dams situated in interprovincial and international boundary waters and canals, and those owned by the Government of Canada. The majority of OPG's dams fall within the jurisdiction of the Province, with approximately 20 dams falling within the jurisdiction of the Province of Québec and 13 dams associated with the Trent-Severn and Rideau Waterways falling under federal jurisdiction. The International Joint Commission has an oversight role for dams and associated works on international boundary waters, including the St. Lawrence River and the Niagara River.

The Province regulates dams under the *Lakes and Rivers Improvement Act* (Ontario) administered by the MNRF. The legislation requires MNRF approval for activities such as the construction, alteration, improvement, or repair of dams.

In August 2011, the MNRF published a revised set of Technical Guidelines for dams, following a period of public consultation. The Technical Guidelines represent the government standards for dam safety. OPG was an active participant in developing the Technical Guidelines through the MNRF's advisory panel. In general, OPG practices in the area of dam safety and public safety around dams exceed the minimum requirements outlined in the Technical Guidelines. In cooperation with the MNRF, OPG is developing a new risk-informed approach to prioritize the outcomes of dam safety assessments.

Currently, there is no federal or provincial regulation with respect to public safety around dams that addresses dam public safety issues relating to changes in operating water levels, discharges from the hydroelectric or dam facilities, and other waterways-based hazards posed by such facilities. The *Navigation Protection Act* (Canada) does, however, require OPG to obtain approvals for the installation of all in-water works, such as safety booms and buoys associated with the OPG Waterways Public Safety Program. Additional details on OPG's Dam Safety and Waterways Public Safety Programs are discussed under the heading, *Workplace Safety and Public Safety – Dam Safety and Waterways Public Safety*.

Generation Operations

Nuclear (Regulated – Nuclear Generation Segment)

Overview of Generating Facilities

OPG owns and operates two nuclear generating stations, the results of which are reported in the Regulated – Nuclear Generation business segment. The Pickering GS, comprised of six operating units and two units in a permanent safe shutdown state, is located on the shore of Lake Ontario in Pickering, Ontario. As at December 31, 2017, the station's total in-service capacity was 3,094 MW. Four of the eight Pickering units originally went into service in the 1970s. A decision was made by Ontario Hydro in the late 1990s to place these four units in voluntary lay-up. In 2003 and 2005, respectively, two of the four laid-up units were returned to commercial operation, with the two remaining units placed in a permanent safe shutdown state. The other four operating units have been in service since the mid 1980s.

The Darlington GS, comprised of three operating units and one unit, Unit 2, undergoing refurbishment as of mid-October 2016, is located on the shore of Lake Ontario in the Municipality of Clarington, Ontario. As at December 31, 2017, the total in-service capacity of the three operating units was 2,634 MW. Unit 2 has a capacity of 878 MW. All four Darlington units have been in service since the early 1990s. Both the Pickering GS and the Darlington GS have been designed to operate at full power as baseload facilities.

The performance of OPG-operated nuclear generating stations during 2017, 2016 and 2015 was as follows:

Regulated – Nuclear Generation Performance (2015 to 2017)

Station	No. of In-Service Units	Unit Capability Factor [1] (%)		
		2017	2016	2015
Darlington [2]	3	**85.2**	89.5	76.9
Pickering	6	**80.0**	75.2	79.4
Total	9			

[1] Unit capability factor is the amount of energy a generating unit is capable of producing as a percentage of its maximum output assuming no external constraints such as transmission limitations. The nuclear unit capability factor excludes unit(s) during the period in which they are undergoing refurbishment.

[2] Excluding Unit 2, which has been undergoing refurbishment since mid-October 2016.

The lower Unit Capability Factor at the Darlington GS in 2017, compared to 2016, reflected the higher number of planned outage days in 2017, largely driven by constraints related to the transition of the station's operating units toward refurbishment. The increase in the Unit Capability Factor at the Pickering GS in 2017, compared to 2016, was primarily due to outage cycle optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station compared to 2016.

OPG's Bruce A and Bruce B nuclear generating stations have been leased on a long-term basis to Bruce Power. The stations are located in the Municipality of Kincardine, Ontario on the shore of Lake Huron.

For additional information on OPG's nuclear operations, refer to the section, *Core Business, Strategy, and Outlook* under the heading, *Operational Excellence – Electricity Generation Production and Reliability* in the Company's 2017 year-end MD&A.

Nuclear Generation Technology

Nuclear generation harnesses the energy released during controlled nuclear fission reactions to produce steam that is used to drive turbines to generate electricity. Nuclear generation has two main advantages. It is a relatively low marginal-cost generation technology, and it produces virtually no GHG, sulphur dioxide, nitrogen oxide, or mercury emissions. The latter advantage has become more significant as governments implement climate change action plans and stricter air emission standards.

However, in contrast to other types of generating facilities, notwithstanding the lower fuel costs, nuclear generating stations incur nuclear waste management and decommissioning costs and greater operating and maintenance expenses. In addition, the construction of nuclear generating stations entails greater initial capital costs than other generation technologies. The higher initial costs reflect the complexity of the technical processes fundamental to nuclear electricity generation, and the additional design and safety precautions taken to protect the public from potential risks associated with nuclear operations.

All of OPG's nuclear generating stations use CANada Deuterium Uranium (CANDU) technology reactors. CANDU is a pressurized-heavy-water, natural-uranium power reactor, originally designed in the 1960s by a consortium of Canadian government agencies and private industry. CANDU reactors are unique in their use of natural-uranium fuel and deuterium oxide, or heavy water, as both a moderator to slow down the fission process and a coolant within the reactor. The refuelling system is also unique in that CANDU reactors can be refuelled at full power. This is due to the subdivision of the reactor core into hundreds of separate fuel channels, each holding a single string of natural uranium fuel bundles, allowing for greater fuel efficiency. In contrast, U.S. reactors, which use enriched uranium fuel, must be shut down during refuelling. All nuclear power reactors in Canada use CANDU technology. CANDU reactors are currently operating in Ontario, New Brunswick, Argentina, Romania, South Korea, India, Pakistan and China.

Nuclear Fuel Procurement

OPG's nuclear fuel supply chain engages in the purchase of uranium concentrate, the purchase of services for the conversion of uranium concentrate to uranium dioxide, and the purchase of services for the manufacture of fuel bundles containing uranium dioxide pellets. OPG currently establishes contractual arrangements with each of these components separately and as appropriate maintains ownership of the uranium throughout the supply chain. OPG maintains a portfolio of multi-year supply contracts for uranium concentrate with domestic and foreign suppliers and commodity traders. Occasionally, short-term spot market purchases are acquired to support a portion of its uranium concentrate needs. OPG's nuclear fuel bundles are supplied by a Canadian-based manufacturer.

Nuclear Regulation

The *Nuclear Safety and Control Act* (NSCA) establishes the mandate and authority of the CNSC to make regulations governing all aspects of the development and application of nuclear energy in Canada. The NSCA grants the CNSC the power to act as a court of record, the right to make regulations, the power to require financial guarantees for nuclear waste management and nuclear facilities decommissioning as a condition of granting a licence, order-making powers, and the power to impose monetary penalties for licence infractions. The NSCA also grants the CNSC the power to require periodic re-certification of nuclear operators and to set requirements for various nuclear facility security measures. It also provides for regulatory authority over environmental matters, including a requirement that licence applicants make adequate provision for the protection of the environment. The NSCA grants the CNSC licensing authority for all nuclear activities in Canada, including but not limited to the issuance of new licences to operators, the renewal of existing licences, protection of the environment arising from nuclear activities, and making regulations related to nuclear activities.

A fundamental principle in nuclear regulation is that the licensee bears the responsibility for safe operation, with the CNSC setting safety objectives in areas such as radiation protection and physical security for nuclear generating stations and the transport of radioactive materials. The CNSC verifies compliance with the licence and performs audits and inspections of the licensee's performance against these objectives. The CNSC also has issued guidance documents to assist licensees in complying with regulatory requirements. Requirements specified in these guidance documents have been incorporated into the design and operating documents for OPG's nuclear generating stations.

Since the operation and regulation of nuclear energy has transboundary impacts, Canada has become a signatory to various international conventions relating to nuclear energy and emergency responses and is bound by conventions that it has ratified. In addition, the CNSC has a bilateral information exchange and co-operation agreement with the U.S. Nuclear Regulatory Commission, which provides, among other things, for the prompt, reciprocal notification of reactor safety problems that could affect both U.S. and Canadian nuclear generation facilities.

The CNSC publishes an annual Regulatory Oversight Report on the safety performance of Canada's nuclear power plants. The report assesses how well plant operators are meeting regulatory requirements and program expectations in the areas of operational performance, safety analysis, radiation protection, waste management and conventional health and safety. On September 8, 2017, the CNSC issued an executive summary of its 2016 annual report, giving both the Darlington GS and the Pickering GS the highest possible safety rating of "Fully Satisfactory". The Darlington GS achieved this rating for the eighth consecutive year, while the Pickering GS achieved this rating for the second consecutive year.

In 2017, the CNSC approved regulatory document *REGDOC 2.2.4 – Fitness for Duty – Managing Alcohol and Drug Use* for use at Canadian nuclear power plants. This document sets out requirements for managing fitness for duty of workers in relation to alcohol and drug use at high-security sites, including for-cause alcohol and drug testing for workers in positions identified as safety-sensitive or safety-critical and random alcohol and drug testing for workers holding safety-critical positions. OPG intends to enhance its existing Fitness for Duty program to comply with these new requirements. OPG is working with its partners in the Canadian nuclear industry to develop a program suitable for Canada and its workers.

All of OPG's nuclear power reactor operating licences and waste facility licences are current and up to date. In 2016, OPG submitted applications with the CNSC seeking a ten-year licence renewal for the Western Waste Management Facility (WWMF), located at the Bruce generating stations' site, to May 31, 2027, and a ten-year licence renewal for the Pickering Waste Management Facility (PWMF) to August 31, 2028. The licence renewal applications were presented to the CNSC at public hearings in April 2017. On May 30, 2017, the CNSC announced that the WWMF licence was renewed for a ten-year period and will be valid until May 31, 2027. On February 7, 2018, the CNSC announced that the PWMF licence was renewed for a ten-year period and will be valid until August 31, 2028. Further details on the operating licence for the Darlington GS are found in the section, *General Development of the Business* under the heading, *Nuclear Business Development – Darlington Refurbishment* and for the Pickering GS in the section, *General Development of the Business* under the heading, *Nuclear Business Development – Extension of Commercial Operations at Pickering to 2024*.

Details on Canada's nuclear liability regime and related insurance coverage can be found under the heading, *Insurance*.

Fukushima Daiichi Response

In response to the 2011 Fukushima Daiichi incident in Japan, OPG has confirmed that its stations are safe and that systems and procedures are in place to withstand significant emergencies. In 2013, a systematic review and verification of defences against external hazards was completed at OPG-operated stations. The review showed that:

- the nuclear safety systems and multiple back-up power systems in place at the stations are effective; and
- the current design of the stations is strong and the stations are able to withstand extreme external events.

The review also provided recommendations for further opportunities to enhance the safety margin and to develop preparedness for unexpected events that go beyond the extreme events already considered in the design of the stations.

OPG's action plan in response to the Fukushima Daiichi event is well aligned with the CNSC's Fukushima Action Plan, issued in mid-2012. In 2013, OPG submitted its plans for the majority of the CNSC's Fukushima Action Plan items applicable to OPG-operated stations to the CNSC. In January 2015, the CNSC recognized OPG's efforts in this area and confirmed that all of the Fukushima action items were closed. OPG's Fukushima Implementation Plan included a number of key safety enhancements for providing additional back-up capability to increase OPG's flexibility to respond to unexpected and highly unlikely external events that can impact either a single unit or multiple units at the same time. CNSC staff concluded that OPG had strengthened reactor defence and enhanced its emergency response at both the Darlington GS and the Pickering GS in response to the lessons learned from the Fukushima Daiichi incident.

Nuclear Generating Station Life

Service life predictions for OPG-operated nuclear stations are developed by assessing the impacts of a number of operating, technical, and regulatory considerations on both unit and station economics. A decision by OPG to remove a unit from service would be primarily an economic decision that becomes more likely as the number of components requiring replacement and the frequency and duration of inspections required to ensure a unit's fitness for service increases. The key life-limiting components at OPG's nuclear stations include fuel channels, feeder tubes, steam generators, and other reactor components. End-of-service life predictions are reviewed as new information on possible degradation mechanisms becomes available and as future generation expectations are revised.

In December 2015, OPG revised the accounting assumptions for the estimated useful lives of the nuclear generating stations it operates. Effective December 31, 2015:

- the average service life of the Darlington GS was extended by one year to 2052 to reflect the approval of the refurbishment schedule in 2015; and
- the average service life of the Pickering GS was extended by less than one year to reflect the technical confidence that all six operating units of the station will operate to the end of 2020.

The accounting end of life assumptions for the Pickering GS have been reassessed in December 2017 based on the technical work performed to confirm that the longer fuel channel life necessary to extend Pickering operations can be achieved and that the units would be fit to operate beyond 2020, taking into account the requirement for the CNSC's approval. Further information can be found in the section, *General Development of the Business* under the heading, *Nuclear Business Development – Extension of Commercial Operations at Pickering to 2024*.

Nuclear Facility Planning

OPG uses a structured approach to identify and prioritize projects to optimize returns from nuclear station reinvestment within the constraints imposed by technical and financial requirements, while ensuring that safety, environmental, and other regulatory programs are of the highest priority. Input from predictive maintenance programs, life cycle management plans, and system health monitoring is used to determine the activities necessary to sustain and improve nuclear unit performance.

A structured framework modeled on the best practices identified by the Electric Power Research Institute, the Institute for Nuclear Power Operations and the World Association of Nuclear Operators (WANO) is used to optimize the maintenance of the nuclear generating stations and assess the health of the facilities. The structured framework includes predictive maintenance programs, which combine technologies and human expertise to analyze equipment performance, maintenance and design data in order to make timely decisions about the scope and timing of inspections and maintenance for major or critical equipment. The predictive maintenance program for each station is prioritized on the basis of the importance of the equipment for reactor safety. Life cycle management plans are maintained for critical station components and are updated annually to incorporate operating experience and new information. The life cycle plans define the inspection and maintenance programs required to ensure that these components perform in accordance with their design basis. In addition, system engineers conduct performance monitoring of station systems according to system performance monitoring plans that are based on a comparison of performance indicators against established targets to improve system performance. System performance is assessed by collecting, trending and analyzing station data. This information is reported in system health reports which are updated, at a minimum, annually.

OPG's practices impacting the performance of the nuclear stations are audited regularly by WANO, with identified areas for improvement acted upon with priority. In May 2016, OPG hosted a WANO peer evaluation that compared the Darlington GS against standards of excellence through an in-depth and objective review by an international panel of industry experts. The review maintained Darlington's excellent standing as one of the top performing nuclear plants in the world. In December 2017, OPG hosted a WANO peer evaluation for the Pickering GS, which focused on the safe and reliable operation of the station while evaluating the plant material condition, functional and cross-functional areas of the organization. Pickering showed significant improvement since its last review and has sustained its strong rating in 2018, resulting in its best ever WANO peer review.

In September 2016, OPG hosted a team of experts from the International Atomic Energy Agency (IAEA) at the Pickering GS to conduct a standard Operational Safety Review Team mission. The team conducted an in-depth review of performance and adherence to international safety standards. In the second quarter of 2017, the IAEA's Operational Safety Review Team released the final report and confirmed that the Pickering GS demonstrates strong commitment to safety.

Nuclear planned outages are necessary to execute inspection and maintenance work related to asset management and regulatory requirements for systems and equipment where access is not possible under normal operating conditions. Planned outages also give OPG an opportunity to perform system and equipment upgrades, project work, configuration changes, and other improvements and modifications. The nuclear generation plan, by reference to the station's life cycle management plans, establishes the number, frequency and duration of the outages for each year required to ensure the continued safe and reliable long-term operation of the plant and its compliance with CNSC regulatory requirements.

The outage cycle determines the number of planned outages at each station in a particular year. The Darlington GS is on a 36-month outage cycle, where each of the four units undergoes an outage every three years, resulting in one or two outages per year for the station. The Pickering GS was on a 24-month outage cycle. Supported by technical assessments undertaken for the extension of Pickering GS, the outage frequency has been optimized and extended from 24 to 30 months. In addition, on a periodic basis all units at each station are required to be shut down to allow for inspection and maintenance on the station vacuum building, containment systems and other safety systems. The CNSC currently requires these

outages every 12 years at the Darlington GS and every ten years at the Pickering GS. The most recent vacuum building outage took place at the Darlington GS in 2015 and at the Pickering GS in 2010.

Nuclear Ancillary Operations

OPG's nuclear generating units contain approximately 7,500 tonnes of deuterium oxide, or heavy water, not including heavy water contained at the leased Bruce stations. The heavy water is required to operate CANDU reactors. Ontario Hydro ceased the operation of its heavy water plants in 1997 and the plants were subsequently decommissioned. There are currently no heavy water plants in Canada. OPG believes that its existing inventory of heavy water will be sufficient to replenish supplies as a result of normal operating losses at its nuclear stations, including the refurbishment of the Darlington GS. OPG also believes that sufficient quantities of heavy water are available for possible changes in operating conditions or for new nuclear generating facilities. OPG seeks opportunities to sell available surplus quantities of heavy water from its inventory.

Tritium is a radioactive substance produced as a by-product of operating CANDU reactors, through the use of heavy water in the reactor moderator and heat transport systems. OPG operates a specialized facility at its Darlington site, the Darlington Tritium Removal Facility (TRF), which removes tritium from the tritiated heavy water (detritiation) used at the nuclear generating stations, in order to control the occupational dose exposure to employees and limit the amount of tritium released to the environment. The extracted tritium is chemically immobilized, placed in special containers, and safely stored in a vault. The Darlington TRF is also expected to be used to detritiate heavy water during the eventual decommissioning of OPG's nuclear generating stations. Some tritium is sold to government-approved organizations for authorized commercial and health industry uses. OPG also provides detritiation services to Bruce Power. Opportunities for providing detritiation services to other third parties are limited because of storage and capacity restrictions at the Darlington TRF.

Cobalt-60 produced and sold by OPG is used mainly in the health industry to sterilize surgical and medical supplies. Cobalt-60 is produced in Units 6, 7 and 8 at the Pickering GS. Cobalt-60 can be produced in reactors which, like the CANDU reactors, use adjuster rods to regulate power. The production process involves replacing the stainless steel rod by a rod containing Cobalt-59, which is isotopically converted into Cobalt-60 after lengthy exposure to the atomic reaction in the reactor core. During planned maintenance outages, the rods are removed, cut, and packaged for sale as Cobalt-60, and new rods are inserted in the reactor to continue the production cycle.

Hydroelectric (Regulated – Hydroelectric and Contracted Generation Portfolio Segments)

Overview of Generating Facilities

Hydroelectric generating stations use the energy of falling water to drive hydraulic turbines that generate electricity. OPG's hydroelectric stations provide one of the Company's competitive advantages – a reliable, relatively low-cost source of renewable energy free of air emissions. Electricity generation from OPG's hydroelectric facilities depends primarily upon the availability of water, which is affected largely by natural factors such as precipitation and evaporation. It is also impacted by the prevalence of SBG conditions.

OPG currently owns and operates 66 hydroelectric generating stations and 241 associated dams located on 24 river systems across Ontario. The results of 54 of these stations that are rate regulated by the OEB are reported in the Regulated – Hydroelectric segment. The results of the remaining 12 stations are subject to long-term ESAs with the IESO and are included in the Contracted Generation Portfolio segment. The 54 regulated hydroelectric stations include the 48 stations prescribed for rate regulation beginning in 2014 and the six stations that have been rate regulated by the OEB since 2008.

As at December 31, 2017, OPG's regulated hydroelectric facilities had a total in-service capacity of 6,426 MW and the non-regulated hydroelectric facilities had a total in-service capacity of 1,042 MW. OPG's hydroelectric generating stations range in age from the newly in-serviced Peter Sutherland Sr. GS to over 119 years and include the oldest assets in OPG's generation portfolio.

Hydroelectric ESAs with 50-year terms are in place for the following hydroelectric facilities:

- Lac Seul and Ear Falls generating stations, with an expiry date of February 2059;
- Healey Falls GS, with an expiry date of April 2060;
- Sandy Falls, Wawaitin, Lower Sturgeon, and Hound Chute generating stations, with an expiry date of December 2060;
- Little Long, Harmon, Smoky Falls, and Kipling generating stations, with an expiry date of January 2064; and
- Peter Sutherland Sr. GS placed in-service in March 2017, with an expiry date of March 2067.

In 2017, the number of regional groups was reduced from five to four, by integrating the central operations work centers into three of the other existing regional operations groups. The following are the four regional operations groups that operate and maintain OPG's hydroelectric facilities:

- Niagara Operations – includes the three Sir Adam Beck stations located on the Niagara River and the two DeCew Falls facilities located on the Welland River. These facilities have been rate regulated by the OEB since 2008. As part of the change in the regional groups, the Gravenhurst work centre joined with seven regulated stations on the Muskoka, Severn and Beaver Rivers. This operations group also includes OPG's wind turbine.
- Eastern Operations – includes the following ten regulated hydroelectric generating stations: the R.H. Saunders GS on the St. Lawrence River; the Otto Holden, Des Joachims, Chenaux, and Chats Falls generating stations on the Ottawa River; and the Mountain Chute, Barrett Chute, Calabogie, Stewartville, and Arnprior generating stations on the Madawaska River. The R.H. Saunders GS has been regulated by the OEB since 2008. As part of the change in the regional groups, the Campbellford work centre joined with eleven regulated stations and one non-regulated station on the Trent, Mississippi and Rideau Rivers.
- Northeast Operations – includes five regulated and eight non-regulated hydroelectric stations in northeastern Ontario. The regulated stations are the Chute and Lower Notch generating stations on the Montreal River; the Abitibi Canyon and Otter Rapids generating stations on the Abitibi River; and the Matabitchuan GS on the Matabitchuan River. The non-regulated stations are the Little Long, Harmon, Smoky Falls, and Kipling generating stations on the Lower Mattagami River; the Wawaitin, Sandy Falls, and Lower Sturgeon generating stations on the Upper Mattagami River; and the Hound Chute GS on the Montreal River. The North Bay and Coniston work centres joined this regional operations group with seven regulated stations on the Wanapitei and French Rivers.
- Northwest Operations – includes nine regulated and two non-regulated generating stations in northwestern Ontario. The regulated stations are the Pine Portage, Cameron Falls, and Alexander generating stations on the Nipigon River; the Silver Falls and Kakabeka Falls generating stations on the Kamanistikwia River; the Manitou Falls and Caribou Falls generating stations on the English River; the Aguasabon GS on the Aguasabon River; and the Whitedog Falls GS on the Winnipeg River. The non-regulated stations are the Lac Seul and Ear Falls generating stations on the English River.

These operations groups are also responsible for the operation and maintenance of OPG's thermal facilities discussed under the heading, *Generation Operations – Thermal (Contracted Generation Portfolio Segment)*.

The performance of OPG's hydroelectric generating stations during 2017, 2016 and 2015 was as follows:

Hydroelectric Generation Performance (2015 to 2017)

	Regulated – Hydroelectric			Contracted Generation Portfolio – Hydroelectric			Total Hydroelectric		
	2017	**2016**	**2015**	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Availability *(%)* [1]	**88.0**	89.0	91.2	**74.6**	77.3	88.6	**86.2**	87.5	90.9

[1] Availability is represented by the percentage of time the generating unit is capable of providing service, whether or not it is actually generating electricity, compared to the total time for the respective period.

Lower availability of the Regulated – Hydroelectric facilities during 2017 was primarily due to a higher number of unplanned outage days at the Northwestern Ontario, Niagara, and Eastern Ontario regions' hydroelectric stations, partially offset by higher availability from the Sir Adam Beck Pump GS due to a higher number of planned outages days in 2016 as a result of the refurbishment of the station's reservoir. Lower availability of the Contracted Generation Portfolio hydroelectric facilities in 2017 was primarily due to an increase in the number of planned outage days at the Lower Mattagami River hydroelectric generating stations.

Lower availability of the Regulated – Hydroelectric facilities during 2016 was primarily due to the planned reservoir refurbishment project at the Sir Adam Beck Pump GS. Lower availability of the Contracted Generation Portfolio hydroelectric facilities in 2016 was primarily due to a higher number of planned outage days at the Kipling and Harmon generating stations.

OPG's objectives for the hydroelectric operations include operating and maintaining the generating facilities in a safe, efficient and cost-effective manner, while increasing the output from the facilities and pursuing opportunities to increase capacity. OPG aims to increase the facilities' output by improving operational flexibility, enhancing reliability, optimizing outage planning and, subject to water conditions, increasing availability to meet electricity system demand. The Company continues to evaluate and implement plans to increase capacity, maintain and improve operational performance, and extend the operating life of its hydroelectric generating assets. These plans are accomplished through multi-year capital investment and other programs, including replacements and upgrades of turbine runners, and refurbishment or replacement of existing generators, transformers, and controls. Over the next four years, OPG plans to increase the total capacity of its renewable generating fleet by approximately 150 MW, which in addition to the runner replacement and upgrade program, includes the Ranney Falls GS and Sir Adam Beck frequency conversion projects. OPG is also planning to repair, rehabilitate, or replace a number of aging civil structures. Where economical and practical, OPG also pursues opportunities to refurbish, expand or redevelop its existing hydroelectric stations.

Additional information on OPG's hydroelectric operations are discussed in the section, *Core Business, Strategy, and Outlook* under the heading, *Operational Excellence – Electricity Generation Production and Reliability* in the Company's 2017 year-end MD&A.

Hydroelectric Facility Planning

Major components of hydroelectric facilities typically include: generating equipment such as turbines, generators and transformers; civil works such as powerhouses, dams, headworks, spillways and water conveyance canals and tunnels; and facilities required to operate and maintain the stations such as control rooms and work centres. Although there is a link between the age of a facility and the capital investment required to maintain that facility, age does not establish an upper limit on the expected useful life of hydroelectric facilities and dams. Regular maintenance and the replacement of specific components typically allow stations to operate for very long periods, especially for facilities built after 1925.

OPG operates six staffed control rooms across Ontario that provide remote control and monitoring for all of OPG's hydroelectric generating facilities. These control rooms are designed to minimize the number of staffed control rooms, reduce control system failures, and increase the amount of information available for production planning.

OPG uses a structured portfolio approach to identify and prioritize projects for its hydroelectric asset investment program. Engineering reviews and station condition assessments are performed to determine short-term and long-term expenditure requirements to sustain or improve the performance of each facility. These may be followed by the preparation of a facility life cycle plan, which is performed on an as-needed basis for marginal assets or assets potentially requiring significant expenditures relative to the value of the facility. This approach is designed to identify necessary capital, operating and maintenance expenditures for each facility and to direct resources towards those facilities that can best maintain or enhance their value.

OPG utilizes a preventive maintenance program that provides a consistent method of identifying, scheduling, and executing maintenance activities at the hydroelectric facilities. The maintenance program is based on the concept of streamlined reliability-centred maintenance, whereby the type and frequency of preventive maintenance applied to an individual component is determined based on the nature and consequences of failure, balancing cost and risk.

The cornerstone of OPG's project prioritization and preventive maintenance approaches for the hydroelectric assets is that safety, environmental, and other regulatory programs are of the highest priority.

Water Management

OPG's water management strategy for its hydroelectric facilities is to safely utilize available water for generation of electricity in conformance with legal, environmental, operational, and WMP and Operational Plan requirements. OPG uses hydrological and meteorological data to manage water levels, water flows and water storage, and strives to schedule water use for optimum utilization and to minimize controllable water spills due to SBG conditions.

Gross Revenue Charge and Water Rental Payments

Hydroelectric generating stations in Ontario are subject to taxes and charges as prescribed by *Ontario Regulation 124/02* under the *Electricity Act, 1998*. These taxes and charges, referred to as Gross Revenue Charge (GRC), are based on station gross revenue, which, for this purpose, is determined as the product of annual station energy generation and the prescribed revenue rate of $40/MWh (Gross Revenue). All OPG hydroelectric generating stations are subject to GRC Property Tax, which is determined by applying graduated tax rates, ranging from 2.5 percent to 26.5 percent through four tiers of production, to a station's annual Gross Revenue. GRC Property Tax payments are made to the OEFC. Hydroelectric generating stations that are subject to water power lease agreements with the MNRF are also subject to GRC Water Rental charges in addition to GRC Property Tax payments. The GRC Water Rental charge is determined as 9.5 percent of a station's annual Gross Revenue. GRC Water Rental payments are made to the Ontario Ministry of Finance.

Annual land rental fees are paid to the MNRF as prescribed by Crown leases and licences of occupation which authorize OPG's tenure (including flooding rights), typically at storage dam sites.

The eight OPG hydroelectric generating stations located on the Trent River and Rideau Canal are subject to rental charges prescribed by licences with Parks Canada. These licences authorize OPG to occupy the lands, maintain and operate the powerhouses and dams, and utilize water that is surplus to navigation needs for the generation of electricity.

Water conveyance charges are paid to the St. Lawrence Seaway Management Corporation as prescribed by a lease agreement providing for the withdrawal of water surplus to navigation needs from the Welland

Canal for utilization at the DeCew Falls generating stations. The water conveyance charges apply to the transport of water from Lake Erie through the Welland Canal to OPG's intakes at Allanburg.

Water rental payments are made to the Government of Québec, as prescribed by an agreement dated January 2, 1943 and a rate amending agreement effective January 2, 1993. These agreements pertain to the sharing of the water powers of the Ottawa River and were ratified by the Governments of Ontario and Québec. Water rental charges payable to the Province of Québec are based on one-half of the energy produced at the three regulated OPG hydroelectric generating stations located on the Ottawa River. The GRC payments made to the Province of Ontario with respect to these three sites are also based on one-half of the energy produced at the stations.

Under the aforementioned 1943 agreement, OPG also provides compensation to Hydro Québec for the generating value at OPG's stations on the Ottawa River attributed to the water diverted into the Ottawa River through the Dozois Reservoir in Québec. OPG shares in operation and maintenance costs pertaining to the dam enabling the Dozois diversion.

The GRC and water rental payments for the regulated hydroelectric stations are recoverable through OEB-approved regulated prices applicable to these stations.

Further details on water rights can be found in the section, *Description of the Business* under the heading, *Water Rights*.

Thermal (Contracted Generation Portfolio Segment)

Overview of Generating Facilities

Thermal generating stations use heat energy to drive steam turbines that generate electricity. OPG's wholly-owned operating thermal facilities are comprised of biomass-fuelled generating units at both Atikokan GS and Thunder Bay GS, and the dual-fuelled generating Lennox GS, which is capable of burning either oil or natural gas. The results of these facilities are reported in the Contracted – Generation Portfolio business segment.

The combined in-service capacity of the three operating thermal facilities was 2,458 MW as at December 31, 2017. The Lennox GS is located in Greater Napanee, Ontario and accounts for approximately 2,100 MW of this in-service capacity. The Atikokan GS is located in Atikokan, Ontario and has an in-service capacity of 205 MW. The Thunder Bay GS is located in Thunder Bay, Ontario and its advanced biomass fuelled unit has an in-service capacity of 153 MW.

Capacity and production from the Lennox GS are subject to an ESA with the IESO for the period from January 2013 to September 2022. Capacity and production from the Atikokan GS are subject to a ten-year ESA expiring in July 2024. For the Thunder Bay GS advanced biomass fuelled unit, capacity and production are subject to a five-year ESA expiring in January 2020.

OPG's three thermal generating stations operate as peaking facilities, depending on electricity demand. This provides Ontario's electricity system with the flexibility to meet changing daily system demand and capacity requirements and has enabled the system to accommodate the expansion of Ontario's renewable generation portfolio. The continued operation of these stations will continue to provide Ontario with capacity and peaking generation.

The three thermal generating stations are operated and maintained as part of regional operations groups used to operate and maintain the Company's hydroelectric facilities. The Lennox GS is operated under Eastern Operations, and the Atikokan and Thunder Bay generating stations are part of Northwest Operations.

Thermal stations that are no longer available to generate electricity are included in the Services, Trading, and Other Non-Generation business segment once they are removed from service. This includes the Lambton GS and Nanticoke GS sites, which ceased coal-fired generation in 2013.

Contracted Generation Portfolio – Thermal Performance (2015 to 2017)

	2017	2016	2015
Equivalent Forced Outage Rate (%) [1]	**2.4**	1.6	11.2

[1] Equivalent Forced Outage Rate is an index of the reliability of a generating unit at OPG's thermal stations. It is measured by the ratio of time a generating unit is forced out of service by unplanned events, including any forced deratings, compared to the amount of time the generating unit was available to operate.

The higher thermal EFOR in 2017, compared to 2016, was primarily due to a higher number of unplanned outage days at a Lennox GS unit as a result of a transmission outage and a generator-related outage in 2017. The change in thermal EFOR in 2016, compared to 2015, was primarily due to an outage in 2015 to perform repair work at the Lennox GS.

Additional information on OPG's thermal operations can be found in the section, *Core Business, Strategy, and Outlook* under the heading, *Operational Excellence – Electricity Generation Production and Reliability* in the Company's 2017 year-end MD&A.

Thermal Fuel Procurement

Due to the relatively low capacity factor of the Lennox GS, natural gas is purchased on the spot market, other than a small volume of fixed term natural gas required for non-generation operational services. Oil for the Lennox GS is contracted for and purchased on an as needed basis. Fuel switching at the station is based on market and fuel economics. Annual procurement of biomass fuel quantities for Atikokan GS and Thunder Bay GS is pre-determined by the corresponding ESAs. Agreements are in place with suppliers for the purchase of all biomass fuel pellets needed to provide fuel for the Atikokan GS for the duration of its ESA, and for most of the advanced biomass fuel pellets needed to provide fuel for the duration of the ESA for the Thunder Bay GS.

Thermal Facility Planning

OPG's facility planning approach is designed to identify necessary capital and operating and maintenance expenditures for each thermal facility. This planning approach aims to sustain facility availability for the remaining service life through station reinvestment within constraints imposed by technical, financial, safety, and system requirements, as well as regulatory and contractual limits. Periodic engineering reviews of major systems are conducted to identify performance issues, provide reinvestment recommendations where appropriate, and ensure that regulatory, safety and operating standards continue to meet expectations. OPG undertakes projects at thermal stations that are expected to achieve an appropriate return within the service life of the stations.

Thermal Station Decommissioning

OPG has recognized, and carries on its balance sheet, a liability to cover future expenditures to decommission and dismantle each of its thermal stations at the end of their estimated service lives. This provision is not funded and is estimated on the basis of station closure. Costs previously incurred by OPG to preserve Lambton and Nanticoke generating stations for potential conversion to natural gas in the future were not charged to the provision, as they were charged against net income as incurred.

Portlands Energy Centre Partnership

OPG has a 49.95 percent partnership interest in Portlands Energy Centre L.P., a limited partnership formed with TransCanada Energy Ltd. (49.95 percent) and the general partner of the partnership, Portlands Energy Centre Inc. (0.1 percent). The shareholders of Portlands Energy Centre Inc. are OPG (50 percent) and TransCanada Energy Ltd. (50 percent). PEC is a 550 MW combined cycle generation natural gas turbine electricity generating facility located on the former R. L. Hearn GS site in the port area of downtown Toronto, Ontario. The station was declared in-service in a combined cycle mode in April 2009. PEC operates under an Accelerated Clean Energy Supply contract with the IESO and trades electricity in the Ontario electricity market.

The Contracted Generation Portfolio segment includes OPG's share of equity income from its 50 percent ownership interest in the station. OPG's share of the in-service generating capacity and generation volume from its interest in the station are included in the operating statistics for the segment.

Brighton Beach Power Partnership

OPG has a 49.95 percent partnership interest in Brighton Beach Power L.P., a limited partnership formed with ATCO Power Canada Ltd. (49.95 percent) and the general partner of the partnership, Brighton Beach Power Ltd. (0.1 percent). The shareholders of Brighton Beach Power Ltd. are OPG (50 percent) and ATCO Power Canada Ltd. (50 percent). Brighton Beach is a 560 MW combined cycle gas turbine electricity generating facility located on the former J.C. Keith GS site in Windsor, Ontario. The station began commercial operation in July 2004. Brighton Beach operates under a tolling arrangement with Shell Energy North America (Canada) Inc. (Shell Energy), pursuant to which Shell Energy owns and trades the electricity produced by the facility in return for the supply of gas and the fees payable under the tolling agreement. Shell Energy's financial obligations are guaranteed by Shell Energy North America (US) L.P. (Shell L.P.), and Shell L.P.'s obligations are in turn guaranteed by Shell Oil Company.

The Contracted Generation Portfolio segment includes OPG's share of equity income from its 50 percent ownership interest in the station. OPG's share of the in-service generating capacity and generation volume from its interest in the station are included in the operating statistics for the segment.

Regulated – Nuclear Waste Management Segment

Overview

OPG is responsible for the ongoing management of radioactive wastes generated by its nuclear operations. In addition, OPG has the obligation for decommissioning its nuclear generating stations and nuclear waste facilities after the end of their useful lives and for managing radioactive wastes that arise in connection with the decommissioning. The handling and disposal of radioactive waste in Canada is subject to federal legislation.

The radioactive wastes generated by OPG's nuclear operations include the following:

- Used nuclear fuel bundles;
- Intermediate-level waste – material that has come in close contact with the reactors, but is less radioactive than used fuel, such as ion exchange resins and reactor equipment and components; and
- Low-level waste – material used in connection with station operation that is not highly radioactive, such as tools and protective clothing.

The Company's Regulated – Nuclear Waste Management segment reports the results of the Company's operations associated with the following:

- management of used nuclear fuel and L&ILW;

- decommissioning of OPG's nuclear generating stations including the stations on lease to Bruce Power and other nuclear facilities;
- management of the Nuclear Segregated Funds established under the ONFA to fund OPG's obligation for nuclear facilities decommissioning and the long-term management of nuclear waste; and
- Other related activities including the inspection and maintenance of the waste storage facilities.

The nuclear accretion expense, which is the increase in the carrying amount of the present value liabilities for nuclear fixed asset removal and nuclear waste management liabilities reported on the balance sheet due to the passage of time, and the earnings from the Nuclear Segregated Funds are reported under this segment. The Regulated – Nuclear Waste Management segment is considered rate regulated because OPG's costs associated with nuclear waste management and nuclear facilities decommissioning liabilities have been included by the OEB in the determination of regulated prices for production from the Pickering and Darlington nuclear generating stations.

Federal Government Policy

In accordance with the requirements of the *Nuclear Fuel Waste Act* (Canada) (NFWA), in 2002, OPG and the other owners of nuclear fuel waste in Canada established a separately incorporated NWMO, with a mandate to manage and coordinate the full range of activities relating to the long-term management of nuclear fuel waste in Canada. This includes the design and implementation of Canada's plan for the long-term management of used nuclear fuel. In 2007, the federal government approved NWMO's submitted option, the Adaptive Phased Management (APM) plan, as the long-term solution for nuclear fuel waste. The APM plan contemplates the eventual long-term permanent disposal of radioactive nuclear fuel waste in a deep geologic repository (DGR) after a collaborative process of communication and engagement with Canadians aimed at selecting a suitable geological site with an informed and willing host community. The NWMO is in the process of undertaking a multi-year site selection process for the used fuel DGR.

The NFWA also requires the nuclear fuel waste owners in Canada to establish and make payments into trust funds for the purpose of funding the implementation of the long-term management plan for used fuel. Accordingly, OPG has established the Ontario NFWA Trust (the NFWA Trust), which forms part of the Nuclear Segregated Funds under the ONFA. Additional details can be found in the section, *Description of the Business* under the heading, *Regulated – Nuclear Waste Management Segment – Funding Mechanisms.*

Current Practices

Used Nuclear Fuel

Used nuclear fuel bundles from OPG's reactors and leased reactors at the Bruce Nuclear site are temporarily stored at each nuclear generating station in water-filled pools, known as wet bays, for a cooling-off period of at least ten years, during which time their radioactivity is substantially reduced. Each nuclear generating station has sufficient capacity to store used nuclear fuel bundles in the wet bays for approximately 15 to 20 years of operation.

After the used nuclear fuel bundles have been stored for the cooling-off period, the bundles are transferred from the wet bays to above-ground dry storage containers at the corresponding nuclear station site. Currently, there is used nuclear fuel bundles in dry storage at the Pickering, Darlington and Bruce Nuclear sites.

OPG's planning assumption for the long-term management of used nuclear fuel bundles is consistent with the NWMO's APM concept of disposal in a deep geological repository. The NWMO has indicated that it currently expects an in-service date of 2043 at the earliest for the used fuel DGR.

Low and Intermediate Level Waste

The majority of OPG's L&ILW is stored at the radioactive waste management facility at WWMF located on the Bruce site. This facility, which continues to be owned and operated by OPG following the lease of the Bruce generating stations, operates under a separate licence issued by the CNSC. A smaller volume of ILW is stored at each of the radioactive waste management facilities at Pickering and Darlington sites. Respectively, these ILW storage facilities house the components from Pickering A's retube in the 1980's and from the recent Darlington Refurbishment of Unit 2. OPG's planning assumption for the long-term management of L&ILW is the placement of this nuclear waste in a separate L&ILW DGR.

Additional details can be found in the section, *Description of the Business* under the heading, *Regulated – Nuclear Waste Management Segment – Deep Geologic Repository for Low and Intermediate Level Waste.*

Station Decommissioning

OPG's planning assumption for the decommissioning of its nuclear generating stations is a deferred dismantlement strategy. Under this strategy, each station will be de-watered and de-fuelled immediately after it has ceased operations and prepared for safe storage and monitoring. Thereafter, OPG intends to monitor the station for approximately 30 years while in safe storage, after which time the station will be dismantled and the site restored over a period of approximately ten years. This strategy has been communicated to the CNSC through regular updates of OPG's preliminary decommissioning plans and liability estimates for the nuclear generating stations. Currently, OPG has received CNSC acceptance of the OPG Financial Guarantee for the five year period from 2018 to 2022 based on the fund performance and estimate for decommissioning the OPG nuclear assets. OPG's nuclear operating licences have been issued based on, amongst other things, CNSC's understanding of this strategy.

Deep Geologic Repository for Low and Intermediate Level Waste

OPG has proposed a deep geologic repository as the preferred solution for the safe long-term management of the L&ILW produced from the continued operation of OPG-owned nuclear generating stations and their eventual decommissioning. Agreement has been reached with local municipalities for OPG to develop the L&ILW DGR on lands adjacent to the WWMF in Kincardine, Ontario.

Under the NSCA, OPG requires licences from the CNSC for activities to be undertaken with respect to the L&ILW DGR project. Before the CNSC can make licensing decisions for the proposal, an EA must be conducted in compliance with the requirements of the *Canadian Environmental Assessment Act*. As part of the EA process for the L&ILW DGR, Environmental Impact Statement, Preliminary Safety Report, and Technical Support Documents were submitted to the CNSC in 2011. The purpose of these submissions was to obtain EA approval and a site preparation and construction licence from the Joint Review Panel (JRP) for the project. The responsibility of the JRP, which was appointed by the Canadian Environmental Assessment Agency (CEAA) and the CNSC in 2012, was to examine the environmental effects of the proposed DGR to meet the requirements of the *Canadian Environmental Assessment Act.* In May 2015, the JRP submitted its report and recommendations on the EA to the federal Minister of Environment. The report concluded that, given mitigation, there is unlikely to be significant environmental impact from the project and recommended that the Minister approve the EA. The report suggested that the project should be implemented expeditiously.

In August 2015, OPG responded to the CEAA's list of potential environmental conditions relating to the JRP report. In February 2016, the federal Minister of Environment and Climate Change requested additional information on certain aspects of the EA, including information related to alternate locations for the project and the impact on environmental effects if Canada's planned used fuel deep geologic repository being developed by the NWMO were to be located in close proximity to OPG's proposed L&ILW DGR. OPG has completed the requested studies and submitted the requested information in December 2016, as planned. Following its review of OPG's submission and a period of public comment, the CEAA requested further information that OPG subsequently provided in May 2017. In June 2017, the CEAA notified OPG that it had sufficient and adequate information to proceed with the next step of the environmental assessment

process and advised that a draft report and updated terms and conditions would be prepared for public review.

On August 21, 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of potential cumulative effects of the project on the Saugeen Ojibway Nation's (SON) physical and cultural heritage, including a description of the potential effects of the project on the Nation's spiritual and cultural connection to the land, taking into account the results of the SON Community Process. OPG is working closely with the SON to formulate a response to the information request.

The L&ILW DGR at the WWMF site remains OPG's preferred solution for the safe long-term management of the L&ILW. The in-service date of the L&ILW DGR is expected to be approximately six to seven years from the start of construction.

Funding Mechanisms

On April 1, 1999, Ontario Hydro's obligation for nuclear facilities decommissioning and nuclear waste management was transferred to OPG. The responsibility for funding the liabilities for nuclear facilities decommissioning and the long-term nuclear waste management between the Province and OPG is described in the ONFA. The key provisions of the ONFA are: (i) for OPG to establish two segregated funds, the Used Fuel Segregated Fund to fund the future costs of long-term nuclear used fuel waste management and certain costs of used fuel storage incurred after the stations are shut down, and the Decommissioning Segregated Fund to fund the future costs of nuclear decommissioning and long-term L&ILW management, and certain costs of used fuel storage incurred after the stations are shut down; (ii) for the OEFC to be responsible for funding approximately $2.4 billion present value as at April 1, 1999 that had been an accumulated liability of Ontario Hydro, which the OEFC has since then fully funded through an initial contribution to the Decommissioning Segregated Fund; (iii) for the Province to limit OPG's financial exposure in relation to the cost of used fuel management for the first 2.23 million bundles of used fuel; and (iv) for the Province to provide financial guarantees to the CNSC for OPG's nuclear decommissioning and nuclear waste management obligations, as required by the CNSC.

The Used Fuel Segregated Fund and the Decommissioning Segregated Fund are administered by a third party custodian and held in accounts segregated from OPG's other assets. OPG has granted a security interest in both funds to the Province. As a result, these funds are not available to satisfy the claims of OPG's creditors.

OPG's required contributions to the Used Fuel Segregated Fund and the Decommissioning Segregated Fund are determined based on reference plans and associated life cycle cost estimates periodically approved by the Province under the ONFA. These reference plans are prepared by OPG with the assistance of external consultants and based on external practices and international benchmarks. Under the ONFA reference plans, the total present value of OPG's future nuclear facilities decommissioning and nuclear waste management costs is determined based on baseline cost estimates and a set of underpinning major planning assumptions, including remaining useful lives of the nuclear stations, proposed methods and timing of nuclear waste disposal, and economic indicators. Given the long-term duration of these life cycle programs, the multiple assumptions involved and the evolving technology to handle nuclear waste, there is a significant degree of inherent uncertainty surrounding the measurement of the underlying costs, which may increase or decrease over time.

The limits to OPG's financial exposure under the ONFA with respect to the life cycle cost of long-term management of the first 2.23 million bundles of used fuel are as follows (all amounts are expressed in January 1, 1999 present value dollars): (i) OPG will bear all costs up to $4.6 billion; (ii) OPG and the Province will share, on an equal basis, costs incurred between $4.6 billion and $6.6 billion; (iii) OPG will be responsible for 10 percent of the costs incurred between $6.6 and $10 billion, and the Province will be responsible for the remaining 90 percent; (iv) the Province will be wholly responsible for any costs above $10 billion. As a result, OPG's funding liability for these used fuel costs under the ONFA is capped at $5.9 billion in January 1, 1999 present value dollars, which is equivalent to approximately $15.7 billion in December 31, 2017 present value dollars. OPG is responsible for all incremental costs

relating to the management of used fuel bundles in excess of the 2.23 million threshold. As at December 31, 2017, approximately 2.6 million bundles of used fuel waste had been produced. The 2.23 million fuel bundles threshold represents the estimated total life cycle bundles based on the initial estimated useful lives of the nuclear stations assumed in the ONFA.

Under the ONFA, the Province guarantees OPG's annual return earned in the Used Fuel Segregated Fund at 3.25 percent plus the rate of change in the Ontario Consumer Price Index, as defined in the ONFA, for funding related to the first 2.23 million used fuel bundles. Upon approval of a new or amended ONFA reference plan, the Province is obligated to make an additional contribution to the Used Fuel Segregated Fund in relation to the first 2.23 million bundles if the fund's assets earned a rate of return that is less than the guaranteed rate of return. If the return on the fund's assets exceeds the Province's guaranteed rate of return, the Province is entitled to withdraw any portion of the excess related to the first 2.23 million bundles, upon approval of a new or amended ONFA reference plan. OPG is responsible for cost increases and investment returns for the portion of the fund attributable to the used fuel bundles in excess of the 2.23 million threshold. OPG also is responsible for cost increases and investment returns for the Decommissioning Segregated Fund.

The investments in the Nuclear Segregated Funds include a diversified portfolio of equities and fixed income securities that are invested across geographic markets, as well as investments in real assets including infrastructure, real estate and agriculture. As the Nuclear Segregated Funds are invested to fund long-term liability requirements, the portfolio asset mix is structured to achieve the required return over a long-term horizon. While the Nuclear Segregated Funds are manage to achieve, in the long term, the target return rate based on the discount rate specified in the ONFA, the rates of return earned in a given period may be subject to various external factors including financial market conditions and changes in the Ontario Consumer Price Index, which, in the short-term, can be volatile and cause fluctuations in the Company's financial results. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

Under the current OEB-approved cost recovery methodology for OPG's nuclear waste management and nuclear facilities decommissioning liabilities, OPG's income is exposed to the rate of return risk for the portion of the Nuclear Segregated Funds related to the Pickering and Darlington nuclear generating stations.

Contributions to the Nuclear Segregated Funds

OPG's contribution requirements under the ONFA are recalculated each time there is an approved new or amended reference plan and under certain other events. Reference plans are required to be prepared at least every five years, or more frequently if there is an underlying change in the assumptions of the reference plan that both OPG and the Province agree are significant enough to trigger a recalculation of the contribution levels during the five-year period.

Prior to 2017, OPG made contributions to the Used Fuel Segregated Fund every quarter, including a one-time special payment in earlier years, as required by the ONFA. These contributions reflected ONFA requirements to fund the majority of the underlying used fuel liability by the end of the initial estimated useful lives of the nuclear stations assumed in the ONFA, resulting in significantly higher contributions to the Used Fuel Segregated Fund in the earlier years of OPG's existence. OPG has not been required to make contributions to the Decommissioning Segregated Fund, which was fully funded at its inception through the initial contribution made by the OEFC and, taking into account asset performance and changes in underlying funding obligations over time, at the time of every subsequent approved ONFA reference plan.

Based on the funded status of the Used Fuel Segregated Fund and the Decommissioning Segregated Fund reflecting the lower life cycle liability estimates per the 2017 ONFA Reference Plan, no overall contributions to either fund were required starting in 2017. Contributions to either or both funds may be required in the future should the funds be in an underfunded position when a new reference plan is approved. Such may be the case as a result of future variability in asset performance due to volatility inherent in financial markets and economic conditions. Future contribution levels also are dependent on changes in baseline cost

estimates and underpinning planning assumptions used to establish the funding obligations in subsequent ONFA reference plans, as well as any changes in the tax treatment of fund earnings. OPG's required contributions could increase, for example, if cost estimates increased, if the operating lives of the nuclear stations were revised, if fund assets earned less than the target rate of return, if the income earned in the funds became subject to tax, or if the NWMO were unable to receive the same sales tax treatment that OPG would be entitled to receive if the NWMO had not been established.

OPG is required to make annual contributions to the NFWA Trust based on a funding formula approved by the federal Minister of Natural Resources for OPG and the other nuclear fuel waste owners in Canada. The NFWA Trust forms part of the Used Fuel Segregated Fund. Any OPG contributions to the Used Fuel Segregated Fund as well as any portion of the Used Fuel Segregated Fund currently not in the NFWA Trust can be applied to satisfy the trust's annual contribution requirements. The funds in the Ontario NFWA Trust will be used for the purposes of long-term management of nuclear used fuel waste, in accordance with the NFWA. OPG and the Province are beneficiaries of the NFWA Trust.

If there is a surplus in the Decommissioning Segregated Fund such that the funding liabilities, as defined by the most recently approved ONFA Reference Plan, are at least 120 percent funded, OPG may direct, at the time a new or amended reference plan is approved, up to 50 percent of the surplus over 120 percent to the Used Fuel Segregated Fund, with the OEFC entitled to a distribution of an equal amount.

If there is a surplus in the Used Fuel Segregated Fund such that the funding liabilities, as defined by the most recently approved ONFA Reference Plan, are at least 110 percent funded, the Province has the right, at any time, to access the excess amount greater than 110 percent. Neither OPG nor the Province have a right to direct any amounts from the Used Fuel Segregated Fund to the Decommissioning Segregated Fund.

Upon termination of the ONFA, the Province has the sole right to any excess funds in the Decommissioning Segregated Fund and the Used Fuel Segregated Fund.

OPG has the responsibility for the management and disposal of the used nuclear fuel and L&ILW generated by the Bruce generating stations and for the eventual decommissioning of these stations. These obligations on the part of OPG are recovered from Bruce Power through annual rent payments and volume based fees per the Bruce Lease and related agreements. Pursuant to the lease agreement, Bruce Power must return the two Bruce stations to OPG together, in a de-fuelled and de-watered state. As such, these de-watering and de-fuelling costs will not be funded by OPG. Further details on the 2015 amendments to these agreements are found in the section, *General Development of the Business* under the heading, *Nuclear Business Development – Bruce Power Refurbishment and Bruce Lease Agreement*.

Provincial Guarantee

In accordance with the NSCA, the CNSC requires OPG to have sufficient funds available to discharge its existing nuclear waste management and nuclear decommissioning obligations. The CNSC process requires the CNSC financial guarantee requirement to be updated once every five years and for OPG to provide an annual report to the CNSC on the assumptions, asset values, and resulting financial guarantee requirements. The CNSC financial guarantee requirement calculation takes into account nuclear waste expected to be generated to the end of each year.

In November 2017, the CNSC accepted OPG's proposed 2018-2022 CNSC financial guarantee requirement to be satisfied by the forecast fair market value of the Nuclear Segregated Funds without the requirement of a Provincial Guarantee for the 2018-2022 period. As required by the terms of the ONFA, the Province is committed to provide a Provincial Guarantee to the CNSC, on behalf of OPG, should there be a shortfall between the CNSC financial guarantee requirement and the value of the Nuclear Segregated Funds in the 2018-2022 period, as it has been done in the past. OPG pays the Province an annual guarantee fee equal to 0.5 percent of the outstanding amount, if any, of the Provincial Guarantee.

Services, Trading, and Other Non-Generation Segment

The Services, Trading, and Other Non-Generation segment is a non-generation segment that is not subject to rate regulation. It includes the revenue and expenses related to OPG's trading and other non-hedging activities. As part of trading activities, OPG transacts with counterparties in Ontario and neighbouring energy markets in predominantly short-term trading activities of typically one year or less in duration. These activities relate to electricity that is purchased and sold at the Ontario border, financial energy trades, financial risk management energy product revenues, and sales of energy-related products.

In addition, the segment includes the results of OPGET, which engages in U.S.-based wholesale energy trading activities in the U.S. northeast. The activities of OPGET include trading electricity in the U.S. using over-the-counter energy-related derivatives. OPGET retains Federal Energy Regulatory Commission market-based rate authorization.

The segment also includes revenue from real estate rentals and non-regulated services, gains or losses on disposition of non-regulated real estate assets, costs associated with non-regulated business development activities, and costs related to the Lambton GS and Nanticoke GS sites.

Fair Hydro Trust Segment

The Fair Hydro Trust segment is a non-generation segment that is not subject to rate regulation. It includes OPG's earnings from the Fair Hydro Trust, which includes the financial results of the Trust, as well as income related to OPG's role as Financial Services Manager of the Fair Hydro Trust and holder of subordinated debt issued by the Trust. Earnings include interest income from OPG's investment in subordinated debt of the Trust of up to 49 percent of the Trust's total outstanding debt, recovery of related to third-party costs and fees for financial management and ongoing administration services, partially offset by interest costs on debt issued by OPG to fund five percent of the subordinated investment in the Trust, incurred third-party costs, and other incurred costs related to the management and administration of the Trust.

Indigenous Relations

The Aboriginal and treaty rights of Indigenous communities are recognized and affirmed in the *Constitution Act, 1982*. OPG's corporate governance includes an Indigenous Relations policy to help build and develop mutually beneficial working relationships with Indigenous communities proximate to the Company's present and future operations. The policy focuses on building respectful relationships with Indigenous communities, businesses and organizations through partnership, collaboration, and support for procurement, employment and educational opportunities. The Company seeks to establish and maintain these relationships based on a foundation of respect for the languages, customs, and political, social and cultural organizations of the indigenous communities.

OPG may be subject to claims by Indigenous communities or other Indigenous groups and individuals. These claims may stem from generation development activities, historic operations of Hydro Electric Power Commission of Ontario and Ontario Hydro that may have impacted Aboriginal and treaty rights, or the absence of legal permits, rights-of-way, or easements. Legal precedents created by court rulings may impact negotiations and resolution of past grievances. To date, OPG has resolved 23 past grievance claims with 21 communities, achieving final settlement agreements.

In line with the company's Indigenous Relations policy, OPG is pursuing prospective generation-related developments and other joint projects with Indigenous communities. OPG currently has four generation development partnerships with Indigenous communities. OPG's first such partnership became operational in early 2009 as part of the Obishikokaang Waasiganikewigamig/Lac Seul GS project. The signing of the "*Amisk-oo-Skow*" Agreement with the Moose Cree First Nation (MCFN) in early 2010 marked the second such partnership. In 2011, the Lower Mattagami Limited Partnership agreement was amended and restated to include the MCFN and their wholly owned Amisk-oo-Skow Finance Corporation as limited partners and to enable the MCFN to acquire up to 25 percent limited partnership interest in the Lower Mattagami River

project. During 2014, the MCFN acquired a 25 percent interest in the assets through its investment in the Lower Mattagami Limited Partnership as incremental units of the project were placed in-service.

OPG and CRP, a wholly owned corporation of the Taykwa Tagamou Nation, established Peter Sutherland Sr. GS Limited Partnership in January 2015. In March 2017, the Peter Sutherland Sr. GS was placed in-service and, in April 2017, the Taykwa Tagamou Nation, through CRP, increased their partnership interest in PSS to 33 percent under the partnership agreement.

Following selection by the IESO in March 2016, OPG and a subsidiary of the Six Nations of Grand River Development Corporation have partnered to develop a new 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands. The Nanticoke Solar Limited Partnership was formed in July 2015, and the Six Nations of Grand River Develop Coproration through its subsidiary acquired a 10 percent ownership interest in August 2015.

Other recent joint projects with Indigenous partners include two shoreline remediation projects completed in 2016. The Whitesand First Nation, working closely with OPG, completed a project to remediate nearly two kilometers of shoreline, while the Long Lake #58 First Nation undertook the management of a five-year shoreline remediation project. OPG also engaged the Mississaugas of New Credit regarding the sale of the Lakeview generating station site. OPG also has been engaging proactively with Indigenous communities regarding the Company's nuclear waste management operations, through regularly scheduled meetings and an ongoing dialogue in connection with OPG's proposed L&ILW DGR, the re-licensing of the PWMF and the WWMF, and the Pickering generating station's relicensing. Further engagement was conducted with First Nations in southwestern Ontario regarding the demolition of the Lambton and Nanticoke generating stations.

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OPG is also committed to improving Indigenous access to procurement and employment opportunities, including increasing the profile of the nuclear generation industry in Indigenous communities. In 2017, OPG launched an Indigenous Business Engagement (IBE) Initiative. The purpose of this initiative is to increase access to procurement opportunities for Indigenous businesses interested in supplying materials and services to OPG. The IBE Initiative is based on a strategy that will identify opportunities in contracts, scopes of work and business plans for potential Indigenous business engagement; include criteria related to suppliers' ability to engage or partner with Indigenous people or businesses in assessing procurement proposals; and invest in relationships with Indigenous communities by increasing outreach efforts to enhance understanding of how to do business with OPG. OPG has been engaging with Indigenous businesses and communities as well as its suppliers to promote the IBE Initiative including the Mohawk Council of Akwesasne as well as the Williams Treaties First Nations, located proximate to the Pickering and Darlington nuclear generating stations.

OPG has been actively developing recruitment plans targeting Indigenous peoples. As part of this initiative, during the fourth quarter of 2017, OPG participated in several Indigenous-specific career fairs, hosted a Day in the Trades event for Indigenous students and job seekers as part of an open house at the Darlington Energy Centre, and approved additional plans aimed at increasing the number of Indigenous apprentices as part of the nuclear operations' recruitment program.

In November 2016, OPG was recognized for its ongoing commitment to engaging local Indigenous communities with the Canadian Electricity Association's (CEA) 2016 Sustainable Electricity award for Leadership in External Collaboration and Partnerships.

Workplace Safety and Public Safety

Workplace Health and Safety

In the area of workplace safety, OPG is committed to achieving excellent performance through continuous improvement and a strong safety culture, with the ultimate goal of zero injuries. OPG utilizes an integrated health and safety management system and a set of operational risk control procedures to ensure continued monitoring of health and safety performance and to support continuous learning and improvement in this area. Over the past five years, OPG has repeatedly stood in the top quartile of its comparator Canadian electrical utilities in various safety performance metrics.

Workplace safety performance is measured using two primary indicators at OPG, All Injury Rate (AIR) and Accident Severity Rate (ASR). OPG's AIR and ASR results for employee workplace safety were as follows for the year ended December 31:

	2017	2016	2015
AIR *(injuries per 200,000 hours worked)*	**0.48**	0.56	0.39
ASR *(days lost per 200,000 hours)*	**3.57**	2.59	0.50

In 2017, OPG's AIR improved from 2016 and was the third-best performance year in the history of the company. For those employee injuries that caused lost time from work, the total time lost from work in 2017 was greater than the previous year. OPG's analysis of the underlying safety events indicated that major contributors to the injuries and near misses included inadequate situational awareness and attention to detail, and suboptimal risk-based decisions, rather than missing or inadequate standards or programs. OPG continues to implement a number of initiatives to target the injury trends based on the analysis of the safety events, with a focus on the use of human performance tools including increased field supervisory oversight, situational awareness, communication, and procedural use and adherence.

In order to strengthen its safety performance, OPG continues to progress an organization-wide "iCare Enough to Act" initiative launched in 2016 and aimed at renewing employees' commitment to their own and each other's safety and well-being. Approaches to supervisory oversight, communication and safe work planning are being modified and updated to further strengthen safety as a foundational element of the Company's values-based culture.

Contractors are required to conduct work safely at OPG sites. In support of this requirement, OPG utilizes an independent contractor pre-qualification process, provides on-site safety support for many of its major projects, and works with contract partners to improve their health and safety programs to meet OPG's requirements. In the past nine years, OPG has consistently shown a better than average Construction Contractor AIR as compared to the Infrastructure Health and Safety Association Contractor AIR, a metric of construction contractor safety performance across Ontario. OPG has maintained this performance while engaging in the refurbishment of the Darlington GS, one of the largest infrastructure projects in Canada. The hours worked by contractors in 2017 were the largest in OPG's history, largely attributable to this project.

Since 2014, OPG has been operating under a single integrated health and safety management system and set of operational risk control procedures across the Company, providing consistent performance expectations for all employees. The control procedures are designed to ensure continued enterprise-wide monitoring of health and safety performance and to support continuous learning and improvement in these areas. Oversight and reporting by corporate and site safety functions is in place to provide senior management with regular information on the effectiveness of the safety management efforts, compliance with legal and corporate requirements, and safety performance trends. OPG's incident management system requires that all incidents, including near misses, be reported and investigated and that where beneficial, corrective action plans be developed and completed in order to prevent reoccurrences.

In 2014, OPG launched a Total Health initiative that aims to embed a health culture that supports employees and their families in their efforts to achieve an optimal level of health and functioning, through health education, health promotion, disease and injury prevention, and crisis intervention. In 2016, the Company launched the Mental Health First Aid training course for employees, an accredited training program facilitated by the Mental Health Commission of Canada. The training aims to increase awareness and empathy for mental illness, reduce stigma, support affected employees, and improve return to work outcomes. By the end of 2017, over 1600 "people leaders" had participated in this training.

Nuclear Radiation Safety

OPG manages a radiation protection program designed to minimize detrimental health effects to employees and members of the public. OPG follows developments in the field of radiation protection as documented by the International Commission on Radiological Protection (ICRP), the United Nations Scientific Committee on the Effects of Atomic Radiation, and the U.S. National Council on Radiation Protection and Measurements. Widely recognized as the main source of expert advice regarding protection from the harmful effects of ionizing radiation, the ICRP periodically issues recommendations concerning principles of radiation protection. These recommendations are usually adopted by most countries without significant modification and are incorporated into the applicable laws. The Canadian Radiation Protection Regulations are based on the recommendations of the ICRP, and OPG's nuclear facilities conform to these regulations. The CNSC is the federal agency that regulates radiation protection in Canada.

Radiation exposures to station personnel and the public are limited by station design and adherence to approved operating procedures. Over the years, OPG has been a leader in applying the principles of keeping radiation doses as low as reasonably achievable. OPG's internal operating limits for occupational exposure are set well below the regulatory limits to ensure that the regulatory limits are not exceeded. OPG's operating targets for radiological emissions are set at even more restrictive levels and typically represent small fractions of the regulatory limits.

To ensure continued public safety, radiation exposure to members of the public resulting from the operation of OPG's nuclear generating stations is estimated on an annual basis for individuals living or working near the stations. The annual dose to the public resulting from operations of each nuclear facility is expressed in microsieverts (μSv), an international unit of radiation dose measurement. For 2015, the annual public doses resulting from the Darlington GS operations and the Pickering GS operations were 0.5 μSv and 1.2 μSv, respectively, which is approximately 0.1 percent of the annual legal limit of 1,000 μSv. For 2016, the annual public doses resulting from the Darlington GS operations and the Pickering GS operations were 0.6 μSv and 1.5 μSv, respectively, which is less than 0.1 and 0.2 percent of the annual legal limit of 1,000 μSv, respectively. While the public doses from OPG's nuclear operations for the 2017 operating year will not be finalized until the second quarter of 2018, they are not expected to differ significantly from the 2016 levels.

As a condition of receiving operating licences for its nuclear facilities, OPG has developed comprehensive emergency plans that detail the Company's planned response to reactor accidents, as well as accidents involving the transportation of radioactive materials. These plans dictate how OPG will work with municipal, regional, provincial, and federal agencies to safeguard station personnel and members of the public in the unlikely event of a radiation emergency at one of OPG's facilities. Station staff are required to regularly participate in emergency exercises to maintain and continuously improve response capability for such events.

Dam Safety and Waterways Public Safety

OPG manages dam safety and other risks associated with the production of hydroelectric power through OPG's Safe Operations Policy and Dam Safety Program. The Safe Operations Policy directs that dams be designed, constructed, operated, and maintained in a manner that meets all regulatory requirements, or, in the absence of regulations, the safety guidelines published by the Canadian Dam Association or other industry best practices. OPG is one of the first dam owners in Canada to have developed and implemented a dam safety program and is considered an industry leader in many aspects of the program.

In addition to effectively managing the safety of dams against catastrophic failure, OPG has developed a number of technical standards and procedures concerning public safety around dams, and materials to educate the public and raise awareness of the hazards associated with the operation of the hydroelectric facilities. This includes the implementation of control measures in the form of signage, safety booms, buoys, fencing and audible alerts at the appropriate facilities. These measures are actively managed to maintain their effectiveness. OPG also strives to entrench a "Stay Clear – Stay Safe" message as part of its public education program, through strategically placed advertisements and engagement of other agencies, such as the MNRF, Ontario Provincial Police, Life Saving Society, Ontario Waterpower Association, and other stakeholders.

Since 2007, OPG has engaged an independent advisory panel consisting of internationally recognized experts to conduct an annual review of its Dam Safety Program. The Chair of the independent panel establishes areas of in-depth review and presents the observations to OPG's Board of Directors. The panel has consistently found that the risks associated with the dams owned and operated by OPG are being managed in alignment with industry best practices and guidelines. OPG remains committed to high standards of public safety on waterways around hydroelectric generating stations and dams, and continues to make investments in waterway and dam safety upgrades.

Additional details on the regulatory regime related to dams and waterways can be found in the section, *Description of the Business* under the heading, *Water Rights.*

Environment

Overview

OPG is committed to meeting compliance obligations, including any environmental commitments that it makes, with the objective of exceeding these compliance obligations where it makes business sense. OPG's Environmental Policy specifically commits the Company to:

- Establish an environmental management system (EMS) and maintain registration for this system to the ISO 14001 Environmental Management System standard;
- Work to prevent or mitigate adverse impacts on the environment with a long-term objective of continual improvement;
- Strive to be a leader in climate change mitigation; and
- Manage sites in a manner that strives to maintain, or enhance where it makes business sense, significant natural areas and associated species of concern.

The policy is implemented through OPG's EMS. Within the EMS, OPG sets environmental objectives and maintains planning, operational control, and monitoring programs to manage its negative and positive impacts on the environment. The most significant environmental aspects of OPG's operations include: chemical emissions to water, spills, fish impingement and entrainment, thermal effluent emissions, displacement of fossil fuels, enhancement and disruption of wildlife habitat, radiological emissions, radioactive waste generation, and water flow and level changes. The policy is reviewed annually as part of the EMS to ensure that it remains appropriate to the nature, scale and environmental impacts of OPG's activities.

OPG communicates its environmental performance to external and internal stakeholders through a range of engagement methods such as reports and correspondence to regulators, meetings, newsletters, open houses, consultations, news releases, advertising campaigns, social media, and participation in community events.

Details of OPG's environmental performance and initiatives to fulfill the Environmental Policy can be found in OPG's annual *Sustainability Report*, which is available on the Company's website at www.opg.com. ***Unless otherwise specifically stated, none of the information contained on, or connected to the Company's website nor any of the contents of the Sustainability Report are incorporated by reference herein.***

Environmental Compliance

OPG must comply with a large number of environmental requirements contained in statutes, regulations, by-laws, licences, permits and approvals. Failure to comply with applicable environmental laws may result in enforcement action, including the potential for orders or charges. OPG reports any incidents of non-compliance to the appropriate federal, provincial or municipal authorities as required, with corrective action plans developed and implemented accordingly.

Changes in environmental regulatory requirements may result in existing operations being in a state of non-compliance, a potential inability to comply, and potential costs and liabilities for OPG. To ensure compliance, such circumstances may require OPG to install control technologies, develop new processes, allowances or offsets, or place constraints on electricity production.

Protection of Fish

Electricity generating facilities located on waterways can impact fish in a number of ways. At nuclear and thermal stations, the intake of water for cooling purposes can result in fish being impinged on station equipment and fish larvae and eggs being entrained in the water as it passes through the station. The warmer water returned to the water body also has the potential to impact aquatic organisms and habitat near the station. At hydroelectric stations, the flow of water through the station turbines can result in fish entrainment and mortality, while physical barriers such as dams can prevent the migration of fish.

OPG utilizes measures such as fish ladders, trap and transport programs, stocking programs, barriers and deterring structures, water flow alterations, habitat protection and creation, and station effluent temperature limits to manage and mitigate impacts to fish. Potential regulatory changes being monitored and managed as risks by the Company include electricity production constraints and water flow management requirements to protect fish and fish habitat, and expanded fish passage requirements.

Biodiversity and Habitat Stewardship

The generation of electricity can have an impact on biodiversity, either directly through habitat loss and fragmentation or indirectly through emissions to the environment. OPG is committed to managing its sites in a manner that strives to maintain significant natural areas and associated species of concern. OPG also works with its community partners to support regional ecosystems and biodiversity through science-based habitat stewardship. OPG's regional biodiversity program strategically funds and promotes efforts to protect and restore biodiversity in areas of Ontario where genetic, species or ecosystem diversity have been most impacted, and substantive threats remain. In 2017, OPG continued efforts to protect and restore habitat, promote biodiversity education and awareness, and help the recovery of species at risk. In November 2017, OPG's biodiversity program was recognized by the CEA with the 2017 Sustainable Electricity award for Commitment to Continuous Performance Improvement.

Climate Change Mitigation and Air Quality

OPG's operational and growth strategies support reductions in GHG emissions and improved air quality. After safely ending coal-fired generation in the province, OPG has become Ontario's largest clean energy provider, producing and selling electricity that is 99 percent free of GHG and smog-causing emissions. The elimination of coal-fired electricity production at OPG's generating stations resulted in coal being reduced from one-quarter of Ontario's energy supply mix in 2003 to zero in 2014.

OPG monitors and reports GHG emissions from its facilities in accordance with the regulatory requirements set out by Environment and Climate Change Canada and the MOECC. In 2016, the Government of Ontario passed the *Climate Change Mitigation and Low-Carbon Economy Act, 2016* and the associated *Cap and Trade Program Regulation*. The legislation provides the foundation for regulating GHG emissions in Ontario and includes a cap and trade program, with the first compliance period being from January 1, 2017 to December 31, 2020. The cap and trade program is a market mechanism intended to give Ontarians an

incentive to reduce GHG emissions by putting a price on carbon. The program requirements are expected to result in increased fuel costs for some OPG-owned and co-owned generating facilities. Fuel costs for these stations are generally recovered from the electricity market. With OPG's low GHG emitting fleet, this is not expected to have a material adverse financial impact on the Company. OPG has established the necessary processes to comply with the cap and trade program requirements.

OPG is monitoring actions being taken by the Government of Ontario and the Government of Canada to reduce GHG emission levels and transition to a low-carbon economy. In support of efforts to mitigate climate change, the Company continues to evaluate and implement plans to increase the generation capacity of its hydroelectric generating fleet, where economical, and invest in other low-carbon technologies. OPG also has a strategy to help position the Company as a leader in transportation electrification in the province. The strategy aims to leverage the Company's clean, reliable and cost-effective electricity to power transportation, capitalize on future commercial growth opportunities, and enhance the Company's social licence. OPG is pursuing initiatives to increase the use of electric vehicles within its operations, and is assessing vehicle grid integration and hydrogen applications for the transportation sector. Ontario's climate change plan aims for electric and hydrogen passenger vehicles to represent five percent of new vehicle sales in the province by 2020.

As part of its commitment to help de-carbonize Ontario's transportation sector, OPG is a founding sponsor of Plug'n Drive, a non-profit organization working to accelerate the adoption of electric vehicles and to maximize their environmental and economic benefits. In May 2017, Plug'n Drive announced the opening of the world's first experiential learning facility dedicated to electric vehicle education and awareness, with OPG sponsoring the Centre's training facility.

Radiological Emissions

Very low levels of radioactivity are released to air and water as a result of operating the reactors at OPG's nuclear generating stations. OPG maintains an effluent monitoring and control program to ensure radiological emissions are kept well below the release limits specified in the station operating licences. OPG also has environmental monitoring programs in the vicinity of the nuclear stations to ensure operations have no adverse impacts on human health and the environment. These programs are designed to assess impacts, demonstrate compliance with regulatory limits, validate the effectiveness of containment and effluent controls, and verify predictions made by environmental risk assessments. Results from the monitoring programs have confirmed OPG's radiological emissions are a small fraction of the regulatory release limits.

In June 2016 and August 2016, the CNSC released sampling results from its independent environmental monitoring program, which confirmed that the public and the environment around OPG's nuclear generating stations continued to be safe.

Further details are discussed under the heading, *Workplace Safety and Public Safety – Nuclear Radiation Safety.*

People and Culture

Workforce Resourcing Strategies

Electricity generation involves complex technologies that require highly skilled and trained workers, and a well trained and engaged workforce is fundamental to the achievement of OPG's strategic imperatives. The Company is focused on improving the capability of its workforce through leadership development, knowledge management, diversity and inclusion programs, and hiring in key areas. Ability to secure the right talent mix in order to effectively meet the Company's immediate and longer term business needs on a timely basis is supported through workforce planning, resourcing and on-boarding strategies, both to acquire external talent into the organization and to develop existing employees. The goal of resourcing strategies and workforce planning is to ensure that the Company's workforce is diverse and has the right skill set and capability for the safe and effective operation of the generating facilities and successful delivery

of major projects, including the Darlington Refurbishment. These strategies are being designed to take into account anticipated staffing requirements to the end of planned commercial operations of the Pickering GS, through to the end of the planned period to de-fuel, de-water and place the station in a safe state condition.

As part of the strategy to develop and engage employees and to build leadership talent in support of the Company's long-term success, OPG has an active succession planning program with a focus on accelerating development. This includes a company-wide high potential leadership development program for qualified internal candidates. This 14-month cross-functional, competitive-entry program is designed to identify and develop candidates for future leadership positions while they are relatively early in their careers. OPG also has a talent management monitoring process to proactively assess staffing risks, challenges and opportunities.

Many positions at OPG have significant educational prerequisites and rigorous requirements for continuous training and periodic requalification. In addition to maintaining its internal training infrastructure, OPG relies on partnerships with government agencies, other electrical industry partners, and educational institutions to meet the required level of qualification.

Effective January 1, 2017, OPG implemented an Executive Compensation Program that is compliant with *Ontario Regulation 304/16: Executive Compensation Framework*, introduced in September 2016. While the Province released two subsequent amendments, *Ontario Regulation 187/17* and *Ontario Regulation 400/17* in June 2017 and November 2017, respectively, OPG's Executive Compensation Program continues to be subject to the original regulation's requirements. The regulation sets out how all employers designated under the *Broader Public Sector Executive Compensation Act, 2014*, including OPG, must establish and post compensation programs for executives. The program must include the compensation philosophy, salary and performance-related pay caps, comparative analysis details, and a description of other elements of compensation. OPG's Executive Compensation Program is designed to provide compensation that is at the 50th percentile of the market and focused on at-risk, performance based pay. The program will better enable OPG to attract, align and retain the executive talent critical to delivering Shareholder and customer value, while ensuring continued safe and reliable operations. For further information, refer to the section, *Corporate Governance* under the heading, *Compensation.*

Employees

OPG's average number of full-time employees and average number of seasonal, casual construction and non-regular staff (Other Staff) in 2017 were as follows:

Business Segment	**Full-time Employees**	**Other Staff**
Regulated – Nuclear Generation [1]	7,360	1,432
Regulated – Hydroelectric	1,125	54
Contracted Generation Portfolio	531	49
Services, Trading, and Other Non-Generation [2]	96	7
Total	**9,111**	**1,541**

[1] Including employees associated with the Regulated – Nuclear Waste Management segment.
[2] The Fair Hydro Trust, a non-generation segment that is not subject to rate regulation, was established in December 2017. As of December 31, 2017 there were 3 full-time employees in the Fair Hydro Trust segment.

The majority of OPG's employees are represented by the PWU and The Society. The PWU includes most workers below the level of first line manager – from clerical staff to technicians and trades staff and station operators. The Society includes supervisors, professional engineers, scientists, and other professionals. Bargaining rights with the 19 craft unions that perform construction work at OPG's generating facilities in addition to the regular workforce are established either through the EPSCA or directly with OPG. EPSCA is a voluntary association of owners and contractors who perform work in the electrical power systems sector. The primary purpose of EPSCA is negotiating and administering collective agreements on behalf of employers performing work on what is now OPG property. Collective agreements between the Company and its construction unions are negotiated either directly or through EPSCA. OPG currently has 17

agreements through EPSCA and two direct trade agreements. The two direct trade agreements are with the Canadian Union of Skilled Workers and the Brick and Allied Craft Union.

Insurance

The principal types of discretionary insurance carried by OPG include directors' and officers' liability, excess commercial general liability, all risks property, boiler and machinery breakdown, including statutory boiler and pressure vessel inspections, and business interruption. In addition to providing coverage for OPG's non-nuclear facilities, this insurance applies to the conventional operations at OPG's nuclear generating stations. OPG also maintains nuclear property insurance, including nuclear boiler and machinery breakdown, for damage to the nuclear portions of its generating stations and for perils propagating from the nuclear to the conventional side of its assets. This coverage complements the conventional property insurance program.

OPG also purchases or requires contractors to purchase discretionary insurance for construction projects. For the Darlington Refurbishment project, the insurance coverage for the pre-requisite construction works was placed in 2013 and for refurbishment execution in 2016. The owner-controlled insurance program for the refurbishment consists of wrap-up liability, course of construction and marine transit insurance.

OPG purchases certain insurance coverage as required by statute, namely owned and leased motor vehicle liability, aviation liability (for drone operations) and nuclear energy liability insurance. The federal *Nuclear Liability and Compensation Act* (NLCA) that came into effect on January 1, 2017, and its predecessor legislation, the *Nuclear Liability Act* (NLA), impose absolute liability on a licensed operator of a nuclear generating station for any damage to property of, or injury to, the public arising from a nuclear incident, other than damage resulting from sabotage or acts of war. As such, the legislation protects all other persons from liability, including suppliers of nuclear fuel and components used in nuclear reactors.

The NLCA requires all operators of nuclear generating stations in Canada to maintain specified amounts of nuclear liability insurance purchased from a federal government approved insurer or other equivalent forms of financial security approved by the federal government. Under the NLCA, OPG is required to maintain an initial $650 million per incident of nuclear energy liability insurance for each of its nuclear installations as defined by the NLCA effective in 2017, for which there is no deductible amount, with successive annual increases to $750 million, $850 million, and $1 billion over the 2018-2020 period. The Pickering GS site and the Darlington GS site are considered to be two separate nuclear installations under the NLCA. OPG is also required to maintain $13 million per incident of nuclear energy liability insurance for the WWMF. OPG is not responsible for purchasing nuclear liability insurance for the Bruce nuclear generating stations. Previously, the NLA required OPG to maintain $75 million per incident of nuclear energy liability insurance for each of the Pickering GS site and the Darlington GS site and $6 million for the WWMF, purchased from a federal government approved insurer. OPG continues to maintain nuclear liability insurance or other forms of financial security that have been approved by the federal government equal to the required liability limits.

Under Part I of the NLCA, an operator is liable for all damages resulting from a nuclear incident. If, in the opinion of the Governor in Council, OPG's liability could exceed the specified insured amount in respect of a nuclear incident, or it would be in the public interest to do so, the Governor in Council shall proclaim Part II of the NLCA as applicable in respect of a nuclear incident. Under Part II of the NLCA, OPG's liability would be effectively limited to the amount of required abovementioned insurance, and the Governor in Council may authorize additional funds to be paid by the federal government as may be specified in an order.

RISK FACTORS

For details on risks faced by OPG, see *Risk Management* in the Company's 2017 year-end MD&A.

DIVIDENDS

The declaration and payment of dividends remains at the sole discretion of OPG's Board of Directors and is dependent on the results of OPG's operations, the Company's financial condition and cash requirements, securities legislation requirements, and other factors considered relevant by the Board of Directors in exercising its discretion and judgment on an ongoing basis. OPG did not declare or pay any dividends for the years 2015 to 2017.

There are no restrictions in the articles of the Company that could prevent the Company from paying dividends. However, the declaration and payment of dividends are subject to financial tests set forth in the OBCA.

DESCRIPTION OF CAPITAL STRUCTURE

The authorized share capital of OPG consists of an unlimited number of common shares (the voting shares of the Company) and Class A shares. As at December 31, 2017, OPG had 256,300,010 common shares issued and outstanding, all of which are owned directly by the Province at a stated value of $5,126 million. As at December 31, 2017, OPG had 12,217,616 Class A shares issued and outstanding, all of which are owned directly by the Province at a stated value of approximately $519 million. OPG is authorized to issue an unlimited number of common shares and Class A shares without nominal or par value. Holders of common shares are entitled to one vote per share at meetings of the shareholders of the Company and, along with Class A shares, to receive dividends if, as, and when declared by the Board of Directors of the Company. Holders of common shares and Class A shares would participate, pro rata to their holding of common shares, and Class A share, in any distribution of the assets of the Company upon its liquidation, dissolution, or winding up. Any issuance of new shares is subject to the consent of all of OPG's shareholders.

All of the Company's voting securities are held by the Province. Accordingly, the Company is controlled by the Province.

CREDIT RATINGS

DBRS Limited (DBRS) and S&P Global Ratings (S&P) provide credit ratings for commercial entities. A credit rating generally provides investors with an independent measure of credit quality of an issue of securities. Credit rating categories for long-term debt instruments range from highest credit quality (generally 'AAA') to default in payment (generally 'D').

In April 2017, DBRS re-affirmed the long-term credit rating on OPG's debt at 'A (low)' and the commercial paper rating at 'R-1 (low)', each with a stable outlook. In July 2017, S&P re-affirmed OPG's long-term credit rating at BBB+ with a stable outlook. On July 7, 2015, S&P lowered OPG's long-term corporate credit rating from 'A-' to 'BBB+' with a stable outlook. S&P's rating action followed its July 6, 2015 downgrade to the Province's rating from 'AA-' to 'A+'. The link between the Province and OPG through ownership and financial support may impact OPG's credit rating. S&P's commercial paper rating for OPG is 'A-1 (low)'.

Long-term debt instruments that are rated in the 'A' category by DBRS are considered to be of good credit quality. The capacity for the payment of financial obligations by the obligor of such instruments is considered to be substantial, but of lesser credit quality than higher-rated entities. Entities in the 'A' category may be vulnerable to future events, but qualifying negative factors are considered manageable. The addition of a "high" or "low" modifier indicates relative standing within the rating category.

A 'BBB' rating category by S&P for long-term debt instruments means that the obligor has adequate capacity to meet its financial commitments, but is considered more subject to adverse economic conditions than higher-rated entities. The addition of a plus '+' or minus '-' designation after a rating indicates the relative standing within a particular rating category.

DBRS's commercial paper credit rating scale ranges from 'R-1(high)' to 'D', which represents the highest to lowest quality of such securities rated. The rating of 'R-1(low)' is the third highest and is considered to be of good credit quality. S&P's Canadian commercial paper rating scale ranges from 'A-1 (high)' to 'D', which represents the highest to lowest quality of such securities rated. The rating of 'A-1 (low)' is the third highest and is considered to be satisfactory.
There can be no assurance that a credit rating will remain in effect for any given period of time or that a credit rating will not be lowered, withdrawn or revised by either or both rating agencies if, in their judgment, circumstances so warrant. The rating of any securities is not a recommendation to buy, sell or hold such securities, and such ratings do not comment as to market price or suitability for a particular investor.

During the past two years, OPG has made payments to DBRS and S&P's credit rating agencies for their credit rating services and for other services. OPG reasonably expects such payments will continue in the future for the services acquired.

MARKET FOR SECURITIES

In October 2017, OPG issued Series 1 Notes with a coupon rate of 3.315 percent for a principal amount of $500 million are currently outstanding and are not listed on any exchange or similar market for securities. The Notes are due in 2027.

CORPORATE GOVERNANCE

National Instrument 58-101 *Disclosure of Corporate Governance Practices* (NI 58-101), has been implemented by Canadian securities regulatory authorities to provide greater transparency for the marketplace regarding issuers' corporate governance practices. OPG's corporate governance practices align with NI 58-101 and National Policy 58-201 *Corporate Governance Guidelines.* In addition, OPG has reviewed its governance practices against the principles discussed in the 2013 Report on Building High Performance Boards issued by the Canadian Coalition for Good Governance and concluded that OPG compares favourably to those principles that apply to OPG.

Information with respect to OPG's Board of Directors is as follows:

Board of Directors

OPG's Board of Directors (Board) is made up of 14 individuals with the following capabilities:

- managing large businesses;
- managing and operating nuclear stations;
- understanding of the Canadian nuclear environment;
- engineering and/or project management, including large infrastructure project management;
- managing capital intensive companies;
- knowledge and expertise in mergers and acquisitions;
- overseeing regulatory, government and public relations;
- human resources management;
- financial, investment, legal and corporate governance expertise;
- knowledge of information technology/cybersecurity;
- knowledge of Indigenous communities; and
- stakeholder management.

The Board exercises its independent supervision over management as follows: the majority of members of the Board are independent of the Company; meetings of the Board are held at least five times a year; a formal Charter for the Board and for each Board committee has been adopted and the charters are reviewed annually; the Board and each Board committee is chaired by an independent Director; and a portion of each Board and Board committee meeting is reserved for independent Directors to meet without management present.

OPG has a written position description for the Chief Executive Officer (CEO). This position is accountable to the Board for: ensuring a culture of integrity and ethical conduct; increasing Shareholder value; defining and executing a corporate strategy, including a sustainable business model that will service the long-term power generation needs of the province; and providing a standard of leadership that will achieve operational excellence with respect to matters of safety, stakeholder relationships, financial performance, asset reliability, and health, environmental and regulatory compliance. In addition, the Board delineates the President and CEO role and responsibilities through the By-laws, the Board Charter, the Board policies, and the corporate and CEO annual goals and objectives. The Board sets, and monitors performance against, annual corporate and CEO targets and objectives.

Director Independence

On an annual basis, the Compensation, Leadership and Governance Committee of the Board reviews the disclosures made by Directors in the annual Director Questionnaire and reviews each disclosed affiliation's relationship with OPG in order to determine whether the Director is (or remains) independent. The Compensation, Leadership and Governance Committee reports on its review to the Board.

Based on the meaning of Independence in Section 1.4 of National Instrument 52-110 *Audit Committees* (NI 52-110) and a review of the applicable factual circumstances against this standard, the Compensation, Leadership and Governance Committee has determined that all Directors listed are independent, except for Jeffrey Lyash, who is considered to have a material relationship with OPG by virtue of his position as President and CEO of OPG.

The Board has a Board of Directors Conflict of Interest Policy and Procedure that governs the disclosure and mitigation of Director conflicts or potential conflicts of interest and has adopted an annual process of written disclosure by Directors in order to:

(i) identify potential conflicts of interest for the purposes of complying with the Board of Directors Conflict of Interest Policy and the OBCA;
(ii) validate the Directors' independence and financial literacy for the purposes of complying with securities regulations related to boards of directors and audit committees; and
(iii) satisfy other disclosures and regulatory filings.

To further minimize potential conflicts of interest, the Board has a policy on interlocking directorships. This policy states that no more than two OPG Directors may sit on a board of directors of another reporting issuer at the same time. Directors must confirm that they are in compliance with OPG's policy on interlocking directorships when disclosing to the Board Chair appointments to other boards of directors.

Strategic Planning

OPG's Board holds an annual strategy session and devotes a significant portion of each regular Board meeting to discussion of strategic matters. Management is responsible for developing the strategy and presenting it to the Board for discussion.

In 2017, the Board received reports on key strategic issues, risks, competitive developments, and corporate opportunities facing the Company. Management ensures that the key strategic elements are incorporated into OPG's annual budget and business plan, which are reviewed and approved by the Board. The Board also periodically receives briefings from external advisors on broad energy industry developments and/or special strategic matters.

Overseeing the Management of Risk

The Board oversees OPG's approach of identifying, reporting and mitigating the risks that could significantly impact the Company's capacity to achieve its long-term strategic objectives, as well as specific business plan objectives. To fulfill its risk oversight responsibilities, the Board has established an Enterprise Risk Management Policy and an Audit and Risk Committee, comprised of independent Directors. The

committee's mandate includes oversight of the Enterprise Risk Management (ERM) framework that management uses to manage the Company's risk profile. The ERM framework assists the Board in understanding how risks may affect the Company and how they are being addressed by management. The Audit and Risk Committee receives quarterly reports from OPG's Chief Risk and Audit Executive (CRAE) on enterprise-wide risks.

Through the Compensation, Leadership and Governance Committee, the Board also monitors the risks associated with the executive compensation program, to preclude the Company's decision-makers from taking excessive risk in order to achieve incentives under the compensation plans. The CRAE and Senior Vice President, People & Culture and Chief Ethics Officer jointly review the executive compensation framework on an annual basis to identify any potential for unintended risk-taking. The CRAE and Senior Vice President, People & Culture and Chief Ethics Officer provide an annual joint report to the Compensation, Leadership and Governance Committee on the results of their review.

Directors

The following tables set forth the name, age, municipality of residence, position with the Company and principal occupation of each of the Directors of the Company as of March 8, 2018. Each Director holds office until he or she resigns or a successor is elected or appointed. For a discussion of the Board Committee structure, refer to the heading, *Committees of the Board of Directors*.

Bernard Lord
Age: 52
Moncton, New Brunswick, Canada

Bernard Lord was appointed Board Chair for Ontario Power Generation on April 1, 2014. Mr. Lord is the CEO of Médavie, a not-for-profit Canadian medical care insurance company headquartered in Moncton, New Brunswick.

Mr. Lord earned a bachelor's degree with a major in economics as well as a bachelor's degree in common law from l'Université de Moncton. He has also received honorary doctorate degrees from University of New Brunswick, l'Université de Moncton and Saint Thomas University. He was admitted to the New Brunswick Law Society in 1993 and was appointed as Queen's Counsel in 2011.

Mr. Lord was the CEO of the Canadian Wireless and Telecommunications Association from October 2008 until August 2016. He also served on several other boards of directors.

In 1999, Mr. Lord became one of Canada's youngest Premiers at the age of 33. His majority government was re-elected in 2003 and he served as Premier of New Brunswick until October 2006. He was elected four times as a Member of the New Brunswick Legislative Assembly.

Mr. Lord's government introduced several new initiatives to support the development of natural resources while also protecting the environment, including a new energy policy that lead to the restructuring of NB Power and the refurbishment of the Point Lepreau nuclear generating station.

During Mr. Lord's terms as Premier, New Brunswick saw the lowest unemployment rate in 30 years and tax cuts each year, combined with balanced budgets and debt reduction. His government made record investments in health care and education while strengthening local democracy and modernizing the Official Languages Act.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since November 2013) *****	8 of 8	100%
Special Committee (since March 2017)	14 of 15	93%
The Board Chair is not a member of any standing Committee. The Board Chair attends all Committee meetings.	18 of 18	100%

Principal Occupation: CEO of Médavie

Board Memberships for other Reporting Issuers: None

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

*Chair

Jeffrey Lyash
Age: 56
Toronto, Ontario, Canada

Jeff Lyash is the President and CEO of OPG. Mr. Lyash was formerly the president of CB&I Power, a position he held from 2013 to 2015, where he was responsible for a full range of engineering, procurement and construction of multi-billion dollar electrical generation projects in both domestic and international markets. He also provided operating plant services for nuclear, coal, gas, oil and renewable generation.

Prior to joining CB&I in 2013, Mr. Lyash served as Executive Vice President of Energy Supply for Duke/Progress Energy from 2008 to 2012. With Duke Energy, he led engineering, maintenance and operations of the company's 42,000-megawatt generation fleet, fuel procurement, power trading, major projects and construction, environmental programs, and health and safety programs.

Before the merger of Progress Energy and Duke Energy, Mr. Lyash served as Executive Vice President of Energy Supply for Progress Energy. In this role, he oversaw Progress Energy's diverse 22,000-megawatt fleet of generating resources including nuclear, coal, oil, natural gas and hydroelectric stations. In addition, he was responsible for generating fleet fuel procurement and power trading operations.

Mr. Lyash began his career in the utility industry in 1981, joining Progress Energy in 1993. Before assuming the role of Executive Vice President of Energy Supply, he served as Executive Vice President of Corporate Development, President and Chief Executive Officer of Progress Energy Florida, Senior Vice President of Energy Delivery Florida, and Vice President of Transmission. He also held a wide range of management and executive roles in Progress Energy's nuclear program, including Operations Manager, Engineering Manager, Plant Manager, and Director of Site Operations.

Before joining Progress Energy, Mr. Lyash worked for the U.S. Nuclear Regulatory Commission (NRC) in a number of senior technical and management positions throughout the northeast United States and in Washington, D.C, receiving the NRC Meritorious Service Award in 1987.

Mr. Lyash earned a Bachelor's Degree in Mechanical Engineering from Drexel University, and was honored with the Drexel University Distinguished Alumnus Award in 2009. He has held a Senior Reactor Operator License from the NRC, and is a graduate of the U.S. Office of Personnel Management Executive Training Program and the Duke Fuqua School of Business Advanced Management Program.

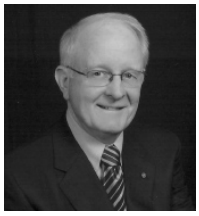
2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since August 2015)	8 of 8	100%
The President and CEO attends all Committee meetings, excluding independent Director in-camera meetings/sessions.	18 of 18	100%

Principal Occupation: President & Chief Executive Officer, Ontario Power Generation Inc.

Board Memberships for other Reporting Issuers: None

Independence from OPG: Not Independent

Interlocking Directorships on Boards of other Reporting Issuers: None



William Coley
Age: 74
Charlotte, North Carolina, U.S.A

Bill Coley served as Chief Executive of British Energy from 2005 to 2009 when he retired following the successful combination of British Energy and EDF Energy. He was President of Duke Power from 1997 until his retirement in February 2003, holding various officer level positions in engineering, operations and senior management during his 37-year career with the company.

Mr. Coley is a director of E.R. Jahna Industries. He also served on the WANO Fukushima Commission

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since January 2013)	8 of 8	100%
Compensation, Leadership and Governance Committee (since February 2016)	5 of 5	100%
Generation Oversight Committee (since February 2016)	4 of 4	100%
Darlington Refurbishment Committee (since May 2015)	4 of 4	100%
Special Committee (since March 2017)	15 of 15	100%

Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: None

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

Elisabeth (Lisa) DeMarco
Age: 50
Toronto, Ontario Canada

Lisa DeMarco is a senior partner at DeMarco Allan LLP with over two decades of experience in law, regulation, policy, and advocacy relating to energy and climate change. Ms. DeMarco was previously a partner at Macleod Dixon LLP from 2002 to 2012, partner at Norton Rose Canada LLP from 2012 to 2013 and partner at Norton Rose Fulbright LLP from 2013 to 2014. She represents several governments and leading energy companies in a wide variety of natural gas, electricity, pipeline and energy storage matters before various regulatory agencies, including the OEB and the National Energy Board. She has been an adjunct professor at Osgoode Hall Law School, is a guest lecturer at a number of law schools and presents regularly.

Ms. DeMarco also assists leading Canadian energy companies and Indigenous business organizations on domestic and overseas power project development, renewable power projects, alternative fuel projects, cleantech development and finance, energy storage, carbon capture and storage, corporate social responsibility, environmental disclosure, clean energy finance, and sustainable business strategy.

She is ranked by Chambers Global as one of the world's leading climate change lawyers and regularly attends and advises on related United Nations negotiations. She is ranked and repeatedly recommended by LEXpert, Expert Guide, International Who's Who, and Chambers Canada as a leading energy (oil, gas, and electricity) and environment lawyer. Ms. DeMarco has worked for multilateral development banks and energy companies on deals and projects in India, Brazil, Sri Lanka, Thailand, Argentina, Chile, Ireland, Africa, Mexico, China, Russia, California, Alberta, Ontario, Nova Scotia, British Columbia, Saskatchewan, Prince Edward Island and Québec. She plays an ongoing and active role in the development and drafting of energy and greenhouse gas emissions policy, regulation, and law throughout Canada, and in various countries around the world. She was also lead counsel on all aspects of the successful sale of an Ontario power distribution company to Hydro One. Lisa was an appointed member of Ontario Premier's Clean Energy Task Force and Climate Action Group.

Ms. DeMarco is a member of theBoard of Directors of the Advanced Energy Centre at MaRS, and Ontario Power Generation. She is a graduate of the University of Western Ontario (BSc Hon. – 1990), the University of Toronto (MSc. – 1992), Osgoode Hall Law School, York University (LLB – 1995) and the Vermont Law School (MSEL, summa cum laude – 1995) and is called to the bar in England and Ontario.

2017 Board/Committee Membership:	**2017 Attendance**	
Board (since April 2014)	8 of 8	100%
Audit and Risk Committee (since February 2016)	5 of 5	100%
Generation Oversight Committee (since February 2016)	4 of 4	100%
Special Committee (since March 2017)	15 of 15	100%

Principal Occupation: Senior Partner, DeMarco Allan LLP

Board Memberships for other Reporting Issuers: None

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

Jean Paul (JP) Gladu
Age: 44
Toronto, Ontario, Canada

JP Gladu is currently the President and CEO of the Canadian Council for Aboriginal Business (CCAB) based in Toronto. Anishinaabe from Thunder Bay, Mr. Gladu is a member of Bingwi Neyaashi Anishinaabek located on the eastern shores of Lake Nipigon. Mr. Gladu has over two decades of experience in the natural resource sector including work with Aboriginal communities and organizations, environmental non-government organizations, industry and governments from across Canada, including involvement in business development for the Bingwi Neyaashi Anishinaabek Nation from 2009 to 2012. He has produced a number of publications related to Aboriginal issues including: forest certification, Native values collection, biofuel opportunities, First Nation community land use plans, criteria and indicators for sustainable forestry, and cedar product development.

Mr. Gladu holds a Forest Technician Diploma from the Sault College of Applied Arts and Technology, a Bachelor of Science degree in forestry from Northern Arizona University, and an Executive Masters of Business Administration from Queens University in Kingston. In 2014, he was a recipient of the Community Service Award – Transformation Awards from Diversity Magazine. Mr. Gladu was nominated for the 2013 Premier's Award for Outstanding Ontario College Graduates, was recognized as one of five Northern Leaders in 2012 by Northern Ontario Business and was elected Class President of the 2012 Queens Executive Masters of Business Administration.

Mr. Gladu currently serves on the Canadian Electricity Associations' Public Advisory Panel, Noront Resources and Chancellor of St, Paul's University Board of Governors. He has also held previous board positions with Colleges and Institutes Canada (previously the Association of Canadian Community Colleges), Northern Policy Institute, Canadian Foundation for Economic Education boards of directors, Centre for Research and Innovation in the Bio-Economy, Papasay Management Corporation, and a board member of the Canadian Bioenergy Association. He also held advisory positions with the Canadian Association of Petroleum Producers Renewable Clean Energy Committee and the Ontario Provincial Forest Policy Committee.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since November 2015)	6 of 8	75%
Compensation, Leadership and Governance Committee (since February 2016)	5 of 5	100%
Generation Oversight Committee (since February 2016)	3 of 4	75%

Principal Occupation: President and CEO, Canadian Council for Aboriginal Business

Board Memberships for other Reporting Issuers: Noront Resources Ltd. *(TSX)*

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

John Herron
Age: 64
Punta Gorda, Florida, U.S.A.

John Herron retired from Entergy in April 2013 where he was the President, CEO and Chief Nuclear Officer of Entergy Nuclear, with responsibility for Entergy's nuclear plants located in New York, Massachusetts, Vermont, Michigan, Louisiana, Mississippi and Arkansas as well as the company's management service to the Cooper Nuclear Station for the state of Nebraska.

He previously served as Entergy's Senior Vice President for Nuclear Operations handling the operational side of fleet management. Mr. Herron joined Entergy in February 2001 as Vice President, Operations at the Waterford 3 Nuclear Station in Killona, Louisiana. He then moved to New York as the Senior Vice President of the Indian Point Energy Center in February 2002.

Mr. Herron began his career in nuclear operations in 1979 at Vermont Yankee Nuclear Power Corporation. His positions there included technical services superintendent, operations manager, technical programs manager, shift supervisor, and supervisory control room operator. In 1994, he moved to Brownville, Nebraska to become plant manager at Nebraska Public Power District's Cooper Nuclear Station.

Mr. Herron then joined the Tennessee Valley Authority as plant manager at Sequoyah Nuclear Plant in Soddy-Daisy, Tennessee, from October 1996 through July 1999. From July 1999 to February 2001, Mr. Herron served as site Vice President at TVA's Browns Ferry Nuclear Plant.

Prior to his career in utilities, Mr. Herron served in the U.S. Navy from 1972 to 1978. He was attached to the USS Tullibee and the S1C NPTU Windsor, where he was an instructor at the Nuclear Submarine Prototype School.

Mr. Herron holds a bachelor's degree in Business Management from Franklin Pierce College in Rindge, New Hampshire. He also attended the Advanced Management Program at the Harvard Business School in May 2005.

Mr. Herron currently serves on the board of directors for Duke Energy. He also served on the board of directors for the Institute of Nuclear Power Operations and on the Nuclear Strategic Issues Advisory Committee of the Nuclear Energy Institute. In the aftermath of Japan's 2011 earthquake, he was named to the WANO Post-Fukushima Commission and the U.S. nuclear industry's Fukushima response steering committee.

2017 Board/Committee Membership:	**2017 Attendance**	
Board (since November 2013)	8 of 8	100%
Generation Oversight Committee* (since February 2016)	4 of 4	100%
Darlington Refurbishment Committee (since May 2015)	4 of 4	100%

Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: Duke Energy (NYSE)

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

* Chair of Committee

Ani Hotoyan-Joly
Age: 56
Markham, Ontario, Canada

Ani Hotoyan-Joly is currently Chief Financial Officer and Corporate Secretary of Coventree Inc. Prior to Coventree, she was V.P. Finance and Chief Financial Officer at Swiss Reinsurance Company Canada (P&C) and prior to that held senior positions at Zurich Canada. Ms. Hotoyan-Joly is a member of the Board of Directors of Women's College Hospital and is a member of the Executive Committee and Chair of the Governance and Nominations Committee. She is currently a member of the Executive Board of Armenian Relief Society's Roubina (Toronto) Chapter and was the Past Chair of A.R.S. Armenian Private School's Board of Trustees.

Ms. Hotoyan-Joly is a Chartered Professional Accountant and Chartered Accountant and holds a Bachelor of Commerce degree from the University of Toronto and the ICD.D designation from the Institute of Corporate Directors. She was elected as a 2016 Diversity 50 Candidate by the Canadian Board Diversity Council.

2017 Board/Committee Membership:	**2017 Attendance**	
Board (since March 2017)	6 of 6	100%
Audit and Risk Committee (since March 2017)	4 of 4	100%
Compensation, Leadership and Governance Committee (since March 2017)	4 of 4	100%

Principal Occupation: Chief Financial Officer and Corporate Secretary, Coventree Inc.

Board Memberships for other Reporting Issuers: None

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

Wendy Kei
Age: 50
Toronto, Ontario, Canada

Ms. Wendy Kei currently serves on the Board of Guyana Goldfields, Inc., as the Chair of the Audit Committee, a member of the Human Resources & Compensation Committee and a member of the Corporate Governance & Nominating Committee. She is an accomplished Finance Executive with over 25 years of business experience in a variety of industries. For the past 14 years, Ms. Kei has been working within the mining industry and brings a strong focus on corporate governance, financial and risk management and a strong expertise in executing complex mergers and acquisitions.

Ms. Kei is a Chartered Professional Accountant and Chartered Accountant and previously served as Chief Financial Officer of Dominion Diamond Corporation (formerly Harry Winston Diamond Corporation and Aber Diamond Corporation).

Ms. Kei is a member of the Chartered Professional Accountants of Ontario, and holds a Bachelor of Mathematics from the University of Waterloo. Ms. Kei was selected as a Diversity 50 2016 Candidate by the Canadian Board Diversity Council.

2017 Board/Committee Membership:	**2017 Attendance**	
Board (since March 2017)	6 of 6	100%
Audit and Risk Committee (since March 2017)	4 of 4	100%
Generation Oversight Committee (since March 2017)	3 of 3	100%

Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: Guyana Goldfields Inc. *(TSX)*

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

M. George Lewis
Age: 57
Toronto, Ontario, Canada

From February 2007 until November 2015, George Lewis was a member of RBC's Group Executive, one of eight executives responsible for setting the overall strategic direction for Royal Bank of Canada, Canada's largest bank. In that capacity, he served as Group Head of RBC Wealth Management from 2007 and RBC Insurance from 2012. As Group Head, Wealth Management, Mr. Lewis led the RBC businesses that serve the wealth management needs of affluent clients globally, and units that provide asset management and trust products. He was also Chairman of RBC Global Asset Management Inc.

From July 2000 to May 2008, Mr. Lewis was Chief Executive Officer of RBC Global Asset Management, which under his leadership became Canada's largest single mutual-fund family (RBC Funds) and one of Canada's largest asset management firms. He previously served as Head of Wealth Management for the Canadian Personal and Business segment and, from 2003 to 2006, was Head of all banking and investment products for RBC's Canadian Business.

From 1998 to 2000, Mr. Lewis was Managing Director, Head of Institutional Equity with RBC Capital Markets, responsible for global institutional-equity sales, trading and research. He was previously a top-rated equity analyst and Director of Research. He began his career with RBC in 1986, in the investment banking division of RBC Capital Markets.

Mr. Lewis has extensive experience in the investment industry, has a Masters of Business Administration degree with distinction from Harvard University and a Bachelor of Commerce degree with high distinction from Trinity College at the University of Toronto. He is also a Chartered Financial Analyst and an FCA/FCPA and has been certified by the Institute of Corporate Directors.

Mr. Lewis serves on the board of directors of Enbridge Income Fund Holdings Inc., the Canadian Film Centre and the Anglican Diocese of Toronto Foundation. He is a current member and past chair of the Bishop's Company of the Anglican Diocese of Toronto, as well as a patron and member of the Cabinet of the United Way of Toronto and York Region. Mr. Lewis also serves as the Honorary Colonel Commandant of the Royal Canadian Chaplain Service of the Canadian Armed Forces.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since February 2005)	8 of 8	100%
Audit and Risk Committee* (since February 2016)	5 of 5	100%
Compensation, Leadership and Governance Committee (since February 2016)	5 of 5	100%
Special Committee* (since March 2017)	15 of 15	100%

Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: Enbridge Income Fund Holdings Inc. *(TSX)*

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

* Chair of Committee

Margaret (Peggy) Mulligan
Age: 59
Cameron, Ontario, Canada

Peggy Mulligan was the Executive Vice President and Chief Financial Officer, Valeant Pharmaceuticals International, Inc. until December 2010. Prior to this, she was a Principal at Priiva Consulting, and before that she served as Executive Vice President and Chief Financial Officer of Linamar Corporation. Prior to Linamar, Mrs. Mulligan was with the Bank of Nova Scotia for eleven years as Executive Vice President, Systems and Operations and Senior Vice President, Audit and Chief Inspector. Before joining Scotiabank, she was an Audit Partner with PricewaterhouseCoopers in Toronto. She holds a B. Math (Honours) from the University of Waterloo and was named a Fellow of the Institute of Chartered Professional Accountants of Ontario in 2003.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since December 2005)	7 of 8	88%
Compensation and Leadership and Governance Committee* (since February 2016)	5 of 5	100%
Darlington Refurbishment Committee (since May 2015)	4 of 4	100%
Special Committee (since March 2017)	14 of 15	93%

Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: Canadian Western Bank (*TSX),* ClearStream Energy Services Inc. *(TSX)* (*previously Tuckamore Capital*)

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

* Chair of Committee

Yezdi Pavri
Age: 68
North York, Ontario, Canada

Yezdi Pavri retired as Vice Chairman of Deloitte Canada in June 2012 after a career of more than 30 years. Prior to being named Vice Chairman, Mr. Pavri was a member of the firm's national Management Committee for over ten years and was the Managing Partner of the Toronto practice since June 2004. He founded Deloitte's national Enterprise Risk Services practice in 1990 and led it for 15 years. He was a founding member of the global firm's India Steering Committee and co-chaired the firm's first Diversity and Inclusion Committee.

Mr. Pavri holds a Bachelor's degree in Aeronautical Engineering from the Indian Institute of Technology in Bombay and a Master's degree in Thermal Power Engineering from Imperial College in London. He is a Fellow of the Chartered Professional Accountants of Ontario.

Mr. Pavri currently serves on the boards of ICICI Bank of Canada, Enterra Holdings Limited (the global parent of Golder Associates) and MD Financial Services, and is a past member of the board of directors of Hydro One. Mr. Pavri is also the immediate past chairman of the board of trustees of United Way Toronto.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since September 2015)	8 of 8	100%
Audit and Risk Committee (February 2016)	5 of 5	100%
Compensation, Leadership and Governance Committee (since February 2016)	5 of 5	100%
Special Committee (since March 2017)	15 of 15	100%

Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: None

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

Gerry Phillips
Age: 77
Ajax, Ontario, Canada

Gerry Phillips was the Member of Provincial Parliament in the Legislative Assembly of Ontario for the east Toronto riding of Scarborough-Agincourt from 1987 to 2011. He served in six cabinet portfolios, including twice as Ontario Minister of Energy, where he was OPG's Shareholder from 2007 to 2008 and again on an interim basis from November 2009 to January 2010, as well as, Minister responsible for Securities Regulation in Ontario. He was also the Chair of the Management Board of Cabinet from 2008 to 2011 and the Chair of the Select Committee on the TMX Transaction in 2011.

Before entering public life, Mr. Phillips graduated from the University of Western Ontario's School of Business and worked in the marketing department of Procter and Gamble. In 1970, he joined the consulting firm of Canadian Marketing Associates and became President in 1977. He later founded two successful spin-off companies – the Sales Development Group in 1979 and the Retail Resource Group in 1982. By 1987, he was Chair of all three companies, with a combined workforce of approximately 300.

Mr. Phillips has an Honours B.A. from the Western School of Business.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since January 2013)	8 of 8	100%
Audit and Risk Committee (since February 2016)	5 of 5	100%
Darlington Refurbishment Committee (since May 2015)	4 of 4	100%

Principal Occupation: Retired

Board Memberships for other Reporting Issuers: None

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

Jim Reinsch
Age: 74
Frederick, Maryland, U.S.A.

Jim Reinsch retired from the Bechtel Group where he was Senior Vice President and Partner, and past President of Bechtel Nuclear. In this role, he was responsible for the global profit/loss, customer relations, operations, project management, marketing and business development of Bechtel's three nuclear business segments: nuclear operating plant services, steam generator replacement, and operations of Bechtel's global nuclear activities. During his 40 years with Bechtel, he also presided over Bechtel Canada, and managed large regions in the United States and Asia. He served as the President of the American Nuclear Society, and was a member of the Nuclear Energy Institute as well as a member of their Executive Committee. Mr. Reinsch is also a member of several international nuclear energy organizations, including the WANO and the World Nuclear Association.

Mr. Reinsch holds a Bachelor of Science degree from the University of Maryland.

Mr. Reinsch currently serves on the board of directors for Frederick Memorial Hospital and the Hood College Board of Trustees, and is a past board member of Duke Energy and the Smithsonian National Portrait Gallery. Additionally, he serves on the Emirate Nuclear Energy Corporation's committee on nuclear power which reports to the board of directors, and is a member of the international advisory board of Terrestrial Power.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since August 2015)	7 of 8	88%
Generation Oversight Committee (since February 2016)	4 of 4	100%
Darlington Refurbishment Committee* (since August 2015)	4 of 4	100%

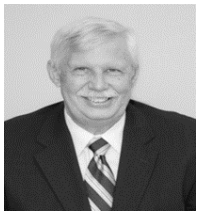
Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: None

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

*Chair of Committee



James Sheppard
Age: 69
Toronto, Ontario, Canada

Mr. Sheppard serves as an Independent Consultant. Mr. Sheppard served as Interim Senior Vice President for Southern California Edison Company and served as its Interim Chief Nuclear Officer from September 2010 to December 9, 2010. From 1993 to 2009, he held several senior positions associated with the South Texas Project nuclear power plant, including Chairman, President and Chief Executive Officer of STP Nuclear Operating Company, which operated the facility for its three owners. He served as Executive Officer of South Texas Project Electric Generating Station. He served as an executive at STP for ten years, he held the positions of Vice President and Assistant to the President and Chief Executive Officer; Vice President of Engineering and Technical Services; Vice President of Business Systems; Assistant to the executive vice president; and General Manager of Licensing. He has been an Independent Director at Xcel Energy Inc. since March 2011.

Mr. Sheppard holds a bachelor of science degree in aerospace engineering from the U.S. Naval Academy and a master's degree in business administration from the Duke University.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since March 2017)	6 of 6	100%
Darlington Refurbishment Committee (since March 2017)	3 of 3	100%
Generation Oversight Committee (since March 2017)	3 of 3	100%

Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: Xcel Energy Inc. *(NYSE)*

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

Nicole Boivin served as a Director from April 2014 to March 2017 and was a member of the Compensation, Leadership and Governance Committee and the Darlington Refurbishment Committee. Brendan Hawley was a Director from April 2014 to March 2017 and was a member of the Audit and Risk Committee and Darlington Refurbishment Committee. Ira Kagan was a Director from April 2014 to March 2017 and served as a member of the Audit and Risk Committee and the Generation Oversight Committee.

Orientation and Continuing Education

The Compensation, Leadership and Governance Committee is responsible for reviewing and recommending appropriate orientation programs for new Directors. New directors are provided relevant documentation relating to OPG's governance practices and policies and to its business. Directors attend plant tours of OPG generating facilities, where they also receive comprehensive introductory briefings from OPG senior executives on OPG's operations and business activities.

The Board supports and sponsors the continuing education of OPG Directors, both in the business of OPG and in their duties as Directors. This includes plant tours of OPG's major facilities, site visits to projects with OPG's Indigenous business partners, and special presentations by internal and external experts on topical business-related issues or on specific aspects of OPG's operations. In 2017, such topics included pension plan governance, the cap and trade program and OPG's dam safety program. Directors also are provided with articles and publications on current topics of interest. Board members have full access to all Board and Board committee materials and records. OPG has developed a Director Governance Handbook, which provides Directors with information necessary to fulfill their roles, including director duties and obligations under the OBCA, and relevant corporate policies and procedures. OPG also sponsors Director attendance at the Institute of Corporate Directors' Director Education Program, or equivalent, and sponsors attendance at the Goizueta Director program for members of Board committees responsible for oversight of nuclear operations.

Ethical Business Conduct

The Board has adopted a policy for ethical business behaviour and a Code of Business Conduct. The mandate of the Audit and Risk Committee requires that it receive regular reports throughout the year on the Code of Business Conduct in order to satisfy itself that appropriate code of conduct and compliance programs are in place and are being enforced, and remedial action is being taken. The Audit and Risk Committee receives quarterly reports from management on the Code of Business Conduct (including reports on any substantiated cases of fraud) and the disposition of cases including disciplinary action, as well as an annual report on the Code of Business Conduct and a report on the annual review of the Board policy. A copy of the Code of Business Conduct can be found on SEDAR at www.sedar.com and also is available on the Company's website at www.opg.com. The Audit and Risk Committee has procedures for the receipt, retention and treatment of complaints received pertaining to accounting, internal controls or auditing matters, and for the confidential anonymous submission by employees concerning such matters.

Nomination of Directors

The Compensation, Leadership and Governance Committee, which is comprised of six independent Directors within the meaning of NI 52-110, is responsible for conducting an annual review of the OPG Board's principles and systems of governance, and oversight of annual Board, Board committee and Director evaluations. The Compensation, Leadership and Governance Committee recommends candidates to the Shareholder. Nominations of Directors by the Shareholder also may be considered by the Compensation, Leadership and Governance Committee. When considering a potential candidate, the committee considers the qualities, experience, and skills that the Board, as a whole, should have in light of the business opportunities and risks facing OPG. The attributes the Compensation, Leadership and Governance Committee considers in a candidate include integrity, business judgment and experience, diversity, professional expertise, independence from management, financial literacy, and communication skills, as well as sufficient time available to fulfill his or her obligations as a Board member. The Board's policy on diversity is to interview a diverse candidate for every vacancy on the Board. OPG defines diversity to include: women, aboriginal peoples, people with disabilities, and visible minorities. These four

enumerated groups mirror the four enumerated groups in the definition of "designated groups" in the federal *Employment Equity Act*.

From time to time, the Compensation, Leadership and Governance Committee may engage outside advisors to assist in identifying potential candidates.

Director Tenure/Board Renewal

The OPG Board Charter guideline for board tenure is 10 to 15 years. When considering board renewal, the Compensation, Leadership and Governance Committee regularly reviews the OPG Board skills profile. The Board maintains an "evergreen list" of potential Board candidates. From time to time, the committee makes recommendations to add skills to the Board that reflect OPG's business opportunities and risks.

Diversity in Leadership

Board of Directors

As noted under the heading, *Nomination of Directors*, the Compensation, Leadership and Governance Committee interviews a diverse candidate for every vacancy on the Board, where diversity is defined as: women, aboriginal peoples, people with disabilities, and visible minorities. The Board has signed on to the Catalyst Accord, set a target for "diverse" representation on the Board of 50 percent, including 40 percent women by 2019 and adopted a target of 25 percent women on the Board by 2017. In 2017, three members were added to the Board, two of whom meet the diversity definition. As of the date of this AIF, overall diversity of the Board is at 50 percent. Representation of women on the Board is 29 percent (four Directors) as of the date of this AIF.

Senior Management

OPG strives to create a workforce that reflects diverse populations of the communities in which it operates. As of December 31, 2017, women filled 25 percent of Corporate Officer roles and 26 percent of senior management (senior managers and above) positions. In total, there were three women in Corporate Officer roles and 153 women in senior management positions. OPG tracks and monitors diversity succession planning metrics and strives to have a diverse candidates list for senior management positions.

Compensation

Executive Compensation Framework

In September 2016, the Government of Ontario introduced *Regulation 304/16: Executive Compensation Framework*. The regulation sets out how all employers, including OPG, designated under the *Broader Public Sector Executive Compensation Act, 2014* must establish and post compensation programs for executives. The regulation requires all designated employers to have a written Executive Compensation Program that describes the compensation they may provide to executives. The program must include the compensation philosophy, salary and performance-related pay caps, comparative analysis details, and a description of other elements of compensation. The regulation also requires that designated employers post their program on their website and provide a reasonable opportunity for members of the public to provide comments. OPG met the requirements of *Ontario Regulation 304/16* and posted its Executive Compensation Framework on the Company's website for public comment on November 30, 2016. OPG reviewed the comments received through the public consultation process and determined that there was no need to alter its Executive Compensation Program, which became effective on January 1, 2017. OPG's Executive Compensation Program applies to employees at the Vice President level and higher. A copy of OPG's Executive Compensation Program can be found on SEDAR at www.sedar.com and is also available on the Company's website at www.opg.com.

Director Compensation

As at March 8, 2018, OPG's Director compensation framework provides each Director who is not an employee of OPG with an annual retainer of $25,000. Directors also receive a $3,000 retainer for each Board committee of which they are a member. There are four standing committees of the Board and Directors serve on at least two committees. Directors receive an additional retainer for serving as committee chairs. The retainer for the chair of the Audit and Risk Committee is $8,000. The chairs of the other three committees receive retainers of $5,000.

In addition to the above, Directors are compensated for each regular and/or special meeting that they attend and receive a fee of $2,000 or $1,000 for a long or short meeting, respectively. The Board Chair may also determine that no fee is warranted.

In order to retain national and international expertise, non-resident Directors are compensated in U.S. dollars and Directors who travel over certain distances receive a travel fee to cover travel time related to Board and Board committee meetings they attend.

Since 2004, the Chair of the Board, in his role as non-executive Chair, receives an all-inclusive annual fee of $150,000 and is reimbursed for out-of-pocket expenses including travel and other expenses.

CEO Compensation

Among its other responsibilities, the Compensation, Leadership and Governance Committee oversees, on behalf of the Board, the setting of the CEO's annual goals and objectives and the annual review of CEO performance, and makes recommendations to the Board with respect to CEO compensation. The Committee may seek input from an independent advisor with regard to monitoring and benchmarking compensation trends.

In August 2015, when the current CEO was appointed, the CEO compensation terms were established based on the benchmarks recommended in the 2007 Report of the Agency Review Panel on Phase 1 of its Review of Ontario's Provincially Owned Electricity Agencies. The CEO's base pay and incentives compensation are compliant with *Ontario Regulation 304/16*. Other elements of the CEO's compensation will be compliant within the three-year period provided in the regulation to bring all elements of compensation into compliance.

For details regarding compensation paid to Directors and executive officers during the financial year ended December 31, 2017, see OPG's Statement of Executive Compensation (Form 51-102F6), which is available on SEDAR at www.sedar.com and incorporated by reference herein.

Committees of the Board of Directors

The following are the current standing Board committees as at March 8, 2018:

Audit and Risk Committee

This committee is responsible for the integrity, quality, and transparency of OPG's financial information, the adequacy of the financial reporting process, the systems of internal controls, and related principles, policies and procedures established by management. The Committee is responsible for the oversight of the Company's regulatory filings, financial statements, MD&A and press releases prior to their disclosures to the public, including approval of quarterly financial statements and recommending approval of the annual financial statements and various other annual disclosures to the Board. The committee is also responsible for recommending the appointment and compensation of the external auditor to the Board and for oversight of the external auditor.

The committee also provides oversight of OPG's corporate financing strategies including:

- policies related to financial exposure management;
- processes for identifying major financial risks;
- performance of the OPG Pension Fund, the Used Fuel Segregated Fund and the Decommissioning Segregated Fund;
- review and approval of the audited financial statements of the OPG Pension Fund, the Used Fuel Segregated Fund and the Decommissioning Segregated Fund; and
- review and approval of the statements of investment policies and procedures for the OPG Pension Fund and the Decommissioning Segregated Fund.

The Audit and Risk Committee also oversees risk and associated risk management activities, including the review of management's assessment of significant risks to achieving OPG's business plan objectives. The committee also is responsible for ensuring that an effective Code of Business Conduct is in place at OPG and monitors compliance with this code.

As of November 22, 2017, the Audit and Risk Committee assumed oversight of OPG's role as Financial Services Manager of the Fair Hydro Trust.

As of the date of this AIF, the Audit and Risk Committee consists of George Lewis (Chair), Elisabeth (Lisa) DeMarco, Ani Hotoyan-Joly, Wendy Kei, Yezdi Pavri, and Gerry Phillips.

For further details regarding the Audit and Risk Committee, see *Audit and Risk Committee Information*.

Compensation, Leadership and Governance Committee

This committee provides oversight of OPG's human resources and compensation policies and practices, including CEO objectives and compensation, disclosure on compensation and human resources matters, leadership talent review, succession planning, and collective bargaining negotiations. The committee also provides oversight of the design of OPG's benefit and pension plans.

The Compensation, Leadership and Governance Committee oversees the Board's governance program and practices to ensure that they are consistent with high standards of corporate governance, including annually reviewing and assessing the Board's system of corporate governance with a view to maintaining these high standards. The committee also is responsible for overseeing OPG's reputation management plan, and for identifying and recommending to the Board candidates for nomination to the Shareholder. Finally, the committee oversees OPG's processes for Board, Board committee, and Director assessments, as well as Director compensation and new Director orientation.

As of the date of this AIF, the Compensation, Leadership and Governance Committee consists of Margaret (Peggy) Mulligan (Chair), Bill Coley, JP Gladu, Ani Hotoyan-Joly, George Lewis and Yezdi Pavri.

Darlington Refurbishment Committee

The Darlington Refurbishment Committee is responsible for the oversight of the execution of the Darlington Refurbishment Program, including retaining external independent oversight advisors. The committee was also responsible for making a recommendation to the Board with respect to a final budget and schedule for the Darlington Refurbishment Program, which was subsequently approved by the Board of Directors in November 2015. The committee monitors and reports on the progress of the refurbishment program against the approved budget and schedule. The committee will make a recommendation to the Board with respect to the refurbishment of subsequent Darlington units, and other recommendations for approvals related to the refurbishment program as may be required from time to time.

As of the date of this AIF, the Darlington Refurbishment Committee consists of Jim Reinsch (Chair), Bill Coley, John Herron, Margaret (Peggy) Mulligan, Gerry Phillips, and James Sheppard.

Generation Oversight Committee

This committee is responsible for the oversight of safe, secure and efficient operations of OPG's generating facilities. Additionally, the committee is responsible for the development, risk management, financing, and execution of the Company's major generation projects including those related to nuclear waste management, other than the Darlington Refurbishment Program. The committee also is responsible for the oversight of OPG's environment and dam safety management systems and OPG's Indigenous relations. The committee reviews reports of internal and external advisors/assessors in respect of OPG's generation operations and management's response to the findings from such assessments. The committee provides oversight to ensure that OPG's generating facilities are in compliance with nuclear safety, industrial and occupational health and safety, and environmental laws and regulations.

As of the date of this AIF, the Generation Oversight Committee consists of John Herron (Chair), Bill Coley, Elisabeth (Lisa) DeMarco, JP Gladu, Wendy Kei, Jim Reinsch, and James Sheppard.

Special Committee of the Board

This Special Committee of the Board was established on March 10, 2017. The Special Committee was responsible for providing timely strategic and other guidance to OPG management in connection with the Province's announcement of Ontario's Fair Hydro Plan on March 2, 2017, which includes refinancing a portion of the Global Adjustment. The Committee was also responsible for making recommendations to the Board with respect to OPG's participation in the Province's implementation of the refinancing proposal. The mandate of the Special Committee concluded on November 22, 2017 and the Audit and Rick Committee will be responsible for the oversight of this process.

Assessments

The Compensation, Leadership and Governance Committee is responsible for the annual process for evaluating the performance of the Board, its committees and individual Directors. The Board and committee evaluations are based upon the completion of confidential questionnaires regarding assessment of performance and compliance with the Board and Committee Charters. The individual Director evaluations are based on self-assessment questionnaires, which are submitted in confidence to the Board Chair and the Chair of the Compensation, Leadership and Governance Committee. In addition, the process includes a follow-up one-on-one meeting between each Director and the Board Chair. The Compensation, Leadership and Governance Committee reports the results of the evaluations to the Board and the results are discussed amongst the Board. The Compensation, Leadership and Governance Committee makes recommendations to the Board for enhancing the Board's governance and effectiveness.

Further Information on OPG Governance

OPG provides additional information on the Company's governance on its website (www.opg.com) including:

- Memorandum of Agreement with the Shareholder
- Shareholder Directives
- List of Corporate Officers
- Board and Committee Charters
- Board and Committee Chair Position Descriptions
- Board of Directors Conflict of Interest Policy
- Indigenous Relations Policy
- Code of Business Conduct
- Disclosure Policy
- Environmental Policy
- Employee Health and Safety Policy
- Nuclear Safety Policy

- Safe Operations Policy
- Cyber Security Policy

Unless otherwise specifically stated, none of the information contained on, or connected to the Company's website nor any of the contents of the aforementioned additional information on OPG's governance are incorporated by reference herein.

EXECUTIVE OFFICERS

The following table sets forth the name, municipality of residence, position with the Company, and the date of commencement for each of the executive officers of the Company as of March 8, 2018:

Name and Municipality of Residence	**Current Position Held**	**Executive Officer Since**
Bernard Lord *Moncton, New Brunswick*	Board Chair	April 2014
Jeff Lyash *Toronto, Ontario*	President and Chief Executive Officer	August 2015
Carlo Crozzoli *Toronto, Ontario*	Senior Vice President, Corporate Business Development and Strategy	December 2011
Chris Ginther *Newmarket, Ontario*	Chief Administrative Officer	July 2012
Ken Hartwick *Milton, Ontario*	Chief Financial Officer & Senior Vice President – Finance	March 2016
Glenn Jager *Clarington, Ontario*	President, OPG Nuclear and Chief Nuclear Officer	November 2013
David Kaposi *Toronto, Ontario*	Vice President, Chief Investment Officer	November 2013
Barb Keenan *Toronto, Ontario*	Senior Vice President, People & Culture and Chief Ethics Officer	March 2010
Catriona King *Richmond Hill, Ontario*	Vice President, Corporate Secretary	February 2005
John Lee *Toronto, Ontario*	Vice President, Treasurer	July 2011
Mike Martelli *Etobicoke, Ontario*	President, Renewable Generation **[CONFIRM]**	July 2013
Dietmar Reiner *Clarington, Ontario*	Senior Vice President, Nuclear Projects	June 2014
Jennifer Rowe *Toronto, Ontario*	Senior Vice President, Corporate Affairs	January 2017

All of the executive officers of the Company have been engaged for more than five years in their current principal occupations, except as set out below:

- Mr. Lyash was Executive Vice President at Duke Energy from May 2008 to January 2012 and President at CB&I Power from July 2013 to July 2015.
- Mr. Crozzoli was Senior Vice President, Corporate Business Development and Chief Risk Officer at OPG from December 2011 to November 2015, Acting Senior Vice President, Finance, Strategy & Risk and Chief Financial Officer at OPG from November 2015 to March 2016 and Senior Vice-President, Corporate Business Development and Chief Risk Officer at OPG from March 2016 to August 2016.
- Mr. Ginther was Senior Vice President, Law and General Counsel and Chief Ethics Officer at OPG from July 2012 to January 2016 and Senior Vice President, Legal, Ethics and Compliance at OPG from January 2016 to February 2017.
- Mr. Hartwick was President and CEO at Just Energy Corp. from February 2008 to April 2014, Interim President and CEO at Atlantic Power Corporation from September 2014 to January 2015, Chief Financial Officer at Wellspring Financial Corporation from February 2015 to March 2016 and Senior Vice President, Finance, Strategy, Risk and Chief Financial Officer at OPG from March 2016 to February 2017.
- Mr. Jager was Senior Vice President, Pickering Nuclear Generating Station at OPG from January 2010 to November 2013 and Chief Nuclear Officer at OPG from November 2014 to March 2015.
- Mr. Kaposi was Global Head of Alternatives for Mercer (Canada) Inc. from November 2007 to June 2012 and Partner, Investor Relations at Bastion Infrastructure Group Inc. from July 2012 to September 2013.
- Ms. Keenan was Senior Vice President, People and Culture at OPG from March 2012 to January 2016 and Senior Vice President, People, Culture and Communications from January 2016 to February 2017.
- Ms. King was Vice President, Corporate Secretary at OPG from June 2005 to May 2012, Vice President, Corporate Secretary & Executive Operations from May 2012 to March 2017.
- Mr. Martelli was Plant Manager for the Niagara Plant Group at OPG from June 2010 to July 2013 and Senior Vice President, Hydro-Thermal Operations at OPG from July 2013 to January 2016.
- Mr. Reiner was Senior Vice President, Nuclear Refurbishment at OPG from March 2010 to April 2014.
- Ms. Rowe was Senior Managing Director – Marketing and Communications and VP Corporate Affairs at Manulife from January 2010 to October 2012 and Senior Vice President and Chief Marketing Officer at Meridan Credit Union from October 2012 to April 2016.

INDEBTEDNESS OF DIRECTORS AND EXECUTIVE OFFICERS

As of the date of this AIF, no director or executive officer of the Company or any of its subsidiaries had any outstanding indebtedness to the Company or any of its subsidiaries except routine indebtedness or had any indebtedness that was the subject of a guarantee, support agreement, letter of credit or other similar arrangement or understanding provided by the Company or any of its subsidiaries.

CEASE TRADE ORDERS, BANKRUPTCIES, PENALTIES OR SANCTIONS

To the knowledge of OPG, no director or executive officer is, at the date of the AIF, or was within 10 years before the date of the AIF, a director, chief executive officer, or chief financial officer of any company, that (a) was subject to an order that was issued while the director or executive officer was acting in the capacity as director, chief executive officer, or chief financial officer, or (b) was subject to an order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer, or chief financial officer, except for:

- Ani Hotoyan-Joly was the Chief Financial Officer of Coventree Inc. on November 8, 2011, when the Ontario Securities Commission issued an order that trading in any securities by Coventree cease and any exemptions contained in Ontario Securities law do not apply to Coventree until such time as Coventree completes it winding up. The order was made on the basis that Coventree had contravened Ontario Securities law by failing to issue and file certain news releases and material change reports in 2007.

- The events in question occurred before she became CFO of Coventree Inc. in May 2009. Coventree Inc. continues in the process of a court-supervised winding up and the order is still in effect.

To the knowledge of OPG, no director or executive officer of OPG, or a shareholder holding a sufficient number of securities of OPG to affect materially the control of OPG (a) is, as at the date of the AIF, or has been within the 10 years before the date of the AIF, a director or executive officer of any company (including OPG) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (b) has, within the 10 years before the date of the AIF, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager, or trustee appointed to hold the assets of the director, executive officer, or shareholder, except for:

- Bernard Lord was a director of AEA Technology from the fall of 2010 until the fall of 2012 when it became insolvent.
- Ani Hotoyan-Joly is currently the CFO and Corporate Secretary of Coventree Inc. from May 2009. On February 15, 2012 Coventree Inc. announced that the winding up of the Company will commence and that Duff & Phelpe Canada Restructuring Inc. (now known as KSV Advisory Inc.) was appointed the liquidator of the Company for the purpose of winding up its affairs.
- Peggy Mulligan was a director of MethylGene Inc. from May 2012 to June 2014. On May 9, 2013, MethylGene announced a plan of arrangement that was successfully completed on June 28, 2013.
- Bernard Lord, was a director of Clean Air Power, during September 2015 while it was subject to liquidation proceedings under the laws of Bermuda. Mr. Lord is no longer a director of Clean Air Power.
- William Coley is a director of Peabody Energy Corporation which declared voluntary Chapter 11 bankruptcy protection in April 2016 for most of its U.S. entities and is currently restructuring. As of April 13, 2017, Mr. Coley is no longer a director of the entity.

AUDIT AND RISK COMMITTEE INFORMATION

NI 52-110 has been implemented by Canadian securities regulatory authorities to encourage reporting issuers to establish and maintain strong, effective, and independent audit committees, to enhance the quality of financial disclosure, and to foster increased investor confidence in Canada's capital markets. The Audit and Risk Committee's Charter is attached to this AIF as Appendix A. Information on OPG's Audit and Risk Committee is as follows:

Composition of the Audit and Risk Committee

As at March 8, 2018, the members of the Audit and Risk Committee were George Lewis (Chair), Elisabeth (Lisa) DeMarco, Ani Hotoyan-Joly, Wendy Kei, Yezdi Pavri and Gerry Phillips. All members are independent within the meaning of NI 52-110 and have experience in business and financial matters. Each member has an understanding of internal controls and procedures for financial reporting. As part of OPG's Continuing Education Program for Directors, Audit and Risk Committee members are provided with access to both internal and external educational resources, including seminars and courses, in order to maintain or enhance their financial literacy.

Activities of the Audit and Risk Committee

The Chartered Professional Accountants of Canada (CPA Canada) and the Canadian Public Accountability Board have recommended that audit committees perform a comprehensive review of the external audit firm at least once every five years. CPA Canada issued guidelines in early 2014 to assist audit committees in implementing these recommendations. The Audit and Finance Committee of the Board conducted its first comprehensive review of the Company's external auditor, Ernst & Young LLP (EY) in 2014, for the period from 2009 to 2013, using the guidelines and format recommended by CPA Canada. EY has been OPG's external auditor since the Company's inception in 1999. EY provides audit and audit related services to OPG, including the audit of OPG's annual consolidated financial statements, reviews of OPG's quarterly financial statements, and audits of the financial statements of OPG's consolidated subsidiaries and other financial information.

In conducting the 2017 review of EY's performance, the Audit and Risk Committee considered input from management, EY, and OPG's internal audit function. The Committee performed this review taking into consideration the information submitted by these parties, as well as their individual experience. The results of the 2017 annual review were discussed at the Audit and Risk Committee meeting in August 2017. As part of the review, the Committee considered factors such as the auditor's independence, engagement team quality including the Committee's involvement in the selection of EY's lead engagement partner, and communication effectiveness between EY and OPG. Upon completion of the review, the Committee was satisfied with the performance of EY, concluded that their reappointment was in the best interests of OPG, and, in November 2017, recommended that the Board reappoint EY as the Company's auditor for the 2018 fiscal year. The Board reappointed EY as the Company's auditor for the 2018 fiscal year in November 2017.

External Auditor Service Fees [UPDATE]

The following fees were accrued by EY:

(thousands of dollars)	**2017**	**2016**
Audit fees		1,959
Audit-related fees		554
All other fees [1]		17

[1] Comprised of fees related to the subscription of an online accounting research tool and training.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Relationship with the Province and the OEFC

Relationship with the Shareholder

As a corporation created under and governed by the OBCA, OPG's management is supervised by its Board of Directors, which is obligated by law to act in the best interests of the Company. The Company's sole Shareholder, the Province, owns all of the Company's issued and outstanding common shares and thereby has the power to determine the composition of the Company's Board of Directors.

As one of several wholly-owned government business enterprises of the Province, OPG has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

Memorandum of Agreement

On August 17, 2005, OPG entered into the MOA with the Shareholder regarding OPG's role and responsibility as a power producer in Ontario. In July 2015, the MOA was revised. The MOA serves as the basis of agreement between OPG and the Shareholder regarding OPG's mandate, governance, performance, reporting and communications, and establishes the accountabilities between OPG and the Province. OPG's strategic imperatives are based on the Company's mandate as set out in the MOA. The MOA was reaffirmed for continuance by both the Ontario Minister of Energy and the OPG Board of Directors' Chair in the fourth quarter of 2016, as required by the MOA following a change in the Minister of Energy.

A copy of the MOA can be found on the Company's website at www.opg.com. ***Unless otherwise specifically stated, none of the information contained on, or connected to the Company's website nor any of the contents of the MOA are incorporated by reference herein.***

Shareholder Directives

The Shareholder may at times direct OPG to undertake special initiatives. A Shareholder directive is issued when the Shareholder finds it necessary to assume decision-making power and authority over certain aspects of the business operations of the Corporation. Under a Shareholder directive, the Shareholder assumes all the rights, powers, duties and liabilities of the Directors to manage or supervise the management of the business and the Directors are relieved of their duties and liabilities. Shareholder directives are communicated as written pursuant to section 108 of the OBCA. Copies of each Shareholder directive can be found on the Company's website at www.opg.com. ***Unless otherwise specifically stated, none of the information contained on, or connected to the Company's website nor any of the contents of the Shareholder directives are incorporated by reference herein.*** The Shareholder directives issued by the Shareholder to date are listed below in reverse chronological order:

- Sale of the Corporation's Lakeview site (June 9, 2016);
- Sale of the Corporation's Head Office (December 14, 2015);
- Bruce Power L.P. Lease Agreement and Used Fuel Agreement (November 30, 2015) – For further details, see *General Development of Business – Nuclear Business Development – Bruce Power Refurbishment and Bruce Lease Agreement*;
- Bruce Power L.P. Amended and Restated Heavy Water and Associated Services Agreement (November 30, 2015) – For further details, see *General Development of Business – Nuclear Business Development – Bruce Power Refurbishment and Bruce Lease Agreement*;
- Conversion of One Unit of Thunder Bay Generating Station to Advanced Biomass (May 1, 2014);
- Thunder Bay Generating Station Conversion (December 16, 2013);
- Early Closure of Ontario Power Generation's Lambton and Nanticoke Coal-Fired Generation Stations (March 7, 2013);
- First Nation Directive (April 1, 2011) – OPG was directed to pay a part of the Shareholder's portion of the settlement liability with a First Nation on its behalf;
- Atikokan Generating Station Conversion (March 8, 2011);
- Addressing Carbon Dioxide Emissions from the Use of Coal at Coal-Fired Generating Stations (May 20, 2010);
- Request for Indicative Prices for the Supply of Wood Pellet Fuel Declaration (Atikokan) (March 18, 2010);

- Request for Expressions of Interest for Supply and Transportation of Solid Biomass Fuel Declaration (January 13, 2009);
- Addressing Carbon Dioxide Emissions from the Use of Coal at Coal-Fired Generating Stations (May 15, 2008);
- Thunder Bay Gas Conversion Cancellation (July 12, 2006);
- Nuclear Directive (June 16, 2006) – OPG was directed to begin feasibility studies on refurbishing existing nuclear units, an environmental assessment on refurbishing Pickering B units, and federal approvals processes (including environmental assessment) for new nuclear units;
- Lower Mattagami River Agreement (May 23, 2006);
- Bruce Power Lease Agreement (October 14, 2005); and
- Thunder Bay Gas Conversion Declaration (October 6, 2005).

Ontario Nuclear Funds Agreement

The ONFA between OPG and the Province sets out the responsibility for funding the liabilities for the decommissioning of OPG's nuclear facilities and the long-term management of OPG's used nuclear fuel and other nuclear waste. Pursuant to the ONFA, the Company has established a Used Fuel Segregated Fund and a Decommissioning Segregated Fund to fund the future costs of these activities. Additional details can be found in the section, *Description of the Business* under the heading, *Regulated – Nuclear Waste Management Segment – Funding Mechanisms*.

OPG Debt Held by the OEFC

OPG's long-term debt has been financed predominantly by the OEFC. As at December 31, 2017, the OEFC held approximately $3.2 billion of OPG's long-term debt with maturities ranging from one month to 30 years. For additional details, see Note 6 to the Company's audited annual financial statements as at and for the year ended December 31, 2017.

Payments-In-Lieu of Corporate Income Taxes and Property Taxes

OPG and its wholly-owned subsidiaries are exempt from tax under the *Income Tax Act* (Canada) and *Taxation Act, 2007* (Ontario). However, under the *Electricity Act, 1998*, OPG is required to make proxy tax payments to the OEFC. These payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by the *Electricity Act, 1998* and related regulations. This results in OPG paying taxes similar to those imposed under the federal and Ontario tax acts.

OPG is subject to income tax audits by the Ontario Ministry of Finance. As of the date of this AIF, income tax audits up to and including the 2013 taxation year have been completed.

The *Electricity Act, 1998* also provides that OPG and certain of its subsidiaries are required to make payments in lieu of property tax to the OEFC on their non-hydroelectric generating station buildings and structures. These payments generally equal the difference between property taxes that would be otherwise payable if these assets were privately owned, and the amount payable to municipalities in respect of these assets as determined under the *Assessment Act, 1990* (Ontario). As with other hydroelectric generators in Ontario, OPG's hydroelectric generation operations are not subject to payments in lieu of property taxes because they are subject to the GRC regime. Additional details on the GRC regime can be found in the section, *Description of the Business* under the heading, *Generation Operations – Hydroelectric (Regulated – Hydroelectric and Contracted Generation Portfolio segments)*.

Stranded Debt

One of the OEFC's purposes under the *Electricity Act, 1998* is to manage "stranded debt," which was not transferred to any of Ontario Hydro's successor entities. The *Electricity Act, 1998* defines stranded debt as the amount of the debt and other liabilities of the OEFC that, in the opinion of the Minister of Finance, cannot reasonably be serviced and retired in a competitive electricity market. Although OPG has no obligations in connection with the stranded debt, the *Electricity Act, 1998* does provide for participants in the electricity sector, including OPG, Hydro One, and the municipal electricity utilities, to make payments to the OEFC, which the OEFC uses in managing the debt and other obligations. These payments include proxy taxes, payments in lieu of tax, including property tax, the Debt Retirement Charge levied on certain electricity consumers, and certain amounts that may be payable by municipal electricity utilities on the transfer of their electricity business.

Commented [GH3]: Not sure if we need to note that Hydro One no longer pays PILs here, given this is OPG's AIF.

Commented [JK4]: If this refers to PILs, then the next change is not needed.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Legal Proceedings

OPG is potentially the subject of various legal proceedings and claims that arise in the ordinary course of business. The outcome of these proceedings and claims is uncertain. Based on information available as of the date of this AIF, management believes that none of the proceedings and claims, individually and in the aggregate, are expected to have a material impact on OPG.

British Energy Claim

On August 9, 2006, a Notice of Action and Statement of Claim filed with the Ontario Superior Court of Justice in the amount of $500 million was served against OPG and Bruce Power by British Energy Limited and British Energy International Holdings Limited (together British Energy). The action is for contribution and indemnity of any amounts British Energy was liable for in an arbitration against it by some of the owners of Bruce Power regarding an alleged breach of British Energy's representations and warranties to the claimants when they purchased British Energy's interest in Bruce Power (the Arbitration). Both the action and the Arbitration relate to corrosion to a steam generator unit discovered after OPG leased the Bruce nuclear generating stations to Bruce Power.

In 2012, the arbitrator found that British Energy was liable to the claimants for some of the damages they claimed. The final settlement amount was valued by British Energy at $71 million. In September 2014, British Energy amended its Statement of Claim (Amended Claim) to reduce the claim amount to $100 million to reflect that the purchasers of British Energy's interest in Bruce Power did not receive the full damages they originally claimed in the Arbitration. British Energy also added an allegation to its Amended Claim that OPG breached a covenant to maintain the steam generator between the time of the initial agreement to lease and the effective date of the lease in accordance with "Good Utility Practices".

In November 2016, British Energy obtained consent to a timetable for the remaining steps in the litigation, pursuant to which the matter must be set down for trial by December 31, 2018. OPG has delivered a statement of defence in accordance with an extension of the original June 30, 2017 delivery deadline set out in the timetable.

Regulatory Actions

OPG is not aware of any penalties or sanctions imposed by a court or securities regulatory authority or other regulatory body against the Company, nor has the Company entered into any settlement agreements before a court or with a securities regulatory authority.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business (unless otherwise required by applicable securities requirements to be disclosed), there were no material contracts entered into by the Company or

its subsidiaries during the most recently completed financial year, or before the most recently completed financial year that are still in effect.

INTERESTS OF EXPERTS

The external auditor of the Company is Ernst & Young LLP, Chartered Professional Accountants, 100 Adelaide Street West, P.O. Box 1, Toronto, Ontario M5H 0B3. Ernst & Young LLP has been the Company's auditors since OPG was formed in 1999, and is independent in accordance with the Rules of Professional Conduct of the Chartered Professional Accountants of Ontario.

GLOSSARY

ancillary service	a service necessary to maintain the reliability of the IESO-controlled grid.
availability	when used in reference to a generating unit, a measure of mechanical reliability represented by the percentage of time a generating unit is capable of providing service, whether or not it is actually in-service, relative to the total time for the period.
baseload facilities	electricity generation facilities that produce a constant supply of energy. In Ontario, baseload facilities are made up of nuclear, run-of-the-river hydroelectric and variable generation facilities such as wind and solar.
bilateral contract	a contract for the purchase and sale of notional electricity usually entered into directly between a generator and an end-user, or between a generator or end-user and a market intermediary.
biomass	plant material from agricultural and forest sources that can be used to produce energy, including beneficiated biomass, which includes torrefied, carbonized, and steam exploded biomass.
CANDU	an acronym for CANada Deuterium Uranium, a family of nuclear fission reactors developed in Canada which use pressurized heavy water coolant or deuterium oxide as a moderating agent and natural uranium (uranium dioxide) as fuel.
capacity factor	the ratio (usually specified as a percentage) of the amount of energy that a generating asset actually generated over a period of time divided by the amount of energy that the generating asset would have produced over the same period of time if it had operated continuously at full capacity.
decommissioning	actions taken in the interest of health, safety, security and protection of the environment to retire a facility permanently from service and render it to a predetermined end-state condition.
detritiation	the removal of tritium from heavy water.
deuterium oxide	see heavy water.
equivalent forced outage rate	the hours of unit failure given as a percentage of the total hours of the availability of that unit.
government business enterprises	Government organizations that are separate legal entities with the power to contract in their own name, have the financial and operating authority to carry on a business, are principally focused on the selling of goods and services to individuals and non-government organizations, and are able to maintain their operations and meet their obligations through revenues generated outside the government reporting entity.
heavy water (deuterium oxide)	water containing significantly more than the natural proportion of heavy hydrogen (deuterium) atoms to ordinary hydrogen atoms, used as a moderator in CANDU reactors.
in-service capacity	the portion of installed capacity (the highest level of output which a generating unit is designed to maintain indefinitely without damage to the unit) that has not been removed from service.

interconnection	a transmission line which carries power across the service area boundary of geographically adjacent jurisdictions.
kWh	a kilowatt hour, the commercial unit of electric energy (the amount of electricity consumed by ten 100 watt light bulbs burning for one hour).
load	the quantity of electricity consumption measured as either the energy consumed over a given period of time or the rate of energy consumption at a given time by a particular customer or group of customers.
MW	a megawatt, equal to 1,000,000 watts or 1,000 kilowatts.
MWh	a megawatt hour, equal to 1,000 kWh.
OEFC	an acronym for the Ontario Electricity Financial Corporation, the legal continuation of the former Ontario Hydro. The OEFC is responsible for managing the debt and certain other obligations not transferred to other successor companies of Ontario Hydro.
ONFA	an acronym for the Ontario Nuclear Funds Agreement between OPG and the Province that sets out the responsibility for funding the liabilities for the decommissioning of OPG's nuclear stations and the long-term management of OPG's used nuclear fuel and other nuclear waste.
Ontario NFWA Trust	a trust established by OPG pursuant to the *Nuclear Fuel Waste Act* (Canada) for the purpose of funding the implementation of Canada's long-term nuclear fuel waste management plan.
operating reserve	the capacity that can be called upon on short notice by the IESO to replace scheduled energy supply that is unavailable as a result of an unexpected outage or to augment scheduled energy as a result of unexpected demand or other contingencies.
reactive support	the control and maintenance of prescribed voltages on the IESO-controlled grid.
refurbishment	the work needed to extend the life of a reactor unit by replacing the major life-limiting components (such as pressure tubes, steam generators, etc).
Shareholder	the sole shareholder of OPG, the Province of Ontario.
surplus baseload generation	a condition that occurs when electricity generation from baseload facilities is greater than the electricity market demand.
tonne	1,000 kilograms or 2,204.6 pounds.
tritium	a radioactive substance that is created within CANDU reactors as a result of heavy water in the reactor moderator and heat transport systems.
TWh	a terawatt hour, equal to 1,000,000 MWh.
unit	an electrical generator, together with its driving turbine and auxiliary equipment.
watt	a scientific unit of electric power representing the rate of work of one joule per second.

APPENDIX A

ONTARIO POWER GENERATION INC.

AUDIT AND RISK COMMITTEE CHARTER

Audit and Risk Committee Charter

Purpose

The function and purpose of the Audit and Risk Committee is to assist the Board of Directors in their responsibility for oversight of matters relating to:

1. The integrity of OPG's financial statements and reporting
2. The integrity and adequacy of internal controls and standards of Codes of Conduct and ethics
3. The performance of OPG's internal audit function
4. The performance and independence of OPG's external auditors
5. Business and financial planning
6. The performance of OPG's pension, nuclear decommissioning, and used fuel investment funds
7. OPG's Enterprise Risk Management
8. Assessment of committee performance and board policies.

Management is responsible for the preparation, presentation and integrity of OPG's interim and annual financial statements and related disclosure documents. Management is responsible for maintaining appropriate accounting and financial reporting principles and policies and systems of internal and disclosure controls and procedures to comply with accounting standards and applicable laws and regulations which

provide reasonable assurance that the assets of the Company are safeguarded and transactions are authorized, executed, recorded and properly reported.

Management is also responsible for the identification, assessment, monitoring, and management of the risks to achieving OPG's strategic and business plan objectives and the development and implementation of policies and procedures to respond to such risks.

The Committee's role is to provide oversight that ensures the Company's assets are protected and safeguarded within reasonable business limits and report such to the Board.

Committee Responsibilities and Duties

The Committee shall perform the duties set out in this Charter and shall perform such other duties as may be necessary or appropriate under applicable law or securities rules, or as may be delegated to the Committee by the Board from time to time.

1. *The integrity of OPG's financial statements and reporting*

   The Committee reviews and makes recommendations to the Board with respect to:

   a) appointment or replacement of the Chief Financial Officer.

   b) OPG's annual financial statements and external audit report, including financial statements, MD&A, related footnotes and any documentation required by the Securities Act to be prepared and filed by OPG or that OPG otherwise files with securities regulators.

   c) OPG's Annual Information Form, if required, prior to filing with securities regulators.

   The Committee reviews and approves:

   d) OPG's quarterly financial statements and interim financial information and disclosures in the Management Discussion and Analysis (MD&A) and earnings press release, prior to filing.

   In carrying out its responsibilities for oversight of the integrity of OPG's financial statements and reporting the Committee will include in its review:

   e) Adequacy of procedures in place for the review of OPG's public disclosure of financial information extracted or derived from OPG's financial statements.

   f) significant accounting principles and reporting issues and impact on the financial statements, including complex or unusual transactions, highly judgmental areas, major issues regarding or changes to OPG's selection/application of accounting principles, financial presentations, the effect of regulatory and accounting initiatives, as well as off-balance sheet arrangements on OPG's financial statements.

   g) analysis prepared by Management and/or the external auditor detailing financial reporting issues and judgments made in connection with the preparation of financial information, including analysis of the effects of alternative generally accepted accounting principles methods.

   h) whether any other matters related to conduct have come to the Committee's attention that causes it to believe that the financial statements contain an untrue statement of material fact or omit to state a necessary material fact.

2. *Integrity and adequacy of Internal Controls and standards of Codes of Conduct and ethics*

In carrying out its responsibilities for the integrity and adequacy of internal controls, including compliance with legal and regulatory requirements and standards of codes of conduct and ethics, the Committee reviews:

a) legal, tax, or regulatory matters that may have a material impact on OPG's operations and the financial statements, including, but not limited to, violations of securities law or breaches of fiduciary duty.

b) the scope of review of internal control over financial reporting, significant findings, recommendations and Management's responses for implementation of actions to correct weaknesses in internal controls.

c) disclosures made by the Chief Executive Officer and Chief Financial Officer during the certification process regarding significant deficiencies in the design or operation of internal controls or any fraud that involves Management or other employees who have a significant role in OPG's internal controls.

d) procedures for the receipt, recording and treatment of complaints received by OPG regarding accounting, internal accounting controls, or auditing matters, and procedures for the confidential and anonymous submission by OPG employees of concerns regarding accounting or auditing matters.

e) expenses of the Board Chair, Board of Directors, President/CEO and the President/CEO's direct reports on an annual basis, and of any other senior officers and employees the Committee considers appropriate.

f) reports from the Chief Ethics Officer on independent reviews and investigations of fraud allegations, matters that may involve fraud and/or Codes of Conduct violations and compliance.

3. *Performance of OPG's internal audit function*

The Committee reviews and makes recommendations to the Board with respect to:

a) Appointment or replacement of the Chief Risk and Audit Executive.

The Committee reviews and approves:

b) The annual internal audit plan and all major changes to the plan, including the organizational structure, budget and the adequacy of resources.

c) the charter of the internal audit function triennially.

In carrying out its responsibilities for the performance of OPG's internal audit function the Committee reviews:

d) results of Internal audit reports, including: significant findings, the adequacy of the control processes, Management's response and the timetable for implementation of Management actions

to correct weaknesses, any difficulties encountered in the course of their work (such as restrictions on the scope of their work or access to information).

e) Internal Audit's confirmation of organizational independence and disclosure of any conflict of interest.

f) Internal Audit performance relative to the annual internal audit plan.

4. *Performance and Independence of External Auditor*

The Committee reviews and makes recommendations to the Board with respect to:

a) the external auditor to be annually appointed on behalf of the Shareholder and related compensation, including results of a cyclical performance review, and a comprehensive review of the external audit firm at least once every five years.

The Committee reviews and approves:

b) pre-approval of additional audit services and fees to be provided by the external auditors if such services are required further to the annual compensation approved by the Board. The Committee may delegate such pre-approval authority to the Committee Chair up to a limit of $250,000. Any decisions of the Committee Chair to whom pre-approval authority is delegated must be presented to the full Audit and Risk Committee at its next scheduled meeting.

In carrying out its responsibilities for the performance and independence of OPG's external audit function the Committee reviews:

c) the work and report of the external auditor engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for OPG, including the resolution of disagreements between Management and the external auditor regarding financial reporting.

d) the independence and qualifications of the external auditor.

e) the annual report by the external auditor describing the auditing firm's internal quality control procedures, any material issues raised by the most recent internal quality-control review or peer review of the auditing firm or by any inquiry or investigation by governmental or professional authorities within the preceding five years respecting one or more independent audits carried out

by the external auditor and any steps taken to deal with any such issues and all relationships between the external auditors and OPG.

f) scope and approach of the annual audit plan with the external auditors.

g) quality and acceptability of OPG's accounting principles including all critical accounting policies and practices used, any alternative treatments that have been discussed with Management as well as any other material communications with Management.

h) external auditor's process for identifying and responding to key audit and internal control risks.

i) rotation of the lead audit partner and other audit partners every seven years, and consider regular rotation of the audit firm.

j) all related-party transactions.

k) OPG's hiring policies regarding partners, employees and former partners and employees of the present and former external auditor of OPG.

5. *Business and Financial Planning*

The Committee reviews and makes recommendations to the Board on:

a) OPG's business plan, including overall financing plan in support of the Company's capital expenditures and medium – long term forecast.

b) OPG's rate applications to the Ontario Energy Board, including proposed payment amounts and any agreement arising from a Settlement Conference with intervenors.

c) corporate financing vehicles, credit facilities, including any plans to access capital debt markets and other related financing activities. The Board may delegate to an officer of the company authority to enter into such financing activities in such a manner as the Board shall determine at the time of

such delegation. Any decisions of the officer to whom authority is delegated must be presented to the full Audit and Risk Committee at its next scheduled meeting.

6. *Pension, Nuclear Decommissioning and Used Fuel Investment Funds*

The Committee reviews and makes recommendations to the Board on:

a) the appointment or replacement of the Chief Investment Officer.

b) the appointment of the auditor for the OPG Pension Fund and the Used Fuel Segregated Fund and Decommissioning Segregated Fund.

c) the broad objectives, governance frameworks and risk posture for the OPG Pension Fund and the Used Fuel Segregated Fund and Decommissioning Segregated Fund and annual status report on these Funds.

d) the tri-ennial valuation of the Pension Fund and annual valuation of the Supplementary Employee Retirement Pension Plans. (The Committee provides advice to the Compensation, Leadership and Governance Committee on the affordability of proposed pension benefit changes.)

The Committee reviews and approves:

e) the appointment of the members of OPG's Pension Committee. In addition, the Committee may, at any time, remove or replace any member of the Pension Committee or fill a vacancy on the Pension Committee. The Pension Committee Chair may temporarily appoint a senior management

employee to fill a vacancy on the Pension Committee until the next regularly scheduled Audit and Risk Committee meeting.

f) the annual audited financial statements for the OPG Pension Fund, the Used Fuel Segregated Fund and the Decommissioning Segregated Fund.

g) the investment policies and procedures, including the design of modifications, for the OPG Pension Fund, as required by the Ontario Pension Benefits Act and its regulations, and for the Decommissioning Segregated Funds, as required by the Ontario Nuclear Funds Agreement.

h) the appointment of the Pension Plan actuary.

In carrying out its responsibilities for the oversight of financial planning and investment funds the Committee reviews:

i) reports on a quarterly, annual or by exception basis, on compliance with and appropriateness of the asset mix policy; total fund and asset class returns relative to benchmarks; material compliance with breaches of policies or procedures; and work conducted by the plan actuary.

j) periodic reports on the calculation of OPG's nuclear waste liability.

7. *OPG's Enterprise Risk Management*

The Committee reviews and makes recommendations to the Board on:

a) the appointment or replacement of the Chief Risk and Audit Executive.

b) the Company's enterprise risk policy, framework, overall risk appetite and targets.

In carrying out its responsibilities for oversight of OPG's Enterprise Risk Management the Committee reviews:

c) the processes employed by Management for identifying and assessing the Company's principal risks.

d) periodic reports on Management's assessment of the principal risks to achieving the Company's strategic and business plan objectives, and the strategies for monitoring, managing and responding to those risks.

e) periodic reports on significant emerging and evolving risks and relevant external events that could potentially impact OPG's risk profile.

f) compliance metrics related to OPG's commercial operations trading, treasury, and fuels management.

g) regular reports on OPG's cyber security position and programs.

h) periodic reports on OPG's Insurance Program.

8. *Assessment of committee performance and board policies*

In carrying out its responsibilities for assessment of committee performance and board policies the Committee shall:

a) Review and assess Committee performance, including a review of the adequacy of and its compliance with this Charter, in accordance with the evaluation process approved by the Board and taking into account all legislative and regulatory requirements applicable to the Committee as well as any best practice guidelines recommended by regulators with whom OPG has a reporting relationship.

b) Provide oversight of the implementation of the following Board of Directors' policies, and review these policies at least annually (or as otherwise noted below) to ensure their continuing adequacy:

   i. Delegation and Exercise of Authority Policy
   ii. Disclosure Policy
   iii. Code of Business Conduct and Supplier Code of Conduct, including anti-bribery and corruption
   iv. Enterprise Risk Management Policy (reviewed every three years)
   v. Cyber Security Policy

c) Provide oversight of the development of any new policies deemed necessary by the Committee.

Organization

Members

The Audit and Risk Committee shall consist of three or more Directors as determined by the Board of Directors. All members of the Committee shall be independent as defined by the Ontario Securities Commission, and not "affiliated" with OPG.

The Board shall appoint the members of the Committee and the Chair of the Committee annually. The Board may appoint a member to fill a vacancy which occurs in the Committee between annual elections of Directors. Any member of the Committee may be removed or replaced at any time by the Board.

If a member of the Committee becomes "affiliated" with OPG, the member may continue as a member of the Committee with the approval of the Board Chair, in consultation with the Corporate Secretary.

As a "venture issuer", OPG is exempt from the statutory requirements of National Instrument 52-110 requiring members of Audit Committees be independent and financially literate. However, OPG considers such independence and financial literacy to be "best practice" and therefore each of the members of the Audit and Risk Committee shall satisfy the applicable independence and financial literacy requirements of the laws and regulations governing Audit Committees.

The Board of Directors shall confirm that each member of the Audit and Risk Committee is financially literate; as such qualification is interpreted by the Board of Directors in its business judgment, and in compliance with National Instrument 52-110 and its Companion Policy.

Meetings

The Committee shall meet as frequently as it determines but not less than quarterly. During quarterly meetings, the Committee will hold separate in camera sessions with the external auditors, the Chief Internal Audit Executive, the Chief Risk Officer and Management to discuss any matters that the Committee believes should be discussed and to provide a forum for any relevant issues to be raised.

Notice of the time and place of each meeting of the Committee must be given to each member of the Committee not less than 48 hours before the time of the meeting.

A quorum of the Committee shall be a majority of its members, but not less than two. The powers of the Committee may be exercised at a meeting at which a quorum of the Committee is present in person or by

telephone or other electronic means, or by a resolution signed by all members entitled to vote on that resolution at a meeting of the Committee. Each member is entitled to one vote in Committee proceedings.

The Chair shall preside at all meetings of the Committee at which he or she is present (or if not able to be present designate another member of the Committee to chair the meeting) and shall develop the agenda for each Committee meeting. The agenda for each meeting of the committee shall be delivered to each member of the Committee at least 48 hours prior to any meeting of the Committee, together with such other materials as the chair determines necessary.

Minutes shall be kept of all meetings of the Committee and shall be maintained by OPG's Corporate Secretary. The procedure at meetings is to be determined by the Committee unless otherwise determined by the by-laws of OPG, by a resolution of the Board or by this Charter.

The Committee may meet in camera (without management present) at any time during the meeting consistent with the Board guideline on the conduct of in camera sessions and the keeping of minutes from in camera sessions.

The Committee may invite any Director, officer or employee of OPG or OPG's counsel or any other person to attend meetings of the Committee to assist in the discussion and examination of the matters under consideration by the Committee.

Reports

The Committee will report its activities and actions to the Board of Directors with recommendations, as the Committee deems appropriate.

The Committee will provide for inclusion in OPG's financial information or regulatory filings any report from the Audit and Risk Committee required by applicable laws and regulations and stating among other things whether the Committee has:

i. Reviewed and discussed the audited financial statements with Management.
ii. Discussed pertinent matters with the internal and external auditors.
iii. Received disclosures from the external auditors regarding the auditors' independence and discussed with the auditors their independence.
iv. Recommended to the Board of Directors that the audited financial statements be included in OPG's Annual Report.

Authority

The Audit and Risk Committee shall have the authority to:

a) conduct or authorize investigations into any matters within the Committee's scope of responsibilities.

b) set and pay the compensation for any advisors employed by the Committee.

c) to communicate directly with the internal and external auditors.

While the Audit and Risk Committee has the responsibilities and powers set forth in this Charter, it is not the duty of the Audit and Risk Committee to plan or conduct audits or risk assessments, or to determine that OPG's financial statements and disclosures are complete and accurate and are in accordance with

generally accepted accounting principles and applicable rules and regulations. These are the responsibility of Management and, as appropriate, the external auditor.

Delegation of Authority

The Committee may not delegate its oversight responsibilities. The Committee may delegate to a sub-committee, the Chief Executive Officer or any employee of OPG the authority to exercise any right, power or responsibility that the Committee may have on such terms and conditions and within such limits as the Committee deems appropriate provided that the sub-committee, Chief Executive Officer or employee subsequently advises the Committee of any right, power or responsibility so exercised.

Access to Management and Outside Advisors

The Audit and Risk Committee shall have unrestricted access to members of Management and relevant information.

The Audit and Risk Committee has the authority to retain legal counsel, accountants or other advisors to assist it in the conduct of any investigation, as it determines necessary to carry out its duties.

ONTARIO POWER GENERATION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

DECEMBER 31, 2017

[DRAFT]

2017 YEAR-END REPORT

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ONTARIO POWER GENERATION INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) should be read in conjunction with the audited consolidated financial statements and accompanying notes of Ontario Power Generation Inc. (OPG or Company) as at and for the year ended December 31, 2017. OPG's consolidated financial statements are prepared in accordance with United States generally accepted accounting principles (US GAAP) and are presented in Canadian dollars.

As required by *Ontario Regulation 395/11*, as amended, a regulation under the *Financial Administration Act* (Ontario) (FAA), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. In 2014, the Ontario Securities Commission (OSC) approved an exemption which allows OPG to apply US GAAP up to January 1, 2019. The term of the exemption is subject to certain conditions, which may result in the expiry of the exemption prior to January 1, 2019. For details, refer to the section, *Critical Accounting Policies and Estimates* under the heading, *Exemptive Relief for Reporting under US GAAP*. This MD&A is dated March 8, 2018.

FORWARD-LOOKING STATEMENTS

The MD&A contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could", and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

All forward-looking statements involve inherent assumptions, risks, and uncertainties, including those set out in the section, *Risk Management,* and forecasts discussed in the section, *Core Business, Strategy, and Outlook.* All forward-looking statements could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's generating station performance and availability, fuel costs, surplus baseload generation (SBG), cost of fixed asset removal and nuclear waste management, performance and earnings of investment funds, refurbishment of existing facilities, development and construction of new facilities, pension and other post-employment benefit (OPEB) obligations and funds, income taxes, proposed new legislation, the ongoing evolution of Ontario's electricity industry, environmental and other regulatory requirements, health, safety and environmental developments, business continuity events, the weather, financing and liquidity, applications to the Ontario Energy Board (OEB) for regulatory prices, the impact of regulatory decisions by the OEB, Ontario's Fair Hydro Plan (Fair Hydro Plan or the Plan) and forecasts of earnings, cash flows, Funds from Operations (FFO) Adjusted Interest Coverage, Return on Common Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI), Total Generating Cost (TGC) and capital expenditures. Accordingly, undue reliance should not be placed on any forward-looking statement. The forward-looking statements included in this MD&A are made only as of the date of this MD&A. Except as required by applicable securities laws, OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events, or otherwise.

THE COMPANY

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG was established under the *Business Corporations Act* (Ontario) (OBCA) and is wholly owned by the Province of Ontario (Province or Shareholder).

As at December 31, 2017, OPG's electricity generation portfolio had an in-service capacity of 16,210 megawatts (MW). OPG operates two nuclear generating stations, 66 hydroelectric generating stations, three thermal generating stations, and one wind power turbine. In addition, OPG and TransCanada Energy Ltd. co-own the 550 MW Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS). OPG and ATCO Power Canada Ltd. co-own the 560 MW Brighton Beach gas-fired combined cycle GS (Brighton Beach). OPG's 50 percent share of the in-service capacity and generation volume of these co-owned facilities is included in the generation portfolio statistics set out in this report. The income from the co-owned facilities is accounted for using the equity method of accounting, and OPG's share of income is presented as income from investments subject to significant influence in the Contracted Generation Portfolio segment.

OPG also owns two other nuclear generating stations, the Bruce A GS and the Bruce B GS, which are leased on a long-term basis to Bruce Power LP (Bruce Power). Income from these leased stations is included in revenue under the Regulated – Nuclear Generation segment. The leased stations are not included in the generation portfolio statistics set out in this report.

All of OPG's owned and co-owned generating facilities are located in Ontario. OPG does not operate PEC, Brighton Beach, the Bruce A GS and the Bruce B GS.

OPG's Reporting Structure

Effective in the fourth quarter of 2017, following the establishment of the Fair Hydro Trust (the Trust) as the financing entity to implement the Fair Hydro Plan under the *Ontario Fair Hydro Plan Act, 2017* (the Fair Hydro Act or the Act), OPG has modified its reportable business segments to include the Fair Hydro Trust segment. Through its control over the key activities of the Trust and its obligation to absorb losses through ownership of the Trust's subordinated debt, the Company consolidates the financial results of the Trust in accordance with US GAAP. The Fair Hydro Trust segment reports the income related to OPG's role as Financial Services Manager under the Act and holder of subordinated debt issued by the Trust, including the financial results of the Trust. The Fair Hydro Plan and the Fair Hydro Trust are discussed in the section, *Recent Developments* and in the section, *Core Business, Strategy, and Outlook* under the heading, *Business Segments*.

The composition of OPG's reportable business segments is as follows:

- Regulated – Nuclear Generation
- Regulated – Nuclear Waste Management
- Regulated – Hydroelectric
- Contracted Generation Portfolio
- Services, Trading, and Other Non-Generation
- Fair Hydro Trust.

OPG receives regulated prices for electricity generated from most of its hydroelectric facilities and all of the nuclear facilities that it operates (collectively, prescribed facilities or regulated facilities). The regulated facilities comprise 54 hydroelectric generating stations across a number of major river systems in the province, the Pickering Nuclear GS (Pickering GS) and Darlington Nuclear GS (Darlington GS).

The operating results related to these regulated facilities are described under the Regulated – Nuclear Generation, Regulated – Nuclear Waste Management, and Regulated – Hydroelectric segments. For the remainder of OPG's operating generating facilities, the operating results are described under the Contracted Generation Portfolio segment. A description of all OPG's segments is provided under the section, *Business Segments*.

In-Service Generating Capacity

OPG's in-service generating capacity by business segment as of December 31 was as follows:

(MW)	**2017**	**2016**
Regulated – Nuclear Generation [1]	**5,728**	5,728
Regulated – Hydroelectric	**6,426**	6,421
Contracted Generation Portfolio [2]	**4,056**	4,028
Total	**16,210**	16,177

[1] The in-service generating capacity as of December 31, 2017 and December 31, 2016 excludes Unit 2 of the Darlington GS. The unit, which has a generating capacity of 878 MW, was taken offline in mid-October 2016 and is currently undergoing refurbishment.

[2] Includes OPG's share of in-service generating capacity of 275 MW for PEC and 280 MW for Brighton Beach.

The total in-service capacity as at December 31, 2017 increased by 33 MW compared to 2016. The increase was primarily due to the completion of the 28 MW Peter Sutherland Sr. hydroelectric GS, which was placed in-service in the first quarter of 2017, and the upgrade of Unit 10 of the Sir Adam Beck 1 hydroelectric GS, which was completed in June 2017. Further details on the Peter Sutherland Sr. GS project are found in the section, *Core Business, Strategy, and Outlook* under the heading, *Project Excellence*.

REVENUE MECHANISMS FOR REGULATED AND NON-REGULATED GENERATION

Regulated Generation

The OEB sets the prices for electricity generated from OPG's regulated nuclear and regulated hydroelectric facilities. The following table presents the OEB-authorized regulated prices for electricity generated from these facilities during the periods from January 1, 2016 to May 30, 2017, as well as new regulated prices retrospectively effective June 1, 2017 that OPG has calculated and submitted to the OEB, based on the OEB's decision on OPG's 2017-2021 application for new regulated prices issued on December 28, 2017:

($/MWh)	2017		2016
	January 1 to May 31	**June 1 to December 31** [1]	
Regulated – Nuclear Generation			
Base regulated price	**59.29**	**80.65**	59.29
Variance and deferral account rate rider	**-**	**-**	10.84 [2]
	59.29	**80.65**	70.13
Regulated – Hydroelectric			
Base regulated price	**40.72**	**41.67**	40.72
Variance and deferral account rate rider	**-**	**-**	3.19 [2]
	40.72	**41.67**	43.91

[1] Regulated prices for the June 1, 2017 to December 31, 2017 period were calculated and submitted to the OEB by OPG in January 2018 based on the OEB's December 28, 2017 decision on OPG's 2017-2021 application for new regulated prices. The final regulated prices will be determined by the OEB as part of the final payment amounts order process, which is expected to be completed in the first half of 2018. As part of the process, the OEB is expected to authorize separate rate riders to allow for the recovery of the shortfall between the new regulated prices and the previous regulated prices that OPG continues to receive during the period between June 1, 2017 and the implementation date of the new regulated prices pending the issuance of the final payment amounts order. The incremental revenue for the period between June 1, 2017 and December 31, 2017 arising from this retrospective application of new regulated prices was accrued in 2017. **[MONITOR]**

[2] The OEB authorized interim period rate riders for the period from October 1, 2015 to December 31, 2016 to allow for the recovery of the riders effective July 1, 2015 for the period from July 1, 2015 to September 30, 2015. The nuclear interim period rate rider was $2.17 per megawatt hour (MWh) and the regulated hydroelectric interim period rate rider was $0.64/MWh. These interim period rate riders have not been included in the above table. All rate riders in effect during 2016 expired on December 31, 2016.

Based on the OEB's December 2017 decision, the new base regulated prices are determined on an incentive ratemaking methodology for the hydroelectric operations and under a custom incentive regulation framework for the nuclear operations. For the hydroelectric facilities, the new base regulated price is determined using a formula that annually escalates the previous regulated prices, subject to some adjustments, based on inflation less a stretch factor to incent additional innovation and efficiency. For the nuclear facilities, the new regulated price is determined under a rate smoothing approach that defers a portion of the approved nuclear revenue requirement for future collection, with the aim of making more stable changes in OPG's production-weighted regulated prices year over year. The nuclear revenue requirement is based on the OEB-approved forecasts of operating costs as reduced by a stretch factor and a return on rate base. Rate base for OPG represents the average net level of investment in regulated fixed and intangible assets in service and an allowance for working capital. The OEB's December 2017 decision and OPG's new regulated prices are discussed further in the section, *Recent Developments*.

The base regulated prices in effect during 2016 were established by the OEB's November 2014 decision and December 2014 order, effective November 1, 2014, using a forecast cost-of-service methodology based on the OEB-approved revenue requirements for the 2014 to 2015 period, taking into account the OEB-approved forecasts of production and operating costs for the regulated facilities and a return on rate base.

The increase in base regulated prices for the Regulated – Nuclear Generation segment from those last approved in 2014 is impacted by lower production for Darlington GS for the duration of Unit 2's refurbishment. The increase also

reflects OPG's ability to earn a return on higher in-service capital and recover costs to enable Pickering to operate beyond 2020 in line with the Long-Term Energy Plan (LTEP).

Rate riders for OPG are typically established to recover or repay approved balances in OEB-authorized regulatory variance and deferral accounts (regulatory accounts). Variance and deferral accounts typically capture, for subsequent review and approval, differences between actual costs and revenues and the corresponding forecast amounts approved by the OEB in setting regulated prices, or record the impact of items not reflected in the approved regulated prices. The rate riders in effect to the end of 2016 were established by the OEB's October 2015 order on OPG's 2014 application to recover the December 31, 2014 variance and deferral account balances. Revenue received from the recovery of variance and deferral account balances is largely offset by amortization expense related to these balances.

Non-Regulated Generation

Electricity generated from most of OPG's non-regulated assets is subject to Energy Supply Agreements (ESAs) with the Independent Electricity System Operator (IESO).

During 2017, ESAs were in effect for the following thermal generating facilities:

- Lennox GS: Capacity and production provided by the station are subject to an ESA for the period from January 1, 2013 to September 30, 2022
- Atikokan GS: Capacity and production provided by the station are subject to a ten-year ESA expiring in July 2024
- Thunder Bay GS: Capacity and production provided by the station are subject to a five-year ESA expiring in January 2020.

In addition, long-term hydroelectric ESAs are in place for the following facilities, with expiry dates ranging from 2059 to 2067:

- Lac Seul and Ear Falls generating stations
- Healey Falls GS
- Sandy Falls, Wawaitin, Lower Sturgeon, and Hound Chute generating stations
- Little Long, Harmon, Smoky Falls, and Kipling generating stations (collectively the Lower Mattagami River generating stations)
- Peter Sutherland Sr. GS, which was placed in-service in March 2017.

HIGHLIGHTS

Overview of Results

This section provides an overview of OPG's operating results for the years ended December 31, 2017 and December 31, 2016.

(millions of dollars – except where noted)	**2017**	**2016**
Revenue	**5,158**	5,653
Fuel expense	**689**	727
Gross margin	**4,469**	4,926
Operations, maintenance and administration	**2,824**	2,747
Depreciation and amortization	**679**	1,257
Accretion on fixed asset removal and nuclear waste management liabilities	**960**	929
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(801)**	(746)
Earnings from Fair Hydro Trust	**(1)**	-
Income from investments subject to significant influence	**(38)**	(37)
Property taxes	**40**	46
Restructuring	**-**	6
	3,663	4,202
Income before other gains, interest, and income taxes	**806**	724
Other gains	**379**	17
Income before interest and income taxes	**1,185**	741
Net interest expense	**95**	120
Income before income taxes	**1,090**	621
Income tax expense	**209**	168
Net income	**881**	453
Net income attributable to the Shareholder	**860**	436
Net income attributable to non-controlling interest [1]	**21**	17
Electricity production (TWh) [2]	**74.1**	78.2
Cash flow		
Cash flow provided by operating activities	**944**	1,817

[1] Relates to the 25 percent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in the Lower Mattagami Limited Partnership, the 33 percent interest of Coral Rapids Power Corporation (CRP), a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership (PSS), and the 10 percent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP. CRP increased its partnership interest to 33 percent in April 2017.

[2] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach and excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS was excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

Net income attributable to the Shareholder was $860 million for 2017, representing an increase of $424 million compared to 2016. Income before interest and income taxes was $1,185 million for 2017, representing an increase of $444 million compared to 2016. The following summarizes the significant factors which contributed to the variance:

Significant factors that increased income before interest and income taxes:

- Higher revenue from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments of approximately $480 million recorded in the fourth quarter of 2017 to reflect the OEB's decision on OPG's application for new regulated rates issued in December 2017 with a retrospective effective date of June 1,

2017. This revenue increase for the June 1, 2017 to December 31, 2017 period was recorded as an increase in regulatory assets, based on new regulated prices for that period proposed in OPG's January 2018 submission to the OEB based on the findings in the December 2017 decision, net of a regulatory liability recognized in relation to OPG's nuclear rate smoothing proposal included in that submission. The new regulated prices, the future collection period for the retrospective revenue increase, and the rate smoothing proposal are pending the OEB's approval through the payment amounts order process, which typically follows the OEB's issuance of a decision on a major rates application. The OEB's approval of the final payment amounts order, including determinations on the new regulated prices and rate smoothing, are not expected to have a material impact on the total revenue recorded for the June 1, 2017 to December 31, 2017 period. The OEB is expected to issue the final payment amounts order in the first half of 2018. **[MONITOR]**

- Higher earnings of $377 million from the Services, Trading, and Other Non-Generation segment, primarily as a result of the gain on sale of OPG's head office premises and associated parking facility, a non-core asset of the business. A gain on sale of $283 million, which is net of tax effects of $95 million, was recognized in net income upon completion of the transaction in the second quarter of 2017. The sale was undertaken pursuant to a Shareholder Declaration and a Shareholder Resolution. Further details can be found under the heading, *Recent Developments – Shareholder Declarations and Shareholder Resolutions to Sell Certain Non-Core Real Estate Properties*.
- Higher earnings of $24 million from the Regulated – Nuclear Waste Management segment, primarily due to higher earnings from the nuclear fixed asset removal and nuclear waste management funds (Nuclear Segregated Funds), partially offset by an increase in accretion expense on the nuclear fixed asset removal and nuclear waste management liabilities (Nuclear Liabilities).

Significant factors that reduced income before interest and income taxes:

- Lower revenue of approximately $285 million, partially offset by a decrease in fuel expense of $31 million, reflecting lower electricity generation of 4.9 terawatt hours (TWh) from the Regulated – Nuclear Generation segment. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS since October 2016, partially offset by an increase in generation from the Pickering GS. The increase in generation from the Pickering GS was primarily due to outage cycle optimization, favourable unit conditions and execution of planned outage work resulting in fewer unplanned and planned outage days at the station.
- Higher operations, maintenance and administration (OM&A) expenses of $77 million, mainly in the Regulated – Nuclear Generation segment, reflecting planned expenditures related to the major maintenance activities occurring at the nuclear stations.
- Higher depreciation and amortization expense of $22 million in the Regulated – Nuclear Generation segment, excluding amortization expense related to balances in regulatory accounts, primarily due to new assets in service.
- A gain of $22 million recorded in the first quarter of 2016 to reflect the OEB's decision on OPG's motion asking the OEB to review and vary parts of its November 2014 decision on OPG's regulated prices.

The expiry of rate riders for the recovery of OEB-approved balances in regulatory accounts on December 31, 2016 contributed to the decrease in revenue in 2017, compared to 2016, but was largely offset by a decrease in the amortization expense related to regulatory account balances.

Net interest expense decreased by $25 million in 2017, compared to 2016, primarily due to a higher amount of interest costs capitalized for the Darlington Refurbishment project.

Income tax expense increased by $41 million in 2017, compared to 2016, primarily due to higher income before income taxes, partially offset by a higher amount of income tax expense deferred in regulatory assets in 2017.

Segment Results

The following table summarizes OPG's income before interest and income taxes by business segment. Significant factors which contributed to the higher income during 2017, compared to 2016, are discussed above. A detailed discussion of OPG's performance by reportable segment is included in the section, *Discussion of Operating Results by Business Segment*.

(millions of dollars)	**2017**	**2016**
Income (loss) before interest and income taxes		
Regulated – Nuclear Generation	**57**	4
Regulated – Hydroelectric	**614**	642
Contracted Generation Portfolio	**300**	282
Total electricity generation business segments	**971**	928
Regulated – Nuclear Waste Management	**(150)**	(174)
Services, Trading, and Other Non-Generation	**364**	(13)
Fair Hydro Trust	**-**	-
	1,185	741

Electricity Generation

Electricity generation for 2017 and 2016 was as follows:

(TWh)	**2017**	**2016**
Regulated – Nuclear Generation	**40.7**	45.6
Regulated – Hydroelectric	**30.7**	29.5
Contracted Generation Portfolio [1]	**2.7**	3.1
Total OPG electricity generation	**74.1**	78.2
Total electricity generation by other generators in Ontario [2]	**70.5**	72.7

[1] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

[2] Non-OPG generation is calculated as the Ontario electricity demand plus net exports, as published by the IESO, minus OPG electricity generation.

Total OPG electricity generation decreased by 4.1 TWh in 2017, mainly due to lower electricity generation of 4.9 TWh from the Regulated – Nuclear Generation segment. As expected, this was primarily the result of the removal from service of Unit 2 at the Darlington GS for the duration of the unit's refurbishment, which began in October 2016. This decrease in electricity generation was partially offset by an increase in generation from the Pickering GS, primarily due to outage cycle optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of outage days at the station, as well as higher electricity generation from the Regulated – Hydroelectric segment.

The higher electricity generation from the Regulated – Hydroelectric segment in 2017 was due to higher water flows primarily on the eastern Ontario river systems, net of forgone electricity generation as a result of SBG conditions, discussed below.

The lower electricity generation from the Contracted Generation Portfolio segment was primarily due to higher SBG conditions.

OPG's operating results are affected by changes in grid-supplied electricity demand resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. Ontario's electricity demand as reported

by the IESO was 132.1 TWh in 2017 and 137.0 TWh and 2016, respectively, which excludes electricity exports out of the province.

Power that is surplus to the Ontario market is managed by the IESO, mainly through generation reductions at hydroelectric and nuclear stations and other grid-connected renewable resources. Reducing hydroelectric production is a measure used by the IESO to manage SBG conditions. Baseload generation supply surplus in Ontario was more prevalent in 2017 than in 2016, mainly due to higher water flows and reduced electricity demand in the province during 2017. During 2017 and 2016, OPG lost 5.9 TWh and 4.7 TWh of hydroelectric generation due to SBG conditions, respectively. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions in 2017 and 2016 was offset by the impact of a regulatory variance account authorized by the OEB. OPG did not forgo any electricity production at its nuclear stations due to SBG conditions.

Average Sales Prices

The majority of OPG's generation is from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments. The regulated prices authorized by the OEB for electricity generated from OPG's nuclear and regulated hydroelectric generating stations are discussed in the section, *Revenue Mechanisms for Regulated and Non-Regulated Generation*.

The average sales price for the Regulated – Nuclear Generation segment during 2017 was 7.1 cents per kilowatt hour (¢/kWh), compared to 6.9 ¢/kWh during 2016. The increase in this average sales price was primarily due to an increase in revenue for the period June 1, 2017 to December 31, 2017 recorded in the fourth quarter of 2017 to reflect the OEB's December 2017 decision on OPG's application for new regulated prices, with an effective date of June 1, 2017. The increase was partially offset by the expiry of an OEB-authorized nuclear rate rider of $10.84 per MWh, on December 31, 2016, for the recovery of variance and deferral account balances. The average sales price for the Regulated – Hydroelectric segment during 2017 was 4.2 ¢/kWh, compared to 4.4 ¢/kWh during 2016. The decrease in this average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized regulated hydroelectric rate rider of $3.19/MWh for the recovery of variance and deferral account balances, partially offset by the impact of an increase in revenue for the period June 1, 2017 to December 31, 2017 recorded in the fourth quarter of 2017 to reflect the OEB's December 2017 decision. The rate riders that expired on December 31, 2016 were established to recover approved balances recorded in the variance and deferral accounts in prior years. As such, the year-over-year changes in revenue from the rate riders were largely offset by changes in amortization expense related to these balances.

Cash Flow from Operations

Cash flow provided by operating activities for 2017 was $944 million, compared to $1,817 million for 2016. The decrease in cash flow provided by operating activities was expected and primarily due to lower generation revenue receipts reflecting lower generation from the Regulated – Nuclear Generation segment as a result of the ongoing refurbishment of Unit 2 at the Darlington GS and the expiry, on December 31, 2016, of the OEB-authorized rate riders for nuclear and regulated hydroelectric generation. The decrease in cash flow was also due to higher income tax instalments during 2017, compared to 2016.

The decrease in cash flow provided by operating activities was partly offset by lower contributions to the Used Fuel Segregated Fund in 2017. Both the Used Fuel Segregated Fund and the Decommissioning Segregated Fund were determined to be fully funded based on an updated estimate of OPG's nuclear waste management and nuclear facilities decommissioning obligations pursuant to an Ontario Nuclear Funds Agreement (ONFA) reference plan approved by the Province, effective January 1, 2017. Pursuant to the ONFA, the reference plan is required to be updated at least once every five years. Contributions to either or both of the Nuclear Segregated Funds may be required in the future should the funds be in an underfunded position at the time of the next ONFA reference plan update. The decrease in cash flow compared to the prior year also was partially offset by the payment of a supplemental rent rebate to Bruce Power in the first quarter of 2016 in relation to a period in 2015. The lease

agreement for the Bruce nuclear generating stations was amended in late 2015 to eliminate this rebate provision going forward.

Funds from Operations Adjusted Interest Coverage

FFO Adjusted Interest Coverage is an indicator of OPG's ability to meet interest obligations from operating cash flow. The indicator is measured over a 12-month period. The FFO Adjusted Interest Coverage was 3.3 times for 2017 compared to 5.1 times for 2016. FFO Adjusted Interest Coverage in 2017 reflected a year-over-year decrease in FFO before interest due to lower cash flow provided by operating activities and changes to non-cash working capital balances, offset by the impact of a lower adjusted interest expense due to a decrease in the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets.

The decrease in the excess of interest on pension and OPEB benefit obligations over expected return on pension plan assets in 2017 was primarily due to the change in the method used to estimate the interest cost and service cost component of pension and OPEB costs prospectively adopted as of January 1, 2017. The change in the method is discussed in the section, *Critical Accounting Policies and Estimates* under the heading, *Pension and Other Post-Employment Benefits*.

Return on Common Equity Excluding Accumulated Other Comprehensive Income

ROE Excluding AOCI is an indicator of OPG's performance consistent with the Company's strategy to provide value to the Shareholder. ROE Excluding AOCI is measured over a 12-month period. ROE Excluding AOCI for 2017 was 7.5 percent, compared to 4.2 percent for 2016. ROE Excluding AOCI increased for 2017, compared to 2016, primarily due to higher net income attributable to the Shareholder as a result of the gain on the sale of OPG's head office premises and associated parking facility recorded during the second quarter of 2017 and an increase in revenue for the period June 1, 2017 to December 31, 2017 recorded in the fourth quarter of 2017 to reflect the OEB's December 2017 decision on OPG's application for new regulated prices, with an effective date of June 1, 2017. The increase in net income attributable to the Shareholder was partially offset by the impact of lower nuclear electricity generation reflecting the Unit 2 refurbishment outage at the Darlington GS.

Enterprise Total Generating Cost per Megawatt-Hour

The Enterprise TGC per megawatt-hour (MWh) was $50.66 for the year ended December 31, 2017, compared to $48.45 for the same period in 2016. The increase in Enterprise TGC per MWh was expected and primarily due to lower nuclear electricity generation as a result of the Unit 2 refurbishment outage at the Darlington GS and higher sustaining capital expenditures, partially offset by higher SBG-adjusted hydroelectric electricity generation reflecting higher water flows.

If Unit 2 at the Darlington GS was not currently undergoing refurbishment and had continued to operate in a manner consistent with the performance of the remaining units at the station, adjusting for generation constraints on these units related to the transition of the station toward refurbishment, the Enterprise TGC would have been approximately $4 to $5 per MWh lower for the year ended December 31, 2017. This sensitivity was calculated using the estimated incremental electricity generation and associated fuel cost that are expected to have had resulted in the absence of the refurbishment.

Nuclear Total Generating Cost per Megawatt-Hour

The Nuclear TGC per MWh was $70.95 for the year ended December 31, 2017, compared to $62.30 for the same period in 2016. The increase in Nuclear TGC per MWh was expected and primarily due to the decrease in nuclear electricity generation primarily as a result of the Unit 2 refurbishment outage at the Darlington GS and higher sustaining capital expenditures.

Hydroelectric Total Generating Cost per Megawatt-Hour

The Hydroelectric TGC per MWh was $23.91 for the year ended December 31, 2017, compared to $25.49 for the same period in 2016. The improvement in the Hydroelectric TGC per MWh was primarily due to higher SBG-adjusted hydroelectricity generation reflecting higher water flows.

ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are not measurements in accordance with US GAAP and should not be considered alternative measures to net income, cash flow provided by operating activities, or any other performance measure under US GAAP. OPG believes that these non-GAAP financial measures are effective indicators of its performance and are consistent with the Company's strategic imperatives and related objectives. The definition and calculation of ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are found in the section, *Supplementary Non-GAAP Financial Measures*.

Recent Developments

OEB's Decision on OPG's Application for New Regulated Prices

The OEB's decision on OPG's May 2016 five-year application for new regulated prices for its nuclear and regulated hydroelectric generation was issued on December 28, 2017, following a public hearing process. The OEB set an effective date for OPG's new regulated prices of June 1, 2017. OPG had requested an effective date of January 1, 2017. The decision reflected the terms of an OEB-approved partial settlement agreement reached by OPG and intervenors on a limited set of issues in the first quarter of 2017 (Settlement Agreement). For the first time since OPG's prescribed facilities became subject to rate regulation, the new prices have been determined on an incentive ratemaking methodology for the hydroelectric operations and a custom incentive regulation framework for the nuclear operations.

For the hydroelectric facilities, effective June 1, 2017, the base regulated prices in effect prior to June 1, 2017, with some adjustments, will be escalated for each of years 2017 to 2021 using a formula equal to an industry-specific weighted inflation factor based on indices published annually by the OEB for use in incentive regulation formulas, less a stretch factor adjustment. The OEB accepted OPG's proposal to set the annual stretch factor adjustment at 0.3 percent. Based on the approved formula, the 2017 increase in the base regulated price for the regulated hydroelectric facilities is 1.4 percent as of June 1, 2017 and the 2018 increase is 0.9 percent as of January 1, 2018. For the 2019-2021 period, the base regulated price for the regulated hydroelectric facilities will be determined annually before the beginning of each year using the approved formula and inflation indices published by the OEB.

For the nuclear operations, a revenue requirement is determined for each of the years 2017 to 2021 based on the OEB-allowed level of OPG's forecast operating costs, reduced by a stretch factor amount, as well as a return on rate base determined using OEB's generic prescribed rate of return and an OPG-specific deemed capital structure. OPG has calculated that the findings of the OEB's December 2017 decision with respect to the forecast operating costs, rate base and deemed capital structure for the nuclear generating facilities will result in nuclear revenue requirements totalling $15.9 billion over the five years.

The OEB's findings with respect to the nuclear revenue requirement include approval for inclusion in rate base of in-service amounts related to the Darlington Refurbishment of $5.5 billion by 2021, including $4.8 billion forecast in the first quarter of 2020 upon return to service of Unit 2, $0.4 billion forecast for pre-requisite projects excluding the Heavy Water Storage and Drum Handling Facility (HWSF) over the 2016-2021 period and $0.3 billion for pre-requisite projects placed in service prior to 2016. The OEB is expected to review the HWSF project as part of a future application. In the decision, the OEB concluded that it is appropriate to evaluate OPG's performance on the Darlington Refurbishment project at an overall level rather by individual cost component, with recovery of any increases over the approved in-service amounts subject to a future prudence review. The revenue requirement impact of differences between the approved in-service additions and the actual in-service additions will be recorded in

the Capacity Refurbishment Variance Account authorized by the OEB pursuant to *Ontario Regulation 53/05*. The $4.8 billion forecast in-service amount upon return to service of Unit 2 includes expenditures incurred during the definition and planning phase of the project.

The OEB also approved OPG's requested forecast costs of approximately $292 million for activities to enable Pickering operations beyond 2020 and agreed to inclusion of operating cost and generation impacts associated with continued operation of Pickering in 2021 in nuclear regulated prices. The differences between approved forecast enabling costs for continued Pickering operations and the actual amounts will be recorded in the Capacity Refurbishment Variance Account for future review and disposition by the OEB.

Excluding amounts that otherwise would have been recorded in OEB-authorized regulatory accounts for repayment to, or recovery from, customers in the future, the OEB's decision reduced OPG's proposed five-year nuclear revenue requirement by $0.6 billion. The main adjustments made by the OEB included a reduction of $100 million per year to requested OM&A costs, a reduction of 10 percent per year to forecast non-Darlington refurbishment capital in-service additions entering rate base over the 2017-2021 period, an increase and expansion of the scope of the stretch factor for nuclear costs that further reduced the revenue requirement, and a rejection of OPG's request to increase the equity component of the existing deemed capital structure of 45 percent equity and 55 percent debt. The OEB increased and expanded the annual stretch factor to 0.6 percent to most of OPG's OM&A expenses incurred directly for, or allocated to, the nuclear facilities, as well as to non-Darlington refurbishment capital in-service additions. The stretch factor is applied starting in 2018 and compounds in each year to 2021.

In accordance with *Ontario Regulation 53/05*, the nuclear revenue requirement continues to be adjusted by the amount of OPG's revenues, net of costs, from leasing the Bruce nuclear generating stations to Bruce Power. As directed by the OEB, OPG's revenues and costs related to the Bruce nuclear generating stations continue to be determined in accordance with US GAAP for the purposes of establishing the nuclear revenue requirement and are subject to the Bruce Lease Net Revenues Variance Account in accordance with *Ontario Regulation 53/05*. This includes costs related to the portion of the Nuclear Liabilities associated with the Bruce nuclear generating stations. The OEB's decision maintained the previously approved cost recovery methodology for the costs of the Nuclear Liabilities for the prescribed facilities and for the Bruce facilities, directing OPG to file a future study examining such methodologies jurisdictionally and for OPG's assets specifically. The decision fully incorporated the impacts of the updated estimate of OPG's obligations for nuclear waste management and nuclear facilities decommissioning as at December 31, 2016, including through a new ONFA reference plan effective January 1, 2017 and the change in the Nuclear Liabilities recorded on December 31, 2016.

As proposed by OPG, the OEB set recovery of pension and OPEB costs in the nuclear revenue requirement on the basis of OPG's cash payments for pension and OPEB plans, with differences between pension and OPEB accrual costs and cash payments continuing to be recorded in the Pension & OPEB Cash to Accrual Differential Deferral Account. The regulatory treatment of pension and OPEB costs is discussed further under the heading, *OEB's Report on Regulatory Treatment of Pension and OPEB Costs*.

The OEB accepted all variance and deferral account balances proposed for recovery that were not already accepted as part of the Settlement Agreement, resulting in approval of recovery of $305 million recorded in variance and deferral variance accounts as at December 31, 2015, without adjustments. The Settlement Agreement provided for the continuation of all applicable existing variance and deferral accounts. In addition to the Rate Smoothing Deferral Account discussed below, the OEB established, as of the effective date of the new regulated prices, new variance and deferral accounts to record costs related to implementing the Canadian Nuclear Safety Commission's (CNSC) Fitness for Duty program and to record differences between forecast and actual amount of Scientific Research & Experimental Development investment tax credits attributable to the nuclear facilities.

Consistent with the requirements of *Ontario Regulation 53/05*, OPG's overall production-weighted regulated prices will be smoothed, with a resulting portion of the approved annual nuclear revenue requirements for the 2017-2021 period deferred in the Rate Smoothing Deferral Account for future collection. The non-deferred portion of each year's

nuclear revenue requirement is divided by the OEB-approved forecast of OPG's nuclear electricity generation for the corresponding year to determine the base nuclear regulated price. The OEB approved the nuclear electricity generation forecast as requested by OPG.

As amended in March 2017, *Ontario Regulation 53/05* requires rate smoothing to be applied in a manner that makes changes in OPG's weighted-average nuclear and hydroelectric regulated prices more stable year over year. Previously, the regulation required that rate smoothing be applied with a view of making more stable year-over-year changes in OPG's nuclear regulated prices only. Per the regulation, the deferral account records interest at a long-term debt rate reflecting OPG's cost of long-term borrowing approved by the OEB, compounded annually. The regulation requires the OEB to authorize recovery of the balance in the account on a straight line basis over a period not to exceed ten years following the end of the Darlington Refurbishment project. OPG recognizes positive amounts deferred under rate smoothing as an increase in net regulatory assets and an increase in revenue in the period to which the underlying approved revenue requirement relates. Negative amounts determined under rate smoothing are correspondingly recorded as a decrease in net regulatory assets and a decrease to revenue.

On January 17, 2018, OPG submitted a draft payment amounts order to the OEB that proposed nuclear base regulated prices for each year of the 2017-2021 period, including a rate smoothing proposal, based on the December 2017 decision's findings. The rate smoothing proposal takes into account the near-term and future impacts on customers, while seeking to ensure that resulting nuclear regulated prices allow for sufficient cash flow to maintain the Company's investment grade credit rating and support availability of cost effective funding, while taking into account both near-term and future impacts on customers. Based on the OEB's direction, the draft payment amounts order also included proposed periods for recovery, through interim period shortfall rate riders, of the retrospective revenue shortfall for the period between June 1, 2017 and the implementation date of the new regulated prices based on proposed new regulated prices that would have been in effect during that period. The draft payment amounts also included proposed recovery periods, through variance and deferral account rate riders, for regulatory account balances approved for recovery in this application. **[MONITOR]**

To reflect the OEB's decision, in the fourth quarter of 2017, OPG recorded incremental revenue of approximately $480 million for the period June 1, 2017 to December 31, 2017 based on the draft payment amounts order. The revenue was recorded as an increase in regulatory assets for the June 1, 2017 to December 31, 2017 revenue shortfall based on proposed new regulated prices for nuclear facilities and regulated hydroelectric facilities, net of a regulatory liability recognized in relation to OPG's rate smoothing proposal. The OEB's approval of the final payment amounts order, including the allocation of the approved revenue requirement between nuclear regulated prices and rate smoothing deferrals, is not expected to have a material impact on the net revenue increase recorded in the fourth quarter of 2017. The OEB is expected to issue the final payment amounts order and implement new regulated prices in the first half of 2018. **[MONITOR]**

Consistent with the effective date of the OEB's December 2017 decision, for the period from January 1, 2017 to May 31, 2017, OPG continued to record additions to the existing variance and deferral accounts for the nuclear and regulated hydroelectric facilities pursuant to the OEB's previous decisions and orders. These additions reflected differences between actual and forecast amounts embedded in the regulated prices in effect prior to the June 1, 2017 effective date.

In January 2018, OPG filed a motion asking the OEB to review and vary the effective date of the new regulated prices to January 1, 2017. The motion did not impact OPG's financial results for the year ended December 31, 2017.

Ontario's 2017 Long-Term Energy Plan

On October 26, 2017, Ontario's Ministry of Energy issued the 2017 LTEP that outlines the Province's plans for the future development of Ontario's electricity system. The 2017 LTEP focuses on the affordability, reliability and flexibility of a clean energy supply in the province. The 2017 LTEP replaces the previous LTEP issued in 2013.

As it relates to the supply of electricity, the 2017 LTEP recognizes the refurbishment of Ontario's nuclear generating stations as the most cost-effective option for producing emission-free baseload generation to meet Ontario's needs and reaffirms the Province's support for the refurbishment of the four units at the Darlington GS and the six units at the Bruce generating stations, subject to the principles established in the 2013 LTEP. The 2017 LTEP also recognizes the value to customers of continuing to operate the Pickering GS until 2024, as planned. With respect to hydroelectric electricity generation, the 2017 LTEP highlights the opportunity to continue to invest in optimizing existing hydroelectric facilities, noting that pumped hydroelectric storage could play an important role in the reliability of the electricity system.

Additionally, the 2017 LTEP discusses the potential impact of a number of innovative technologies on the future of the electricity system. Among others, these include the increased electrification of the transportation sector, the emergence of energy storage, and the opportunity for Ontario to foster nuclear innovation technologies. OPG continues to assess how best to capitalize on potential business opportunities in these and other areas. The 2017 LTEP also recognizes the importance of Indigenous peoples' continuing role in shaping Ontario's energy planning, projects and policies.

Darlington Refurbishment

In October 2016, OPG commenced the refurbishment of the first Darlington GS unit, Unit 2, as part of the Darlington Refurbishment project. The de-fuelling of the reactor and islanding of Unit 2, the physical separation of the unit under refurbishment from the three operating units, were completed in the first half of 2017.

The disassembly of reactor components commenced in the third quarter of 2017, with the removal of feeder tubes completed in September 2017. The removal of fuel channel assemblies commenced in October 2017. As part of the fuel channel assemblies, the removal of pressure tubes is in progress and will be followed by the removal of calandria tubes. The second major segment and the removal of all reactor components is expected to be completed by mid-2018.

All of the pre-requisite projects, including construction of facilities, infrastructure upgrades and installation of safety enhancements, with the exception of the HWSF, have been completed and placed in service. The completion of the HWSF has been delayed due to challenges with construction, with construction activities suspended for a portion of 2017. Construction to complete the facility recommenced in the fourth quarter of 2017, including work to preserve and protect the facility during winter. The HWSF is expected to be completed by the second quarter of 2019 and is not on the critical path for the Darlington Refurbishment project, which continues to track on schedule. The increase in the cost estimate for the HWSF will be accommodated within the overall Darlington Refurbishment budget of $12.8 billion. Taking into account the execution performance of the Unit 2 refurbishment, the overall Darlington Refurbishment project continues to track on budget.

On November 21, 2017, the Financial Accountability Office of Ontario issued a report, "*An Assessment of the Financial Risks of the Nuclear Refurbishment Plan*". The report assesses the impact of OPG and Bruce Power's nuclear refurbishments on customers and the Province based on mechanisms in place for the recovery of the costs to refurbish and subsequently operate the nuclear stations. The report concludes that refurbishment of the four units at the Darlington GS and the six units at the Bruce nuclear generating stations provides the most cost effective, low emission generation source available to meet Ontario's baseload electricity requirements.

The Darlington Refurbishment project is discussed further in the section, *Core Business, Strategy, and Outlook* under the heading, *Project Excellence*.

Canadian Nuclear Safety Commission Safety Rating for the Darlington GS and the Pickering GS

The CNSC publishes an annual report on the safety performance of Canada's nuclear power plants. The report assesses how well plant operators are meeting regulatory requirements and program expectations in the areas of operational performance, safety analysis, radiation protection, waste management and conventional health and

safety. On September 8, 2017, the CNSC issued an executive summary of its 2016 annual report, giving both the Darlington GS and the Pickering GS the highest possible safety rating of "Fully Satisfactory". The Darlington GS achieved this rating for the eighth consecutive year, while the Pickering GS achieved this rating for the second consecutive year.

Ontario's Fair Hydro Plan

On March 2, 2017, the Province announced the Fair Hydro Plan aimed at reducing electricity bills for eligible residential, farm, small businesses ~~and other eligible~~ consumers (Specified Consumers) in the province by refinancing a portion of the Global Adjustment costs over a longer period of time. The Global Adjustment includes the difference between Ontario's electricity market clearing price used to dispatch generation and the prices paid to contracted and regulated generators in the province, and the cost of conservation and demand management programs. On June 1, 2017, the Fair Hydro Act received Royal Assent and the associated general regulation came into force in June 2017. The Act established a framework under which the costs and benefits associated with the Government of Ontario's clean energy initiatives are to be allocated between present and future consumers of electricity under the Fair Hydro Plan. The general regulation provides details on the structural, operational and financial elements required to implement the Fair Hydro Plan.

Pursuant to the Act, effective May 1, 2017, the IESO began to defer a portion of the Global Adjustment costs. The Act allows the IESO to transfer a portion of the deferred balance to a financing entity that would fund the deferral in exchange for an irrevocable right to recover the balance and associated financing and other costs from Specified Consumers in the future (Investment Interest). The legislation appointed OPG as the Financial Services Manager under the Act and conveyed upon the Financial Services Manager statutory obligations, including the creation of one or more financing entities that may acquire Investment Interests from the IESO.

In November 2017, OPG's Board of Directors provided its final approval regarding OPG's involvement with the Trust on commercial terms following the fulfilment of all conditions it established in May 2017. Accordingly, the Fair Hydro Trust was established as the financing entity contemplated by the Act in December 2017. The majority unitholder and beneficiary of the Trust is a wholly-owned subsidiary of OPG. The Trust is structured to be bankruptcy remote and ring fenced from OPG in order to protect the Company's assets and operations.

In order for the Trust to finance the Investment Interest acquired from the IESO, it will incur senior debt from capital markets and subordinated debt from OPG. The Trust's investment will attract financing amounts and other related fees, which, under the general regulation, will be payable by the IESO as carrying costs until July 2021 and by Specified Consumers through the Clean Energy Adjustment to be invoiced by local distribution companies commencing in May 2021, with the three-month lag in 2021 intended to cover the billing and collection lag from the introduction of the Clean Energy Adjustment. The carrying costs include all financing and third-party costs other than payment of principal on debt.

Concurrent with every issuance of the Trust's senior notes, it is expected that OPG will purchase subordinated debt of the Trust in an aggregate amount not to exceed 49 percent of the Trust's total outstanding debt, with 44 percent of the funding to be provided by the Province through equity injections and five percent to be provided by OPG. The subordination level may vary over time, but must at least equal to, or be greater than 35 percent of all outstanding debt. Through OPG's control over the key activities of the Trust and its obligation to absorb losses through ownership of the Trust's subordinated debt, the Company consolidates the financial results of the Trust in accordance with US GAAP.

On December 21, 2017, the Trust purchased its first tranche of Investment Interest from the IESO in the amount of approximately $1.18 billion. Fifty-one percent of the funding requirement or $601 million was financed by the Trust through a revolving warehouse facility ranked as senior notes, and the remaining 49 percent was funded through the issuance of short-term subordinated debt to OPG. The Investment Interest has been classified as a financing receivable on OPG's consolidated balance sheet.

OPG's subordinated debt investment in the Trust was funded through the following sources:

- The Province provided 44 percent of the total funding requirement or $519 million, through an equity injection in OPG in exchange for approximately 12.2 million non-voting Class A common shares at a price of $42.46 per share. The Company's Articles of Amalgamation were amended effective December 1, 2017 to allow for the creation and issuance of Class A shares. Refer to Note 14 of OPG's 2017 audited consolidated financial statements for further details; and
- OPG provided five percent of the total funding requirement or approximately $60 million.

In February 2018, the Trust issued $500 million of senior notes payable with a coupon interest rate of 3.36 percent and an effective interest rate of 3.42 percent, payable semi-annually until maturity on May 15, 2033. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility issued in December 2017. By the end of the first quarter of 2018, the Trust is expected to acquire another tranche of Investment Interest from the IESO, which it expects to fund using its revolving warehouse facility.

Refer to the section, *Liquidity and Capital Resources* under the heading, *Financing Activities* for further details on the Trust's financing arrangements and OPG's public debt offering.

OEB's Report on Regulatory Treatment of Pension and OPEB Costs

On September 14, 2017, the OEB issued its final report on the guiding principles and policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the Ontario electricity and natural gas sectors. The report establishes the accrual basis of accounting as the method of determining pension and OPEB amounts for rate-setting purposes, unless the OEB finds that this method does not result in just and reasonable rates in the circumstances of a particular utility. The report also provides for the establishment of a generic variance account to record asymmetric carrying charges in favour of ratepayers on the differences between the accrual costs recovered and cash payments made by a utility in respect of pension and OPEB plans. Carrying charges on this differential are to be assessed at the OEB's prescribed interest rate, on a prospective basis from the effective date of the new variance account. For OPG, this differential will include amounts going back to November 1, 2014, with the charges calculated on the portion of the differential that has been recovered through regulated prices. None of this differential has been recovered to date. The prescribed interest rate is set quarterly by the OEB based on the quarterly return of a mid-term corporate bond index yield.

The OEB's September 2017 report and the OEB's December 2017 decision on OPG's application for new regulated prices require OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the Pension & OPEB Cash to Accrual Differential Deferral Account in effect since November 1, 2014, until such time as the OEB approves resumption of the accrual basis of recovery for OPG. The future recovery of amounts recorded in the account will be subject to this approval. The OEB's report did not impact OPG's financial results for the year ended December 31, 2017.

The Company recognizes the amount set aside in the Pension & OPEB Cash Versus Accrual Differential Deferral Account as a regulatory asset. As at December 31, 2017, the regulatory asset had a balance of $614 million. Consistent with the expectations set out in the OEB's December 2017 decision, in 2018, OPG plans to file an application with the OEB requesting disposition of the Pension & OPEB Cash Versus Accrual Differential Deferral Account balance as well as balances accumulated since December 31, 2015 in other regulatory accounts.

Shareholder Declarations and Shareholder Resolutions to Sell Certain Non-Core Real Estate Properties

In December 2015, OPG received a Shareholder Declaration and a Shareholder Resolution requiring the Company to sell its head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street in Toronto, Ontario. The sale was completed in April 2017, with a gain on sale of $283 million, which is net of tax effects of $95 million, recognized in net income in the second quarter of 2017. The pre-tax gain on sale was recorded

as an item of Other gains in the consolidated statement of income in the Services, Trading and Other Non-Generation segment. Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. The amount of designated proceeds transferred into the Consolidated Revenue Fund are expected to approximate ~~will be equal to~~ the after-tax gain on sale. **[MONITOR]** The transfer is expected to take place ~~as early as~~ in the first quarter of 2018, through a special dividend authorized by OPG's Board of Directors in March 2018. **[MONITOR]**

Commented [DS1]: The amount of designated proceeds will be determined by regulation and therefore uncertain until the regulation is filed and made public.

In June 2016, OPG received a Shareholder Declaration and a Shareholder Resolution that requires the Company to sell its former Lakeview GS site located in Mississauga, Ontario. OPG has entered into a purchase and sale agreement with a purchaser with the sale scheduled to close in March 2018. An estimated after-tax gain on sale of approximately $200 million is expected to be recognized in net income upon completion of the transaction in the first quarter of 2018. **[MONITOR]** Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. OPG anticipates the amount of designated proceeds transferred into the Consolidated Revenue Fund to approximate the after-tax gain on the sale. In accordance with the Shareholder Resolution, approximately one-third of the site is to be transferred to the City of Mississauga, by the purchaser, for parkland, institutional, and cultural uses.

CORE BUSINESS, STRATEGY, AND OUTLOOK

OPG's mission is to provide low cost power in a safe, clean, reliable and sustainable manner for the benefit of its customers and its Shareholder. OPG also seeks to pursue, on a commercial basis, generation development projects and other business expansion opportunities to the benefit of the Shareholder.

OPG's four key strategic imperatives are as follows:

- Operational Excellence
- Project Excellence
- Financial Strength
- Social Licence.

Operational Excellence

Operational excellence at OPG is accomplished by the safe and environmentally responsible generation of reliable and cost-effective electricity from the Company's generating assets through a highly trained and engaged workforce.

Workplace Safety and Public Safety

Workplace safety and public safety are fundamental core values at OPG. OPG is committed to operating all of its facilities in a safe, secure, and reliable manner that minimizes risks to a reasonably achievable level. Safety is an overriding priority in all activities performed at OPG's generating and other facilities, and all employees and contractors are expected to conduct themselves in manner that ensures workplace safety and public safety in line with the Company's safety culture.

In the area of workplace safety, OPG is committed to achieving excellent performance through continuous improvement and a strong safety culture, with the ultimate goal of zero injuries. OPG utilizes an integrated health and safety management system and a set of operational risk control procedures to ensure continued monitoring of health and safety performance and to support continuous learning and improvement in this area. Over the past five years, OPG has repeatedly stood in the top quartile of its comparator Canadian electrical utilities in various safety performance metrics.

Workplace safety performance is measured using two primary indicators at OPG, All Injury Rate (AIR) and Accident Severity Rate (ASR). OPG's AIR and ASR results for employee workplace safety were as follows for the year ended December 31:

	2017	2016
AIR *(injuries per 200,000 hours worked)*	**0.48**	0.56
ASR *(days lost per 200,000 hours)*	**3.57**	2.59

In 2017, OPG's AIR improved from 2016 and was the third-best performance year in the Company's history. For those employee injuries that caused lost time from work, the total time lost from work in 2017 was greater than the previous year. OPG's analysis of the underlying safety events indicated that major contributors to the injuries and near misses included inadequate situational awareness and attention to detail, and suboptimal risk-based decisions, rather than missing or inadequate standards or programs. OPG continues to implement a number of initiatives to target the injury trends based on the analysis of the safety events, with a focus on the use of human performance tools including increased field supervisory oversight, situational awareness, communication, and procedural use and adherence.

In order to strengthen its safety performance, OPG continues to progress an organization-wide "iCare Enough to Act" initiative launched in 2016 and aimed at renewing employees' commitment to their own and each other's safety and well-being. Approaches to supervisory oversight, communication and safe work planning are being modified and updated to further strengthen safety as a foundational element of the Company's values-based culture.

Contractors are required to conduct work safely at OPG sites. In support of this requirement, OPG utilizes an independent contractor pre-qualification process, provides on-site safety support for many of its major projects, and works with contract partners to improve their health and safety programs to meet OPG's requirements. In the past nine years, OPG has consistently shown a Construction Contractor AIR that is markedly better than the Infrastructure Health and Safety Association Contractor AIR, a metric of construction contractor safety performance across Ontario. OPG has maintained this performance while engaging in the refurbishment of the Darlington GS, one of the largest infrastructure projects in Canada. The hours worked by contractors in 2017 were the largest in OPG's history, largely attributable to this project.

OPG continues to maintain a strong focus on the nuclear safety program and to invest in nuclear safety systems. To ensure continued public safety, radiation exposure to members of the public resulting from the operation of OPG's nuclear generating stations is estimated on an annual basis for individuals living or working near the stations. The annual dose to the public resulting from operations of each nuclear facility is expressed in microsieverts (µSv), which is an international unit of radiation dose measurement. For 2016, the annual public doses resulting from the Darlington GS operations and the Pickering GS operations were 0.6 µSv and 1.5 µSv, respectively, which is less than 0.1 and 0.2 percent of the annual legal limit of 1,000 µSv, respectively. While the public doses from OPG's nuclear operations for the 2017 operating year will not be finalized until the second quarter of 2018, they are not expected to differ significantly from the 2016 levels.

In June 2016 and August 2016, the CNSC released sampling results from its independent environmental monitoring program, which confirmed that the public and the environment around OPG's nuclear generating stations continued to be safe. In September 2017, the CNSC issued an executive summary of its 2016 annual report on the safety performance of Canada's nuclear power plants, which gave both the Pickering GS and the Darlington GS the highest possible safety rating of "Fully Satisfactory". For further details, refer to the CNSC safety rating discussion in the section, *Highlights* under the heading, *Recent Developments*.

OPG remains committed to high standards of public safety on waterways around hydroelectric generating stations and dams, and continues to make investments in waterway and dam safety upgrades. The Company's practices in this area are routinely reviewed by an independent panel comprised of internationally recognized experts, who have

concluded that OPG's Dam Safety Program is industry leading in a number of areas. During 2017, OPG continued its water safety campaign with a series of public service announcements illustrating the danger of water near hydroelectric dams and hydroelectric generating stations.

Electricity Generation Production and Reliability

Key strategic initiatives in support of operational excellence, specific to each of OPG's core generating operations, are discussed below. Generation and reliability performance for 2017 is discussed by operating segment in the section, *Discussion of Operating Results by Business Segment*.

Nuclear Operations

OPG is pursuing a number of strategic initiatives aimed at the continued safe and reliable operation of the Pickering GS and targeting top performance at the Darlington GS.

OPG's objective is to maximize the safe and reliable operating life of the Pickering units. As announced in 2016 and approved by the Province, OPG is continuing to execute on a plan to extend safe and reliable operation of the Pickering GS to 2024. In addition to providing Ontario with a clean, reliable source of baseload electricity during nuclear unit refurbishments at the Darlington GS and the Bruce nuclear generating stations, extending operations at the Pickering GS will provide continued employment for up to 4,000 full-time employees at OPG and help to reduce approximately 17 million tonnes of carbon dioxide emissions, which is equivalent to removing approximately 3.4 million cars from Ontario's roads.

As part of the plan to extend Pickering operations, OPG has been continuing to undertake the required technical work to confirm that the station's pressure tubes, a key life-limiting component of the station, will remain fit for service for operation to 2024. In the fourth quarter of 2017, OPG has confirmed that technical assessments completed to date provide sufficient confidence in the programs and provisions in place to assure fitness-for-service of fuel channel components in line with the planned extended operations period. This evaluation is consistent with the safety case reflected in OPG's operating licence renewal application for the Pickering GS submitted to the CNSC in 2017, discussed below. Taking these factors into account, OPG revised the accounting end-of-life assumptions for the Pickering GS from December 31, 2020 for all units to December 31, 2022 for Units 1 and 4 and December 31, 2024 for Units 5 to 8, effective December 31, 2017.

The change in the Pickering GS accounting end-of-life assumptions did not impact OPG's net income in 2017. The change is expected to decrease depreciation expense by $77 million in 2018, including the associated impact on the nuclear asset retirement obligation (ARO) recorded as of December 31, 2017 but before the impact of regulatory accounts. Regulatory accounts, including a new deferral account proposed by OPG in a December 2017 application to the OEB, are expected to largely offset the decrease in depreciation expense. The change in the nuclear ARO recorded in the fourth quarter of 2017 is discussed in the section, *Critical Accounting Policies and Estimates* under the heading, *Asset Retirement Obligation*. On December 29, 2017, OPG applied for an accounting order to establish a variance account to record, from January 1, 2018 until the effective date of the OEB's next payment amounts order, the revenue requirement impact of changes to nuclear liabilities and depreciation and amortization expense resulting from changes to station end-of-life dates for OPG's Pickering prescribed nuclear facilities that will be effective December 31, 2017. Pending the OEB's review of the application, an interim order was issued January 31, 2018 establishing the proposed variance account effective January 1, 2018. The OEB's final decision for the account is expected later in 2018.

OPG's current five-year operating licence for the Pickering GS was approved by the CNSC in 2013 and expires on August 31, 2018. This current licence was issued assuming that the station would shut down in 2020. On June 28, 2017, OPG confirmed to the CNSC that it intends to cease commercial operation of all Pickering units on December 31, 2024. On August 28, 2017, OPG submitted a ten-year licence renewal application to the CNSC. The requested licence term spans the planned extended commercial operations period, through to the planned period of de-fuelling,

de-watering and beginning to place the station in a safe storage state in 2028. In support of the licence renewal, OPG undertook a Periodic Safety Review (PSR), a comprehensive assessment of the station's design and operation to confirm that there is a high level of safety throughout the operating life and to determine what reasonable and practical enhancements can be made to further improve safety. The PSR also includes a component condition assessment of the station to identify the work required to support the station's continued operation. The PSR has confirmed that extending operations of the Pickering units will continue to pose minimal risk to the health, safety and security of workers, the public and the environment. The final major component of the PSR was submitted to the CNSC in November 2017. The CNSC's review of the PSR submission and licence application is in progress. Based on the evidence and documentation submitted to the CNSC, OPG is confident in obtaining a licence renewal that would support its extended operations plan for Pickering GS.

OPG's nuclear operations are regularly benchmarked against top performing nuclear facilities around the world. This allows OPG to identify, develop and implement initiatives to further improve performance. In September 2016, OPG hosted a team of experts from the International Atomic Energy Agency (IAEA) at the Pickering GS to conduct a standard Operational Safety Review Team mission. The team conducted an in-depth review of performance and adherence to international safety standards. In the second quarter of 2017, the IAEA's Operational Safety Review Team released the final report and confirmed that the Pickering GS demonstrates strong commitment to safety. In December 2017, OPG hosted a World Association of Nuclear Operators (WANO) peer evaluation for the Pickering GS, which focused on the safe and reliable operation of the station while evaluating the plant material condition, functional and cross-functional areas of the organization. Pickering showed significant improvement since its last review and has sustained its strong rating in 2018, resulting in its best ever WANO peer review.

OPG remains focused on improving reliability and increasing electricity generation output from its nuclear fleet. This includes improving equipment reliability, optimizing outages, implementing integrated asset management planning and enhancing maintenance programs. Improved equipment reliability generally results in fewer generation interruptions. Nuclear inspection and testing programs are largely driven by maintenance and regulatory requirements, and are designed to ensure that equipment is performing safely and reliably. Execution of this and other outage work continues to be a high priority. As part of its commitment to operational excellence, OPG continues to focus on improving the planning, execution, monitoring, and reporting of outage work.

OPG continues to make investments in the performance of the Pickering GS, with a focus on improving plant reliability and maximizing the value of the asset over its remaining life through implementing equipment modifications and fuel handling reliability improvements, reducing equipment maintenance backlogs, and completing critical and high priority work. OPG also continues to make investments in the Darlington GS necessary to sustain safe and reliable operations for the next three decades and aimed at positioning the station for industry-leading operating and cost performance in the longer term. This includes investments in life cycle and aging management projects, facility upgrades as well as work in support of regulatory commitments.

Delivering solutions that provide the best combination of safety, cost and effectiveness, as well as establishing challenging financial targets based on comprehensive benchmarking and taking into account the operating environment of the nuclear stations, continues to be a vital part of OPG's strategy to improve performance of the nuclear business unit. Financial and staffing targets continue to be reviewed and adjusted where necessary to reduce operating costs, while ensuring safety and reliability are not compromised.

In 2016, OPG submitted applications with the CNSC seeking a ten-year licence renewal for the Western Waste Management Facility (WWMF), located at the Bruce generating stations' site, to May 31, 2027, and a ten-year licence renewal for the Pickering Waste Management Facility (PWMF) to August 31, 2028. The licence renewal applications were presented to the CNSC at public hearings in April 2017. On May 30, 2017, the CNSC announced that the WWMF licence was renewed for a ten-year period and will be valid until May 31, 2027. On February 7, 2018, the CNSC announced that the PWMF licence was renewed for a ten-year period and will be valid until August 31, 2028.

In 2017, the CNSC approved regulatory document *REGDOC 2.2.4 – Fitness for Duty – Managing Alcohol and Drug Use* for use at Canadian nuclear power plants. This document sets out requirements for managing fitness for duty of workers in relation to alcohol and drug use at high-security sites, including for-cause alcohol and drug testing for workers in positions identified as safety-sensitive or safety-critical and random alcohol and drug testing for workers holding safety-critical positions. OPG intends to enhance its existing Fitness for Duty program to comply with these new requirements. OPG is working with its partners in the Canadian nuclear industry to develop a program suitable for Canada and its workers.

Hydroelectric Operations

The objectives of OPG's hydroelectric operations include operating and maintaining the generating facilities in a safe, efficient and cost-effective manner, while increasing the output from the facilities and pursuing opportunities to increase capacity. OPG aims to increase the facilities' output by improving operational flexibility, enhancing reliability, optimizing outage planning and, subject to water conditions, increasing availability to meet electricity system demand. OPG continues to evaluate and implement plans to increase capacity, maintain and improve operational performance, and extend the operating life of its hydroelectric generating assets.

OPG's hydroelectric operations are regularly benchmarked against peer utilities in North America. Based on 2016 data, 19 of the OPG's 25 large regulated hydroelectric facilities benchmarked in the top two quartiles for unit energy costs. This group of 19 facilities represents 94 percent of the energy delivered from the regulated hydroelectric fleet. Similarly, 18 of 25 large regulated hydroelectric facilities benchmarked in the top two quartiles for availability based on 2016 data. OPG continues to pursue innovation and technology-based improvements in its asset management and equipment maintenance strategies in order to increase reliability and further reduce costs of the hydroelectric fleet.

As part of OPG's ongoing strategy to reduce costs and increase operational efficiency, the operations of the Company's hydroelectric and thermal assets were previously combined into one organization, with five regional operations groups. In 2017, OPG reduced the number of regional operations groups to four, by integrating the Central Operations work centres into three of the other existing regional operations groups. In addition, during the third quarter of 2017, OPG opened an amalgamated control room located at the Saunders hydroelectric GS, combining the Chenaux and Saunders control rooms. The amalgamated control room will control all operational activities at the ten hydroelectric stations along the Madawaska, Ottawa and St. Lawrence rivers.

OPG's plans for its existing hydroelectric generating stations are accomplished through multi-year capital investment and other programs, including replacements and upgrades of turbine runners, and refurbishment or replacement of existing generators, transformers, and controls. The aim of OPG's runner replacement and upgrade program is to increase hydroelectric station capacity by leveraging efficiency enhancements in runner design. Where economical and practical, OPG also pursues opportunities to refurbish, expand or redevelop its existing hydroelectric stations. Over the next four years, OPG plans to increase the total capacity of its hydroelectric generating fleet by approximately 150 MW, which, in addition to the runner replacement and upgrade program, includes the Ranney Falls GS and Sir Adam Beck frequency conversion projects. OPG is also planning to repair, rehabilitate, or replace a number of aging civil hydroelectric structures.

As part of its commitment to operational excellence, OPG continues to make investments in its existing hydroelectric generating fleet. During 2017, OPG continued to execute a number of projects, including:

- Completion of the overhaul and upgrade of Unit 10 of the Sir Adam Beck 1 GS, which increased the station's capacity by 6 MW
- Continued work on the overhaul and rehabilitation of Unit 1 of the Sir Adam Beck Pump GS to ensure reliable unit operation for approximately the next 20 years
- Completion of the replacement of the Shebandowan Lake Control Dam at the Kakabeka Falls GS, which will maintain structural integrity and enhance dam safety for another 100 years

- Continued work on the overhaul and upgrade of Unit 1 of the Harmon GS with completion of the turbine upgrade, generator rehabilitation and upgrade of protection and control systems
- Continued work on the overhaul and upgrade of Unit 2 of the DeCew Falls GS, with turbine and generator rehabilitation and upgrade of protection and control systems completed during the year, and, in the fourth quarter of 2017, commencement of the overhaul and upgrade of Unit 2 of the Little Long GS
- Continued work on the overhaul and rehabilitation of Unit 2 of the Lower Notch GS, with generator rehabilitation completed during the year, and in the fourth quarter of 2017, commencement of the overhaul and rehabilitation of Unit 6 of the Sir Adam Beck Pump GS
- Commencement of definition phase work for the Water Conveyance System project to rehabilitate the Sir Adam Beck 1 GS canal and associated structures, ensuring their continued safe and reliable operations for approximately the next 50 years.

In 2018, OPG plans to commence execution of several major sustaining projects across the hydroelectric fleet, including the overhaul and upgrade of Unit 5 of the Sir Adam Beck 1 GS, the rehabilitation of Caribou Falls Block Dam No.2, and automatic sluicegates system replacement at the Whitedog Falls GS. Definition phase activities on several other major projects are also expected to commence in 2018, including frequency conversion of Units 1 and 2 of the Sir Adam Beck 1 GS and the overhaul and upgrade of the R.H. Saunders GS units.

Thermal Operations

OPG's thermal operations consist of biomass-fuelled generating units at each of Atikokan GS and Thunder Bay GS, and the oil/gas dual-fuelled Lennox GS.

These stations, which operate as peaking facilities under their respective energy supply requirements, provide Ontario's electricity system with the flexibility to meet changing daily system demand and capacity requirements and enable the system to accommodate the expansion of Ontario's renewable generation portfolio. The continued operation of these stations will continue to provide Ontario with over 2,000 MW of peaking generation capacity. The stations operate under their respective ESAs.

OPG's biomass-fuelled generating units are among the world's leading in their innovation. The Atikokan GS is the largest generating station in North America fuelled by 100 percent biomass, while the Thunder Bay GS unit uses advanced biomass that is thermally treated to allow it to be stored outdoors and withstand exposure to the weather.

Former thermal stations that are no longer available to generate electricity are included in the Services, Trading, and Other Non-Generation segment once they are removed from service. This includes the Lambton GS and Nanticoke GS sites, which ceased operations in 2013. Over 2015 and 2016, OPG announced that these stations would be decommissioned safely, securely and in an environmentally responsible manner. The costs of the decommissioning are charged to a previously established decommissioning provision.

During 2017, OPG substantially completed the demolition of the Nanticoke coal yard equipment and structures and issued a contract for the demolition of the Nanticoke powerhouse and associated structures. In the fourth quarter of 2017, the demolition contractor had been mobilized to prepare for the removal of the powerhouse and associated structures and initiated the preparatory work for the demolition of the stacks. The demolition of the stacks took place in February 2018. **[MONITOR]** A competitive bidding process for the demolition of the Lambton GS is in progress, with a contract for the removal of the powerhouse and associated structures expected to be issued during 2018. The decommissioning plan for the Nanticoke GS accommodates the construction and operation of the Nanticoke solar facility.

An update of the asset retirement obligations related to the Nanticoke and Lambton sites has been completed. For a discussion of the revaluation of this liability for non-nuclear fixed asset removal as at December 31, 2017, refer to the section, *Critical Accounting Policies and Estimates* under the heading, *Asset Retirement Obligations*.

Environmental Performance

OPG's Environmental Policy states that "OPG shall meet compliance obligations, including any environmental commitments that it makes, with the objective of exceeding these compliance obligations where it makes business sense". This policy commits OPG to:

- maintain an ISO 14001-registered environmental management system (EMS)
- work to prevent or mitigate adverse impacts on the environment with a long-term objective of continual improvement
- strive to be a leader in climate change mitigation
- manage sites in a manner that strives to maintain, or enhance where it makes business sense, significant natural areas and associated species of concern.

In 2017, OPG maintained the ISO 14001 registration of its company-wide EMS. Within the EMS, OPG has planning, operational control, and monitoring programs to manage the Company's positive and negative impacts on the environment. Significant environmental aspects of OPG's operations include: spills, chemical and thermal emissions to water, water flow and level changes, radiological emissions, low and intermediate level radioactive waste (L&ILW), enhancement and disruption of wildlife habitat, displacement of fossil fuels, and fish impingement and entrainment. Further details regarding OPG's environmental risks can be found in the section, *Risk Management* under the heading, *Environmental Risk*.

Environmental performance targets are set as part of the annual business planning process. These targets are based on past performance and external benchmarking to promote continual improvement. OPG met or outperformed its 2017 targets for spills, environmental infractions, carbon-14 emissions to air, and L&ILW. Targets for tritium emissions to air and water were not achieved due to equipment performance issues; however, emissions remained less than one percent of the regulatory limit. There were no significant environmental events during 2017.

In 2016, the Government of Ontario passed the *Climate Change Mitigation and Low-Carbon Economy Act, 2016* and the associated *Cap and Trade Program Regulation*. The legislation provides the foundation for regulating greenhouse gas (GHG) emissions in Ontario and establishes a cap and trade program, with the first compliance period being from January 1, 2017 to December 31, 2020.

The cap and trade program is a market mechanism intended to give Ontarians an incentive to reduce GHG emissions by putting a price on carbon. OPG has an internal program to meet its GHG emissions compliance obligations. With OPG's low GHG emitting fleet, these obligations are not expected to have a material financial impact on the Company.

OPG monitors actions being taken by the Government of Ontario and the Government of Canada to reduce GHG emission levels and transition to a low-carbon economy. In support of efforts to mitigate climate change, the Company continues to evaluate and implement plans to increase the generation capacity of its hydroelectric generating fleet, where economical, invest in other low-carbon technologies, and take a leadership role in the electrification of Ontario's transportation sector.

OPG has developed biodiversity management plans that identify priority natural areas, conservation goals, threats, and proposed actions to sustain biodiversity at its properties. To maximize benefits and manage impacts, initiatives include biodiversity monitoring, site naturalization, habitat creation, and control of invasive species.

OPG works with community partners to support regional ecosystems and biodiversity across Ontario. In 2017, OPG continued efforts to protect and restore habitat, promote biodiversity education and awareness, and help the recovery of species at risk. In November 2017, OPG's biodiversity program was recognized by the Canadian Electricity Association with the 2017 Sustainable Electricity award for Commitment to Continuous Performance Improvement.

OPG communicates its environmental performance internally to employees and to external stakeholders, including the Ontario Ministry of the Environment and Climate Change (MOECC), Environment and Climate Change Canada, the CNSC, and local communities. Details of OPG's environmental performance and initiatives to fulfill the Company's Environmental Policy can be found in OPG's 2016 Sustainability Report, available on the Company's website at www.opg.com.

Improving Efficiency and Reducing Costs

As part of its commitment to operational excellence, OPG remains strongly focused on reducing costs by pursuing sustainable efficiency and productivity improvements across operating business units and support functions, while ensuring that there is no adverse impact on the safety, reliability and environmental sustainability of the Company's operations. Building on significant efficiency achieved since 2011 under a more scalable, centre-led organizational model, this includes streamlining of processes, simplifying governance, upgrading technology, optimizing service delivery models, and continuing to leverage attrition to achieve human resource targets aligned with business requirements. Strategies to improve cost performance and organizational capability are being implemented at the enterprise and business unit level. These strategies are supported by continuing to embed an outcomes-driven culture that reinforces cost effectiveness, efficiency and organizational agility as part of business decision-making.

OPG is proceeding with an enterprise-wide process to evaluate the impact of the eventual shutdown of the Pickering GS on the Company's operating cost structure. This multi-year initiative, known as OPG25, involves identifying and implementing a coordinated set of plans and targets to ensure the optimization of the Company's longer-term operating model, business strategies and organizational design between now and the planned end of Pickering commercial operations. The overall aim of the initiative is to ensure ongoing cost effectiveness of the Company's operations after the eventual shutdown of the Pickering GS and to mitigate the cost impacts associated with the shutdown. Through this work and a continued focus on productivity enhancements, OPG expects to deliver increased value to customers and achieve improvement in outcomes of future applications for regulated prices under the OEB's incentive regulation framework.

In 2017, OPG also launched a strategy to accelerate the pace of digital transformation across the enterprise. The strategy is focused on making investments to modernize information technology infrastructure, enhance mobility, connectivity and field and office productivity, and improve equipment reliability and station performance through data management and data analysis. The strategy will increase operational efficiency, reduce operating costs and help to enable optimization initiatives in support of OPG25.

People and Culture

A well trained and engaged workforce is fundamental to the achievement of OPG's strategic imperatives. To succeed in a demanding business environment, OPG is focused on building a diverse, healthy, engaged workforce and fostering a culture of collaboration, accountability and innovation. OPG also continues to communicate and implement the values and behaviours expected from its employees in order to maintain a strong focus on safety, performance excellence, continuous improvement, and corporate citizenship.

The Company continues to focus on improving the capability of its workforce through leadership development, knowledge management, diversity and inclusion programs, and hiring in critical areas. Ability to secure the right talent mix in order to effectively meet the Company's immediate and longer term business needs on a timely basis is supported through workforce planning, resourcing and on-boarding strategies, both to acquire external talent into the organization and to develop existing employees. The goal of workforce planning and resourcing strategies is to ensure that the Company has a diverse workforce with the right skill set and capability for the safe and effective operation of the generating facilities and successful delivery of major projects, including the Darlington Refurbishment. These strategies take into account changes in anticipated staffing requirements leading up and subsequent to the end of planned commercial operations of the Pickering GS and the period to de-fuel, de-water and

place the station in a safe state condition after shutdown. The end of commercial operations at the Pickering GS is expected to lead to a significant reduction in OPG's workforce.

As part of the strategy to develop and engage employees and to build leadership talent in support of the Company's long-term success, OPG has an active succession planning program with a focus on accelerating development. This includes a company-wide high-potential leadership development program for qualified internal candidates. This 14-month cross-functional, competitive-entry program is designed to identify and develop candidates for future leadership positions while they are relatively early in their careers. OPG also has a talent management monitoring process to proactively assess staffing risks, challenges and opportunities.

Electricity generation involves complex technologies that require highly skilled and trained workers. Many positions at OPG have significant educational prerequisites and rigorous requirements for continuous training and periodic requalification. In addition to maintaining its internal training infrastructure, OPG relies on partnerships with government agencies, other electrical industry partners and educational institutions to meet the required level of qualification. Training delivery models are evaluated for effectiveness and efficiency.

Effective January 1, 2017, OPG implemented an Executive Compensation Program that is compliant with *Ontario Regulation 304/16: Executive Compensation Framework*, introduced in September 2016. While the Province released two subsequent amendments, *Ontario Regulation 187/17* and *Ontario Regulation 400/17* in June 2017 and November 2017, respectively, OPG's Executive Compensation Program continues to be subject to the original regulation's requirements. The regulation sets out how all employers designated under the *Broader Public Sector Executive Compensation Act, 2014*, including OPG, must establish and post compensation programs for executives. The program must include the compensation philosophy, salary and performance-related pay caps, comparative analysis details, and a description of other elements of compensation. OPG's Executive Compensation Program, which applies to employees at the Vice President level and higher, is designed to provide compensation that is at the 50th percentile of the market and focused on at-risk, performance based pay. The program will better enable OPG to attract, align and retain the executive talent critical to delivering Shareholder and customer value, while ensuring continued safe and reliable operations.

Project Excellence

OPG is pursuing a number of generation development and other major projects in support of Ontario's electricity planning initiatives. OPG also continues to plan and execute maintenance and capital improvement projects related to its existing assets. OPG strives for excellence in the planning and delivery of all projects across the Company.

OPG's vision for project excellence is to be an industry leader in project management capability and performance. As part of its commitment to project excellence, OPG continues to enhance and streamline its approach to project planning and execution, with the goal of delivering all projects safely, on time, on budget, and with high quality. Achieving project excellence at OPG involves, among other things, implementing a common, scalable project delivery model across all business units, establishing qualified project management teams, optimizing contracting strategies, engaging qualified and experienced vendors, and effectively monitoring and controlling performance.

The status updates for OPG's major projects as of December 31, 2017 are outlined below.

Project	Capital expenditures		Approved budget	Expected in-service date	Current status
(millions of dollars)	Year-to-date	Life-to-date			
Darlington Refurbishment	1,249	4,434	12,800 [1]	First unit - 2020 Last unit - 2026	All Unit 2 feeder tubes were removed safety in the fourth quarter of 2017 and the removal of fuel channel assemblies is in progress. Construction activities on the HWSF have recommenced in the fourth quarter. Planning and procurement activities for the refurbishment of Unit 3 are continuing. The overall project is tracking on schedule and on budget.
Peter Sutherland Sr. Hydroelectric GS	41	277	300	2017	The station was placed in-service on March 31, 2017, ahead of the originally planned schedule, and is expected to close below the approved budget. Project close-out activities are in progress.
Sir Adam Beck Pump GS Reservoir Refurbishment	3	49	58	2017	The refurbishment was completed and the reservoir was returned to service in February 2017, ahead of the originally planned in-service date and below the approved budget.
Ranney Falls Hydroelectric GS	25	28	77	2019	Excavation has been completed and construction is continuing in the expanded forebay, powerhouse and spillway area. Concrete placement of the new powerhouse and the spillway integrated structure is in progress. The project is tracking on schedule and on budget.
Nanticoke Solar Facility	2	3	107	2019	Significant contracts for equipment and engineering construction services have been executed, with construction planned to commence in the first quarter of 2018. **[MONITOR]**
Deep Geologic Repository (DGR) for L&ILW	9 [2]	204 [2]			On August 21, 2017, the federal Minister of Environment and Climate Change requested further information related to the project's environmental assessment (EA). OPG is working on a response to this information request.

[1] The total project budget of $12.8 billion is for the refurbishment of all four units at the Darlington GS.
[2] Expenditures are charged against the Nuclear Liabilities.

Darlington Refurbishment

The Darlington generating units are approaching their originally designed end-of-life. Refurbishment of the four generating units is expected to extend the operating life of the station by approximately 30 years. The approved budget for the four-unit refurbishment is $12.8 billion, which includes the costs of the pre-requisite projects in support of the execution phase of the refurbishment. The first refurbished unit is scheduled to be returned to service in the first quarter of 2020 and the last unit is scheduled to be completed by 2026. The project continues to track on schedule.

The Darlington Refurbishment project is a multi-phase program comprising the following five major sub-projects:

- **Retube and Feeder Replacement**, which includes the removal and replacement of fuel channel assemblies and feeder tubes in each reactor
- **Turbines and Generators**, which consists of inspections and repairs of turbine generator sets and the replacement of analog control systems with digital control systems
- **De-fuelling and Fuel Handling**, which involves the de-fuelling of the reactors and the refurbishment of the fuel handling equipment
- **Steam Generators**, which includes mechanical cleaning, water lancing, and inspection and maintenance work on the generators
- **Balance of Plant**, which consists of work on smaller projects to replace or repair certain other station components.

In 2016, the Darlington Refurbishment project transitioned from the planning phase to the execution phase, as OPG commenced the refurbishment of the first unit, Unit 2, in October 2016 as planned. The unit was taken offline on October 15, 2016. De-fuelling of the reactor was completed in January 2017, with a total of 480 fuel channels de-fuelled. Islanding of Unit 2, the physical separation of the unit under refurbishment from the three operating units, was completed in April 2017, signifying the completion of the first major segment of the project.

The second major segment includes preparatory work to support the removal of feeder tubes and fuel channel assemblies, followed by the removal of reactor components. The preparatory work was completed in the second quarter of 2017. The Re-tube Tooling Platform for hosting the tooling for the removal, inspection and installation activities, and the setup of specialized tooling and equipment needed for the removal and replacement of the reactor components were completed in the third quarter of 2017. The disassembly of reactor components commenced in August 2017, with the removal of all 960 feeder tubes completed safely in September 2017. The removal of fuel channel assemblies commenced in October 2017. As part of the fuel channel assemblies, the removal of pressure tubes is in progress and will be followed by the removal of calandria tubes. The second major segment and the removal of all reactor components is expected to be completed by mid-2018. Key projects in the second major segment finished in 2018 include the completion of the primary side steam generator layup and installation of steam generator access ports to support future inspections. Other key project activities being executed during the second segment include the continuation of the major turbine generator overhaul, which will be completed in the second quarter of 2018, and continued execution of the major electrical scope. OPG is also continuing to execute work to support the requirements set out in the CNSC-approved Integrated Implementation Plan for the station.

Most of the pre-requisite projects, including construction of facilities, infrastructure upgrades and installation of safety enhancements, have been completed and placed in-service. The Re-tube Waste Processing Building was completed in November 2017. Completion of the HWSF has been delayed due to challenges with construction. OPG suspended the project in the second quarter of 2017 to evaluate the best approach to optimize cost and schedule and complete the project. Construction to complete the facility recommenced in the fourth quarter of 2017. The HWSF is expected to be completed by the second quarter of 2019 and is not on the critical path for the Darlington Refurbishment project, which continues to track on schedule. The increase in the cost estimate for the HWSF will be accommodated within the overall Darlington Refurbishment budget of $12.8 billion. Taking into account the execution performance of the Unit 2 refurbishment, the overall Darlington Refurbishment project continues to track on budget.

In addition to the execution of refurbishment activities on Unit 2, OPG is continuing planning activities for the refurbishment of the second unit, Unit 3, and is entering into associated commitments to procure major components that require long lead times. As of December 31, 2017, $93 million has been invested in planning activities related to the refurbishment of the second unit, Unit 3. These planning activities are being undertaken in accordance with the refurbishment project schedule. In February 2018, the Province confirmed its commitment to proceed with Darlington's Unit 3 refurbishment in 2020. **[MONITOR]**

Peter Sutherland Sr. Hydroelectric GS

In March 2017, the project to construct the 28 MW two-unit Peter Sutherland Sr. hydroelectric GS successfully completed final testing and commissioning of the turbine and generator units, and both units were declared substantially complete. On March 31, 2017, the project received a permit from the MOECC to take water for operations to allow the station to operate commercially. This in-service date was well ahead of the originally planned schedule of the first half of 2018. The project's schedule was accelerated to take advantage of favourable weather conditions. The project is expected to close below the approved budget of $300 million. Project close-out activities are in progress. OPG began to receive contracted revenue for the project following the IESO's confirmation of the station's commercial operations as of March 31, 2017, under a hydroelectric ESA.

Under the partnership agreement, as the unit is placed in-service, the CRP, a corporation wholly owned by the Taykwa Tagamou Nation, may acquire up to a 33 percent partnership interest through its investment in PSS. In April 2017, the CRP acquired a 33 percent interest in PSS.

Sir Adam Beck Pump GS Reservoir Refurbishment

The Sir Adam Beck Pump GS refurbishment construction began in April 2016 and the 300-hectare reservoir was returned to service in February 2017 upon completion of the reservoir commissioning program. The Sir Adam Beck Pump GS facility allows OPG to pump and store water diverted from the Sir Adam Beck generating complex during periods of low electricity demand, to be used to generate up to 600 MW of electricity during subsequent periods of high electricity demand. The work on the project included installation of a new partial liner and construction of a grout curtain in the bedrock foundation of the reservoir dyke. The refurbishment is expected to add approximately 50 more years to the reservoir's life. The project was completed ahead of the originally planned in-service date of April 2017 and below the approved budget of $58 million. The Sir Adam Beck Pump GS is reported in the Regulated – Hydroelectric segment.

Ranney Falls Hydroelectric GS

In 2017, OPG began construction work on a 10 MW single-unit powerhouse on the existing Ranney Falls GS site, as part of the Regulated – Hydroelectric segment. The new unit will replace an existing unit that reached its end of life in 2014. The existing forebay structure has been demolished and the new concrete structure has been completed. Excavation has been completed and construction continues in the expanded forebay, powerhouse and spillway area. The new forebay concrete wall has been completed, and concrete placement of the new powerhouse and the spillway integrated structure is in progress. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget.

Nanticoke Solar Facility

The construction of a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands under a Large Renewable Procurement contract with the IESO, through Nanticoke Solar LP, a partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation, is planned to commence in the first quarter of 2018. During 2017, the partnership continued work to obtain approvals and permits required to enable the commencement of construction. Significant contracts for equipment and engineering construction services were executed in the first quarter of 2018. The facility is expected to be completed in the first quarter of 2019, with a budget of $107 million. **[MONITOR]**

Deep Geologic Repository for Low and Intermediate Level Waste

OPG has proposed a deep geologic repository as the preferred solution for the safe long-term management of the L&ILW produced from the continued operation of OPG-owned nuclear generating stations. Agreement has been reached with local municipalities for OPG to develop the L&ILW DGR on lands adjacent to the WWMF in Kincardine, Ontario. The environmental effects of the proposed L&ILW DGR were examined by the CNSC and Canadian Environmental Assessment Agency (CEAA)-appointed Joint Review Panel (JRP) to meet the requirements of the *Canadian Environmental Assessment Act*. The JRP submitted its report on the EA to the federal Minister of Environment in May 2015, concluding that, given mitigation, there is unlikely to be significant environmental impact from the project and recommending that the Minister approve the EA. In December 2016, at the request of the federal Minister of Environment and Climate Change, OPG submitted additional information on certain aspects of the EA, including information related to alternate locations for the project. Following its review of OPG's submission and a period of public comment, the CEAA requested further information that OPG subsequently provided in May 2017. In June 2017, the CEAA notified OPG that it had sufficient and adequate information to proceed with the next step of the environmental assessment process and advised that a draft report and updated terms and conditions would be prepared for public review.

On August 21, 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of potential cumulative effects of the project on the Saugeen Ojibway Nation's (SON) physical and cultural heritage, including a description of the potential effects of the project on the Nation's spiritual and cultural connection to the land, taking into account the results of the SON Community Process. OPG is working closely with the SON to formulate a response to the information request.

The L&ILW DGR at the WWMF site remains OPG's preferred solution for the safe long-term management of the L&ILW. The in-service date of the L&ILW DGR is expected to be approximately six to seven years from the start of construction.

Financial Strength

As a commercial enterprise, OPG's financial priority is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future expansion. Inherent in this priority are four objectives:

- Increasing revenue, reducing costs and achieving appropriate return
- Ensuring availability of cost effective funding for operational needs, generation development projects and other business opportunities, and long-term obligations
- Pursuing opportunities to expand the existing core business and capitalize on new growth paths
- Managing risks, which is discussed in the section, *Risk Management*.

Increasing Revenue, Reducing Costs and Achieving Appropriate Return

In line with its commercial mandate, OPG is focused on increasing revenue and net income and achieving an appropriate rate of return on the Shareholder's investment, while taking into account the impact on Ontario electricity customers by seeking further efficiencies in the Company's cost structure.

For the regulated operations, achievement of the above objectives is largely dependent on outcomes of rate applications to the OEB and growth of the asset base earning a return as part of the regulated prices.

With respect to rate application outcomes, OPG has been focused on demonstrating in its rate applications that the costs required to operate and invest in the assets are reasonable and being prudently incurred, and should be fully recovered, and that the Shareholder's investment in these assets should earn an appropriate rate of return. While the OEB's decision on OPG's 2017-2021 application for new regulated prices reduced OPG's forecasted costs used to set new regulated prices, the decision will result in a substantial increase in revenue and net income compared to

existing regulated prices. The existing base regulated prices were set in 2014 to allow the Company to recover its approved nuclear costs over a higher nuclear production volume, based on the 2014 and 2015 outage profile that did not include a Darlington refurbishment outage.

The OEB's decision to reduce recovery of OPG's forecasted cost levels, including through the use of stretch factors under an incentive rate-making model, will negatively impact OPG's ability to earn an appropriate return on the Shareholder's investment in the regulated assets. To improve the financial strength of the regulated operations, OPG will continue to focus on optimizing operational performance and outage plans across the generating fleet and on pursuing further efficiency improvements in the Company's cost structure and operating model. OPG's cost and productivity improvement strategies are discussed further in the section, *Core Business, Strategy and Outlook* under the heading, *Operational Excellence – Improving Efficiency and Reducing Costs*.

OPG continues to invest in the regulated asset base, with the Darlington Refurbishment project being the single largest such capital investment. In its decision on OPG's 2017-2021 application for new regulated prices, the OEB has allowed inclusion of a total of $5.5 billion in Darlington Refurbishment in-service capital additions by 2021, including pre-requisite projects other than HWSF and including in-service amounts upon planned return to service of Unit 2 in the first quarter of 2020. Once in-service, these assets will attract a return on equity of approximately 8.8 percent during the 2017-2021 period set by the OEB, based on a deemed capital structure of 45 percent equity and 51 percent debt. The average OEB-approved cost of deemed debt for the 2017-2021 period is approximately 4.6 percent. OPG also continues to pursue an extensive capital program across its regulated hydroelectric operations that includes expansion, redevelopment and life extension of the generating facilities, where economic. These renewable assets have long service lives and, with either maintenance efforts or rebuilding, will continue to supply electricity for the foreseeable future. The OEB's decision on OPG's application for new regulated prices is discussed further in the section, *Highlights* under the heading, *Recent Developments*.

For generation assets that do not form part of the assets regulated by the OEB, OPG's strategy has been to secure appropriate long-term revenue arrangements. In line with this strategy, virtually all of OPG's non-regulated operating facilities and assets under construction are subject to long-term ESAs or other long-term contracts with the IESO. This includes the Peter Sutherland Sr. GS, which was placed in service and began receiving contracted revenue under a hydroelectric ESA as of March 31, 2017. The Peter Sutherland Sr. GS ESA expires in 2067.

OPG's capital structure currently reflects lower levels of debt than the deemed capital structure reflected in the Company's existing regulated prices and maintained by the OEB's December 2017 decision on new regulated prices. OPG continues to evaluate strategies to enhance Shareholder returns by optimizing the Company's capital structure through better alignment with the deemed capital structure, taking into account the overall financial strength of the Company and the potential impact on the Company's investment grade credit rating.

Ensuring Availability of Cost Effective Funding

OPG actively monitors its funding requirements and forecasts availability of funds to ensure that it can meet the Company's operational needs, project commitments and long-term obligations. OPG utilizes multiple sources of funds, including funds generated from operations, commercial paper, securitization of assets, letters of credit, credit facilities, long-term corporate debt (sourced from both the OEFC and public debt offerings), credit facilities with the OEFC, private placement project financing, and equity issuance. The Company's financing strategy leverages the strength of its balance sheet to obtain cost effective long-term corporate debt. OPG also accesses the capital markets for private placement project financing, secured by the assets of the project, where the characteristics of the project support such financing. Maintaining an investment grade credit rating is critical to OPG's ability to access cost effective financing.

In April 2017, DBRS Limited (DBRS) re-affirmed the long-term credit rating on OPG's debt at 'A (low)' and OPG's commercial paper rating at 'R-1 (low)'. All ratings from DBRS have a stable outlook. In July 2017, S&P Global

Ratings (S&P) re-affirmed OPG's long-term credit rating at 'BBB+' with a stable outlook. S&P's commercial paper rating for OPG is 'A-1 (low)'.

OPG intends to continue to access the capital markets, where appropriate, to obtain cost effective financing for future generation development projects. The Company continues to evaluate arrangements that would appropriately support its financing needs, its capital expenditure programs, its financing of OPG's subordinated debt investment in the Trust, and the Trust's acquisition of Investment Interest from the IESO. OPG's liquidity and capital resources are discussed in the section, Liquidity and Capital Resources.

Building Our Business

Through pursuit of commercial-based opportunities to expand its business, OPG strives to be a leader in the North American transition toward a low carbon future while maintaining and expanding the Company's scale and energy industry leadership. This strategy considers the Company's financial position and anticipated future changes in the generating fleet, including the eventual end of Pickering commercial operations. The strategy is also informed by industry, technological, environmental, social, and economic external factors. Opportunities are evaluated using financial and risk-based analyses as well as strategic considerations.

Currently, OPG's strategy primarily focuses on the renewal and expansion of the Company's portfolio of generating assets in Ontario, including the redevelopment and expansion of existing sites and potential new developments. The strategy leverages OPG's operating and project development expertise as well as the Company's existing diverse physical asset base. Acquisition opportunities are considered as they arise, taking into account operating synergies, strategic benefits, financial returns and risk profile. OPG's current major generation development projects and asset life extension initiatives are discussed in the section, *Core Business, Strategy, and Outlook* under the headings, *Operational Excellence* and *Project Excellence*.

OPG also actively seeks to expand beyond its core generation business through investments in innovation and emergent low-carbon technologies, including selective solar generation, nuclear innovation, energy storage, distributed generation, electric vehicle infrastructure and other development. Additionally, OPG continues to consider potential paths to extend its business through broader electricity sector opportunities, within and outside Ontario. Business expansions opportunities may be pursued in partnership with other commercial entities where appropriate synergies exist and are aligned with OPG's business objectives.

Social Licence

As the largest electricity generator in Ontario with diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust. OPG is committed to maintaining high standards of public safety and corporate citizenship, including environmental stewardship, transparency, community engagement, and Indigenous relations. OPG works to maintain public trust with stakeholders by engaging site communities, sharing information, and being transparent about performance. In addition, OPG's operations are subject to extensive regulatory oversight, with public participation, by the CNSC, the OEB, and other bodies. OPG's commitment to safety is discussed in the section, *Core Business, Strategy, and Outlook* under the heading, *Workplace and Public Safety*.

OPG is focused on building long-term, mutually beneficial working relationships with Indigenous communities, businesses and organizations across Ontario, and continues to support procurement, employment and educational opportunities with its Indigenous community partners. The Company seeks to establish these relationships based on a foundation of respect for the languages, customs, and political, social and cultural organizations of the Indigenous communities.

OPG's commitment in this area includes pursuing generation-related development partnerships on the basis of long-term commercial arrangements, such as the construction of the Peter Sutherland Sr. GS in partnership with Taykwa Tagamou Nation and the development of the Nanticoke solar facility in partnership with the Six Nations of the Grand

River. During 2017, OPG also continued to engage with Indigenous communities regarding the Company's nuclear waste management operations, through regularly scheduled meetings and ongoing dialogue in connection with OPG's proposed L&ILW DGR, the re-licensing of the PWMF and the WWMF, and the Pickering GS re-licensing. Engagement was also conducted with First Nations in southwestern Ontario regarding the demolition of the Lambton and Nanticoke generating stations and with the Mississaugas of New Credit regarding the Shareholder-directed sale of the former Lakeview GS site.

OPG is also committed to improving Indigenous access to procurement and employment opportunities, including increasing the profile of the nuclear generation industry in Indigenous communities. In 2017, OPG launched an Indigenous Business Engagement (IBE) Initiative. The purpose of this initiative is to increase access to procurement opportunities for Indigenous businesses interested in supplying materials and services to OPG. The IBE Initiative is based on a strategy that will identify opportunities in contracts, scopes of work and business plans for potential Indigenous business engagement; include criteria related to suppliers' ability to engage or partner with Indigenous people or businesses in assessing procurement proposals; and invest in relationships with Indigenous communities by increasing outreach efforts to enhance understanding of how to do business with OPG. OPG has been engaging with Indigenous businesses and communities as well as its suppliers to promote the IBE Initiative, including the Mohawk Council of Akwesasne as well as the Williams Treaties First Nations, located proximate to the Pickering and Darlington nuclear generating stations.

OPG has been actively developing recruitment plans targeting Indigenous peoples. As part of this initiative, during the fourth quarter of 2017, OPG participated in several Indigenous-specific career fairs, hosted a Day in the Trades event for Indigenous students and job seekers as part of an open house at the Darlington Energy Centre, and approved plans aimed at increasing the number of Indigenous apprentices as part of the nuclear operations' recruitment program.

OPG also contributes to the well-being of its host communities through the Company's Corporate Citizenship Program (CCP), which supports charitable and non-profit grassroots initiatives in the areas of environment, education, and community involvement, including support for Indigenous initiatives. In 2017, OPG's CCP provided support to over 800 initiatives, of which 84 were Indigenous.

OPG has a strategy to help position the Company as a leader in transportation electrification in the province. The strategy aims to leverage the Company's clean, reliable and cost-effective electricity to power transportation, capitalize on future commercial growth opportunities, and enhance the Company's social licence. OPG is pursuing initiatives to increase the use of electric vehicles within its operations, and is assessing vehicle grid integration and hydrogen applications for the transportation sector. Ontario's climate change plan aims for electric and hydrogen passenger vehicles to represent five percent of new vehicle sales in the province by 2020.

As part of its commitment to help de-carbonize Ontario's transportation sector, OPG is a founding sponsor of Plug'n Drive, a non-profit organization working to accelerate the adoption of electric vehicles and to maximize their environmental and economic benefits. In May 2017, Plug'n Drive announced the opening of the world's first experiential learning facility dedicated to electric vehicle education and awareness, with OPG sponsoring the Centre's training facility.

Further details regarding OPG's commitment to sustainable development, including information regarding the Company's environmental and social performance and initiatives, are provided in OPG's 2016 Sustainability Report available on the Company's website at www.opg.com.

Outlook

The financial performance of OPG's regulated operations is driven, in large part, by the outcome of applications for regulated prices to the OEB. Subject to the OEB's issuance of the final payment amounts order expected in the first half of 2018, the OEB's December 2017 decision on OPG's application for new regulated prices provides substantial

price certainty for the regulated business for the 2017 to 2021 period. During this period, OPG will continue to focus on optimizing operational performance and outage plans across the generating fleet and on pursuing further efficiency improvements in the Company's cost structure and operating model.

The OEB's decision established June 1, 2017 as the effective date of the new regulated prices, which negatively affected OPG's net income and ROE Excluding AOCI in 2017 relative to OPG's requested effective date of January 1, 2017. The full-year effect of new regulated prices in 2018 is expected to contribute to an improvement in net income and ROE Excluding AOCI over the 2017 results.

Subject to the OEB's final determination on nuclear rate smoothing as part of the payment amounts order process, OPG expects an improvement in cash flow from operating activities in 2018, compared to 2017. This will reflect OPG beginning to receive revenue from the IESO based on new regulated prices following the OEB's implementation of these prices, expected in the first half of 2018. Additionally, the Fair Hydro Trust segment will begin to contribute positive cash flow from operating activities in 2018. OPG expects to continue to have the necessary financial capacity and sufficient access to cost effective financing sources to continue to fund its capital requirements and other disbursements, including the financing of the Fair Hydro Trust.

Several OEB-authorized regulatory variance and deferral accounts currently in place contribute to reducing the relative variability of the Company's net income and ROE Excluding AOCI. Among others, the regulatory accounts include those related to the revenue impact of variability in water flows and forgone production due to SBG conditions at the regulated hydroelectric stations. As there are no variance or deferral accounts in place related to the impact of generation performance of the nuclear stations on revenue from base regulated prices, the Regulated – Hydroelectric segment generally is expected to produce overall more predictable earnings. OPG continues to operate and maintain its nuclear facilities with a view to optimize their performance and availability, while focusing on improving the overall reliability and predictability of the fleet.

Electricity generated from most of OPG's non-regulated assets is subject to ESAs or other long-term contracts with the IESO. Based on these agreements, OPG expects the Contracted Generation Portfolio segment to continue to contribute a generally stable level of earnings and cash flow from operating activities going forward.

Lower nuclear generation due to the Darlington Refurbishment outages will continue, as planned, to negatively impact the Enterprise TGC and Nuclear TGC metrics for the duration of the refurbishment project. Lower hydroelectric generation due to outages related to various refurbishment and operational projects may negatively impact Enterprise TGC and Hydroelectric TGC for the duration of these projects. Variability in sustaining capital investment expenditures and nuclear outage profile may also impact TGC metrics in future periods.

OPG's total forecast capital expenditures for the 2018 year are approximately $2.1 billion. **[CONFIRM]** This includes amounts for the Darlington Refurbishment project, hydroelectric and other development projects including the Ranney Falls GS redevelopment and construction of the Nanticoke solar facility, and sustaining capital investments across the generating fleet. OPG's major projects are discussed in the section, *Project Excellence*.

In addition to the operating and financial performance of the electricity generation business, OPG's results are affected by the earnings on the Nuclear Segregated Funds, which are reported in the Regulated – Nuclear Waste Management segment. While the Nuclear Segregated Funds are managed to achieve, in the long term, the target rate of return based on the discount rate specified in the ONFA, the rates of return earned in a given period can be subject to various external factors including financial market conditions and, for the portion of the Used Fuel Segregated Fund guaranteed by the Province under the ONFA, changes in the Ontario consumer price index (CPI). In the near term, these factors can be volatile and cause fluctuations in the Company's income. This volatility is partially mitigated by the impact of the OEB-authorized Bruce Lease Net Revenues Variance Account and the funded status of the two segregated funds, discussed below.

As OPG does not have the right to withdraw surplus amounts from the Nuclear Segregated Funds, OPG limits the amount of Nuclear Segregated Funds assets reported on the balance sheet to the present value of the underlying life cycle funding liabilities per the most recently approved ONFA Reference Plan. This reduces the volatility of earnings on the Nuclear Segregated Funds reflected in net income when the funds are in a fully funded or overfunded position. As at December 31, 2017, the Decommissioning Segregated Fund was overfunded by approximately 27 percent, and the Used Fuel Segregated Fund was marginally overfunded, by less than one percent, based on the 2017 ONFA Reference Plan. Variability in asset performance due to volatility inherent in financial markets and changes in Ontario CPI, or changes in funding liability estimates, may result in either or both funds becoming underfunded in the future.

OPG's results are also affected by the earnings from the Fair Hydro Trust segment. Management expects an increase in 2018 earnings from the segment, primarily related to interest income from OPG's investment in subordinated debt of the Trust. OPG's involvement with the Fair Hydro Plan over time is expected to put downward pressure on ROE Excluding AOCI as a result of increases in shareholder's equity through future issuances of Class A common shares to partially fund OPG's subordinated debt investment in the Trust.

KEY OPERATING AND FINANCIAL PERFORMANCE INDICATORS

OPG evaluates the performance of its generating stations using a number of key indicators. Key operating performance indicators aligned with corporate strategic imperatives are measures of production reliability, cost effectiveness, environmental performance, and safety performance. Certain of the measures used vary depending on the generating technology.

Enterprise TGC, Nuclear TGC, Hydroelectric TGC, ROE Excluding AOCI, and FFO Adjusted Interest Coverage ratio discussed below are not measurements in accordance with US GAAP. They should not be considered as alternative measures to net income or any other measure of performance under US GAAP. However, OPG believes that these non-GAAP financial measures are effective indicators of its performance and are consistent with the Company's strategic imperatives and related objectives. The definition and calculation of Enterprise TGC per MWh, Nuclear TGC per MWh, Hydroelectric TGC per MWh, ROE Excluding AOCI, and FFO Adjusted Interest Coverage are found in the section, *Supplementary Non-GAAP Financial Measures*.

Enterprise Total Generating Cost per Megawatt-Hour

Enterprise TGC per MWh is used to measure OPG's overall organizational cost performance. Enterprise TGC per MWh is defined as OM&A expenses (excluding the Darlington Refurbishment project and other generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to OPG's electricity generation business), fuel expense for OPG-operated stations including hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures (excluding the Darlington Refurbishment project and other generation development projects) incurred during the period, divided by total electricity generation from OPG-operated generating stations plus electricity generation forgone due to SBG conditions during the period.

Nuclear Total Generating Cost per Megawatt-Hour

Nuclear TGC per MWh is used to measure the cost performance of OPG's nuclear generating assets. Nuclear TGC per MWh is defined as OM&A expenses of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to OPG's nuclear electricity generation business), nuclear fuel expense for OPG-operated stations (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs) incurred during the period, divided by nuclear electricity generation for the period.

Hydroelectric Total Generating Cost per Megawatt-Hour

Hydroelectric TGC per MWh is used to measure the cost performance of OPG's hydroelectric generating assets. Hydroelectric TGC per MWh is defined as OM&A expenses of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segments (excluding generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the hydroelectric electricity generation business), hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding expenditures related to the Peter Sutherland Sr. GS, Ranney Falls GS, and other hydroelectric generation development projects) incurred during the period, divided by total hydroelectric electricity generation plus hydroelectric electricity generation forgone due to SBG conditions during the period. OPG reports hydroelectric gross revenue charge and water rental payments as fuel expense.

Nuclear Unit Capability Factor

OPG's nuclear stations are baseload facilities that are not designed for fluctuating production levels to meet peaking demand. The nuclear Unit Capability Factor is a key measure of nuclear station performance. It measures the amount of energy that the unit(s) generated over a period of time, adjusted for externally imposed constraints such as transmission or demand limitations, as a percentage of the amount of energy that would have been produced over the same period had the unit(s) produced maximum generation. Capability factors are primarily affected by planned and unplanned outages. By industry definition, capability factors exclude production losses beyond plant management's control, such as grid-related unavailability. The nuclear Unit Capability Factor also excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS is excluded from the measure effective October 15, 2016, when the unit was taken offline as part of the Darlington Refurbishment project.

Hydroelectric Availability

OPG's hydroelectric stations operate as baseload, intermediate, or peaking stations. Hydroelectric Availability represents the percentage of time the generating unit is capable of providing service, whether or not it is actually generating electricity, compared to the total time for the respective period.

Thermal Equivalent Forced Outage Rate

Equivalent Forced Outage Rate (EFOR) is an index of the reliability of a generating unit at OPG's thermal stations. It is measured by the ratio of time a generating unit is forced out of service by unplanned events, including any forced deratings, compared to the amount of time the generating unit was available to operate.

Return on Common Equity Excluding Accumulated Other Comprehensive Income

ROE Excluding AOCI is an indicator of OPG's performance consistent with its objective to deliver value to the Shareholder. ROE Excluding AOCI is defined as net income attributable to the Shareholder for the period divided by average equity attributable to the Shareholder excluding AOCI for that period, and is measured over a period of 12 months.

Funds from Operations Adjusted Interest Coverage

The FFO Adjusted Interest Coverage ratio is an indicator of OPG's ability to meet interest obligations from operating cash flow and is consistent with the Company's objective of ensuring availability of cost effective funding. The FFO Adjusted Interest Coverage ratio is defined as FFO before interest divided by adjusted interest expense, and is measured over a period of 12 months.

Other Key Indicators

In addition to production reliability, cost effectiveness, and financial performance indicators, OPG has identified certain environmental and safety performance measures. These measures are discussed in the section, *Core Business, Strategy, and Outlook*.

BUSINESS SEGMENTS

Effective in the fourth quarter of 2017, OPG has the following six reportable business segments:

- Regulated – Nuclear Generation
- Regulated – Nuclear Waste Management
- Regulated – Hydroelectric
- Contracted Generation Portfolio
- Services, Trading, and Other Non-Generation
- Fair Hydro Trust.

Regulated – Nuclear Generation Segment

The Regulated – Nuclear Generation business segment operates in Ontario, generating and selling electricity from the Pickering GS and the Darlington GS, both owned and operated by OPG. The business segment also includes revenue under the terms of a long-term lease arrangement and related agreements with Bruce Power related to the Bruce nuclear generating stations. This revenue includes lease revenue, fees for nuclear waste management, and revenue from heavy water sales and detritiation services. The segment also earns revenue from isotope sales and ancillary services supplied by OPG from the nuclear stations it operates. Ancillary revenues are earned through voltage control and reactive support. Revenues under the agreements with Bruce Power, including a portion of heavy water sales, and from existing isotope sales contracts and ancillary services are included by the OEB in the determination of the regulated prices for production from OPG's nuclear facilities, which has the effect of reducing these prices.

Regulated – Nuclear Waste Management Segment

OPG's Regulated – Nuclear Waste Management segment reports the results of the Company's operations associated with the management of nuclear used fuel and L&ILW, the decommissioning of OPG's nuclear generating stations including the stations on lease to Bruce Power and other facilities, the management of the Nuclear Segregated Funds, and related activities including the inspection and maintenance of the waste storage facilities. Accordingly, accretion expense, which is the increase in the Nuclear Liabilities carried on the consolidated balance sheets in present value terms due to the passage of time, and earnings from the Nuclear Segregated Funds are reported under this segment.

As the nuclear generating stations operate over time, OPG incurs incremental costs related to used nuclear fuel and L&ILW, which increase the Nuclear Liabilities. OPG charges these incremental costs to current operations in the Regulated – Nuclear Generation segment to reflect the cost of producing energy from the Pickering and Darlington nuclear generating stations and earning revenue under the Bruce Power lease arrangement and related agreements. Since the incremental costs increase the Nuclear Liabilities reported in the Regulated – Nuclear Waste Management segment, OPG records an inter-segment charge between the Regulated – Nuclear Generation and the Regulated – Nuclear Waste Management segments. The impact of the inter-segment charge is eliminated in the consolidated statements of income and balance sheets.

The Regulated – Nuclear Waste Management segment is considered rate regulated because OPG's costs associated with the Nuclear Liabilities are included in the OEB's determination of regulated prices for production from the Pickering and Darlington nuclear generating stations.

Regulated – Hydroelectric Segment

OPG's Regulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from most of the Company's hydroelectric generating stations. The business segment comprises the results of 54 hydroelectric generation stations across a number of major river systems in the province.

In addition, the business segment includes ancillary and other revenues from OPG's regulated hydroelectric stations. Ancillary revenues are earned through offering available generating capacity as operating reserve and through the supply of other ancillary services including voltage control and reactive support, certified black start facilities, regulation service, and other services. These ancillary revenues and other revenues are included by the OEB in the determination of the regulated prices for production from OPG's prescribed hydroelectric facilities, which has the effect of reducing these prices.

Contracted Generation Portfolio Segment

The Contracted Generation Portfolio business segment operates in Ontario, generating and selling electricity from the Company's generating stations that are not prescribed for rate regulation. The segment primarily includes generating facilities that are under an ESA with the IESO or other long-term contracts.

The Contracted Generation Portfolio segment also includes OPG's share of equity income from its 50 percent ownership interests in the PEC and Brighton Beach stations. Brighton Beach operates under an energy conversion agreement between Brighton Beach and Shell Energy North America (Canada) Inc., and the PEC station is operated under the terms of an Accelerated Clean Energy Supply contract with the IESO. OPG's share of the in-service generating capacity and generation volume from its interests in the PEC and Brighton Beach stations are reported in this segment.

The business segment also includes ancillary revenues and other revenues from the stations included in the segment, which are earned through offering available generating capacity as operating reserve, and the supply of other ancillary services including voltage control and reactive support, certified black start facilities, regulation service, and other services.

Services, Trading, and Other Non-Generation Segment

The Services, Trading, and Other Non-Generation segment is a non-generation segment that is not subject to rate regulation. It includes the revenue and expenses related to OPG's trading and other non-hedging activities. As part of trading activities, OPG transacts with counterparties in Ontario and neighbouring energy markets in predominantly short-term trading activities of typically one year or less in duration. These activities relate to electricity that is purchased and sold at the Ontario border, financial energy trades, financial risk management energy product revenues, and sales of energy-related products. In addition, OPG has a wholly owned trading subsidiary that transacts solely in the United States (US) market. The results of this subsidiary are reported in this segment. All contracts that are not designated as hedges are recorded as assets or liabilities at fair value on the consolidated balance sheets, with changes in fair value recorded in the revenue of this segment.

In addition, the segment includes revenue from real estate rentals and non-regulated services, gains or losses on disposition of non-regulated real estate assets, costs associated with non-regulated business development activities, and costs related to the Lambton GS and Nanticoke GS sites.

Fair Hydro Trust Segment

The Fair Hydro Trust segment is a non-generation segment that is not subject to rate regulation. It includes OPG's earnings from the Fair Hydro Trust, which includes the financial results of the Trust, as well as income related to OPG's role as Financial Services Manager of the Fair Hydro Trust and holder of subordinated debt issued by the Trust. Earnings include interest income from OPG's investment in subordinated debt of the Trust of up to 49 percent of the Trust's total outstanding debt, recovery of third-party costs and fees for financial management and ongoing administration services, partially offset by interest costs on debt issued by OPG to fund five percent of the subordinated investment in the Trust, incurred third-party costs, and other incurred costs related to the management and administration of the Trust.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

Regulated – Nuclear Generation Segment

(millions of dollars)	**2017**	**2016**
Revenue	**3,095**	3,481
Fuel expense	**284**	315
Gross margin	**2,811**	3,166
Operations, maintenance and administration	**2,293**	2,210
Depreciation and amortization	**431**	925
Property taxes	**26**	26
Income before other losses, interest, and income taxes	**61**	5
Other gains	**4**	1
Income before interest and income taxes	**57**	4

Income before interest and income taxes from the segment increased by $53 million in 2017, compared to 2016. Segment earnings were favourably affected by the OEB's decision on OPG's application for new regulated prices issued in December 2017 with a retrospective effective date of June 1, 2017. The revenue increase of approximately $465 million in relation to the June 1, 2017 to December 31, 2017 period resulting from the OEB's decision was recorded as an increase in net regulatory assets in the fourth quarter of 2017. This revenue increase was based on new regulated prices for that period proposed in OPG's January 2018 submission to the OEB based on the findings in the decision and is net of a regulatory liability recognized in relation to OPG's nuclear rate smoothing proposal in that submission.

Segment earnings were unfavourably affected by a reduction in electricity generation of 4.9 TWh in 2017, compared to 2016. This reduced revenue by approximately $285 million, partially offset by a decrease in fuel expense. The lower electricity generation was primarily due to the ongoing Unit 2 refurbishment outage at the Darlington GS that began in October 2016, partially offset by the higher electricity generation from the Pickering GS. The income impact of OEB-approved regulatory accounts also contributed to the decrease in income for the year.

The increase in OM&A expenses of $83 million in 2017, compared to 2016, reflected planned expenditures related to the major maintenance activities and higher project expenditures occurring at the nuclear stations. Depreciation and amortization expenses, excluding amortization expense related to regulatory account balances, increased by $22 million primarily due to new assets in service in 2017.

The expiry of a nuclear rate rider for the recovery of OEB-approved balances in regulatory accounts on December 31, 2016 contributed to the decrease in segment revenue in 2017, compared to 2016, but was largely offset by a decrease in amortization expense related to these balances.

The Unit Capability Factors for the Darlington GS and Pickering GS for 2017 and 2016 were as follows:

	2017	2016
Unit Capability Factor *(%)* [1]		
Darlington GS	**85.2**	89.5
Pickering GS	**80.0**	75.2

[1] The nuclear Unit Capability Factor excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS was excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

The lower Unit Capability Factor at the Darlington GS in 2017, compared to 2016, reflected the higher number of planned outage days in 2017, largely driven by constraints related to the transition of the station's operating units toward refurbishment.

The increase in the Unit Capability Factor at the Pickering GS in 2017, compared to 2016, was primarily due to outage cycle optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station compared to 2016.

The definition of the nuclear Unit Capability Factor is found in the section, *Key Operating and Financial Performance Indicators.*

Regulated – Nuclear Waste Management Segment

(millions of dollars)	2017	2016
Revenue	**121**	138
Operations, maintenance and administration	**129**	146
Accretion on nuclear fixed asset removal and nuclear waste management liabilities	**943**	912
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(801)**	(746)
Loss before interest and income taxes	**(150)**	(174)

Earnings from the segment improved by $24 million in 2017 compared to 2016. The improvement was primarily due to higher earnings from the Nuclear Segregated Funds, partially offset by an increase in accretion expense on the Nuclear Liabilities. Accretion expense represents a financing cost due to the increase in the present value of the underlying liabilities with the passage of time.

The year-over-year increase in the earnings from the funds was primarily due to a reduction in the earnings recorded in the fourth quarter of 2016 to reflect an accounting adjustment to limit Nuclear Segregated Funds assets reported on the consolidated balance sheet to the underlying funding liabilities based on an updated ONFA reference plan approved by the Province. The updated ONFA reference plan resulted in a reduction in the funding liabilities. As both the Decommissioning Segregated Fund and the Used Fuel Fund have been in an overfunded position since the beginning of 2017, the earnings on the funds recognized in net income during the year reflected the growth rate in the present value of the funding liabilities and were not impacted by market returns and the rate of return guaranteed by the Province for the portion of the Used Fuel Segregated Fund. Further details on the accounting for the Nuclear Segregated Funds can be found in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

The year-over-year increase in accretion on nuclear fixed removal and nuclear waste management liabilities in 2017, compared to 2016, was primarily due to the impact on accretion expense related to the increase in asset retirement obligation associated with the life extension of the Bruce nuclear assets from the agreement executed between Bruce Power and the Province in late 2015. This increase was offset in 2016 due to the Bruce Lease Net Revenues Variance Account but is reflected in accretion with the resetting of base rates in 2017. This increase was partially

offset by the impact of the decrease in Nuclear Liabilities to reflect an updated estimate as part of the ONFA reference plan update process.

As of December 31, 2016, OPG recorded a decrease of approximately $1,570 million to the Nuclear Liabilities and associated asset retirement costs capitalized as part of the carrying value of the nuclear generating stations to reflect an updated estimate of OPG's obligations for nuclear waste management and nuclear facilities decommissioning determined as part of the ONFA reference plan update process. The resulting year-over-year decreases in accretion expense recorded in the Regulated – Nuclear Waste Management segment and depreciation and fuel expenses recorded in the Regulated – Nuclear Generation segment were offset by the impact of the OEB-authorized Bruce Lease Net Revenues Variance Account and Nuclear Liability Deferral Account recorded in the corresponding segments for the period up to May 31, 2017, and by the retrospective revenue impact of the OEB's decision for the period from June 1, 2017 to December 31, 2017 recorded in the Regulated – Nuclear Generation segment.

Regulated – Hydroelectric Segment

(millions of dollars)	**2017**	**2016**
Revenue [1]	**1,436**	1,527
Fuel expense	**351**	353
Gross margin	**1,085**	1,174
Operations, maintenance and administration	**330**	325
Depreciation and amortization	**139**	225
Property tax	**1**	1
Income before other gains, interest and income taxes	**615**	623
Other losses (gains)	**1**	(19)
Income before interest and income taxes	**614**	642

[1] During 2017 and 2016, the Regulated – Hydroelectric segment revenue included incentive payments of $12 million and $14 million, respectively, related to the OEB-approved hydroelectric incentive mechanism. The mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers.

The decrease in income before interest and income taxes of $28 million in 2017, compared to 2016, was primarily due to a gain of $22 million recognized during the first quarter of 2016 to reflect the OEB's January 2016 decision reversing a portion of an earlier capital cost disallowance related to the Niagara Tunnel project expenditures, in response to a motion by OPG. The income impact of OEB-approved regulatory accounts and higher OM&A expenses also contributed to the decrease in income for the year. The higher OM&A expenses were primarily related to overhaul work and civil repairs completed during the year.

These factors were partially offset by the recognition of a revenue increase of approximately $15 million in the fourth quarter of 2017 to reflect the OEB's decision on OPG's application for new regulated prices. This incremental revenue was in relation to the June 1, 2017 to December 31, 2017 period based on the June 1, 2017 retrospective effective date of the new regulated prices and was recorded as an increase to regulatory assets.

The decrease in revenue from the segment for the year ended December 31, 2017, compared to the same period in 2016, was largely due to the expiry of an OEB-authorized hydroelectric rate rider on December 31, 2016. As the rate rider allowed for the recovery of approved balances in OEB-authorized regulatory accounts, this decrease in revenue was largely offset by lower amortization expense related to these balances.

The Hydroelectric Availability for the stations included in the Regulated – Hydroelectric segment was as follows:

	2017	2016
Hydroelectric Availability *(%)*	**88.0**	89.0

The Hydroelectric Availability decreased during 2017, compared to 2016, primarily due to a higher number of unplanned outage days at the Northwestern Ontario, Niagara, and Eastern Ontario regions' hydroelectric stations, partially offset by higher availability from the Sir Adam Beck Pump GS due to a higher number of planned outages days in 2016 as a result of the refurbishment of the station's reservoir.

The definition of Hydroelectric Availability is found in the section, *Key Operating and Financial Performance Indicators*.

Contracted Generation Portfolio Segment

(millions of dollars)	2017	2016
Revenue	**579**	573
Fuel expense	**53**	58
Gross margin	**526**	515
Operations, maintenance and administration	**169**	178
Depreciation and amortization	**79**	75
Accretion on fixed asset removal liabilities	**9**	9
Property taxes	**7**	7
Income from investments subject to significant influence	**(38)**	(37)
Income before other losses, interest, and income taxes	**300**	283
Other losses	**-**	1
Income before interest and income taxes	**300**	282

Income before interest and income taxes increased by $18 million during 2017, compared to 2016. The increase in earnings primarily resulted from revenues from the Peter Sutherland Sr. GS that was placed in-service at the end of the first quarter of 2017 and lower OM&A expenses, partially offset by lower revenues from the Lower Mattagami River hydroelectric generating stations and Atikokan GS. The lower OM&A expenses were mainly due to the prospective adoption of the full yield curve approach to the estimation of the service and interest cost components of pension and OPEB costs starting in 2017.

The Hydroelectric Availability and the Thermal EFOR for the Contracted Generation Portfolio segment were as follows:

	2017	2016
Hydroelectric Availability *(%)*	**74.6**	77.3
Thermal EFOR *(%)*	**2.4**	1.6

Lower Hydroelectric Availability during 2017, compared to 2016, was primarily due to an increase in the number of planned outage days at the Lower Mattagami River hydroelectric generating stations.

The higher thermal EFOR in 2017, compared to 2016, was primarily due to a higher number of unplanned outage days at a Lennox GS unit as a result of a transmission outage and a generator-related outage in 2017.

The definitions of Hydroelectric Availability and Thermal EFOR are found in the section, *Key Operating and Financial Performance Indicators*.

Services, Trading, and Other Non-Generation Segment

(millions of dollars)	2017	2016
Revenue	**43**	68
Fuel expense	**1**	1
Gross margin	**42**	67
Operations, maintenance and administration	**18**	22
Depreciation and amortization	**30**	32
Accretion on fixed asset removal liabilities	**8**	8
Property taxes	**6**	12
Restructuring	**-**	6
Loss before other gain, interest, and income taxes	**(20)**	(13)
Other gains	**(384)**	-
Income before interest and income taxes	**364**	(13)

Segment earnings improved by $377 million in 2017 compared to 2016. The increase in earnings mainly reflected the gain on the sale of OPG's head office premises and associated parking facility recorded during the second quarter of 2017 of $283 million, which is net of tax effects of $95 million, partially offset by a decrease in rental revenue due to the sale of the head office premises.

The year-over-year decrease in OM&A expenses in 2017 reflected higher expenses incurred in 2016 prior to the decision taken in the fourth quarter of 2016 to proceed with the decommissioning of the Lambton GS, largely offset by a higher write-off of previously incurred project expenditures in 2017.

During the fourth quarter of 2017, OPG recorded $12 million in Other gains related to the revaluation of the asset retirement obligations for Lambton and Nanticoke generating stations in line with the current decommissioning plans and cost estimates. During each of 2017 and 2016, OPG recorded a charge against earnings to adjust the scrap value estimate for the Lambton GS, as a reduction to Other gains.

Fair Hydro Trust Segment

(millions of dollars)	2017
Operations, maintenance and administration	**1**
Earnings from Fair Hydro Trust	**(1)**
Income before interest and income taxes	**-**

The Fair Hydro Trust was established on December 20, 2017. The Fair Hydro Trust segment includes the revenue and expenses related to OPG's role as Financial Services Manager of the Fair Hydro Trust and holder of subordinated debt issued by the Trust, including the financial results of the Trust. Earnings from Fair Hydro Trust were $1 million in 2017, primarily due to net interest income earned on OPG's subordinated debt investment for the 11-day period following the acquisition of the first tranche of Investment Interest from the IESO on December 21, 2017. The earnings were offset by an allocation of OM&A expenses for labour costs relating to OPG's employees that are not exclusively dedicated to the segment but who provided services to set up the Trust during the year. Pursuant to the general regulation of the Fair Hydro Act, such labour costs are not recoverable as part of OPG's fees for 2017. Refer to the section, *Recent Developments* under the heading, *Ontario's Fair Hydro Plan* and the section, *Business Segments* under the heading, *Fair Hydro Trust Segment* for further details on the Fair Hydro Trust.

LIQUIDITY AND CAPITAL RESOURCES

OPG's primary sources of liquidity and capital are funds generated from operations, bank financing, credit facilities provided by the Ontario Electricity Financial Corporation (OEFC), long-term corporate debt, including public debt offerings and notes payable to the OEFC, private placement project financing, and equity issuance. These sources are used for multiple purposes including: to invest in plants and technologies, to undertake major projects, to fund long-term obligations such as contributions to the pension fund and the Nuclear Segregated Funds, to make payments under the OPEB plans, to fund expenditures on Nuclear Liabilities not eligible for reimbursement from the Nuclear Segregated Funds, and to service and repay long-term debt, to provide general working capital, and to fund a portion of OPG's subordinated debt investment in the Fair Hydro Trust and the Trust's acquisition of Investment Interest from the IESO.

Changes in cash and cash equivalents for 2017 and 2016 were as follows:

(millions of dollars)	**2017**	**2016**
Cash and cash equivalents, beginning of period	**186**	464
Cash flow provided by operating activities	**944**	1,817
Cash flow used in investing activities	**(2,478)**	(1,919)
Cash flow provided by (used in) financing activities	**1,582**	(176)
Net increase (decrease) in cash and cash equivalents	**48**	(278)
Cash and cash equivalents, end of period	**234**	186

For a discussion regarding cash flow provided by operating activities and the FFO Adjusted Interest Coverage ratio, refer to the details in the section, *Highlights* under the heading, *Overview of Results*.

Investing Activities

Electricity generation is a capital-intensive business. It requires continued investment in plants and technologies to maintain and improve operating performance including asset reliability, safety and environmental performance, to increase the generating capacity of existing stations, and to invest in the development of new generating stations, emerging technologies and other business growth opportunities.

Cash flow used in investing activities in 2017 increased by $834 million compared to 2016. The increase in net cash flow used in investing activities was primarily due to the Trust's acquisition of the first tranche of Investment Interest from the IESO in the amount of approximately $1.18 billion in December 2017 and higher expenditures on the Darlington Refurbishment project in 2017.

The increase in net cash flow used in investing activities was partially offset by the receipt of proceeds from the sale of OPG's head office premises and associated parking facility in 2017 and the acquisition of nine million common shares of Hydro One Limited (Hydro One) in 2016. OPG acquired the Hydro One shares for investment purposes, to mitigate the risk of future price volatility related to the Company's future share delivery obligations under the current collective agreements with the Power Workers' Union (PWU) and The Society of Energy Professionals (The Society).

Financing Activities

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. In the second quarter of 2017, OPG renewed and extended the expiry date of both tranches from May 2021 to May 2022. There were no amounts outstanding under the bank credit facility as at December 31, 2017.

There was $100 million of commercial paper outstanding under OPG's commercial paper program as at December 31, 2017.

As at December 31, 2017, OPG also maintained $25 million of short-term, uncommitted overdraft facilities, and a further $468 million of short-term, uncommitted credit facilities which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other general corporate purposes. As at December 31, 2017, a total of $390 million of Letters of Credit had been issued under these facilities. This included $353 million for the supplementary pension plans, $36 million for general corporate purposes, and $1 million related to the operation of the PEC.

The Company has an agreement to sell an undivided co-ownership interest in its current and future accounts receivable to an independent trust, expiring on November 30, 2018. The maximum amount of co-ownership interest that can be sold under this agreement is $150 million. As at December 31, 2017, no borrowings were issued under this agreement and there were Letters of Credit outstanding under this agreement of $150 million, which were issued in support of OPG's supplementary pension plans.

As at December 31, 2017, Lower Mattagami Energy Limited Partnership (LME) maintained a $400 million bank credit facility to support the funding requirements for the Lower Mattagami River project including support for LME's commercial paper program. The facility consists of a $300 million tranche maturing in August 2022 and a $100 million tranche maturing in August 2018. As at December 31, 2017, there was $160 million commercial paper outstanding under LME's commercial paper program. A letter of credit of $55 million was issued in July 2017 and remains outstanding as at December 31, 2017 under the $300 million tranche of LME's credit facility.

In June 2016, OPG entered into a $700 million general corporate credit facility agreement with the OEFC, with an expiry date of December 31, 2017. During 2017, the agreement was amended to increase the credit facility to $2,350 million and to extend its expiry date to December 31, 2018. As at December 31, 2017, there were outstanding long-term borrowings of $800 million under this credit facility.

In February 2017, OPG issued senior notes payable to the OEFC totalling $200 million and maturing in February 2047. The effective interest rate and coupon interest rate of these notes was 4.12 percent. In June 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in June 2047. The effective interest rate and coupon interest rate of these notes was 3.65 percent. In August 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in August 2047. The effective interest rate and coupon interest rate of these notes was 3.86 percent. In September 2017, OPG issued senior notes payable to the OEFC totalling $400 million and maturing in September 2047. The effective interest rate and coupon interest rate of these notes was 4.07 percent.

In October 2017, OPG issued $500 million of senior notes payable under a Medium Term Note Program. The notes bear a coupon interest rate of 3.32 percent and an effective rate of 3.43 percent, payable semi-annually until maturity on October 4, 2027. The offering was made under OPG's $2 billion short form base shelf prospectus dated September 12, 2017. The net proceeds will be used for general corporate purposes.

In December 2017, the Fair Hydro Trust entered into an $800 million revolving warehouse facility agreement with an expiry date of December 21, 2019. As at December 31, 2017, there were outstanding senior notes of $601 million under this credit facility, which were used to finance 51 percent of the Trust's funding requirement for the acquisition of the first tranche of Investment Interest from the IESO in December 2017.

In February 2018, the Trust issued $500 million of senior notes payable with a coupon interest rate of 3.36 percent and an effective interest rate of 3.42 percent, payable semi-annually until maturity on May 15, 2033. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility issued by the Trust in December 2017. By the end of the first quarter of 2018, the Trust is expected to acquire another tranche of Investment Interest from the IESO, which it expects to fund using its revolving warehouse facility.

As at December 31, 2017, OPG's long-term debt outstanding was $5,735 million, including $398 million due within one year and excluding Fair Hydro Trust's senior debt included in OPG's consolidated balance sheets. The Fair Hydro Trust's senior debt outstanding was $601 million as at December 31, 2017.

Contractual Obligations

OPG's contractual obligations as at December 31, 2017, are as follows:

(millions of dollars)	2018	2019	2020	2021	2022	Thereafter	Total
Fuel supply agreements	158	125	115	88	67	67	620
Contributions to the OPG registered pension plan [1]	215	219	-	-	-	-	434
OPG long-term debt repayment	398	368	663	413	172	3,721	5,735
Interest on OPG long-term debt	244	226	204	175	161	3,006	4,016
Fair Hydro Trust senior debt repayment [2]	-	601	-	-	-	-	601
Interest on Fair Hydro Trust senior debt	15	15	-	-	-	-	30
Commitments related to Darlington Refurbishment project [3]	473	-	-	-	-	-	473
Commitments related to Ranney Falls GS project	29	5	-	-	-	-	34
Operating licences	40	41	24	28	28	87	248
Operating lease obligations	28	24	24	22	22	79	199
Unconditional purchase obligations	59	58	56	5	-	-	178
Accounts payable and accrued charges	957	8	-	-	-	16	981
Other	57	30	2	1	1	64	155
Total	2,673	1,720	1,088	732	451	7,040	13,704

[1] The pension contributions include ongoing funding requirements and additional funding requirements towards the deficit, in accordance with the actuarial valuation of the OPG registered pension plan as at January 1, 2017. The next actuarial valuation of the OPG registered pension plan must have an effective date no later than January 1, 2020. The pension contributions are affected by various factors including market performance, changes in actuarial assumptions, plan experience, changes in the pension regulatory environment, and the timing of funding valuations. Funding requirements after 2019 are excluded due to significant variability in the assumptions required to project the timing of future cash flows. The amount of OPG's additional, voluntary contribution, if any, is revisited from time to time.

[2] The notes were issued by the Fair Hydro Trust under an $800 million two-year revolving warehouse facility in December 2017. In February 2018, the Trust issued $500 million of senior notes payable to repay the majority of the outstanding balance of the revolving warehouse facility.

[3] Represents estimated currently committed costs to close the project, including accruals for completed work, demobilization of project staff and cancellation of existing contracts and material orders.

Other Commitments

Collective Agreements

As of December 31, 2017, OPG had approximately 9,200 regular employees. Most of OPG's regular employees are represented by two unions:

- The PWU – This union represents approximately 4,850 OPG employees or approximately 53 percent of OPG's regular workforce as at December 31, 2017. Union membership includes operators, technicians, skilled trades, clerical, and security personnel. The current collective agreement between OPG and the PWU has a three-year term, expiring on March 31, 2018. Negotiations for a new labour agreement with the PWU are underway. **[MONITOR]**
- The Society – This union represents approximately 3,250 OPG employees or approximately 35 percent of OPG's regular workforce as at December 31, 2017. Union membership includes supervisors, professional engineers, scientists, and other professionals. The current collective agreement between OPG and The Society has a three-year term, expiring on December 31, 2018.

In addition to the regular workforce, construction work is performed through 19 craft unions with established bargaining rights at OPG facilities. These bargaining rights are established either through the Electrical Power Systems Construction Association (EPSCA) or directly with OPG. Collective agreements between the Company and its construction unions are negotiated either directly or through EPSCA. All of these collective agreements currently have multi-year terms, expiring on April 30, 2020.

BALANCE SHEET HIGHLIGHTS

The following section provides other highlights of OPG's audited consolidated financial position using selected balance sheet data as at December 31:

(millions of dollars)	**2017**	**2016**
Property, plant and equipment – net	**21,322**	19,998
The increase was primarily due to capital expenditures on the Darlington Refurbishment project, partially offset by depreciation expense.		
Nuclear fixed asset removal and nuclear waste management funds *(current and non-current portions)*	**16,724**	15,984
The increase was primarily due to earnings on the Nuclear Segregated Funds, partially offset by reimbursement of eligible expenditures on nuclear fixed asset removal and nuclear waste management activities.		
Regulatory assets and liabilities – net *(current and non-current portions)*	**6,637**	5,545
The increase was primarily due to the addition of the Interim period revenue shortfall account, increases in the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB AOCI regulatory asset. In addition, there was no amortization recorded in 2017 consistent with OPG's proposal in the Draft Payment Amounts Order filed with the OEB in January 2018.		
Long-term debt *(current and non-current portions)*	**6,319**	5,520
The increase was primarily due to the issuance of senior notes payable by the Trust to finance the acquisition of an Investment Interest in the shortfall from the rate reductions mandated by the Fair Hydro Act of $601 million, issuance of senior notes payable totaling $804 million during 2017 primarily with the OEFC, and issuance of senior notes totaling $500 million under the Medium Term Note Program. The balance is offset by the debt repayment of $1 billion in 2017.		
Fixed asset removal and nuclear waste management liabilities	**20,421**	19,484
The increase was primarily a result of accretion expense representing the increase in the present value liabilities due to the passage of time, and an increase in the estimate for the nuclear ARO of $188 million recorded in 2017, which is discussed in *Critical Accounting Policies and Estimates* under the heading, Asset Retirement *Obligation*. The increase was partially offset by expenditures on nuclear fixed asset removal and waste management activities.		
Pension liabilities	**3,423**	3,012
The increase was primarily due to the re-measurement of the liabilities at the end of 2017 reflecting lower discount rates, partially offset by the excess of actual returns on pension plan assets over interest costs on the liabilities during 2017, as discussed in the section, *Critical Accounting Policies and Estimates* under the *heading, Pension and Other Post-Employment Benefits.*		
Other post-employment benefit liabilities	**3,092**	2,897
The increase was primarily due to the remeasurement of the liabilities at the end of 2017 reflecting lower discount rates, partially offset by the updated lower per capital health care claims costs assumption as part of the 2017 actuarial valuation.		

Off-Balance Sheet Arrangements

In the normal course of operations, OPG engages in a variety of transactions that, under US GAAP, are either not recorded in the Company's interim consolidated financial statements or are recorded in the Company's interim consolidated financial statements using amounts that differ from the full contract amounts. Principal off-balance sheet activities for OPG include guarantees and long-term contracts.

Guarantees

As part of normal business, OPG and certain of its subsidiaries and joint ventures enter into various agreements to provide financial or performance assurance to third parties. Such agreements include guarantees, standby Letters of Credit and surety bonds. For more details on guarantees issued by the company, refer to Note 15 of OPG's audited consolidated financial statements.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

OPG's significant accounting policies, including the impact of major recent accounting pronouncements, are outlined in Note 3 of the audited consolidated financial statements. Certain of these policies are recognized as critical accounting policies by virtue of the subjective and complex judgments and estimates required around matters that are inherently uncertain and could result in materially different amounts being reported under different conditions or assumptions. The critical accounting policies and estimates that affect OPG's US GAAP consolidated financial statements are highlighted below.

Exemptive Relief for Reporting under US GAAP

As required by *Ontario Regulation 395/11,* as amended, under the FAA, OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. Since January 1, 2012, OPG also has received exemptive relief from the OSC from the requirements of section 3.2 of National Instrument 52-107 *Acceptable Accounting Policies and Auditing Standards* (NI 52-107). The exemption allows OPG to file consolidated financial statements with the OSC based on US GAAP, rather than International Financial Reporting Standards (IFRS), without becoming a U.S. Securities and Exchange Commission registrant.

The current OSC exemption, received in 2014, will terminate on the earliest of the following:

- January 1, 2019
- The financial year that commences after OPG ceases to have activities subject to rate regulation
- The effective date prescribed by the International Accounting Standards Board (IASB) for the mandatory application of a standard within IFRS specific to entities with rate-regulated activities.

As a result of OPG's 2011 decision to adopt US GAAP, as required by the FAA regulation, OPG's earlier plan to convert to IFRS, effective January 1, 2012, was discontinued. OPG had substantively completed its IFRS conversion project, which included separate diagnostic, development, and implementation phases, when it suspended the project. If a future transition to IFRS for the purposes of OPG's consolidated financial statements is required, conversion work can be effectively restarted with sufficient lead time to evaluate and conclude on changes that occurred subsequent to the decision to suspend the project. OPG continues to monitor the IASB's current standard-setting project related to entities with rate-regulated activities and is evaluating alternatives with respect to the Company's future financial reporting.

Rate Regulated Accounting

The *Ontario Energy Board Act, 1998* and *Ontario Regulation 53/05* provide that OPG receives regulated prices for electricity generated from 54 hydroelectric generating stations and the Pickering and Darlington nuclear generating stations. OPG's regulated prices for these facilities are determined by the OEB.

The OEB is a self-funding Crown corporation. Its mandate and authority come from the *Ontario Energy Board Act, 1998*, the *Electricity Act, 1998*, and a number of other provincial statutes. The OEB is an independent, quasi-judicial tribunal that reports to the Legislature of the Province through the Ontario Ministry of Energy. It regulates market participants in Ontario's natural gas and electricity industries. The OEB carries out its regulatory functions through public hearings and other more informal processes such as consultations.

US GAAP recognizes that rate regulation can create economic benefits and obligations that are required by the regulator to be obtained from, or settled with, the customers. When the Company assesses that there is sufficient assurance that incurred costs in respect of the regulated facilities will be recovered in the future, those costs are deferred and reported as a regulatory asset. When the Company is required to refund amounts to customers in the future in respect of the regulated facilities, including amounts related to costs that have not been incurred and for which the OEB has provided recovery through regulated prices, the Company records a regulatory liability.

Certain of the regulatory assets and liabilities recognized by the Company relate to variance and deferral accounts authorized by the OEB, including those authorized pursuant to *Ontario Regulation 53/05.* The measurement of these regulatory assets and liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of *Ontario Regulation 53/05* and the OEB's decisions. The estimates and assumptions made in the interpretation of the regulation and the OEB's decisions are reviewed as part of the OEB's regulatory process.

Regulatory assets and liabilities for variance and deferral account balances approved by the OEB for inclusion in regulated prices are amortized based on approved recovery or repayment periods.

In addition to regulatory assets and liabilities for variance and deferral accounts, OPG recognizes regulatory assets and liabilities for unamortized amounts recorded in AOCI in respect of pension and OPEB obligations, and deferred income taxes, in order to reflect the expected recovery or repayment of these amounts through future regulated prices charged to customers. There are measurement uncertainties related to these balances due to the assumptions made in the determination of pension and OPEB obligations and deferred income taxes that are attributed to rate regulated business segments.

The regulatory asset for unamortized pension and OPEB amounts recorded in AOCI has reflected the OEB's use, since April 1, 2008, of the accrual basis of accounting for including pension and OPEB amounts in approved regulated prices for OPG. This is also the manner in which these costs are recognized in OPG's consolidated financial statements. Therefore, unamortized amounts in respect of OPG's pension and OPEB plans recognized in AOCI generally would not be reflected in regulated prices until they have been reclassified from AOCI and recognized as amortization components of the benefit costs for these plans.

Since November 1, 2014, the OEB has limited amounts for pension and OPEB costs included in the approved revenue requirements and regulated prices to the regulated business portion of the Company's cash expenditures for its pension and OPEB plans. The difference between actual pension and OPEB costs determined using the accrual method applied in OPG's audited consolidated financial statements and OPG's corresponding actual cash expenditures for these plans is captured in OEB-authorized Pension & OPEB Cash Versus Accrual Differential Deferral Account for future consideration. In 2017, the OEB issued a report outlining the guiding principles and policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the Ontario electricity and natural gas sectors. The report establishes the accrual basis of accounting as the method of determining pension and OPEB amounts for rate-setting purposes, unless the OEB finds that this method does not result in just and reasonable rates in the circumstances of a particular utility. The OEB's report and the OEB's December 2017 decision on OPG's

application for new regulated prices require OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the existing deferral account, until such time as the OEB approves resumption of the accrual basis of recovery for OPG. The future recovery of amounts recorded in the account will be subject to this approval. Further details on the OEB's 2017 report can be found in the section, *Highlights* under the heading, *Recent Developments – OEB's Decision on OPG's Application for New Regulated Prices*.

It remains the Company's position that, taken collectively, OEB's decisions on OPG's applications for regulated prices and the OEB's 2017 report in this area do not constitute a change in the basis of OPG's rate recovery of pension and OPEB costs. The Company continues to believe that there is sufficient likelihood that unamortized pension and OPEB amounts that have not yet been reclassified from AOCI will be included in future regulated prices, or in an OEB-authorized regulatory account for future recovery, as they are recognized in benefit costs. Similarly, the Company continues to believe that there is sufficient likelihood that amounts recorded in the Pension & OPEB Cash Versus Accrual Differential Deferral Account will be recovered, and consistent with the expectations set out in the OEB's December 2017 decision, plans to file an application with the OEB in 2018 requesting recovery of the account balance. Therefore, the Company continues to recognize regulatory assets for the above amounts.

See Notes 3, 5, 8, 9, and 11 of OPG's 2017 audited consolidated financial statements for additional disclosures related to the OEB's decisions, regulatory assets and liabilities, and rate regulated accounting.

Useful Lives of Long-Lived Assets

OPG reviews estimated station useful lives for its generating assets on a regular basis.

Nuclear Generating Stations

For the nuclear stations, this process involves reviewing major life limiting components (such as pressure tubes, feeders and steam generators) to determine an appropriate end-of-life date for the station. Useful lives are set such that, with normal and customary maintenance activities, stations are expected to be operational until such time as their life-limiting component's threshold is expected to be reached.

Hydroelectric and Thermal Generating Stations

Although there is a link between the age of a facility and the capital investment required to maintain that facility, age does not establish an upper limit on the expected useful life of hydroelectric facilities and dams. Regular maintenance and the replacement of specific components typically allow hydroelectric stations to operate for very long periods. For hydroelectric generating stations, an upper age limit of 100 years have been set.

Thermal generating stations reported in the Contracted – Generation Portfolio business segment primarily have useful lives that are in line with the term of the Energy Supply Agreements with the IESO.

Financing Receivables

Financing receivables consist of the current and irrevocable right of the Fair Hydro Trust to collect payments from Specified Consumers in the future in accordance with the Fair Hydro Act and associated general regulation. These amounts are measured at the transaction price entered into with the IESO on market terms upon acquisition and subsequently measured on an amortized cost basis. The basis of amortization follows the effective interest method.

Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

In accordance with the ONFA, OPG sets aside and invests funds that are held in segregated custodian and trustee accounts specifically for discharging its obligation for nuclear facilities decommissioning and long-term nuclear waste management. The Decommissioning Segregated Fund was established to fund the future costs of nuclear fixed asset removal and long-term L&ILW management, and certain costs of used fuel storage incurred after the stations are shut down. The Used Fuel Segregated Fund was established to fund the future costs of long-term nuclear used

fuel management and certain costs of used fuel storage incurred after the stations are shut down. Costs for L&ILW management and used fuel storage incurred during station operation are not funded by the Nuclear Segregated Funds. They are funded through the Company's operating cash flow or other sources of liquidity.

Based on the current approved ONFA reference plan, starting in 2017, OPG is not currently required to make overall contributions to the Used Fuel Segregated Fund or the Decommissioning Segregated Fund. Prior to 2017, OPG made contributions to the Used Fuel Segregated Fund quarterly, including a one-time special payment in earlier years, as required by the ONFA. These contributions reflected ONFA requirements to fund the majority of the underlying used fuel liability by the end of the initial estimated useful lives of the nuclear stations assumed in the ONFA, resulting in significantly higher contributions to the Used Fuel Segregated Fund in the earlier years of OPG's existence. OPG has not been required to make contributions to the Decommissioning Segregated Fund, which was fully funded at its inception through the initial contribution made by the Ontario Electricity Financial Corporation (OEFC), an agency of the Province, and, taking into account asset performance and changes in underlying funding obligations over time, at the time of every subsequent approved ONFA reference plan. Contributions to either or both funds may be required in the future should the funds be in an underfunded position when a new reference plan is prepared. Such may be the case as a result of variability in asset performance due to volatility inherent in financial markets and, for the portion of the Used Fuel Segregated Fund guaranteed by the Province, changes in the Ontario CPI. Future contribution levels also are dependent on changes in baseline cost and liability estimates and underpinning assumptions used to establish the funding obligations in subsequent ONFA reference plans.

Decommissioning Segregated Fund

Upon termination of the ONFA, the Province has the sole right to any excess funds in the Decommissioning Segregated Fund. Accordingly, when the Decommissioning Segregated Fund is overfunded, OPG limits the fund earnings it recognizes in the consolidated financial statements by recording an amount due to the Province, such that the fund asset recognized on the consolidated balance sheet is equal to the cost estimate of the liability based on the most recently approved ONFA reference plan. Additionally, OPG recognizes the portion of the surplus that it may direct to the Used Fuel Segregated Fund, which is possible when the surplus is such that the underlying liabilities, as defined by the most recently approved ONFA reference plan, are at least 120 percent funded. In those circumstances, OPG may direct, at the time a new or amended reference plan is approved, up to 50 percent of the surplus over 120 percent to the Used Fuel Segregated Fund, with the OEFC entitled to a distribution of an equal amount. Therefore, when the Decommissioning Segregated Fund is at least 120 percent funded, OPG recognizes 50 percent of the excess greater than 120 percent in income, up to the amount by which the Used Fuel Segregated Fund is underfunded.

The amount due to the Province in respect of the Decommissioning Segregated Fund could be reduced in subsequent periods in the event that the fund earns less than is target rate of return, a new ONFA reference plan is approved with a higher underlying liability, or the amount of the underfunding in the Used Fuel Segregated Fund increases.

When the Decommissioning Segregated Fund is underfunded, the earnings on the fund reflect actual fund returns based on the market value of the assets.

Used Fuel Segregated Fund

Under the ONFA, the Province guarantees OPG's annual return in the Used Fuel Segregated Fund at 3.25 percent plus the change in the Ontario CPI, as defined in the ONFA, for funding related to the first 2.23 million used fuel bundles ("committed return"). OPG recognizes the committed return on the Used Fuel Segregated Fund as earnings on the Nuclear Segregated Funds. The difference between the committed return and the actual market return determined based on the fair value of the fund's assets related to the first 2.23 million used fuel bundles is recorded as due to or due from the Province. This amount represents the amount OPG would pay to, or receive from, the Province if the committed return were to be settled as of the consolidated balance sheet date. Upon approval of a

new or amended ONFA reference plan, the Province is obligated to make an additional contribution to the Used Fuel Segregated Fund in relation to the first 2.23 million used fuel bundles if the fund's assets earned a rate of return that is less than the guaranteed rate of return. If the return on the fund's assets exceeds the Province's guaranteed rate of return, the Province is entitled to withdraw any portion of the excess related to the 2.23 million used fuel bundles, upon approval of a new or amended ONFA reference plan. The 2.23 million threshold represents the estimated total life cycle fuel bundles based on the initial estimated useful lives of the nuclear stations assumed in the ONFA.

As prescribed under the ONFA, OPG's contributions attributed to the used fuel bundles in excess of 2.23 million are not subject to the rate of return guaranteed by the Province, and earn a return based on changes in the market value of the assets of the Used Fuel Segregated Fund.

If there is a surplus in the Used Fuel Segregated Fund such that the funding liabilities, as defined by the most recently approved ONFA Reference Plan, are at least 110 percent funded, the Province has the right, at any time, to access the excess amount greater than 110 percent. Upon termination of the ONFA, the Province is entitled to any surplus in the fund. Accordingly, when the Used Fuel Segregated Fund is overfunded, OPG limits the fund earnings it recognizes in the consolidated financial statements by recording an amount due to the Province, such that the balance of the fund is equal to the cost estimate of the liability based on the most recently approved ONFA reference plan. In accordance with the ONFA, neither OPG nor the Province have a right to direct any amounts from the Used Fuel Segregated Fund to the Decommissioning Segregated Fund.

Provincial Guarantee

In accordance with the *Nuclear Safety and Control Act* (Canada), the CNSC requires OPG to have sufficient funds available to discharge its existing nuclear waste management and nuclear decommissioning obligations. The CNSC process requires the CNSC financial guarantee requirement to be updated once every five years and for OPG to provide an annual report to the CNSC on the assumptions, asset values, and resulting financial guarantee requirements. The CNSC financial guarantee requirement calculation takes into account nuclear waste expected to be generated to the end of each year.

In November 2017, the CNSC accepted OPG's proposed 2018-2022 CNSC financial guarantee requirement to be satisfied by the forecast fair market value of the Nuclear Segregated Funds without the requirement of a Provincial Guarantee for the 2018-2022 period. As ~~required~~ provided for by the terms of the ONFA, the Province is committed to provide a Provincial Guarantee to the CNSC as required, on behalf of OPG, should there be a shortfall between the CNSC financial guarantee requirement and the fair market value of the Nuclear Segregated Funds in the 2018-2022 period, as it has done in the past. OPG pays the Province an annual guarantee fee equal to 0.5 percent of the outstanding amount, if any, of the Provincial Guarantee.

The value of the Provincial Guarantee in effect through to the end of 2017 was $1,551 million. Based on this guarantee amount, OPG paid a guarantee fee of $8 million to the Province for each of 2016 and 2017.

Pension and Other Post-Employment Benefits

The determination of OPG's pension and OPEB costs and obligations is based on accounting policies and assumptions, as discussed below.

Accounting Policy

OPG's post-employment benefit programs consist of a contributory defined benefit registered pension plan, a defined benefit supplementary pension plan, and other post retirement benefits (OPRB) including group life insurance and health care benefits, and long-term disability (LTD) benefits. Post-employment benefit programs also are provided by the Nuclear Waste Management Organization (NWMO), which is consolidated into OPG's financial results. Unless otherwise noted, information on the Company's post-employment benefit programs is presented on a consolidated basis.

OPG accrues its obligations under pension and OPEB plans in accordance with US GAAP. The obligations for pension and OPRB are determined using the projected benefit method pro-rated on service. The obligation for LTD benefits is determined using the projected benefit method on a terminal basis. Pension and OPEB obligations are impacted by factors including interest rates, adjustments arising from plan amendments, demographic assumptions, experience gains or losses, salary levels, inflation, and health care cost escalation assumptions. Pension and OPEB costs and obligations are determined annually by independent actuaries using management's best estimate assumptions.

Pension fund assets include equity securities, corporate and government debt securities, pooled funds, real estate, infrastructure and other investments. These assets are managed by professional investment managers. The pension fund does not invest in equity or debt securities issued by OPG. Pension fund assets are valued using market-related values for purposes of determining the amortization of actuarial gains or losses and the expected return on plan assets. The market-related value recognizes gains and losses on equity assets relative to a six percent assumed real return over a five-year period.

Pension and OPEB costs include current service costs, interest costs on the obligations, the expected return on pension plan assets, adjustments for plan amendments and adjustments for actuarial gains or losses, which result from changes in assumptions and experience gains and losses. Past service costs or credits arising from pension and OPRB plan amendments are amortized on a straight-line basis over the expected average remaining service life to full eligibility of the employees covered by the corresponding plan. Past service costs or credits arising from amendments to LTD benefits are immediately recognized as OPEB costs in the period incurred. Due to the long-term nature of pension and OPRB liabilities, the excess of the net cumulative unamortized gain or loss, over 10 percent of the greater of the benefit obligation and the market-related value of the plan assets (the corridor) for each plan is amortized over the expected average remaining service life of the employees covered by the plan, which represents the period during which the associated economic benefits are expected to be realized by the Company. Actuarial gains or losses for LTD benefits are immediately recognized as OPEB costs in the period incurred.

OPG recognizes the funded status of its defined benefit plans on the consolidated balance sheets. The funded status is measured as the difference between the fair value of plan assets and the benefit obligation, on a plan-by-plan basis.

Actuarial gains or losses and past service costs or credits arising during the year that are not recognized immediately as components of benefit costs are recognized as increases or decreases in other comprehensive income (OCI), net of income taxes. These unamortized amounts in AOCI are subsequently reclassified and recognized as amortization components of pension and OPRB costs as described above.

As at December 31, 2017, the unamortized net actuarial loss and unamortized past service costs for the pension and OPEB plans totalled $4,148 million (2016 – $3,668 million). Details of the unamortized net actuarial loss and unamortized past service costs as at December 31, 2017 and 2016 are as follows:

(millions of dollars)	Registered Pension Plans 2017	2016	Supplementary Pension Plans 2017	2016	Other Post-Employment Benefits 2017	2016
Net actuarial gain not yet subject to amortization due to use of market-related values	**(418)**	(570)	**-**	-	**-**	-
Net actuarial loss not subject to amortization due to use of the corridor	**1,735**	1,619	**36**	34	**299**	267
Net actuarial loss subject to amortization	**2,333**	2,238	**80**	72	**79**	3
Unamortized net actuarial loss	**3,650**	3,287	**116**	106	**378**	270
Unamortized past service costs	**-**	-	**-**	-	**4**	5

OPG records an offsetting regulatory asset or liability for the portion of the adjustments to AOCI that is attributable to the regulated operations in order to reflect the expected recovery or refund of these amounts through future regulated prices charged to customers. For the recoverable or refundable portion attributable to regulated operations, OPG records a corresponding change in this regulatory asset or liability for the amount of the increases or decreases in OCI and for the reclassification of AOCI amounts into benefit costs during the period.

When the recognition of the transfer of employees and employee-related benefits gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement. A curtailment is the loss by employees of the right to earn future benefits under the plan. A settlement is the discharge of a plan's liability.

Accounting Assumptions

Assumptions are significant inputs to actuarial models that measure pension and OPEB obligations and related effects on operations. Discount rate, inflation rate and changes in salary levels are three critical assumptions in the determination of benefit costs and obligations. In addition, the expected long-term rate of return on plan assets is a critical assumption in the determination of registered pension plan cost, and the health care cost trend rate is a critical assumption in the determination of OPEB cost and obligations. These assumptions, as well as other assumptions involving demographic factors such as retirement age, mortality, and employee turnover, are evaluated periodically by management in consultation with independent actuaries. During the evaluation process, the assumptions are updated to reflect past experience and expectations for the future. Actual results in any given year will often differ from actuarial assumptions because of economic and other factors giving rise to actuarial gains and losses.

The discount rates, which are representative of the AA corporate bond yields, are used to calculate the present value of the expected future cash flows on the measurement date in order to determine the projected benefit obligations for the Company's employee benefit plans. A lower discount rate increases the benefit obligations. The weighted-average discount rate used to determine the projected pension and OPEB benefit obligations as at December 31, 2017 was 3.6 percent. This represents a decrease compared to the 3.9 percent discount rate that was used to determine the obligations as at December 31, 2016.

In 2016 and prior years, benefit costs were calculated using the same single weighted-average discount rates as reflected in the calculation of the benefit obligations. Effective January 1, 2017, OPG adopted a full yield curve approach to the estimation of the service and interest cost components of pension and OPEB costs, by applying the specific spot rates along the yield curve used in the determination of the projected benefit obligations to the relevant projected cash flows. The change improves the correlation between projected benefit cash flows and the corresponding yield curve spot rates, and provides a more precise measurement of service and interest costs. This change in the method was accounted for prospectively, as a change in estimate. The resulting reduction in pension and OPEB costs is estimated at approximately $135 million for the twelve months ended December 31, 2017. Approximately 90 percent of this reduction in pension and OPEB costs was attributed to the Company's regulated

business segments and therefore was offset by the impact of OEB-authorized regulatory accounts. The change does not affect the measurement of the total benefit obligation as the change in the current service and interest cost components from the previous method is offset by a corresponding change in the actuarial gain or loss recorded in AOCI.

The expected rate of return on plan assets is determined based on the pension fund's asset allocation and the expected return considering long-term risks and returns associated with each asset class within the plan portfolio. A lower expected rate of return on plan assets increases pension cost.

A new actuarial valuation of the OPG registered pension plan was filed with the Financial Services Commission of Ontario in September 2017 with an effective date of January 1, 2017. The annual funding requirements in accordance with the new actuarial valuation are outlined in the section, *Liquidity and Capital Resources* under the heading, *Contractual and Commercial Commitments*. OPG conducted a comprehensive actuarial valuation for accounting purposes of its pension and OPEB plans in 2017, using demographic data as at January 1, 2017 consistent with the new funding valuation and using assumptions as at December 31, 2017. As part of the valuation, the plans' demographic and other assumptions were reviewed and revised, as necessary, by independent actuaries.

The deficit for the registered pension plan, for accounting purposes, increased from $2,693 million as at December 31, 2016 to $3,081 million as at December 31, 2017. This increase was largely due to a re-measurement of the liabilities at the end of 2017 reflecting lower discount rates, partially offset by the excess of actual returns on the pension plan assets over interest costs on the liabilities during the year.

The projected benefit obligations for OPEB increased from $2,992 million as at December 31, 2016 to $3,190 million as at December 31, 2017. This increase was largely due to a re-measurement of the liabilities at the end of 2017 reflecting a decrease in the discount rates, partially offset by the updated, lower per capita health care claims costs assumption as part of the 2017 actuarial valuation.

A change in the following assumptions, holding all other assumptions constant, would increase (decrease) pension and OPEB costs for the year ended December 31, 2017 as follows:

(millions of dollars)	**Registered Pension Plans [1]**	**Supplementary Pension Plans [1]**	**Other Post-Employment Benefits [1]**
Expected long-term rate of return			
0.25% increase	(32)	n/a	n/a
0.25% decrease	32	n/a	n/a
Discount rate			
0.25% increase	(56)	(1)	(2)
0.25% decrease	59	1	13
Inflation			
0.25% increase	98	1	-
0.25% decrease	(91)	(1)	-
Salary increases			
0.25% increase	22	3	-
0.25% decrease	(20)	(2)	-
Health care cost trend rate			
1% increase	n/a	n/a	77
1% decrease	n/a	n/a	(29)

n/a – change in assumption not applicable.

[1] Excludes the impact of regulatory accounts.

Asset Retirement Obligation

OPG recognizes ARO for fixed asset removal and nuclear waste management liabilities, discounted for the time value of money. OPG estimates both the amount and timing of future cash expenditures based on the plans for fixed asset removal and nuclear waste management. The ARO is comprised of expected costs to be incurred up to and beyond termination of operations and the closure of nuclear and thermal generating plant facilities and other facilities. Costs are expected to be incurred for activities such as preparation for safe storage and safe storage of nuclear stations, dismantlement, demolition and disposal of facilities and equipment, remediation and restoration of sites, and the ongoing and long-term management of nuclear used fuel bundles and L&ILW material. The liabilities associated with the decommissioning of the nuclear generating stations and the long-term management of used nuclear fuel comprise the most significant amounts of the total obligation.

The nuclear decommissioning liability includes the estimated costs of closing the nuclear stations after the end of their service lives, which includes preparation and placement of the stations into a safe state condition followed by an assumed 30-year safe store period prior to station dismantlement and site restoration. Activities associated with the placement of stations into a safe state condition include de-fuelling and de-watering of the nuclear reactors. OPG is responsible for the nuclear waste management and nuclear decommissioning obligations associated with the Bruce nuclear generating stations and includes the associated costs in its ARO. Pursuant to the lease agreement, Bruce Power must return the two Bruce stations to OPG together, in a de-fuelled and de-watered state. As such, these de-watering and de-fuelling costs are not part of OPG's ARO.

The life cycle costs of L&ILW management include the costs of processing and storage of such radioactive wastes during and following the operation of the nuclear stations, as well as the costs of the ultimate long-term management of these wastes. The current assumptions used to establish the obligation for these costs include an L&ILW DGR facility to be constructed and operated by OPG, as discussed in the section, *Core Business, Strategy, and Outlook* under the heading, *Project Excellence*. To estimate the liability for nuclear used fuel management, OPG has adopted an approach consistent with the Adaptive Phased Management concept approved by the Government of Canada, which assumes a deep geologic repository for the long-term management of Canada's nuclear used fuel waste. The NWMO is responsible for the design and implementation of Canada's plan for the long-term management of used nuclear fuel.

The following costs are recognized as a liability on OPG's consolidated balance sheets:

- the present value of the costs of decommissioning the nuclear and thermal production facilities and other facilities after the end of their useful lives
- the present value of the fixed cost portion of nuclear waste management programs that are required based on the total volume of waste expected to be generated over the assumed lives of the stations
- the present value of the variable cost portion of nuclear waste management programs taking into account waste volumes generated to date.

The significant assumptions underlying operational and technical factors used in the calculation of the accrued liabilities are subject to periodic review. Changes to these assumptions, including changes to assumptions on the timing of the programs including construction of assumed waste disposal facilities, station end-of-life dates, waste disposal methods, financial indicators, decommissioning strategy, and the technology employed may result in significant changes to the value of the accrued liabilities. With programs of such long-term duration and the evolving technology to handle nuclear waste, there is a significant degree of inherent uncertainty surrounding the measurement of the costs for these programs. These costs may increase or decrease over time.

The estimates for the Nuclear Liabilities are reviewed on an ongoing basis as part of the overall nuclear waste management program. A comprehensive reassessment of all underlying assumptions and baseline cost estimates is performed periodically, at least once every five years, in line with the required ONFA reference plan update process. Changes in the Nuclear Liabilities resulting from changes in assumptions or estimates that impact the amount or

timing of the estimated undiscounted future cash flows are recorded as an adjustment to the liabilities. Upward revisions in the Nuclear Liabilities represent the present value of a net increase in future undiscounted cash flows determined using a current credit-adjusted risk-free rate. Downward revisions in the Nuclear Liabilities represent the present value of a net decrease in future undiscounted cash flows determined using the weighted average discount rate reflected in the existing liability. Resulting changes in the related asset retirement costs are capitalized as part of the carrying amount of nuclear fixed assets in service.

As of December 31, 2017, OPG recorded an increase of $188 million in the Nuclear Liabilities and associated asset retirement costs capitalized as part of carrying value of property, plant and equipment (PP&E) reflecting the change in the Pickering GS accounting end-of-life assumptions from December 31, 2020 for all operating units to December 31, 2022 for Units 1 and 4 and December 31, 2024 for Units 5 to 8. The increase in the liabilities is primarily due to higher fixed costs associated with the Used Fuel Disposal and L&ILW Storage programs, discounted using the current credit-adjusted risk-free rate of 2.94 percent. The adjustment did not impact net income for 2017. The adjustment is not expected to have a material impact on net income in 2018 as the associated impact on expenses is expected to be largely offset by OEB-authorized regulatory accounts. The change in accounting end-of-life assumptions for the Pickering GS are discussed in further detail in the section, *Core Business, Strategy, and Outlook* under the heading, *Operational Excellence – Electricity Generation Production and Reliability*.

For the purposes of calculating OPG's Nuclear Liabilities, as at December 31, 2017, consistent with the current accounting end-of-life assumptions, nuclear station decommissioning activities are projected to occur over approximately the next 80 years.

The liability for nuclear fixed asset removal and nuclear waste management on a present value basis as at December 31, 2017 was $20,077 million (2016 – $19,103 million). As at December 31, 2017, the undiscounted cash flows of expenditures for OPG's Nuclear Liabilities in 2017 dollars are as follows:

(millions of dollars)	**2018**	**2019**	**2020**	**2021**	**2022**	**Thereafter**	**Total**
Expenditures for nuclear fixed asset removal and nuclear waste management [1]	323	326	323	311	598	40,513	42,394

[1] The majority of the expenditures are expected to be reimbursed by the Nuclear Segregated Funds established by the ONFA. Any contributions required under the ONFA are not included in these undiscounted cash flows. Accounting for the Nuclear Segregated Funds is discussed in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

The liability for non-nuclear fixed asset removal was $344 million as at December 31, 2017 (2016 – $381 million). This liability primarily represents the present value of estimated costs of decommissioning OPG's thermal generating stations at the end of their service lives. OPG has updated the asset retirement obligations for the thermal generating stations as of December 31, 2017, based on a review of required decommissioning, clean-up and restoration activities, underlying economic assumptions and anticipated timing of these activities in line with current accounting end-of-life assumptions for the operating sites. For the shutdown Nanticoke and Lambton generating stations, the update reflects the estimated cost of executing current decommissioning plans. For the currently operating sites, OPG recognized a decrease of $18 million in the non-nuclear fixed asset removal liabilities and associated asset retirement costs capitalized as part of the carrying value of PP&E as at December 31, 2017. For the Nanticoke and Lambton sites, a reduction in the non-nuclear fixed asset removal liabilities and a gain of approximately $12 million was recorded in net income in the fourth quarter of 2017, in the, Services, Trading, and Other Non-Generation segment.

For the purpose of measuring the non-nuclear fixed asset removal liability, asset removal activities are assumed to take place approximately over the next one to 12 years. The amount of undiscounted estimated future cash flows associated with the thermal liabilities is approximately $400 million.

OPG has no legal obligation associated with the decommissioning of its hydroelectric generating facilities and the costs cannot be reasonably estimated because of the long service life of these assets. With either maintenance efforts or rebuilding, the water control structures are assumed to be used for the foreseeable future. Accordingly, OPG has not recognized a liability for the decommissioning of its hydroelectric generating facilities.

Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly arm's-length transaction between market participants at the measurement date. Fair value measurements are required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model.

The fair value of financial assets and liabilities for which quoted prices in an active market are available, including exchange traded derivatives and other financial instruments, are determined directly from those quoted market prices.

For financial instruments for which quoted market prices are not directly available, fair values are estimated using forward price curves developed from observable market prices or rates. The estimation of fair value may include the use of valuation techniques or models, based wherever possible on assumptions supported by observable market prices or rates prevailing at the consolidated balance sheet dates. This is the case for over-the-counter derivatives and securities, which include energy commodity derivatives, foreign exchange derivatives, interest rate swap derivatives, and fund investments. Pooled fund investments are valued at the unit values supplied by the pooled fund administrators. The unit values represent the underlying net assets at fair values, determined using closing market prices. Valuation models use general assumptions and market data and therefore do not reflect the specific risks and other factors that may affect a particular instrument's fair value. The methodologies used for calculating the fair value adjustments are reviewed on an ongoing basis to ensure that they remain appropriate. If the valuation technique or model is not based on observable market data, specific valuation techniques are used, primarily based on recent comparable transactions, comparable benchmark information, bid/ask spread of similar transactions, and other relevant factors.

For the financing receivables related to the Investment Interest acquired from the IESO, fair value is estimated to equal the fair value of the underlying debt due to the direct relationship of the asset, and the debt instruments that financed the acquisition.

OPG's use of financial instruments exposes the Company to certain risks, including credit risk, foreign currency risk and interest rate risk. A discussion of how OPG manages these and other risks is found under the section, *Risk Management*.

Recent Accounting Pronouncements Not Yet Adopted

The recent US GAAP accounting pronouncements related to revenue recognition, leases, and financial instruments are described below. Other recent accounting pronouncements applicable to OPG are outlined in Note 3 of the audited consolidated financial statements.

Revenue from Contracts with Customers

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09, *Revenue from Contracts with Customers* (Topic 606), which supersedes nearly all existing revenue recognition guidance, including industry-specific guidance, under US GAAP. The core principle of Topic 606 is to recognize revenues when promised goods or services are transferred to customers in an amount that reflects the consideration to which an entity expects to be entitled for those goods or services. Either a full retrospective

application or a modified retrospective application is required for annual periods beginning on or after January 1, 2018, including interim periods within that year. Early adoption is permitted.

OPG has assessed the impact of the standard on accounting for the Company's revenue streams and consolidated financial statements. OPG's major revenue streams include regulated generation revenue from base regulated prices and rate riders established by the OEB, as well as revenue from generation assets under long-term contractual arrangements with the IESO. OPG has completed its analyses of the impact of Topic 606 on all of its revenue streams, and has not identified any material differences in the timing or amount of revenue recognition for these streams.

The Company will apply the new revenue standard in its 2018 first quarter interim financial statements and is in the process of evaluating the additional disclosures required under the new standard.

Lease Accounting

In February 2016, the FASB issued ASU No. 2016-02, *Leases* (Topic 842). The update includes comprehensive changes to existing guidance for lease accounting, particularly for lessees, and aims to increase transparency and comparability among organizations by requiring the recognition of lease assets and lease liabilities on the balance sheet. The standard is effective for annual periods beginning after December 15, 2018, including interim periods within that year.

Under the current guidance, entities are required to use a modified retrospective approach for leases that exist, or are entered into, after the beginning of the earliest comparative period presented in the financial statements of the period of adoption. Under this method, Topic 842 would effectively be implemented by recognizing any adjustments stemming from the transition, as of beginning of the earliest comparative period presented in the entities' financial statements. Full retrospective application is prohibited. In January 2018, the FASB issued a proposed ASU wherein entities would be able to utilize an additional optional transition method of recording the cumulative impact of adopting the new lease standard to the opening balance in the initial period of adoption; with comparative periods continuing to be presented in accordance with the existing leasing standard, Topic 840 - *Leases*, including disclosures. [**MONITOR**] The Company will continue to monitor the status of this proposed ASU.

The FASB also issued ASU No. 2018-01, *Land Easement Practical Expedient for Transition to Topic 842* in January 2018. The amendments therein allows an entity to choose not to evaluate under Topic 842 land easements that exist or expired before the entity's adoption of the new leasing standard and that were not previously accounted for as leases under Topic 840.

The Company continues to implement and execute a comprehensive project governance framework, which comprises a Steering Committee, Implementation & Stakeholder Committee, Project Management Office, and various working groups in order to evaluate the implement the new standard. The working groups are represented by cross functional finance and non-finance stakeholders who will support the financial and operational implementation of the standard. The Company continues to evaluate the impact of the new leasing standard on its consolidated financial statements.

Recognition and Measurement of Financial Assets and Financial Liabilities

In January 2016, the FASB issued ASU No. 2016-01, *Financial Instruments – Overall: Recognition and Measurement of Financial Assets and Financial Liabilities*. Under the updated guidance, entities will have to measure equity investments at fair value and recognize any changes in fair value in net income. The update will be effective for OPG's 2018 fiscal year, including interim periods. As a result of this update, effective January 1, 2018, the available-for-sale (AFS) classification for equity securities will no longer be available, with any unrealized gains and losses related to such securities recognized in net income instead of OCI. Any unrealized gains and losses for AFS securities reported by OPG in AOCI as of the end of 2017 will be reclassified to retained earnings as of January 1, 2018. OPG's equity shareholdings in Hydro One are currently the Company's only AFS securities. As at December

31, 2017, these shares are valued on the consolidated balance sheet at $188 million, for which a loss of $8 million has been recorded in AOCI. OPG does not expect the new standard to have any other significant impact on its consolidated financial statements.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost

In March 2017, the FASB issued ASU No. 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. Under the new guidance, employers that sponsor defined benefit plans for pensions and/or other postretirement benefits are required to present the service cost component of net periodic benefit cost in the same statement of income line item as other employee compensation costs arising from services rendered during the period. The other components of the net periodic benefit cost are to be presented separately from the line item that includes the service cost and outside of any subtotal of income from operations, if such a subtotal is presented. In addition, the new guidance requires that only the service cost component of net benefit cost be eligible for capitalization.

This guidance is effective for fiscal years beginning after December 15, 2017, including interim periods of those years. The guidance is not expected to have a material impact on OPG's consolidated financial statements, as OPG currently capitalizes only the service cost component of post-retirement benefits costs. Additionally, OPG already includes the service cost component of post-retirement benefit costs with other compensation costs, within the operations, maintenance and administration expenses line item in the consolidated statements of income, and does not show a subtotal of income from operations. As such, the new guidance is not expected to affect the presentation of OPG's consolidated financial statements.

RISK MANAGEMENT

Overview

OPG faces various risks that could significantly impact the achievement of its strategic imperatives. The objective of risk management is to identify, assess and mitigate key risks, and to preserve and increase the value of the Shareholder's investment in the Company.

The Audit and Risk Committee is mandated to fulfill the oversight responsibilities of the Board of Directors for matters relating to the identification and management of the Company's key business risks. OPG's Enterprise Risk Management framework is designed to identify and evaluate risks on the basis of their potential impact on the Company's strategic imperatives and business plan objectives. Formal risk management policies, procedures and systems are in place to identify, assess and mitigate risks to the Company. Senior management also establishes set limits for the market risk, credit risk and energy trading activities of the Company.

The key risks to OPG's strategic imperatives are briefly described below. These are key risks that management believes could materially affect its business, revenues, net income, assets or capital resources. There may be further risks and uncertainties that are not presently known, or that are not currently believed to be material, that may in the future adversely affect the Company's performance or financial condition.

Risks to Achieving Operational Excellence

OPG is exposed to variable output from its existing generating stations that could adversely impact its financial performance. The operational risks of a station are generally a function of its age, human performance, and the technology used.

Asset Conditions and Generation Variability

The uncertainty associated with electricity production by OPG's generating units is primarily driven by the condition of station components and systems, which are subject to the effects of aging and the manner in which the units operate. To safely operate the units to meet electricity system requirements, a unit could be derated resulting in reduced generation. The primary implications of these risks may include additional safety requirements, lower than expected generation and revenues, and higher operating or capital costs. To respond to this risk, OPG continues to:

- monitor performance, implement extensive inspection and maintenance programs;
- identify future work required to sustain and, as appropriate, upgrade a station equipment; and
- undertake projects required to reliably operate within design and operating parameters.

Extension of Commercial Operations at Pickering to 2024

In January 2016, the Province of Ontario announced its approval of OPG's plan to pursue the continued safe and reliable operation of the Pickering GS to 2024. Under OPG's plan, the six operating units at the Pickering GS would operate until 2022, at which point two units would be shut down and the remaining four units would continue to operate until 2024. The current operating licence for the Pickering GS, which expires in August 2018, was issued in 2013 assuming that the station would shut down in 2020. Technical assessments have been completed to determine the ability of the Pickering units to continue to be fit for service to support extended operations. There is high technical confidence in the programs and provisions in place to operate the station to the end of 2024.

Inability to extend operations as planned would result in a reduction of OPG's future generation revenue and cash flows and lead to the advancement of station shutdown and decommissioning expenditures.

Risk factors for extended operations include the discovery of unexpected conditions, equipment failures, the state of critical plant components that are reaching end-of-life and a requirement for significant plant modifications. To mitigate these risks, OPG has implemented actions recommended from the technical assessments as part of the outage work program. OPG has also incorporated those actions into the comprehensive inspection and maintenance program under the Life Cycle Management Plan.

Supply Chain

OPG's ability to operate effectively is in part dependent upon timely access to equipment, materials, and service suppliers. Loss of key equipment, materials and service suppliers, particularly for the nuclear business, could affect OPG's operations and execution of major capital projects. OPG mitigates this risk, to the extent possible, through contract negotiations, contract terms, vendor monitoring, diversification of supplier base and business continuity plans.

Cyber Security

OPG's operations depend in part, on the efficient operation and management of the Company's complex information technology and operational systems in a secure, vigilant and resilient manner that minimizes cyber risks. Cyber security incidents may have an adverse impact on OPG's reputation, energy production, and public and employee safety.

Cyber security incidents have been on the rise for the past few years and this trend is only expected to intensify as global reliance on technology increases. OPG has strategies in place to prepare for, respond to, and recover from cyber security incidents. OPG continuously monitors, assesses, and improves the effectiveness of its strategies and program considering leading industry practices and remains proactive in information and intelligence sharing to learn and adapt to the changing cyber environment. In 2017, the media reported several worldwide cyber-attacks, such as WannaCry and Petya, which impacted multiple sectors including power and utilities. OPG's operational responses to those cyber-attacks were timely and effective resulting in no or low operational impact to OPG.

As a registered Ontario market participant, OPG must comply with reliability standards that apply to the Bulk Electric System elements specified under North American Electric Reliability Corporation and the relevant Bulk Power System facilities as determined by the Northeast Power Coordinating Council. In addition, OPG's nuclear cyber assets are subject to CNSC licensing conditions and regulatory requirements. For other cyber assets not subject to applicable regulatory requirements, OPG has adopted a risk-based approach based on the National Institute of Standards and Technology cyber security framework to manage its cyber security. Policies are in place to manage the Company's cyber risks and programs which are subject to oversight by management and the Board.

Regulatory Compliance

OPG is subject to extensive federal and provincial legislation and regulations by various entities such as the OEB, CNSC and the IESO.

The uncertainty associated with nuclear regulatory compliance is driven by plant aging, changes to technical codes, and challenges raised by the public at regulatory hearings, particularly in the areas of safety, environment and emergency preparedness. Addressing these requirements could add to the cost of operations, including replacement or modification of a station component or additional requirements for waste management. In some instances, these requirements may result in a reduction or elimination of the productive capacity of a station.

The Provincial agency, Office of the Fire Marshal and Emergency Management (OFMEM) is required to periodically update the Provincial Nuclear Emergency Response Plan (PNERP). In 2016, the CNSC advised the OFMEM to consider more severe accidents in the update to the PNERP, which may result in potential changes to the planning basis. Potentially, these changes may include new protective requirements and expansion of the emergency plan requirements for Pickering. In December 2017, the Province approved the updated PNERP Master Plan. The development of a detailed Implementing Plan for the Pickering GS is in progress. To date, there is no significant impact on OPG from the updated PNERP.

In December 2015, the CNSC granted the Darlington GS a ten-year operating licence, valid until November 30, 2025. The new licence spans most of the planned duration of the Darlington Refurbishment project, which provides greater regulatory stability and reduces regulatory risk. As discussed in the section, *Core Business, Strategy and Outlook*, under the heading, *Nuclear Operations*, the plan to extend Pickering operations to 2024 is subject to the CNSC's approval of the Pickering licence renewal application and other regulatory requirements as set out by the CNSC.

Nuclear Waste Management

The handling, storage and disposal of nuclear waste exposes OPG to various risks that it manages in accordance with the applicable regulatory requirements. Additionally, the interim storage of nuclear waste is subject to rigorous oversight and monitoring.

Currently, there are no licenced facilities in Canada for the permanent disposal of used nuclear fuel or L&ILW. The risks to OPG's proposed L&ILW DGR for the safe long-term management of L&ILW are discussed below under the heading, *Risks to Achieving Project Excellence – Deep Geologic Repository for Low and Intermediate Level Waste*.

Human Resources and Organizational Structure

The development of new leaders and retention of staff in critical roles is a key factor to OPG's success. The risk associated with the alignment and availability of skilled and experienced resources continues to exist for OPG in specific areas, including leadership and project management positions. To mitigate this risk, OPG continues to focus on succession planning, leadership development and knowledge management programs to improve the capability of its workforce. OPG expects to meet the human resource needs of the business by developing existing employees and hiring in specific areas, while continuing to leverage attrition through realignment of work and streamlining of processes, where appropriate.

Labour Relations

As of December 31, 2017, approximately 88 percent of OPG's regular labour force was represented by a union. The collective agreements with the PWU and The Society are due for renewal in 2018. There is a risk that OPG may not be able to negotiate terms that allow for compensation levels consistent with its rate orders.

OPG's current collective agreements with the PWU expires on March 31, 2018 and renewal negotiations began in early 2018. In the event of a labour disruption by the PWU, OPG could face financial or reputational implications. OPG has contingency plans in place to minimize the impact. **[MONITOR]**

The collective agreement between OPG and The Society expires on December 31, 2018 and renewal negotiations are expected to begin in mid-2018. The parties do not have the right to strike or lock-out. If the parties are unable to reach an agreement, the terms of the new collective agreement would be decided through interest mediation/arbitration.

Health and Safety

OPG's operations involve inherent occupational safety risks and hazards that could impact the achievement of the Company's health and safety goals. OPG is committed to continuous improvement and achievement of its ultimate goal of zero injuries through a formal enterprise-wide safety management system and by continuing to foster a strong health and safety culture among its employees and contractors. The safety management system serves to focus the Company on proactively managing safety risks and hazard exposures to employees and contractors. OPG also strategically engages with external parties for benchmarking and auditing. This ensures that OPG's management system achieves its intended results and maximizes the opportunity to incorporate program improvements.

Business Continuity and Emergency Management

OPG may be exposed to natural, technological or human-caused hazards including significant events against which it is not fully insured or indemnified; or to parties that fail to meet their indemnification obligations. These hazards have the potential to disrupt operations resulting in decreased generation revenue or additional costs to repair damages and restore operations.

OPG's business continuity program provides a framework to build resilience into critical business processes to ensure continued operation of critical business functions. OPG's emergency management program is designed to ensure that the Company can manage an emergency in a timely and effective manner. OPG's plans and implementation procedures identify immediate response actions to be taken to protect the health and safety of workers and the public, and to limit the impact of the incident on site security, production capability and the environment. The program elements are designed to meet legal and regulatory requirements.

Risks to Achieving Project Excellence

OPG is undertaking several capital intensive projects with significant investments. There may be an adverse effect on the Company if it is unable to: obtain necessary approvals; raise the necessary funds; effectively manage the projects on time and on budget; or fully recover capital costs and earn an appropriate return on investment. These projects may also have a significant impact on OPG's borrowing capacity and credit rating. Some projects may be ultimately reassessed as being uneconomic. The risks associated with OPG's current major projects are described below.

Darlington Refurbishment

There are financial and reputational risk exposures for OPG if actual costs exceed the budget or if OPG does not meet the project schedule. In addition, failure to achieve the objectives of the refurbishment project may result in future forced outages and more complex planned outages, potentially impacting the post-refurbishment performance or useful life of the units. Failure to carry out the refurbishment of the first unit as planned may result in the Province

exercising an off-ramp for the refurbishment of the remaining units. In January 2018, Refurbishment senior management met with the Minister of Energy, Cabinet and Treasury Board to provide an update on the status of the Darlington Refurbishment project and to request a decision to not exercise the Unit 3 off-ramp. The request was based on the performance to date on the Unit 2 project. Additionally, OPG continues to apply lessons learned that have been captured on the execution of Unit 2 into the planning of future units.

Commented [JK2]: Is Energy okay with this wording? Does such disclosure normally reference meetings of Cabinet or its committees?

There are a number of specific risks that OPG is managing and mitigating in relation to the Darlington Refurbishment project, which include OPG and vendor performance risks, delay or productivity risks, financial risks related to escalation of costs, technical risks such as equipment conditions resulting in additional scope and execution risks. A large portion of the costs for the Darlington Refurbishment project is being paid to contractors and suppliers, including vendors that will engineer, procure and construct components of the project. There is a risk that, as the volume of work increases significantly, vendor capability, capacity and performance shortfalls may impact project objectives and deliverables.

OPG systematically manages the risks associated with the Darlington Refurbishment project through robust risk management practices to achieve project deliverables on time and budget with quality. OPG engaged in an extensive five-year project planning phase to determine the project scope and to rigorously estimate costs. During this phase, OPG also took into account major lessons learned from other nuclear refurbishments and large scale, complex projects. In order to fully define the scope and material requirements for the project, the planning phase included the completion of detailed designs before proceeding with the execution of the unit refurbishments. Further risk mitigation has been implemented through the construction of a full scale model training reactor, which allows for simulations and training for unit refurbishment execution tasks.

OPG's risk management strategy aims to ensure that contractors are held accountable and appropriate incentives and disincentives are in place. There is also an increased risk of contractor initiated safety events, which may impact OPG's reputation. Mitigating actions include:

- Collaborative training and planning with vendors on executing work safely;
- An enhanced human performance program;
- Increased field presence by supervisory staff; and
- Collaboration with Bruce Power to streamline processes and reduce burden on vendors.

OPG is also managing other ongoing risks that could potentially impact the project, including those related to continuity of skilled leaders within OPG and its vendor partners, as well as the availability of technical resources to support the project through execution.

Both management and Board of Directors have engaged Independent, third-party oversight for the execution phase of the project.

Deep Geologic Repository for Low and Intermediate Level Waste

OPG, with the support of Bruce County municipalities, is proposing to construct and operate a deep geologic repository for the safe long-term management of L&ILW. While broad local community support for the proposed L&ILW DGR is stable, OPG continues its engagement with the SON towards securing support for the project.

In August 2017, the federal Minister of Environment and Climate Change wrote to OPG and commended OPG for its collaborative work with the SON and for the practical demonstration of reconciliation practices. In light of that work, the Minster requested OPG to update its analysis of the potential cumulative effects of the DGR project on the physical and cultural heritage of the SON, taking into account the results of the SON Community Process. OPG continues to work with the SON, however the timing and outcome of the SON Community Process and the EA decision by the Minister are uncertain.

Risks to Maintaining Financial Strength

Risks related to rate regulation, financial markets and long-term obligations could significantly impact OPG's financial performance. The Company is also exposed to risks such as weak electricity demand, displacement of generation by competitors and financial risk associated with energy trading.

Rate Regulation

There is an inherent risk that regulated prices established by the OEB may not provide for the recovery of actual costs incurred by OPG's regulated operations or allow the regulated operations to earn an appropriate rate of return. This could occur if, in setting regulated prices, the OEB makes adjustments to forecasts submitted by OPG, if actual production and costs significantly differ from the forecasts approved by the OEB, or if OPG is unable to achieve OEB-approved stretch factors included in regulated prices under incentive ratemaking. Differences between OPG's actual and forecast production and costs could be due to factors such as outages or project execution risks. In providing evidence in support of its applications for regulated prices, OPG aims to clearly demonstrate to the OEB that the costs for the regulated operations are reasonable, prudently incurred and should be fully recovered from customers.

Certain differences between elements of OEB-approved revenue requirements and OPG's actual results are recorded in OEB-approved variance and deferral accounts for future review by the OEB. Additionally, these accounts may be subject to an OEB prudence review. There is uncertainty associated with the outcomes of future proceedings for the recovery or refund of these balances.

Nuclear Rate Smoothing Proposal

Consistent with the requirements of *Ontario Regulation 53/05*, OPG's nuclear rates will be smoothed as a result of OPG deferring a portion of the approved annual nuclear revenue requirements during the period from January 1, 2017 to the end of the Darlington Refurbishment project in a Rate Smoothing Deferral Account.

There is a risk that the magnitude of the deferral ordered by the OEB will result in regulated prices that do not provide sufficient cash flow to the Company for meeting its financial objectives in an optimal manner, including ensuring sufficient liquidity, cost effectively funding the Darlington Refurbishment project and other expenditures and maintaining the Company's investment grade credit rating. Maintaining adequate levels of credit metrics will support OPG's investment grade credit rating. As such, OPG requested the OEB to consider the impact on its credit rating when smoothing the nuclear base rates. **[MONITOR]**

Post-Employment Benefit Obligations Risk

OPG's post-employment benefit obligations include pension, group life insurance, health care benefits, and LTD benefits. OPG's post-employment benefit obligations and costs and pension plan contributions could be materially affected in the future by numerous factors including: changes in discount rates, inflation rates and other actuarial assumptions; future investment returns; experience gains and losses; the funded status of the pension plans; changes in benefits; changes in the regulatory environment including potential changes to the *Pension Benefits Act* (Ontario); changes in OPG's operations and the measurement uncertainty incorporated into the actuarial valuation process.

The OPG registered pension plan, which covers most of OPG's employees and retirees, is a contributory defined benefit plan that is indexed to inflation up to a certain maximum. Contributions to the OPG registered pension plan are determined by actuarial valuations, which are filed with the appropriate regulatory authorities at least every three years. Future actuarial valuations could increase OPG's funding requirements due to market and economic-related conditions. A significant decline in the financial markets could trigger an immediate requirement to update the actuarial valuation based on declines in the funded status. OPG continues to assess the requirements for contributions to the registered pension plan, including the timing of future actuarial valuations. OPG's OPEB

obligations are not funded and the associated employee benefits are paid from cash flows provided by operating activities or other sources of liquidity.

Nuclear Liabilities and Nuclear Segregated Funds

As required by the CNSC, OPG is responsible for the management of used nuclear fuel and L&ILW and the decommissioning of its nuclear stations and waste management facilities. The cost estimates for OPG's nuclear waste management and decommissioning obligations are based on multiple underlying assumptions and estimates that are inherently uncertain and may evolve over time. The assumptions include station end-of-life dates, waste volumes, waste disposal methods, the timing of construction of assumed waste disposal facilities, waste packaging systems, decommissioning strategy and financial indicators. To address the inherent uncertainty, OPG undertakes to perform a comprehensive review of the underlying assumptions and baseline cost estimates at least once every five years, in line with the required ONFA Reference Plan update process.

The most recent comprehensive update of the nuclear waste management and decommissioning obligations was approved by the Province in December 2016 as part the 2017 ONFA Reference Plan. An approved ONFA Reference Plan determines OPG's contributions to the Nuclear Segregated Funds. Based on the 2017 ONFA Reference Plan, no contributions are currently required to the Nuclear Segregated Funds. Additional contributions may be required should the Nuclear Segregated Funds be in an underfunded position in the future.

Nuclear Funds are segregated under ONFA in order to fund the long-term waste management, used fuel management and decommissioning expenditures. These funds are managed to achieve, in the long term, the target rate of return based on the discount rate specified in the ONFA. Investments in the Nuclear Segregated Funds are allocated to certain asset classes including fixed income securities, domestic and international equity securities, pooled funds, infrastructure, agriculture and real estate. The rates of return earned on these segregated funds may vary depending on current and future financial market conditions. The asset mix of the funds is determined jointly by OPG and the Province in accordance with the ONFA.

Under ONFA, OPG bears the market risk related to the portion of the Nuclear Segregated Funds set aside for:

- decommissioning of Pickering and Darlington nuclear generating stations; and
- long-term management of the irradiated used fuel bundles in excess of the first 2.23 million bundles and L&ILW after the respective Pickering GS and Darlington GS shut down.

A significant drawdown in the Nuclear Funds would first reduce the surplus in the respective funds before impacting OPG's net income. As such, the income statement impact of this risk is reduced when the Nuclear Segregated Funds are in a fully funded position.

Liquidity

OPG operates in a capital intensive business. Significant financial resources are required to fund major development and other capital improvement projects, including the Darlington Refurbishment project. In addition, the Company has other significant disbursement requirements including pension contributions, payments towards OPEB and other benefit plans, funding ongoing operations, debt maturities with the OEFC, OPG's investment in the Fair Hydro Plan and investments in new generating capacity and other business development opportunities. OPG must ensure that it has the financial capacity and sufficient access to cost effective financing sources to fund its capital requirements and other disbursements. In support of this objective, OPG utilizes multiple sources and forecasts availability of funds, actively monitors funding requirements and is focused on maintaining its investment grade credit rating. The Company's ability to arrange sufficient and cost-effective debt financing could be adversely affected by a number of factors, including, financial market and general economic conditions, the regulatory environment in Ontario, the Company's results of operations and financial conditions, the ratings assigned to the Company by credit rating agencies and the current timing of debt maturities.

A discussion of corporate liquidity is included in the section, *Liquidity and Capital Resources*.

Commodity Markets

Changes in the market price of fuels used to produce electricity can adversely impact OPG's earnings and cash flow from operations.

To manage the risk of unpredictable increases in the price of fuels, the Company has fuel hedging programs, which include using fixed price and indexed contracts.

The percentages hedged of OPG's fuel requirements are shown in the following table. These amounts are based on yearly forecasts of generation and supply mix and, as such, are subject to change as these forecasts are updated.

	2018	2019	2020
Estimated fuel requirements hedged [1]	72.9%	68.2%	65.3%

[1] Represents the approximate portion of megawatt-hours of expected generation production (and year-end inventory targets) from each type of OPG-operated facility (nuclear, hydroelectric and thermal) for which the Company has entered into contractual arrangements or obligations in order to secure the price of fuel, or which is subject to regulation. In the case of hydroelectric generation, this represents the gross revenue charge and water rental charges. Excess fuel inventories (nuclear and thermal) in a given year are attributed to the next year for the purpose of measuring hedge ratios.

Foreign Exchange

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are primarily denominated in, or tied to US dollars (USD). To manage this risk, OPG employs various financial instruments such as forwards and other derivative contracts, in accordance with approved risk management policies. As at December 31, 2017, OPG had total foreign exchange contracts outstanding with a notional value of USD $5 million.

Trading

OPG's financial performance can be affected by its trading activities. OPG's electricity trading operations are closely monitored, with total exposures measured and reported to senior management on a daily basis. The main metric used to measure the financial risk of trading activity is Value at Risk (VaR). VaR is defined as a probabilistic maximum potential future loss expressed in monetary terms for a portfolio based on normal market conditions over a set period of time. During 2017, the VaR utilization ranged between $0.1 million and $0.4 million, compared to between nil and $1.5 million in 2016.

Credit

The Company's credit risk exposure is a function of its electricity sales, trading and hedging activities, treasury activities including investing and commercial transactions with various suppliers of goods and services. OPG's credit risk exposure relating to electricity sales is considered low as the majority of sales are through the IESO-administered spot market. The IESO oversees the credit worthiness of all market participants. In accordance with the IESO's prudential support requirements, market participants are required to provide collateral to cover funds that they might owe to the market.

The following table summarizes OPG's credit exposure to all counterparties from electricity transactions and trading as at December 31, 2017:

	All Counterparties		Largest Counterparties	
Credit Rating [1]	**Number of Counterparties** [2]	**Potential Exposure** [3] *(millions of dollars)*	**Number of Counterparties**	**Potential Exposure** *(millions of dollars)*
Investment grade	15	18	5	14
IESO [4]	1	360	1	360
Total	16	378	6	374

[1] Credit ratings are based on OPG's own analysis, taking into consideration external rating agency analysis where available, as well as recognizing explicit credit support provided through parental guarantees, Letters of Credit or other forms of security.

[2] OPG's counterparties are defined on the basis of individual master agreements.

[3] Potential exposure is OPG's statistical assessment of maximum exposure over the life of each transaction at a 95 percent confidence interval.

[4] Credit exposure is an estimate of the short-term receivable amount arising from OPG's electricity sales into the IESO market. The credit exposure and associated receivable vary each month based on electricity sales. The monthly receivable from the IESO is typically paid to OPG in the subsequent month as per the IESO payment schedule.

Other major components of OPG's credit risk exposure include those associated with vendors that are contracted to provide services or products. OPG manages its exposure to various suppliers or counterparties by evaluating their financial condition and ensuring that the Company holds appropriate collateral or other forms of security.

Contracted Generation

The Company's generating stations that operate under ESAs with the IESO or other long-term contracts are subject to several obligations, including but not limited to:

- availability targets;
- monthly and annual reporting; and
- must offer obligations, as specified in their respective contracts.

OPG could incur penalties up to and including termination of the respective contract if these facilities fail to meet their contractual obligations. This risk is mitigated through:

- education of staff who work with these facilities;
- continuous communication between staff managing the contracts and staff managing the stations;
- processes that monitor and address contractual obligations and milestones; and
- the implementation of maintenance, capital investment (approved by the IESO when required by the contracts) and other programs.

OPG's owned and co-owned thermal generating stations operate under ESAs with the IESO or other long-term agreements. While OPG expects that its thermal generating stations will continue to provide capacity to the market over the term of the respective agreements, there is a risk that, upon expiry of the current agreements, subsequent contracts for these stations may not be available or may not be financially viable. The Thunder Bay Biomass ESA is the first such contract to reach the end of its term, scheduled for early 2020.

Ontario Electricity Market

OPG's revenue can be impacted by external factors related to the electricity market including: the entrance of new participants into the Ontario market; the competitive actions of market participants; Ontario electricity demand; changes in the regulatory environment; and wholesale electricity prices in the interconnected markets.

The IESO is in the preliminary stages of a Market Renewal Program, which is expected to result in a fundamental redesign of Ontario's electricity markets and may impact OPG depending on the market design that is implemented. To mitigate this risk, OPG is actively participating in Market Renewal stakeholder committees as well as continuing to collaborate with the IESO.

Ownership by the Province

The Province owns all of OPG's issued and outstanding common shares. Accordingly, the Province, as represented by the Ontario Ministry of Energy, has the authority to make appointments to OPG's Board of Directors. OPG could be subject to Shareholder direction, under Section 108 of the OBCA that can directly influence major decisions. These directions could include those related to project development, timing and strategy of applications for regulated prices, acquisitions and asset divestitures, financing and capital structure. As a result, OPG could be required to undertake activities that result in increased expenditures, or that reduce revenues or cash flows relative to the business activities or strategies that would have otherwise been undertaken. In addition, the obligation of OPG's Shareholder to respond to a broad range of matters in its role as the Government of Ontario may compete with OPG's commitment to maximize the return on the Shareholder's investment in the Company. This includes, but is not limited to, the Province's response to mitigate the impact of rising electricity prices on consumers.

Government Legislation and Regulation Change

OPG's core business and strategy may be impacted by changes in federal and provincial legislation and regulations. Matters that are subject to regulation include, among others, rate regulation, electricity generating operations, nuclear waste management and nuclear decommissioning, the Ontario electricity market and taxation. Regulatory bodies may change or enact regulations or rules that could increase OPG's costs, decrease OPG's revenue, or limit the Company's ability to recover appropriate costs or earn a return on the assets.

The next Ontario provincial election is set to take place in June 2018 and electricity rates are a focus of each party's platform. Depending on the outcome of the election, there may be significant legislative changes that could impact OPG.

Since legal requirements are subject to change and to interpretation, OPG is unable to predict the impact of such changes on the Company and its operations. To mitigate legislative risks, OPG continues to monitor and actively engage with the federal and provincial governments in order to determine if future legislation will impact the Company.

Litigation

OPG or its subsidiaries are involved in various legal proceedings covering a range of matters arising out of their business activities. Each of these matters is subject to various uncertainties and some of these matters may be resolved unfavourably. Refer to Note 16 of OPG's 2017 audited consolidated financial statements under the heading, *Litigation* for further details.

Risks to Maintaining Social Licence

OPG is exposed to risks associated with its social licence and public profile due to changes in the opinions of:

- Various stakeholders, including Ontario electricity customers, local communities, government agencies; and
- Indigenous communities.

Maintaining public trust and meeting stakeholders and Indigenous communities' expectations are critical to OPG's success. OPG focuses on building and maintaining its social licence and corporate reputation through safe, reliable, environmentally-responsible operations as well as corporate citizenship initiatives across the province. The inability to maintain safe, reliable operations could negatively impact OPG's reputation and result in a loss of public support.

Ontario Fair Hydro Plan Act

The Fair Hydro Act received Royal Assent and came into force on June 1, 2017. As the Financial Services Manager under the Act, OPG's reputation could potentially be adversely impacted through this involvement and through stakeholder opinions related to this involvement.

Indigenous Communities

The quality of OPG's relationships and the outcome of negotiations with Indigenous communities may impact OPG's project and financial performance, as well as its social licence to operate.

OPG may be subject to claims by Indigenous communities. These claims stem from projects and generation development related to the operations of OPG and historic operations of OPG's predecessor company, Ontario Hydro, which may have impacted the Aboriginal and/or Treaty rights of Indigenous communities.

OPG has an Indigenous Relations Policy, which sets out the Company's commitment to proactively build and maintain positive relationships with Indigenous communities. OPG has been successful in working collaboratively with Indigenous communities to resolve a number of past grievances. However, the outcome of ongoing and any future negotiations depends on a number of factors, including legislation and regulations and precedents created by court rulings, which are subject to change over time. OPG pursues generation-related developments in partnerships with Indigenous communities on the basis of long-term mutually beneficial commercial arrangements.

Environmental Risks

OPG's operations and facilities are subject to environmental compliance obligations at the municipal, provincial and federal levels that include protection of land, water, air, living organisms and natural systems. A failure to comply with applicable environmental laws may result in enforcement actions, remediation actions or restrictions to operations. Changes in compliance obligations can result in new operational requirements and increased costs.

OPG has an ISO 14001 registered EMS to manage its environmental responsibilities. For further information, see discussion in the section, *Core Business, Strategy, and Outlook* under the heading, *Environmental Performance*.

OPG recognizes that efforts are required to plan for the impacts of climate change and has identified climate change adaptation as a strategic priority for the company. OPG monitors developments in climate science, adaptation activities, and potential changes to policy and regulatory requirements. OPG continues to work with stakeholders to better define adaptation requirements through analysis and understanding of impacts on watersheds, equipment and the electricity market. OPG undertakes a risk-based analysis to determine the extent of adaptation requirements to reduce the impact of climate change on its operations, and also collaborates with all levels of government and industry to increase the resiliency of the electricity infrastructure.

A carbon cap and trade program became effective in Ontario in January 2017. The program is not expected to have a material adverse economic impact on OPG due to the Company's low GHG emissions. Further details can be found in the section, *Core Business, Strategy and Outlook* under the heading, *Environmental Performance*.

RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One, the IESO and the OEFC. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly-owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions for the years ended December 31 are summarized below:

	2017		2016	
(millions of dollars)	**Revenue**	**Expense**	**Revenue**	**Expense**
Hydro One				
Electricity sales	**8**	**-**	6	-
Services	**1**	**10**	1	5
Dividends	**7**	**-**	6	-
Province of Ontario				
Change in Decommissioning Segregated Fund amount due to Province [1]	**-**	**456**	-	192
Change in Used Fuel Segregated Fund amount due to Province [1]	**-**	**591**	-	235
Hydroelectric gross revenue charge	**-**	**110**	-	120
ONFA guarantee fee	**-**	**8**	-	8
Other	**-**	**2**	-	-
OEFC				
Hydroelectric gross revenue charge	**-**	**216**	-	203
Interest expense on long-term notes	**-**	**158**	-	169
Income taxes, net of investment tax credits	**-**	**246**	-	104
IESO				
Electricity related revenue	**4,802**	**-**	5,082	-
Fair Hydro Trust	**4**	**3**	-	-
	4,822	**1,800**	5,095	1,036

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at December 31, 2017 and December 31, 2016, the Nuclear Segregated Funds were reported net of amounts due to the Province of $4,462 million and $3,415 million, respectively.

The receivable, AFS securities, payable and long-term debt balances between OPG and its related parties are summarized below:

(millions of dollars)	**December 31 2017**	**December 31 2016**
Receivables from related parties		
Hydro One	**1**	1
IESO – Electricity related receivables	**354**	421
IESO – Fair Hydro Trust [1]	**7**	-
OEFC	**-**	1
PEC	**4**	4
Province of Ontario	**3**	2
Financing receivables		
IESO – Fair Hydro Trust	**1,179**	-
Available-for-sale securities		
Hydro One shares	**188**	212
Accounts payable and accrued charges		
Hydro One	**1**	-
OEFC	**52**	61
Province of Ontario	**9**	2
IESO – Electricity-related payables	**5**	2
IESO – Fair Hydro Trust	**3**	-
Long-term debt (including current portion)		
Notes payable to OEFC	**3,195**	3,295

[1] Balance consists of unbilled revenue.

OPG holds interest-bearing Province of Ontario bonds in the Nuclear Segregated Funds and the OPG registered pension fund. As at December 31, 2017, the Nuclear Segregated Funds held $1,503 million of interest-bearing Province of Ontario bonds. As at December 31, 2016, the Nuclear Segregated Funds and the registered pension fund held $1,652 million and $284 million of interest-bearing Province of Ontario bonds, respectively. These bonds are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

In December 2017, the Trust purchased its first tranche of Investment Interest from the IESO for an exchange amount of $1.18 billion, which has been classified as a financing receivable on OPG's consolidated balance sheet. The transaction was settled in cash using proceeds from the Trust's issuance of senior and subordinated debt. Pursuant to the general regulation of the Act, the IESO is required to pay and remit carrying costs of the Trust, excluding repayment of principal on any debt obligations, up to July 31, 2021. Commencing May 1, 2021, Specified Consumers will be invoiced by their local distribution company for the Clean Energy Adjustment to pay financing and other costs of the Trust. These funds will be remitted to the Trust through the IESO and will be used to settle all funding and other related expenses of the Trust that underlie the financing receivable.

As at December 31, 2017, OPG's consolidated balance sheet included approximately $7 million of unbilled revenue from the IESO primarily for OPG's general fee for 2017 as Financial Services Manager relating to incurred third-party and certain direct labour costs. In February 2018, OPG submitted to the OEB its proposed general fee for 2017 in the amount of approximately $6 million for review pursuant to the requirements of the general regulation of the Fair Hydro Act. Once approved, the fees will be remitted to the Trust by the IESO and the Trust will pay OPG's fees as Financial Services Manager.

INTERNAL CONTROLS OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

Management, including the President and Chief Executive Officer (President and CEO) and the Chief Financial Officer (CFO), are responsible for maintaining Disclosure Controls and Procedures (DC&P) and Internal Controls over Financial Reporting (ICOFR). DC&P is designed to provide reasonable assurance that all relevant information is gathered and reported to senior management, including the President and CEO and the CFO, on a timely basis so that appropriate decisions can be made regarding public disclosure. ICOFR is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the financial statements in accordance with US GAAP.

There were no changes in OPG's ICOFR during the year ended December 31, 2017 that have materially affected or are reasonably likely to materially affect OPG's ICOFR.

Management, including the President and CEO and the CFO, concluded that, as of December 31, 2017, OPG's DC&P and ICOFR (as defined in National Instrument 52-109 – *Certification of Disclosure in Issuers' Annual and Interim Filings*) were effective.

FOURTH QUARTER

Discussion of Results

(millions of dollars) (unaudited)	Three Months Ended December 31 2017	2016
Revenue	**1,619**	1,388
Fuel expense	**171**	186
Gross margin	**1,448**	1,202
Operations, maintenance and administration	**770**	686
Depreciation and amortization	**162**	316
Accretion on fixed asset removal and nuclear waste management liabilities	**251**	233
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(222)**	(126)
Earnings from Fair Hydro Trust	**(1)**	-
Income from investments subject to significant influence	**(9)**	(9)
Property taxes	**10**	11
Restructuring	**-**	6
Income before other losses, interest, and income taxes	**487**	85
Other losses	**1**	6
Income before interest and income taxes	**486**	79
Net interest expense	**39**	28
Income before income taxes	**447**	51
Income tax expense	**81**	59
Net income (loss)	**366**	(8)
Net income (loss) attributable to the Shareholder	**362**	(13)
Net income attributable to non-controlling interest	**4**	5

Net income attributable to the Shareholder for the fourth quarter was $362 million, compared to a net loss of $13 million for the same quarter in 2016.

Income before interest and income taxes was $486 million during the fourth quarter of 2017, an increase of $407 million compared to income before interest and income taxes of $85 million during the same period in 2016. The following summarizes the significant factors which contributed to the variance:

Significant factors that increased income before interest and income taxes:

- Higher revenue from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments totaling approximately $480 million recorded in the fourth quarter of 2017 to reflect the OEB's decision on OPG's application for new regulated rates issued in December 2017 with a retrospective effective date of June 1, 2017.
- Higher earnings of $77 million from the Regulated – Nuclear Waste Management segment, primarily due to higher earnings from the Nuclear Segregated Funds reflecting the growth rate in the present value of the funding liabilities, partially offset by an increase in accretion expense on the Nuclear Liabilities.

Significant factors that decreased income before interest and income taxes:

- Lower revenue from the nuclear base regulated price of approximately $55 million, partially offset by a decrease in fuel expense of $9 million, reflecting lower electricity generation of 0.9 terawatt hours (TWh) from the Regulated – Nuclear Generation segment. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS since October 2016, partially offset by an increase in generation from the Pickering GS. The increase in generation from the Pickering GS was primarily due to outage cycle optimization, favourable unit conditions and execution of planned outage work resulting in fewer unplanned and planned outage days at the station.
- Higher OM&A expenses of $55 million, mainly in the Regulated – Nuclear Generation segment, reflected planned expenditures related to the major maintenance expenditures occurring at the nuclear stations.

The increase in income tax expense during the fourth quarter of 2017, compared to the same quarter in 2016, was primarily due to higher income before income taxes, partially offset by a higher amount of tax expense deferred in regulatory assets in 2017.

Average Sales Prices

The average sales price for the Regulated – Nuclear Generation segment during the fourth quarter of 2017 was 11.0 ¢/kWh, compared to 6.9 ¢/kWh during the same quarter in 2016. The increase in the average sales price was primarily due to the OEB ruling issued in December 2017, in which OPG received a base rate increase, retroactive to June 1, 2017. The average sales price for the Regulated – Hydroelectric segment during 2017 was 4.3 ¢/kWh, compared to 4.4 ¢/kWh during 2016. The decrease in this average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized regulated hydroelectric rate rider of $3.19/MWh for the recovery of variance and deferral account balances. The rate riders were established to recover approved balances recorded in the variance and deferral accounts in prior years. As such, the year-over-year changes in revenue from the rate riders were largely offset by changes in amortization expense related to these balances.

Electricity Generation

OPG's electricity generation for the three months ended December 31, 2017 and 2016 was as follows:

(TWh)	Three Months Ended December 31 2017	2016
Regulated – Nuclear Generation	**10.1**	11.0
Regulated – Hydroelectric	**7.2**	6.7
Contracted Generation Portfolio [1]	**0.8**	0.6
Total OPG electricity generation	**18.1**	18.3
Total electricity generation by all other generators in Ontario [2]	**18.8**	18.9

[1] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

[2] Non-OPG generation is calculated as the Ontario electricity demand plus net exports, as published by the IESO, minus OPG electricity generation.

The decrease in OPG's electricity generation of 0.2 TWh during the fourth quarter of 2017, compared to the same quarter in 2016, was mainly due to lower electricity generation of 0.9 TWh from the Regulated – Nuclear Generation segment. This was mainly the result of more planned outage days at Pickering in 2017 as well as the refurbishment of Unit 2 at the Darlington GS, which began in mid-October 2016 and continued for all of 2017. This was largely offset by higher production from the Regulated - Hydroelectric and Contracted Generation Portfolio segments mainly due to higher water flows on the eastern Ontario river systems.

Ontario's electricity demand as reported by the IESO was 33.6 TWh during the fourth quarter of 2017, compared to 33.2 TWh during the fourth quarter of 2016.

Liquidity and Capital Resources

Cash flow provided by operating activities during the three months ended December 31, 2017 was $246 million, compared to $606 million for the same period in 2016. The decrease in cash flow was primarily due to lower generation revenue receipts and higher OM&A expenditures during the fourth quarter of 2017.

Cash flow used in investing activities during the three months ended December 31, 2017 was $1,758 million, compared to $666 million during the same period in 2016. The increase was primarily due to the acquisition of the Fair Hydro Trust financing receivables and higher expenditures on the Darlington Refurbishment project in 2017.

Cash flow provided by financing activities during the three months ended December 31, 2017 was $1,466 million, compared to cash flow used in financing activities of $180 million for the same period in 2016. The increase in cash flow provided by financing activities was primarily due to higher net issuance of long-term debt and short-term notes by the Trust, as well as issuance of Class A shares in the four quarter of 2017. The increase was partially offset by the repayment of short term notes.

QUARTERLY FINANCIAL HIGHLIGHTS

The following tables set out selected annual financial information for the last three years and financial information for each of the eight most recently completed quarters. This information is derived from OPG's unaudited interim consolidated financial statements and the audited consolidated financial statements, and has been prepared in accordance with US GAAP.

Annual Financial Information

(millions of dollars – except where noted)	**2017**	**2016**	**2015**
Revenue	**5,158**	5,653	5,476
Net income attributable to the Shareholder	**860**	436	402
Earnings per common share *(dollars)*	**$3.35**	$1.70	$1.57
Total assets	**48,822**	44,372	44,250
Total long-term liabilities	**34,933**	31,460	32,404
Weighted average common shares outstanding *(millions)*	**256.7**	256.3	256.3

Quarterly Financial Information

(millions of dollars – except where noted) *(unaudited)*	**2017 Quarters Ended**				
	December 31	**September 30**	**June 30**	**March 31**	**Total**
Revenue	**1,619**	**1,217**	**1,146**	**1,176**	**5,158**
Net income	**366**	**140**	**307**	**68**	**881**
Less: Net income attributable to non-controlling interest	**4**	**9**	**4**	**4**	**21**
Net income attributable to the Shareholder	**362**	**131**	**303**	**64**	**860**
Earnings per common share, attributable to the Shareholder *(dollars)*	**$1.41**	**$0.51**	**$1.18**	**$0.25**	**$3.36**

Quarterly Financial Information

(millions of dollars – except where noted) *(unaudited)*	**2016 Quarters Ended**				
	December 31	**September 30**	**June 30**	**March 31**	**Total**
Revenue	1,388	1,400	1,387	1,478	5,653
Net (loss) income	(8)	198	135	128	453
Less: Net income attributable to non-controlling interest	5	4	3	5	17
Net (loss) income attributable to the Shareholder	(13)	194	132	123	436
Per common share, attributable to the Shareholder *(dollars)*	($0.05)	$0.76	$0.51	$0.48	$1.70

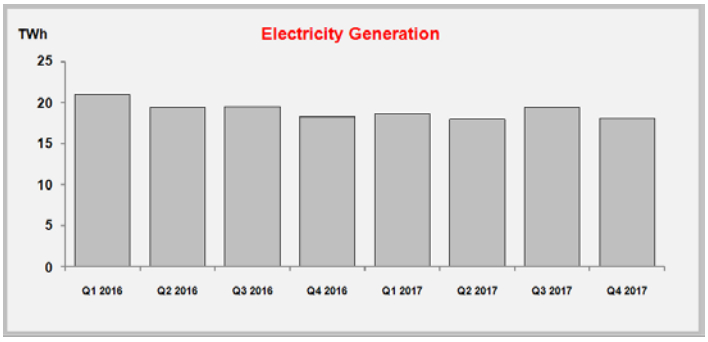
Trends

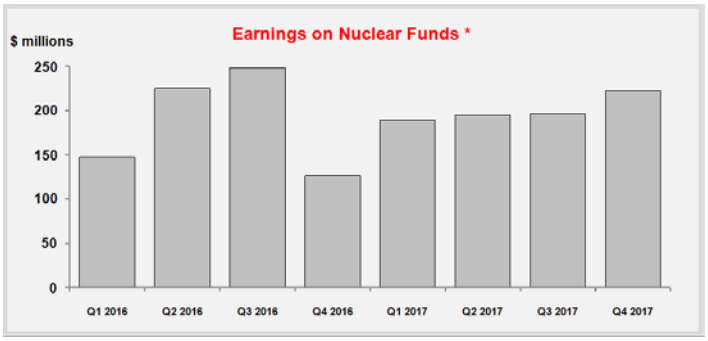
OPG's quarterly results are affected by changes in grid-supplied electricity demand, primarily resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. Weather conditions affect water flows, electricity demand, and prevalence of SBG conditions. Historically, OPG's revenues have been higher in the first quarter of a fiscal year as a result of winter heating demands and in the third quarter due to air conditioning and cooling demands. The financial impact of forgone production due to SBG conditions at the regulated hydroelectric stations and the financial impact of differences between forecast water flows reflected in OEB-approved regulated prices and the actual water flows are offset by regulatory variance accounts authorized by the OEB.

The timing of planned outages at a nuclear generating station during the year can cause variability in year-over-year operating results for partial periods of a fiscal year, including the impact on revenue and OM&A expenses, but is not a significant driver of variability for full fiscal year results.

OPG's electricity generation was reduced as a result of the Unit 2 refurbishment outage at the Darlington GS, which began in October 2016 and is expected to continue until early 2020.

OPG's financial results are also affected by the earnings on the Nuclear Segregated Funds, net of the impact of the Bruce Lease Net Revenues Variance Account. The volatility of the earnings on the Nuclear Segregated Funds is mitigated by their funded status.





*net of regulatory variance account

SUPPLEMENTARY NON-GAAP FINANCIAL MEASURES

In addition to providing net income and other financial information in accordance with US GAAP, certain non-GAAP financial measures are also presented in OPG's MD&A. These non-GAAP measures do not have any standardized meaning prescribed by US GAAP and, therefore, may not be comparable to similar measures presented by other issuers. OPG utilizes these measures to make operating decisions and assess performance. Readers of the MD&A would utilize these measures in assessing the Company's financial performance from ongoing operations. The Company believes that these indicators are important since they provide additional information about OPG's performance, facilitate comparison of results over different periods, and present measures consistent with the Company's strategies to provide value to the Shareholder, improve cost performance, and ensure availability of cost effective funding. These non-GAAP financial measures have not been presented as an alternative to net income, cash flow provided by operating activities, or any other measure in accordance with US GAAP, but as indicators of operating performance.

The definitions of the non-GAAP financial measures are as follows:

(1) ROE Excluding AOCI is defined as net income attributable to the Shareholder divided by average equity attributable to the Shareholder excluding AOCI, for the period.

ROE Excluding AOCI is measured over a 12-month period and is calculated as follows for the period ended December 31:

(millions of dollars – except where noted) (unaudited)	**2017**	**2016**
ROE Excluding AOCI		
Net income attributable to the Shareholder	**860**	436
Divided by: Average equity attributable to the Shareholder, excluding AOCI	**11,498**	10,442
ROE Excluding AOCI *(percent)*	**7.5**	4.2

(2) **FFO Adjusted Interest Coverage** is defined as FFO before interest divided by adjusted interest expense. FFO before interest is defined as cash flow provided by operating activities adjusted for interest paid, interest capitalized to fixed and intangible assets, and changes to non-cash working capital balances for the period. Adjusted interest expense is calculated as net interest expense plus interest income, interest capitalized to fixed and intangible assets, interest related to regulatory assets and liabilities, and the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets, for the period.

FFO Adjusted Interest Coverage is measured over a 12-month period and is calculated as follows for the period ended December 31:

(millions of dollars – except where noted) (unaudited)	**2017**	**2016**
FFO before interest		
Cash flow provided by operating activities	**944**	1,817
Add: Interest paid	**258**	269
Less: Interest capitalized to fixed and intangible assets	**(162)**	(141)
Less: Changes to non-cash working capital balances	**(54)**	(180)
FFO before interest	**986**	1,765
Adjusted interest expense		
Net interest expense	**95**	120
Add: Interest income	**9**	7
Add: Interest capitalized to fixed and intangible assets	**162**	141
Add: Interest related to regulatory assets and liabilities	**30**	30
Add: Excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets [1]	**-**	45
Adjusted interest expense	**296**	343
FFO Adjusted Interest Coverage *(times)*	**3.3**	5.1

[1] A value of nil is used in the calculation when interest on pension and OPEB projected benefit obligations is equal to, or lower than, expected return on pension plan assets.

(3) **Enterprise Total Generating Cost per MWh** is used to measure OPG's overall organizational cost performance. Enterprise TGC per MWh is defined as OM&A expenses (excluding the Darlington Refurbishment project and other generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to OPG's electricity generation business), fuel expense for OPG-operated stations including hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures (excluding the Darlington Refurbishment project and other generation development projects) incurred during the period, divided by total electricity generation from OPG-operated generating stations plus electricity generation forgone due to SBG conditions during the period.

Enterprise TGC per MWh is calculated as follows for the 12-month period ended December 31:

(millions of dollars – except where noted)	**2017**	**2016**
Enterprise TGC		
Total OM&A expenses	**2,824**	2,747
Total fuel expense	**689**	727
Total capital expenditures	**1,926**	1,704
Less: Darlington Refurbishment capital and OM&A costs	**(1,285)**	(1,022)
Less: Other generation development project capital and OM&A costs	**(65)**	(163)
Add: OM&A and fuel expenses (refundable through) deferred in regulatory variance and deferral accounts	**(1)**	62
Less: Nuclear fuel expense for non OPG-operated stations	**(57)**	(67)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**69**	49
Less: OM&A expenses ancillary to electricity generation business	**(18)**	(28)
Other adjustments	**(43)**	(19)
	4,039	3,990
Adjusted electricity generation *(TWh)*		
Total OPG electricity generation	**74.1**	78.2
Adjust for electricity generation forgone due to SBG conditions and OPG's share of electricity generation from co-owned facilities	**5.6**	4.1
	79.7	82.3
Enterprise TGC per MWh *($/MWh)* [1]	**50.66**	**48.45**

[1] Amounts may not calculate due to rounding.

(4) **Nuclear Total Generating Cost per MWh** is used to measure the cost performance of OPG's nuclear generating assets. Nuclear TGC per MWh is defined as OM&A expenses of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the nuclear electricity generation business), nuclear fuel expense for OPG-operated stations (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs) incurred during the period, divided by nuclear electricity generation for the period.

Nuclear TGC per MWh is calculated as follows for the 12-month period ended December 31:

(millions of dollars – except where noted)	**2017**	**2016**
Nuclear TGC		
Regulated – Nuclear Generation OM&A expenses	**2,293**	2,210
Regulated – Nuclear Generation fuel expense	**284**	315
Regulated – Nuclear Generation capital expenditures	**1,631**	1,338
Less: Darlington Refurbishment capital and OM&A costs	**(1,285)**	(1,022)
Add: Regulated – Nuclear Generation OM&A and fuel expenses deferred in regulatory variance and deferral accounts	**35**	81
Less: Nuclear fuel expense for non OPG-operated stations	**(57)**	(67)
Less: Regulated – Nuclear Generation OM&A expenses ancillary to electricity generation business	**(6)**	(10)
Other adjustments	**(10)**	(4)
	2,885	2,841
Nuclear electricity generation *(TWh)*	**40.7**	45.6
Nuclear TGC per MWh *($/MWh)* [1]	**70.95**	62.30

[1] Amounts may not calculate due to rounding.

(5) **Hydroelectric Total Generating Cost per MWh** is used to measure the cost performance of OPG's hydroelectric generating assets. Hydroelectric TGC per MWh is defined as OM&A expenses of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the hydroelectric electricity generation business), hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding expenditures related to the Peter Sutherland Sr. GS, Ranney Falls GS, and other hydroelectric generation development projects) incurred during the period, divided by total hydroelectric electricity generation plus hydroelectric electricity generation forgone due to SBG conditions during the period. OPG reports hydroelectric gross revenue charge and water rental payments as fuel expense.

Hydroelectric TGC per MWh is calculated as follows for the 12-month period ended December 31:

(millions of dollars – except where noted)	**2017**	**2016**
Hydroelectric TGC		
Regulated – Hydroelectric OM&A expenses	**330**	325
Regulated – Hydroelectric fuel expense	**351**	353
Contracted Generation Portfolio OM&A expenses	**169**	178
Contracted Generation Portfolio fuel expense	**53**	58
Regulated – Hydroelectric and Contracted Generation Portfolio capital expenditures	**226**	330
Less: Regulated – Hydroelectric and Contracted Generation Portfolio Generation Portfolio generation development project capital and OM&A costs	**(63)**	(158)
Less: Thermal OM&A and fuel expenses and capital expenditures in the Contracted Generation Portfolio	**(166)**	(177)
Less: Regulated – Hydroelectric OM&A and fuel expenses refundable through regulatory variance and deferral accounts	**(36)**	(24)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**69**	49
Other adjustments	**(1)**	(1)
	932	933
Adjusted hydroelectric electricity generation *(TWh)*		
Regulated – Hydroelectric electricity generation	**30.7**	29.5
Contracted Generation Portfolio electricity generation	**2.7**	3.1
Adjust for hydroelectric electricity generation forgone due to SBG conditions and non-hydroelectric electricity generation of the Contracted Generation Portfolio, including OPG's share of electricity generation from co-owned facilities	**5.5**	4.0
	38.9	36.6
Hydroelectric TGC per MWh *($/MWh)* [1]	**23.91**	25.49

[1] Amounts may not calculate due to rounding.

(6) **Gross margin** is defined as revenue less fuel expense**.**

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ONTARIO POWER GENERATION

News
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[DRAFT]

Mar. 8, 2018

OPG REPORTS 2017 FINANCIAL RESULTS

OPG records increase in net income for third consecutive year

[Toronto]: – Ontario Power Generation Inc. (OPG or Company) today reported net income attributable to the Shareholder of $860 million for 2017, compared to $436 million in 2016.

"As stewards of Ontario's publicly-owned generating assets, I am pleased with our strong 2017 financial results, which marks the third year-over-year increase in net income. OPG's major focus remains on the largest clean energy project in Canada, the refurbishment of the Darlington Generating Station. This ten-year project will extend the life of this asset and ensure a safe, reliable, and clean source of electricity for another 30 years," said Jeff Lyash, OPG President and CEO. "Darlington's Unit 2 recently passed the halfway point, based on work performed, while remaining on time and on budget due to the hard work and dedication of our employees and partners. This success was recognized by our shareholder, the Province of Ontario, wh~~e~~ich has confirmed its commitment to proceed with Darlington's Unit 3 refurbishment in 2020."

Commented [RK1]: Comment for Energy: Has MENE signed off on this wording?

Lyash continued, "The Peter Sutherland Sr. Generating Station was completed in 2017, on budget and ahead of schedule, and is the latest example of OPG's commitment to working closely in partnership with Indigenous communities."

"Pickering Generating Station significantly improved its operating performance over last year by increasing its capability factor to 80 per cent in 2017. By continuing to operate this important asset to 2024, we will ensure a safe and clean source of reliable power during the refurbishment of Darlington. OPG has applied to its regulator, the Canadian Nuclear Safety Commission, for a licen~~c~~s~~e~~e to keep Pickering online until 2024 and expects a decision on this application in 2018," added Lyash.

The Ontario Energy Board's (OEB) decision on OPG's new regulated rates was issued in December 2017, establishing new rates to be applied with an effective date of June 1, 2017. OPG recognized the impact of the newly established base regulated rates for OPG's nuclear and most of its hydroelectric generation for the year resulting in additional net revenues of approximately $480 million **[MONITOR]**. Net income was negatively impacted by the planned reduction in nuclear electricity generation, primarily due to the Darlington Refurbishment, in conjunction with the continued application of previously established interim rates for the period in 2017 prior to the effective date of the new base regulated rates.

The OEB's approval of the final payment amounts order, including determinations on the new regulated prices and rate smoothing, are not expected to have a material impact on the total revenue recorded for the June 1, 2017 to December 31, 2017 period. The OEB is expected to issue the final payment amounts order in the first half of 2018 **[MONITOR]**. OPG continues to provide electricity at a price that is 40 per cent less than other generators and is the only electricity generator in Ontario that has its prices set through a public hearing process by the OEB.

Commented [RK2]: The average of?

The gain of $283 million on the sale of OPG's head office building and parking facility recorded in the second quarter of 2017 and higher earnings on the nuclear fixed asset removal and nuclear waste management segregated funds of $24 million during 2017 compared to 2016 offset the year-to-date reduction in generation revenue.

The Fair Hydro Trust (the Trust) was established in December 2017 in accordance with the *Ontario Fair Hydro Act*, 2017, (the Fair Hydro Act), which appointed OPG as the Financial Services Manager of the Trust. The Fair Hydro Act established a framework under which the costs of clean energy investments [and benefits] associated with the ~~Government~~Province of Ontario's clean energy initiatives are to be allocated more fairly between present and future consumers of electricity under the Fair Hydro Plan. In December 2017, the Trust purchased its first tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $1.2 billion. In February 2018, the Trust issued $500 million of senior notes payable maturing on May 15, 2033.

Commented [RK3]: Is Energy okay with this wording?

Generating and Operating Performance

Electricity generated in 2017 decreased to 74.1 terawatt hours (TWh) from 78.2 TWh in 2016. The decrease in electricity generation reflected the expected lower generation from the Darlington GS and lower generation from the contracted plants. The decrease was partially offset by higher generation from the Pickering GS, primarily due to fewer outage days, and higher generation from the regulated hydroelectric stations.

Regulated – Nuclear Generation Segment

Lower nuclear generation of 4.9 TWh during 2017 was primarily due to the removal from service of Unit 2 at the Darlington GS for the duration of the unit's refurbishment that began in October 2016 and is expected to continue until early 2020. Offsetting the reduction in generation from the Darlington GS was an increase in generation of 1.5 TWh from the strong performance of the Pickering GS during 2017.

For 2017, the unit capability factor for the operating units at the Darlington GS was 85.2 per cent, compared to 89.5 per cent for 2016. The decrease was primarily a result of a higher number of planned outage days at the station in 2017, largely driven by the planned transition of the station towards refurbishment.

At the Pickering GS, the unit capability factor increased to 80.0 per cent for 2017, compared to 75.2 per cent for 2016, primarily due to outage cycle optimization and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station in 2017.

Regulated – Hydroelectric Segment

Higher generation from the regulated hydroelectric stations of 1.2 TWh during 2017 compared to 2016, was due to higher water flows, primarily on the eastern Ontario river systems.

The availability of 88.0 per cent at these stations in 2017 was slightly lower than 89.0 per cent for 2016. The marginal decrease in the availability was primarily due to a higher number of unplanned outage days at the Northwestern Ontario, Niagara and Eastern Ontario region hydroelectric stations, partially offset by higher availability from the Sir Adam Beck Pump GS due to a higher number of planned outages days in 2016 as a result of the refurbishment of the station's reservoir.

Contracted Generation Portfolio Segment

Lower generation from the Contracted Generation Portfolio of 0.4 TWh during 2017 compared to 2016, was mainly due to higher surplus baseload generation conditions.

The availability of these hydroelectric stations for 2017 was 74.6 per cent, compared to 77.3 per cent for 2016. The decrease in the availability was primarily due to an increase in the number of planned outage days at the Lower Mattagami River hydroelectric generating stations.

Total Generating Cost

The Enterprise Total Generating Cost per megawatt hour (MWh) for 2017 was $50.66, compared to $48.45 for 2016. The increase was expected and mainly a result of lower electricity generation due to the Unit 2 refurbishment outage at the Darlington GS and higher sustaining capital expenditures, which was partially offset by higher hydroelectric electricity generation adjusted for surplus baseload generation.

If Unit 2 at the Darlington GS were~~as~~ not currently undergoing refurbishment and had continued to operate in a manner consistent with the performance of the remaining units at the station, adjusted for generation constraints on these units related to the transition of the station toward refurbishment, the Enterprise Total Generating Cost would have been approximately $4 to $5 per MWh lower for 2017. This sensitivity was calculated using the estimated incremental electricity generation and associated fuel cost that are expected to have resulted in the absence of the refurbishment.

Generation Development

OPG is undertaking a number of generation development and life extension projects in support of Ontario's electricity planning initiatives. Significant developments during 2017 were as follows:

Darlington Refurbishment

The Darlington Refurbishment project is expected to extend the operating life of the four-unit Darlington GS by approximately 30 years. The approved budget for the four-unit refurbishment is $12.8 billion, which includes the costs of the pre-requisite projects in support of the execution phase of the refurbishment. In October 2016, OPG commenced the refurbishment of the first unit, Unit 2. The de-fuelling of the reactor and islanding of Unit 2 were completed in the first half of 2017. The Re-tube Tooling

Platform for hosting the tooling for the removal, inspection and installation activities, and the setup of specialized tooling and equipment needed for the removal and replacement of the reactor components were completed in the third quarter of 2017. The disassembly of reactor components began in August 2017, with the removal of all 960 feeder tubes completed in September 2017. The removal of fuel channel assemblies commenced in October 2017. As part of the fuel channel assemblies, the removal of pressure tubes is in progress and will be followed by the removal of calandria tubes. The second major segment and the removal of all reactor components is expected to be completed in mid-2018.

Most of the pre-requisite projects, including construction of facilities, infrastructure upgrades and installation of safety enhancements, have been completed and placed in service. The Re-tube Waste Processing Building was completed in November 2017. Construction activities for the Heavy Water Storage and Drum Handling Facility (HWSF) have recommenced following the substantial completion of the Re-tube Waste Processing Building. This sequencing ensured that the necessary resources were available to support the execution of both projects. The HWSF is expected to be completed by the second quarter of 2019 and is not on the critical path for the Darlington Refurbishment project, which continues to track on schedule. The increase in the cost estimate for the HWSF will be accommodated within the overall Darlington Refurbishment budget of $12.8 billion. Taking into account the execution performance of the Unit 2 refurbishment, the overall Darlington Refurbishment project continues to track on budget.

In addition to the execution of refurbishment activities on Unit 2, OPG is continuing planning activities for the refurbishment of the second unit, Unit 3, and is entering into associated commitments to procure major components that require long lead times. As of December 31, 2017, $93 million has been invested in planning activities related to the refurbishment of the second unit.

Total life-to-date capital expenditures on the project were approximately $4.4 billion as at December 31, 2017.

Ranney Falls Hydroelectric GS

In 2017, OPG began construction work on a 10 MW single-unit powerhouse on the existing Ranney Falls GS site, as part of the Regulated – Hydroelectric segment. The new unit will replace an existing unit that reached its end of life in 2014. The existing forebay structure has been demolished and the new concrete structure has been completed. Excavation has been completed and construction continues in the expanded forebay, powerhouse and spillway area. The new forebay concrete wall has been completed, and concrete placement of the new powerhouse and the spillway integrated structure is in progress. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget.

Nanticoke Solar Facility

The construction of a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands, through Nanticoke Solar LP, a partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation, is planned to commence in the first quarter of 2018. During 2017, the partnership continued work to obtain approvals and permits required to enable the commencement of construction. Significant

contracts for equipment and engineering construction services were executed in the first quarter of 2018. The facility, to operate under a contract with the IESO, is expected to be completed in the first quarter of 2019, with a budget of $107 million. **[MONITOR]**

FINANCIAL AND OPERATIONAL HIGHLIGHTS

(millions of dollars – except where noted)	**2017**	**2016**
Revenue	**5,158**	5,653
Fuel expense	**689**	727
Gross margin	**4,469**	4,926
Operations, maintenance and administration	**2,824**	2,747
Depreciation and amortization	**679**	1,257
Accretion on fixed asset removal and nuclear waste management liabilities	**960**	929
Earnings on Nuclear Segregated Funds - (a reduction to expenses)	**(801)**	(746)
Earnings from Fair Hydro Trust - (a reduction to expenses)	**(1)**	-
Income from investments subject to significant influence	**(38)**	(37)
Other net (gains) expenses	**(339)**	35
Income before interest and income taxes	**1,185**	741
Net interest expense	**95**	120
Income tax expense	**209**	168
Net income	**881**	453
Net income attributable to the Shareholder	**860**	436
Net income attributable to non-controlling interest [1]	**21**	17
Income before interest and income taxes		
Electricity generation business segments	**971**	928
Regulated – Nuclear Waste Management	**(150)**	(174)
Services, Trading, and Other Non-Generation	**364**	(13)
Fair Hydro Trust	**-**	-
Total income before interest and income taxes	**1,185**	741
Cash flow		
Cash flow provided by operating activities	**944**	1,817
Electricity generation (TWh)		
Regulated – Nuclear Generation	**40.7**	45.6
Regulated – Hydroelectric	**30.7**	29.5
Contracted Generation Portfolio [2]	**2.7**	3.1
Total electricity generation	**74.1**	78.2
Nuclear unit capability factor (per cent) [3]		
Darlington Nuclear GS	**85.2**	89.5
Pickering Nuclear GS	**80.0**	75.2
Availability (per cent)		
Regulated – Hydroelectric	**88.0**	89.0
Contracted Generation Portfolio – hydroelectric stations	**74.6**	77.3
Equivalent forced outage rate		
Contracted Generation Portfolio – thermal stations	**2.4**	1.6
Enterprise Total Generating Cost (TGC) per MWh for the twelve months ended December 31, 2017 and 2016 ($/MWh) [4]	**50.66**	48.45
Return on Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI) for the twelve months ended December 31, 2017 and 2016 (%) [4]	**7.5**	4.2
Funds from Operations (FFO) Adjusted Interest Coverage for the twelve months ended December 31, 2017 and 2016 (times) [4]	**3.3**	5.1

[1] Relates to the 25 per cent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation in the Lower Mattagami Limited Partnership, the 33 per cent interest of Coral Rapids Power Corporation (CRP), a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership, and the 10 per cent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP. CRP increased its partnership interest to 33 percent in April 2017.

[2] Includes OPG's share of generation volume from its 50 per cent ownership interests in the Portlands Energy Centre and Brighton Beach GS.

[3] Nuclear unit capability factor excludes unit(s) during the period in which they are undergoing refurbishment. Unit 2 of the Darlington GS is excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

[4] Enterprise TGC per MWh, ROE Excluding AOCI, and FFO Adjusted Interest Coverage are non-GAAP financial measures and do not have any standardized meaning prescribed by US GAAP. Additional information about the non-GAAP measures is provided in OPG's Management's Discussion and Analysis for the year ended December 31, 2017, in the sections *Highlights – FFO Adjusted Interest Coverage*, *Highlights – Return on Common Equity Excluding Accumulated Other Comprehensive Income*, and *Highlights – Enterprise Total Generating Cost per MWh*, as well as *Supplementary Non-GAAP Financial Measures.*

Ontario Power Generation Inc. is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. Our mission is providing low cost power in a safe, clean, reliable and sustainable manner for the benefit of our customers and shareholder.

Ontario Power Generation Inc.'s audited consolidated financial statements and Management's Discussion and Analysis as at and for the year ended December 31, 2017 can be accessed on OPG's web site (www.opg.com), the Canadian Securities Administrators' web site (www.sedar.com), or can be requested from the Company.

For further information, please contact: Investor Relations 416-592-6700
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ONTARIO POWER GENERATION INC.

CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2017

[DRAFT]

STATEMENT OF MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL INFORMATION

Ontario Power Generation Inc.'s (OPG) management is responsible for the presentation and preparation of the annual consolidated financial statements and Management's Discussion and Analysis (MD&A).

The consolidated financial statements have been prepared in accordance with United States generally accepted accounting principles (US GAAP). The MD&A has been prepared in accordance with the requirements of securities regulators, including National Instrument 51-102 of the Canadian Securities Administrators and its related published requirements.

The consolidated financial statements and information in the MD&A necessarily include amounts based on informed judgments and estimates of the expected effects of current events and transactions with appropriate consideration to materiality. Something is considered material if it is reasonably expected to have a significant impact on the Company's earnings, cash flow, value of an asset or liability, or reputation. In addition, in preparing the financial information, we must interpret the requirements described above, make determinations as to the relevancy of information to be included, and make estimates and assumptions that affect the reported information. The MD&A also includes information regarding the impact of current transactions and events, sources of liquidity and capital resources, operating trends, and risks and uncertainties. Actual results in the future may differ materially from our present assessment of this information because future events and circumstances may not occur as expected.

In meeting our responsibility for the reliability of the financial information, we maintain and rely on a comprehensive system of internal controls and internal audits, including organizational and procedural controls and internal controls over financial reporting. Our system of internal controls includes: written communication of our policies and procedures governing corporate conduct and risk management; comprehensive business planning; effective segregation of duties; delegation of authority and personal accountability; careful selection and training of personnel; and accounting policies, which we regularly update. This structure ensures appropriate internal controls over transactions, assets and records. We also regularly test internal controls. These controls and testing are designed to provide us with reasonable assurance that the financial records are reliable for preparing financial statements and other financial information, assets are safeguarded against unauthorized use or disposition, liabilities are recognized, and we are in compliance with all regulatory requirements.

Management, including the President and Chief Executive Officer (CEO) and the Chief Financial Officer (CFO), is responsible for maintaining disclosure controls and procedures (DC&P) and internal controls over financial reporting (ICOFR). DC&P is designed to provide reasonable assurance that all relevant information is gathered and reported to senior management, including the President and CEO and the CFO, on a timely basis so that appropriate decisions can be made regarding public disclosure. ICOFR is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements in accordance with US GAAP.

An evaluation of the effectiveness of the design and operation of OPG's DC&P and ICOFR was conducted as of December 31, 2017. Accordingly, we, as OPG's President and CEO and CFO, will certify OPG's annual disclosure documents filed with the Ontario Securities Commission, which includes attesting to the design and effectiveness of OPG's DC&P and ICOFR.

The Board of Directors, based on recommendations from its Audit and Risk Committee, reviews and approves the consolidated financial statements and the MD&A, and oversees management's responsibilities for the presentation and preparation of financial information, maintenance of appropriate internal controls, management and control of major areas of financial risk, and assessment of significant and related party transactions.

The consolidated financial statements have been audited by Ernst & Young LLP, independent external auditors appointed by the Board of Directors. The Independent Auditors' Report outlines the auditors' responsibilities and the scope of their examination and their opinion on OPG's consolidated financial statements. The independent external auditors, as confirmed by the Audit and Risk Committee, had direct and full access to the Audit and Risk Committee, with and without the presence of management, to discuss their audit and their findings therefrom, as to the integrity of OPG's financial reporting and the effectiveness of the system of internal controls.

Jeff Lyash
President and Chief Executive Officer

Ken Hartwick
Chief Financial Officer and Senior Vice President – Finance

March 8, 2018

INDEPENDENT
AUDITORS' REPORT

To the Shareholder of Ontario Power Generation Inc.

We have audited the accompanying consolidated financial statements of Ontario Power Generation Inc., which comprise the consolidated balance sheets as at December 31, 2017 and 2016, and the consolidated statements of income, comprehensive income, cash flows and changes in shareholder's equity for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with United States generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Ontario Power Generation Inc. as at December 31, 2017 and 2016, and the results of its operations and its cash flows for the years then ended in accordance with United States generally accepted accounting principles.

Toronto, Canada

March 8, 2018

Ernst & Young LLP

Chartered Professional Accountants,
Licensed Public Accountants

CONSOLIDATED STATEMENTS OF INCOME

Years Ended December 31 *(millions of dollars except where noted)*	**2017**	**2016**
Revenue *(Note 17)*	**5,158**	5,653
Fuel expense *(Note 17)*	**689**	727
Gross margin	**4,469**	4,926
Operations, maintenance and administration *(Note 17)*	**2,824**	2,747
Depreciation and amortization *(Note 4)*	**679**	1,257
Accretion on fixed asset removal and nuclear waste management liabilities *(Note 8)*	**960**	929
Earnings on nuclear fixed asset removal and nuclear waste management funds *(Note 8)*	**(801)**	(746)
Earnings from Fair Hydro Trust *(Note 17)*	**(1)**	-
Income from investments subject to significant influence	**(38)**	(37)
Property taxes	**40**	46
Restructuring	**-**	6
	3,663	4,202
Income before other gains, interest and income taxes	**806**	724
Other gains *(Note 17)*	**379**	17
Income before interest and income taxes	**1,185**	741
Net interest expense *(Note 6)*	**95**	120
Income before income taxes	**1,090**	621
Income tax expense *(Note 9)*	**209**	168
Net income	**881**	453
Net income attributable to the Shareholder	**860**	436
Net income attributable to non-controlling interest	**21**	17
Basic and diluted net income per common share *(dollars) (Note 15)*	**3.35**	1.70

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Years Ended December 31 *(millions of dollars)*	2017	2016
Net income	**881**	453
Other comprehensive income, net of income taxes *(Note 10)*		
Actuarial loss on re-measurement of liabilities for pension and other post-employment benefits [1]	**(23)**	(6)
Reclassification to income of amounts related to pension and other post-employment benefits [2]	**10**	12
Reclassification to income of losses on derivatives designated as cash flow hedges [3]	**18**	19
Unrealized loss on available-for-sale securities [4]	**(8)**	(1)
Other comprehensive (loss) income for the year	**(3)**	24
Comprehensive income	**878**	477
Comprehensive income attributable to the Shareholder	**857**	460
Comprehensive income attributable to non-controlling interest	**21**	17

[1] Net of income tax recovery of $7 million and $2 million for 2017 and 2016, respectively.
[2] Net of income tax expenses of $3 million and $4 million for 2017 and 2016, respectively.
[3] Net of income tax expenses of $2 million for each of 2017 and 2016.
[4] Net of income tax recovery of $2 million and nil for 2017 and 2016, respectively.

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31 *(millions of dollars)*	2017	2016
Operating activities		
Net income	**881**	453
Adjust for non-cash items:		
Depreciation and amortization *(Note 4)*	**679**	1,257
Accretion on fixed asset removal and nuclear waste management liabilities	**960**	929
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(801)**	(746)
Pension and other post-employment benefit costs *(Note 11)*	**412**	464
Deferred income taxes	**19**	(36)
Mark-to-market on derivative instruments	**(3)**	3
Provision for used nuclear fuel and low and intermediate level nuclear waste	**116**	118
Regulatory assets and liabilities	**(558)**	(170)
Provision for materials and supplies	**33**	42
Other gains	**(371)**	-
Other	**1**	(25)
	1,368	2,289
Contributions to nuclear fixed asset removal and nuclear waste management funds	**-**	(150)
Expenditures on fixed asset removal and nuclear waste management	**(313)**	(275)
Reimbursement of eligible expenditures on nuclear fixed asset removal and nuclear waste management	**79**	70
Contributions to pension funds and expenditures on other post-employment benefits and supplementary pension plans	**(322)**	(363)
Expenditures on restructuring	**(4)**	(6)
Distributions received from investments subject to significant influence	**50**	52
Net changes to other long-term assets and liabilities	**32**	20
Net changes to non-cash working capital balances *(Note 18)*	**54**	180
Cash flow provided by operating activities	**944**	1,817
Investing activities		
Acquisition of Fair Hydro Trust financing receivables *(Notes 3 and 19)*	**(1,179)**	-
Purchase of available-for-sale securities	**-**	(213)
Proceeds from deposit note	**70**	110
Net proceeds from sale of property, plant and equipment	**484**	-
Investment in property, plant and equipment and intangible assets	**(1,853)**	(1,816)
Cash flow used in investing activities	**(2,478)**	(1,919)
Financing activities		
Issuance of Class A shares *(Note 14)*	**519**	-
Issuance of long-term debt *(Note 6)*	**1,301**	334
Repayment of long-term debt	**(1,103)**	(273)
Issuance of long-term debt by Fair Hydro Trust *(Note 6)*	**601**	-
Distribution to non-controlling interest	**(15)**	(14)
Capital contribution from non-controlling interest	**19**	-
Issuance of short-term notes	**1,960**	3,108
Repayment of short-term debt	**(1,700)**	(3,331)
Cash flow provided by (used in) financing activities	**1,582**	(176)
Net increase (decrease) in cash and cash equivalents	**48**	(278)
Cash and cash equivalents, beginning of year	**186**	464
Cash and cash equivalents, end of year	**234**	186

See accompanying notes to the consolidated financial statements

CONSOLIDATED BALANCE SHEETS

As at December 31 *(millions of dollars)*	2017	2016
Assets		
Current assets		
Cash and cash equivalents [1]	**234**	186
Available-for-sale securities	**188**	212
Receivables from related parties *(Note 19)*	**369**	429
Nuclear fixed asset removal and nuclear waste management funds *(Notes 8 and 17)*	**23**	24
Fuel inventory *(Note 17)*	**309**	310
Materials and supplies *(Note 17)*	**103**	100
Prepaid expenses	**192**	198
Other current assets	**146**	298
	1,564	1,757
Property, plant and equipment *(Notes 4 and 17)*	**29,950**	29,315
Less: accumulated depreciation	**8,628**	9,317
	21,322	19,998
Intangible assets *(Notes 4 and 17)*	**565**	503
Less: accumulated amortization	**432**	404
	133	99
Other assets		
Nuclear fixed asset removal and nuclear waste management funds *(Notes 8 and 17)*	**16,701**	15,960
Financing receivables *(Note 19)*	**1,179**	-
Long-term materials and supplies *(Note 17)*	**355**	345
Regulatory assets *(Note 5)*	**7,231**	5,855
Investments subject to significant influence *(Note 20)*	**309**	321
Other long-term assets	**28**	37
	25,803	22,518
	48,822	44,372

[1] Includes $4 million restricted for Fair Hydro Trust purposes.

See accompanying notes to the consolidated financial statements

CONSOLIDATED BALANCE SHEETS

As at December 31 *(millions of dollars)*	2017	2016
Liabilities		
Current liabilities		
Accounts payable and accrued charges *(Note 19)*	**1,228**	1,164
Short-term debt *(Note 7)*	**260**	2
Deferred revenue due within one year	**12**	12
Long-term debt due within one year *(Note 6)*	**398**	1,103
Income taxes payable	**80**	123
	1,978	2,404
Long-term debt *(Notes 6 and 17)*	**5,921**	4,417
Other liabilities		
Fixed asset removal and nuclear waste management liabilities *(Notes 8 and 17)*	**20,421**	19,484
Pension liabilities *(Note 11)*	**3,423**	3,012
Other post-employment benefit liabilities *(Note 11)*	**3,092**	2,897
Long-term accounts payable and accrued charges	**252**	213
Deferred revenue	**351**	298
Deferred income taxes *(Note 9)*	**879**	829
Regulatory liabilities *(Note 5)*	**594**	310
	29,012	27,043
Equity		
Common shares [1] *(Note 14)*	**5,126**	5,126
Class A shares [2] *(Note 14)*	**519**	-
Retained earnings	**6,396**	5,534
Accumulated other comprehensive loss *(Note 10)*	**(295)**	(295)
Equity attributable to the Shareholder	**11,746**	10,365
Equity attributable to non-controlling interest *(Note 22)*	**165**	143
Total equity	**11,911**	10,508
	48,822	44,372

[1] 256,300,010 common shares outstanding at a stated value of $5,126 million as at December 31, 2017 and December 31, 2016.

[2] 12,217,616 Class A shares outstanding at a stated value of $519 million as at December 31, 2017.

Commitments and Contingencies *(Notes 6, 9, 11 and 16)*

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY

Years Ended December 31 *(millions of dollars)*	**2017**	**2016**
Common shares	**5,126**	5,126
Class A shares *(Note 14)*	**519**	-
Retained earnings		
Balance at beginning of year	**5,534**	5,098
Net income attributable to the Shareholder	**860**	436
Reclassification of non-controlling interest on change in ownership interest *(Note 22)*	**2**	-
Balance at end of year	**6,396**	5,534
Accumulated other comprehensive loss, net of income taxes		
Balance at beginning of year	**(295)**	(319)
Other comprehensive (loss) income	**(3)**	24
Reclassification of non-controlling interest on change in ownership interest *(Note 22)*	**3**	-
Balance at end of year	**(295)**	(295)
Equity attributable to the Shareholder	**11,746**	10,365
Equity attributable to non-controlling interest		
Balance at beginning of year	**143**	140
Equity contribution from non-controlling interest *(Note 22)*	**21**	-
Reclassification of non-controlling interest on change in ownership interest *(Note 22)*	**(5)**	-
Distribution to non-controlling interest	**(15)**	(14)
Income attributable to non-controlling interest	**21**	17
Balance at end of year	**165**	143
Total equity	**11,911**	10,508

See accompanying notes to the consolidated financial statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the years ended December 31, 2017 and 2016

1. DESCRIPTION OF BUSINESS

Ontario Power Generation Inc. (OPG or the Company) was incorporated on December 1, 1998 pursuant to the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the Province or the Shareholder). OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario.

2. BASIS OF PRESENTATION

These consolidated financial statements have been prepared and presented in accordance with United States generally accepted accounting principles (US GAAP).

As required by *Ontario Regulation 395/11,* as amended, under the *Financial Administration Act* (Ontario), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. Since January 1, 2012, OPG also has received exemptive relief from the Ontario Securities Commission (OSC) from the requirements of section 3.2 of National Instrument 52-107, *Acceptable Accounting Policies and Auditing Standards*. The exemption allows OPG to file consolidated financial statements based on US GAAP, rather than International Financial Reporting Standards (IFRS), without becoming a US Securities and Exchange Commission registrant, or issuing public debt.

The current OSC exemption, received in 2014, will terminate on the earliest of the following:

- January 1, 2019
- The financial year that commences after OPG ceases to have activities subject to rate regulation
- The effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within IFRS specific to entities with rate-regulated activities.

All dollar amounts are presented in Canadian dollars, except in tabular format where noted. Certain of the 2016 comparative amounts have been reclassified from financial statements previously presented to conform to the 2017 consolidated financial statement presentation.

3. SIGNIFICANT ACCOUNTING POLICIES AND ESTIMATES

Consolidation

The consolidated financial statements of the Company include the accounts of OPG and its majority-owned subsidiaries, and variable interest entities (VIEs) where OPG is the primary beneficiary. All significant intercompany balances and intercompany transactions have been eliminated on consolidation.

Where OPG does not control an investment, but has significant influence over operating and financing policies of the investee, the investment is accounted for under the equity method. OPG co-owns the Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS) with TransCanada Energy Ltd. and co-owns the Brighton Beach gas-fired combined cycle GS (Brighton Beach) with ATCO Power Canada Ltd. OPG accounts for its 50 percent ownership interest in each of these jointly controlled entities using the equity method.

Variable Interest Entities

OPG performs ongoing analysis to assess whether it holds any VIEs. VIEs of which OPG is deemed to be the primary beneficiary are consolidated. The primary beneficiary of a VIE has both the power to direct the activities of the entity that most significantly impact its economic performance and the obligation to absorb losses of the entity that could potentially be significant to the Company. In circumstances where OPG is not deemed to be the primary beneficiary, the VIE is not recorded in OPG's consolidated financial statements.

Nuclear Waste Management Organization (NWMO)

In 2002, OPG and other Canadian nuclear waste producers established a separately incorporated NWMO in accordance with the *Nuclear Fuel Waste Act* (Canada) (NFWA). The primary long-term mandate of the NWMO is to implement an approach to address the long-term management of used nuclear fuel in Canada. In addition to the above mandate, the NWMO currently provides project management services for OPG's proposed Deep Geologic Repository (DGR) for the long-term management of low and intermediate level waste (L&ILW) and certain other nuclear life cycle liability management services. OPG has the majority of voting rights at the NWMO Board of Directors' and members' level. The NFWA requires the nuclear fuel waste owners to establish and make payments into trust funds for the purpose of funding the implementation of the long-term nuclear used fuel management plan in accordance with the NFWA. OPG provides over 90 percent of NWMO's funding, primarily towards the design and implementation of Canada's Adaptive Phased Management plan for the long-term management of nuclear used fuel. As a result, OPG is expected to absorb a majority of the NWMO's expected losses through future funding in the event of any shortfall. Therefore, OPG holds a variable interest in the NWMO, of which it is the primary beneficiary. Accordingly, the applicable amounts in the accounts of the NWMO, after elimination of all significant intercompany transactions, are consolidated.

Fair Hydro Trust

On March 2, 2017, the Province announced Ontario's Fair Hydro Plan (the Fair Hydro Plan) aimed at reducing electricity bills for eligible~~all~~ residential customers, and as many as half a million farm and~~,~~ small businesses ~~and other eligible consumers~~ (Specified Consumers) in the province on average by 25 percent. The rate reduction is inclusive of an eight percent rebate equivalent to the provincial portion of the harmonized sales tax granted by the Ontario government in January 2017. As part of the Fair Hydro Plan, a portion of the Global Adjustment costs ~~resulting from the Fair Hydro Plan shortfall~~ will be refinanced over a longer time period. The Global Adjustment includes the difference between Ontario's electricity market clearing price used to dispatch generation and the prices paid to contracted and regulated generators in the province, and the cost of conservation and demand management programs. On June 1, 2017, the *Ontario Fair Hydro Plan Act, 2017* (the Fair Hydro Act or the Act) received Royal Assent and the associated general regulation came into force in June 2017. Effective May 1, 2017, the Independent Electricity System Operator (IESO) began to defer a portion of the Global Adjustment costs. The Act allows for the IESO to transfer a portion of the balance in the variance account to a financing entity that will fund the deferral in exchange for the right to recover the balance and associated financing and other costs from Specified Consumers in the future (Investment Interest).

In December 2017, the Fair Hydro Trust (the Trust) was established as the financing entity contemplated by the Fair Hydro Act. Immediately after the establishment, OPG entered into a management agreement with the Trust which conveys to OPG all of the powers and duties of managing the Trust, including determining whether to acquire Investment Interests from the IESO related to the shortfall from the rate reduction mandated by the Fair Hydro Act, negotiating and executing all agreements, fulfilling all reporting requirements, and administering all of its day-to-day activities. In addition to the powers and duties delegated to OPG as manager under the management agreement, OPG is also required to comply with its duties as Financial Services Manager under the Fair Hydro Act and the regulations.

The Trust is essentially all debt funded and has minimal equity at risk to finance its activities. As part of the funding structure of the Trust, concurrent with every issuance of senior debt, it is expected that OPG will purchase subordinated debt of the Trust in an aggregate amount equal to, but no more than 49 percent of all of the required funding. The subordination level may vary over time, but must at least equal to, or be greater than 35 percent of all outstanding debt. Approximately 90 percent of such amount is expected to be funded through equity investments in OPG by the Province, with the remainder being funded from OPG's available funds, including all or a portion of the proceeds from OPG's medium term notes program. Based on management's assessment, it is concluded that OPG holds a variable interest in the Trust through its ownership of the most subordinated debt, of which it is the primary beneficiary. Accordingly, the applicable amounts in the accounts of the Trust, after elimination of all significant intercompany transactions, have been consolidated by OPG.

PSS Generating Station Limited Partnership (PSS or the Partnership)

As at December 31, 2017, PSS has recognized sufficient level of income and has eliminated deficits within the partnership. Hence, the Partnership has met the criteria of having sufficient equity at risk to finance its activities, and ceased being classified as a variable interest entity. Since OPG is the primary beneficiary of PSS, it continues to consolidate the Partnership.

Use of Management Estimates

The preparation of consolidated financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the consolidated financial statements, and the reported amounts of revenues and expenses for the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in the period incurred. Significant estimates are included in the determination of pension and other post-employment benefit (OPEB) balances, asset retirement obligations (AROs) and associated asset retirement costs capitalized as part of property, plant and equipment (PP&E), income taxes (including deferred income taxes), contingencies, regulatory assets and liabilities, valuation of investments in segregated funds, depreciation and amortization expenses. Actual results may differ significantly from these estimates.

Cash and Cash Equivalents and Short-Term Investments

Cash and cash equivalents include cash on deposit and money market securities with a maturity of less than 90 days on the date of purchase. All other money market securities with a maturity on the date of purchase that is greater than 90 days, but less than one year, are recorded as short-term investments and classified as current assets. These securities are valued at the lower of cost and market.

Inventories

Inventories, consisting of fuel and materials and supplies, are measured at the lower of cost and net realizable value. Cost is determined as weighted average cost for fuel inventory and average cost for materials and supplies.

Property, Plant and Equipment, Intangible Assets and Depreciation and Amortization

PP&E and intangible assets are recorded at cost. Interest costs incurred during construction and development are capitalized as part of the cost of the asset based on the interest rates on OPG's long-term debt. Expenditures for replacements of major components are capitalized.

Depreciation and amortization rates for the various classes of assets are based on their estimated service lives. Asset removal costs that have not been specifically provided for in current or previous periods are charged to operations, maintenance and administration (OM&A) expenses when incurred. Repairs and maintenance costs also are expensed when incurred.

PP&E are depreciated on a straight-line basis, except for computers, which are depreciated on a declining balance basis. Intangible assets, which consist of major application software, are amortized on a straight-line basis.

As at December 31, 2017, the amortization periods of PP&E and intangible assets are as follows:

Nuclear generating stations and major components	15 to 74 years [1]
Thermal generating stations and major components	5 to 50 years
Hydroelectric generating stations and major components	10 to 100 years
Administration and service facilities	10 to 50 years
Computers – declining balance	12% to 40% per year
Major application software	5 years
Service equipment	5 to 10 years

[1] As at December 31, 2017, the end of station life for depreciation purposes for the Darlington, Pickering, Bruce A and Bruce B nuclear generating stations ranged between 2022 and 2061. Major components are depreciated over the lesser of the station life and the life of the components.

Asset Impairment

Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. The review is based on the presence of impairment indicators such as the future economic benefit of the assets and external market conditions. The net carrying amount of assets is considered impaired if it exceeds the sum of the estimated undiscounted cash flows expected to result from the asset's use and eventual disposition. In cases where the sum of the undiscounted expected future cash flows is less than the carrying amount, an impairment loss is recognized. This loss equals the amount by which the carrying amount exceeds the fair value. Fair value is determined using expected discounted cash flows when quoted market prices are not available. The impairment is recognized in income in the period in which it is identified.

The carrying values of investments accounted for under the equity method are reviewed annually for the presence of any indicators of impairment. If an impairment exists and is determined to be other-than-temporary, an impairment charge is recognized. This charge equals the amount by which the carrying value exceeds the investment's fair value.

Rate Regulated Accounting

The *Ontario Energy Board Act, 1998* and *Ontario Regulation 53/05* provide that OPG receives regulated prices for electricity generated from the Sir Adam Beck 1, 2 and Pump hydroelectric generating stations, the DeCew Falls 1 and 2 hydroelectric generating stations, the R.H. Saunders Hydroelectric GS, the 48 hydroelectric generating stations prescribed for rate regulation effective in 2014, and the Pickering and Darlington nuclear generating stations (collectively, prescribed facilities or regulated facilities). OPG's regulated prices for these facilities are determined by the Ontario Energy Board (OEB).

The OEB is a self-funding Crown corporation. Its mandate and authority come from the *Ontario Energy Board Act, 1998,* the *Electricity Act, 1998*, and a number of other provincial statutes. The OEB is an independent, quasi-judicial tribunal that reports to the Legislature of the Province through the Ontario Ministry of Energy. It regulates market participants in Ontario's natural gas and electricity industries. The OEB carries out its regulatory functions through public hearings and other more informal processes such as consultations.

US GAAP recognizes that rate regulation can create economic benefits and obligations that are required by the regulator to be obtained from, or settled with, the customers. When the Company assesses that there is sufficient assurance that incurred costs in respect of the regulated facilities will be recovered in the future, those costs are deferred and reported as a regulatory asset. When the Company is required to refund amounts to customers in the future in respect of the regulated facilities, including amounts related to costs that have not been incurred but for which the OEB has provided recovery through regulated prices, the Company records a regulatory liability.

Certain of the regulatory assets and liabilities recognized by the Company relate to variance and deferral accounts authorized by the OEB, including those authorized pursuant to *Ontario Regulation 53/05*. Variance and deferral accounts typically capture differences between actual costs and revenues and the corresponding forecast amounts

approved by the OEB in setting regulated prices, or record the impact of items not reflected in the approved regulated prices. The measurement of these regulatory assets and liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of *Ontario Regulation 53/05* and the OEB's decisions. The estimates and assumptions made in the interpretation of the regulation and the OEB's decisions are reviewed as part of the OEB's regulatory process.

Regulatory assets and liabilities for variance and deferral account balances approved by the OEB for inclusion in regulated prices are amortized based on approved recovery or repayment periods. Disallowed balances are charged to operations in the period that the corresponding OEB decision is issued.

Regulatory assets and liabilities for variance and deferral account balances approved by the OEB are classified as current if they are expected to be recovered from, or refunded to, customers within 12 months of the end of the reporting period, based on recovery or repayment periods authorized by the OEB. All other regulatory asset and liability balances are classified as non-current on the consolidated balance sheets.

In addition to regulatory assets and liabilities for variance and deferral accounts, OPG recognizes regulatory assets and liabilities for unamortized amounts recorded in accumulated other comprehensive income (AOCI) in respect of pension and OPEB obligations, and deferred income taxes, in order to reflect the expected recovery or repayment of these amounts through future regulated prices charged to customers. There are measurement uncertainties related to these balances due to the assumptions made in the determination of pension and OPEB obligations and deferred income taxes that are attributed to rate regulated business segments.

The regulatory asset for unamortized pension and OPEB amounts recorded in AOCI has reflected the OEB's use, since April 1, 2008, of the accrual basis of accounting for including pension and OPEB amounts in approved regulated prices for OPG. This is also the manner in which these costs are recognized in OPG's consolidated financial statements. Therefore, unamortized amounts in respect of OPG's pension and OPEB plans recognized in AOCI generally would not be reflected in regulated prices until they have been reclassified from AOCI and recognized as amortization components of the benefit costs for these plans. The regulatory asset is reversed as underlying unamortized balances are amortized as components of the benefit cost.

In setting OPG's regulated prices effective November 1, 2014, the OEB limited amounts for pension and OPEB costs allowed in the approved revenue requirements to the regulated business portion of the Company's cash expenditures on its pension and OPEB plans. It is the Company's position that this decision by the OEB does not constitute a change in the basis of rate recovery for OPG's pension and OPEB costs. This position is based on the OEB's establishment of the Pension & OPEB Cash Versus Accrual Differential Deferral Account pursuant to its November 2014 decision, and the expectation expressed by the OEB in that decision that a transition from the accrual basis of recovery for OPG, if required, would be addressed in a future OPG rate proceeding, informed by the outcome of an OEB generic proceeding related to the regulatory treatment and recovery of pension and OPEB costs. Effective November 1, 2014, the Pension & OPEB Cash Versus Accrual Differential Deferral Account records the difference between OPG's actual pension and OPEB costs for the regulated business determined using the accrual method applied in OPG's audited consolidated financial statements and OPG's corresponding actual cash expenditures for these plans. The OEB's November 2014 decision indicated that the future recovery, if any, of amounts recorded in the deferral account would be subject to the outcome of an OEB generic proceeding on the regulatory treatment and recovery of pension and OPEB costs. In May 2015, the OEB began a consultation process to develop standard principles to guide its future review of pension and OPEB costs of rate regulated utilities in the electricity and natural gas sectors, including establishing appropriate regulatory mechanisms for cost recovery. The consultation is continuing. On September 14, 2017, the OEB issued its final report on the guiding principles and the policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the Ontario electricity and natural gas sectors. The report establishes the accrual basis of accounting as the method of determining pension and OPEB amounts for rate-setting purposes, unless the OEB finds that this method does not result in just and reasonable rates in the circumstances of a particular utility.

In consideration of the above factors, the Company continues to believe that there is sufficient likelihood that unamortized pension and OPEB amounts that have not yet been reclassified from AOCI will be included in future regulated prices or in an OEB-authorized deferral or variance account for future recovery, as they are recognized in benefit costs. Therefore, the Company continues to recognize a regulatory asset for these unamortized amounts and also has recognized a regulatory asset for the balance of the Pension & OPEB Cash Versus Accrual Differential Deferral Account discussed in Note 5.

See Notes 5, 8, 9, and 11 for additional disclosures related to the OEB's decisions, regulatory assets and liabilities, and rate regulated accounting.

Revenue Recognition

All of OPG's electricity generation is offered into the real-time energy spot market administered by the IESO. Revenue is recognized as electricity is generated and metered to the IESO.

Revenue Recognition – Regulated Generation

Energy revenue generated from OPG's regulated facilities is based on regulated prices determined by the OEB that include a base regulated price and, as applicable, rate riders for the recovery or repayment of approved variance and deferral account balances.

The base regulated prices in effect during 2016 were established by the OEB's November 2014 decision and December 2014 order, using a forecast cost-of-service rate-setting methodology based on the OEB-approved revenue requirements, taking into account the OEB-approved forecasts of production and operating costs for the regulated facilities for 2014 and 2015 and a return on rate base. Rate base is a regulatory construct that, for OPG, represents the average net level of investment in regulated fixed and intangible assets in-service and an allowance for working capital. The revenues from the regulated hydroelectric facilities are also subject to the OEB-approved hydroelectric incentive mechanism. This mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers.

The rate riders in effect during 2016 were established by the OEB in its October 2015 order on OPG's application to recover balances in most of the Company's authorized variance and deferral accounts as at December 31, 2014. The OEB-authorized variance and deferral accounts are discussed in Note 5.

The OEB's decision and order on OPG's May 2016 five-year application for new regulated prices for its nuclear and regulated hydroelectric generation was issued on December 28, 2017, following a public hearing process. The OEB set an effective date for OPG's new regulated prices of June 1, 2017. OPG had requested an effective date of January 1, 2017 and has filed a motion with the OEB in January 2018 to review and vary this aspect of the OEB's December 2017 decision. [**MONITOR**] See Note 5 for further information on OPG's May 2016 application.

Revenue Recognition – Non-regulated Generation and Other Revenue

The electricity generation from OPG's non-regulated assets receives the Ontario electricity spot market price, except where an energy supply agreement (ESA) with the IESO or another contractual agreement is in place. As at December 31, 2017, most of OPG's operating non-regulated assets are subject to an ESA. Revenue from the generating stations subject to an ESA is recognized in accordance with the terms of the agreement.

OPG also sells into, and purchases from, interconnected markets of other provinces and the northeast and midwest regions of the US. All contracts that are not designated as hedges are recorded on the consolidated balance sheets at market value, with gains or losses recorded in the consolidated statements of income. Gains and losses on energy trading contracts (including those to be physically settled) are recorded on a net basis in the consolidated statements of income. Accordingly, power purchases of $15 million were netted against revenue in 2017 (2016 – $19 million).

OPG derives non-energy revenue under the terms of a lease arrangement and associated agreements with Bruce Power L.P. (Bruce Power) related to the Bruce nuclear generating stations. This includes lease revenue and revenue from heavy water sales, detritiation services and waste management services. OPG's net revenues from the lease of these stations and related agreements, including a portion of heavy water sales, are credited to customers and therefore have reduced regulated prices for the generation from the nuclear facilities owned and operated by OPG. The minimum lease payments are recognized in revenue on a straight-line basis over the term of the lease.

In addition, non-energy revenue includes isotope sales, real estate rentals and other service revenues. Revenues from these activities are recognized as services are provided, or as products are delivered, in accordance with the terms stipulated in the respective contracts.

Fixed Asset Removal and Nuclear Waste Management Liabilities

OPG recognizes AROs for fixed asset removal and nuclear waste management, discounted for the time value of money. OPG estimates both the amount and timing of future cash expenditures based on the plans for fixed asset removal and nuclear waste management. The liabilities are initially recorded at their estimated fair value, which is based on a discounted value of the expected costs to be paid.

On an ongoing basis, the liabilities for nuclear fixed asset removal and nuclear waste management (Nuclear Liabilities) are increased by the present value of the incremental (variable) cost portion for the nuclear waste generated each year, with the corresponding amounts charged to OM&A expenses. Variable expenses relating to L&ILW are charged to OM&A expenses. Variable expenses relating to the management and storage of nuclear used fuel are charged to fuel expense. The liabilities may also be adjusted due to changes in the estimated amount or timing of the underlying future cash flows, with resulting changes in the related asset retirement costs capitalized as part of the carrying amount of the related fixed assets in service. A comprehensive reassessment of all underlying assumptions and baseline cost estimates for the Nuclear Liabilities is performed periodically. Changes in the Nuclear Liabilities resulting from changes in assumptions or estimates that impact the amount or timing of the originally estimated undiscounted future cash flows are recorded as an adjustment to the liabilities. Upward revisions in the Nuclear Liabilities represent the present value of increases in future undiscounted cash flows determined using a current credit-adjusted risk-free rate. Downward revisions in the Nuclear Liabilities represent the present value of decreases in future undiscounted cash flows determined using the weighted average discount rate reflected in the existing liability. Upon settlement of the liabilities, a gain or loss would be recorded.

Accretion arises because the fixed asset removal and nuclear waste management liabilities are reported on a net present value basis. Accretion expense is the increase in the carrying amount of the liabilities due to the passage of time.

The asset retirement cost is capitalized by increasing the carrying value of the related fixed assets in service. The capitalized cost is depreciated over the remaining service life of the related fixed assets and is included in depreciation and amortization expenses.

OPG has no legal obligation associated with the decommissioning of its hydroelectric generating facilities and the costs cannot be reasonably estimated because of the long service life of these assets. With either maintenance efforts or rebuilding, the water control structures are assumed to be used for the foreseeable future. Accordingly, OPG has not recognized a liability for the decommissioning of its hydroelectric generating facilities.

Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

Pursuant to the Ontario Nuclear Funds Agreement (ONFA) between OPG and the Province, OPG has established and sets aside funds in a Used Fuel Segregated Fund and a Decommissioning Segregated Fund (together the Nuclear Segregated Funds). The Used Fuel Segregated Fund is intended to fund expenditures associated with the long-term management of radioactive used nuclear fuel bundles and certain costs of used fuel storage incurred after the nuclear stations are shut down, while the Decommissioning Segregated Fund was established to fund the costs

of nuclear fixed asset removal and long-term L&ILW management, and certain costs of used fuel storage incurred after the nuclear stations are shut down. OPG's funding obligations and resulting contributions to the Nuclear Segregated Funds are determined based on periodically updated reference plans approved by the Province under the ONFA. OPG maintains the Nuclear Segregated Funds in third-party custodial and trust accounts that are segregated from the rest of OPG's assets.

OPG's investments in the Nuclear Segregated Funds and the corresponding amounts payable to/receivable from the Province are classified as held-for-trading. The Nuclear Segregated Funds are measured at fair value based on the bid prices of the underlying equity and fixed income securities, and, in the case of the alternative investment portfolio, using appropriate valuation techniques as outlined in Note 13, with realized and unrealized gains and losses recognized in OPG's consolidated statements of income.

Financing Receivables

Financing receivables consist of the current and irrevocable right of the Fair Hydro Trust to collect payments from Specified Consumers in the future in accordance with the Fair Hydro Act and associated general regulation. These amounts are measured at the transaction price entered into with the IESO on market terms upon acquisition and subsequently measured on an amortized cost basis. The basis of amortization follows the effective interest method.

Derivatives

All derivatives, including embedded derivatives that must be separately accounted for, generally are classified as held-for-trading and recorded at fair value in the consolidated balance sheets. Transaction costs are expensed as incurred for financial instruments classified or designated as held-for-trading.

Derivatives qualify for hedge accounting if they meet stringent documentation requirements, and if the derivative instrument that is designated as a hedge is expected to effectively hedge the identified risk throughout the life of the hedged item. At the inception of a hedging relationship, OPG documents the relationship between the hedging instrument and the hedged item, its risk management objective, and its strategy for undertaking the hedge. A documented assessment is made, both at the inception of a hedge and on an ongoing basis, of whether or not the derivatives that are used in hedging transactions are highly effective in offsetting the changes attributable to the hedged risks in the fair values or cash flows of the hedged items.

All derivative contracts not designated as hedges are recorded on the consolidated balance sheets as derivative assets or liabilities at fair value, with changes in the fair value recorded in the revenue of the Services, Trading, and Other Non-Generation segment. Refer to Note 12 for a discussion of OPG's risk exposures and the derivative instruments used to manage these risks.

Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly arm's-length transaction between market participants at the measurement date. Fair value measurements are required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model. OPG uses a fair value hierarchy, grouping assets and liabilities into three levels based on the relative objectivity of the inputs used to measure fair value, with Level 1 representing the most objective. Refer to Note 13 for a discussion of fair value measurements and the fair value hierarchy.

Available-for-Sale Securities

Available-for-sale (AFS) securities are measured at fair value, with unrealized gains and losses due to changes in fair value recognized in other comprehensive income (OCI). Gains and losses are realized and included in net income when the securities are sold or awarded. Related transaction costs are expensed as incurred, and dividend income

is included in net income in the period dividends are declared. Equity securities are initially measured at the transaction price.

Research and Development

Research and development costs are expensed as incurred. Research and development costs incurred to discharge long-term obligations for which specific provisions have already been made, such as the Nuclear Liabilities, are charged to the related liability.

Leases

Leases are evaluated and classified as either operating or capital leases for financial reporting purposes. Capital leases, which transfer substantially all of the risks and benefits incidental to ownership of the leased item, are capitalized at the inception of the lease at the fair value of the leased property or, if lower, at the present value of the minimum lease payments. Capital leases are depreciated over the shorter of the estimated useful life of the asset and the lease term.

Leases where the lessor retains substantially all the risks and benefits incidental to ownership of the asset are classified as operating leases. Operating lease payments, other than contingent rentals, are recognized as an expense in the consolidated statements of income on a straight-line basis over the lease term. Where the amount of rent expense recognized is different from the actual operating lease payment, other than contingent rentals, the difference is deferred and included as assets or liabilities on the consolidated balance sheets.

Pension and Other Post-Employment Benefits

OPG's post-employment benefit programs consist of a contributory defined benefit registered pension plan, a defined benefit supplementary pension plan, and other post-retirement benefits (OPRB) including group life insurance and health care benefits, and long-term disability (LTD) benefits. Post-employment benefit programs are also provided by the NWMO, which is consolidated into OPG's financial results. Unless otherwise noted, information on the Company's post-employment benefit programs is presented on a consolidated basis.

OPG accrues its obligations under pension and OPEB plans in accordance with US GAAP. The obligations for pension and OPRB are determined using the projected benefit method pro-rated on service. The obligation for LTD benefits is determined using the projected benefit method on a terminal basis. Pension and OPEB obligations are impacted by factors including interest rates, adjustments arising from plan amendments, demographic assumptions, experience gains or losses, salary levels, inflation, and health care cost escalation assumptions. Pension and OPEB costs and obligations are determined annually by independent actuaries using management's best estimate assumptions.

Assumptions are significant inputs to actuarial models that measure pension and OPEB obligations and related effects on operations. Discount rate, inflation rate, and changes in salary levels are three critical assumptions in the determination of benefit costs and obligations. In addition, the expected long-term rate of return on plan assets is a critical assumption in the determination of registered pension plan cost and the health care cost trend rate is a critical assumption in the determination of OPEB cost and obligations. These assumptions, as well as other assumptions involving demographic factors such as retirement age, mortality, and employee turnover, are evaluated periodically by management in consultation with independent actuaries. During the evaluation process, the assumptions are updated to reflect past experience and expectations for the future. Actual results in any given year will often differ from actuarial assumptions because of economic and other factors giving rise to actuarial gains and losses. In accordance with US GAAP, for pension and OPRB, the impact of these updates and differences on the respective benefit obligations is accumulated and amortized over future periods. For LTD benefits, the impact of these updates and differences is immediately recognized as OPEB costs in the period incurred.

The discount rates, which are representative of AA corporate bond yields, are used to calculate the present value of the expected future cash flows on the measurement date in order to determine the projected benefit obligations for the Company's employee benefit plans. A lower discount rate increases the benefit obligations and increases benefit costs. The expected rate of return on plan assets is based on the pension fund's asset allocation and the expected return considering long-term risks and returns associated with each asset class within the plan portfolio. A lower expected rate of return on plan assets increases pension cost.

Pension fund assets include equity securities, corporate and government debt securities, pooled funds, real estate, infrastructure, and other investments. These assets are managed by professional investment managers. The pension fund does not invest in equity or debt securities issued by OPG. Pension fund assets are valued using market-related values for purposes of determining the amortization of actuarial gains or losses and the expected return on plan assets. The market-related value recognizes gains and losses on equity assets relative to a six percent assumed real return over a five-year period.

Pension and OPEB costs include current service costs, interest costs on the obligations, the expected return on pension plan assets, adjustments for plan amendments, and adjustments for actuarial gains or losses, which result from changes in assumptions and experience gains and losses. Past service costs or credits arising from pension and OPRB plan amendments are amortized on a straight-line basis over the expected average remaining service life to full eligibility of the employees covered by the corresponding plan. Past service costs or credits arising from amendments to LTD benefits are immediately recognized as OPEB costs in the period incurred. Due to the long-term nature of pension and OPRB liabilities, the excess of the net cumulative unamortized gain or loss, over 10 percent of the greater of the benefit obligation and the market-related value of the plan assets (the corridor), is amortized over the expected average remaining service life of the employees, which represents the period during which the associated economic benefits are expected to be realized by the Company. Actuarial gains or losses for LTD benefits are immediately recognized as OPEB costs in the period incurred.

OPG recognizes the funded status of its defined benefit plans on the consolidated balance sheets. The funded status is measured as the difference between the fair value of plan assets and the benefit obligation, on a plan-by-plan basis.

Actuarial gains or losses and past service costs or credits arising during the year that are not recognized immediately as components of benefit costs are recognized as increases or decreases in OCI, net of income taxes. These unamortized amounts in AOCI are subsequently reclassified and recognized as components of pension and OPRB costs as described above.

OPG records an offsetting regulatory asset or liability for the portion of the adjustments to AOCI that is attributable to the regulated operations in order to reflect the expected recovery or refund of these amounts through future regulated prices charged to customers. For the recoverable or refundable portion attributable to regulated operations, OPG records a corresponding change in this regulatory asset or liability for the amount of the increases or decreases in OCI and for the amounts reclassified from AOCI into benefit costs during the period.

When the recognition of the transfer of employees and employee-related benefits gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement. A curtailment is the loss by employees of the right to earn future benefits under the plan. A settlement is the discharge of a plan's liability.

Income Taxes and Investment Tax Credits

OPG is exempt from income taxes under the *Income Tax Act* (Canada). However, under the *Electricity Act, 1998*, OPG is required to make payments in lieu of corporate income taxes to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by the *Electricity Act, 1998* and related regulations. This results in OPG paying taxes similar to those imposed under the federal and Ontario tax acts.

OPG's operations are complex and the computation of the provision for income taxes involves interpretation of the various tax statutes and regulations. OPG has taken certain filing positions in calculating the amount of its income tax provision. These filing positions may be challenged on audit by the Ontario Ministry of Finance and some of them possibly disallowed, resulting in a potential significant change in OPG's tax provision upon reassessment. A change in the tax provision upon reassessment impacting regulated operations may be recoverable from or refundable to customers through the Income and Other Taxes Variance Account authorized by the OEB.

OPG follows the liability method of accounting for income taxes. Under the liability method, deferred income tax assets and liabilities are determined based on differences between the accounting and tax bases of assets and liabilities. Deferred amounts are measured using the enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect of a change in tax rates on deferred income tax assets and liabilities is included in income in the period the change is enacted.

If management determines that it is more likely than not that some, or all, of a deferred income tax asset will not be realized, a valuation allowance is recorded to report the balance at the amount expected to be realized.

OPG recognizes deferred income taxes associated with its regulated operations and records an offsetting regulatory asset or liability for the deferred income taxes that are expected to be recovered or refunded through future regulated prices charged to customers.

Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return and investment tax credits are recorded only when the more likely than not recognition threshold is satisfied. Tax benefits and investment tax credits recognized are measured at the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement.

Investment tax credits are recorded as a reduction to income tax expense. OPG classifies interest and penalties associated with unrecognized income tax benefits as income tax expense.

Change in Accounting Estimates

Change in Nuclear Liabilities Estimate

In the fourth quarter of 2017, OPG achieved sufficient confidence in the Company's plans to pursue the continued safe and reliable operation of two units at the Pickering GS to 2022 and the four remaining units to 2024. This resulted in a change to the useful lives for the Pickering GS, for the purposes of calculating depreciation. Effective December 31, 2017, the change to the estimated service live of the Pickering GS has been reflected in an increase to the estimate of the Nuclear Liabilities of $188 million, and a corresponding changes in the carrying value of the nuclear generating stations to which the liabilities relate. The increase in the liabilities is primarily due to higher fixed costs associated with the Used Fuel Disposal and L&ILW Storage programs, discounted using the current credit-adjusted risk-free rate of 2.94 percent.

OPG filed an application with the OEB (EB-2018-0002) on December 29, 2017 to seek approval to establish a deferral account to record, from January 1, 2018 until the effective date of the OEB's next payment amounts order, the revenue requirement impact of changes to nuclear liabilities and depreciation and amortization expense resulting from changes to station end-of-life dates for OPG's Pickering prescribed nuclear facilities that were effective December 31, 2017. On January 31, 2018 the OEB issued an interim order (EB-2018-0002) for the establishment of the Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account, pending the outcome of the proceeding.

Pension and Other Post-Employment Benefits

Effective January 1, 2017, OPG changed the method used to estimate the service and interest cost components of pension and OPEB costs. OPG adopted a full yield curve approach to the estimation of these cost components, by applying the specific spot rates along the yield curve used in the determination of the projected benefit obligations to the relevant projected cash flows. Under the previous method, these components of pension and OPEB costs were calculated using the same single weighted-average discount rates as reflected in the calculation of the benefit obligations. This change in the method was accounted for prospectively, as a change in estimate. The resulting reduction in pension and OPEB costs is estimated at approximately $135 million in 2017. Approximately 90 percent of this reduction in pension and OPEB costs was attributed to the Company's regulated business segments and therefore was offset by the impact of regulatory variance and deferral accounts authorized by the OEB. This change does not affect the measurement of the total benefit obligation as the change in the current service and interest cost components from the previous method will be offset by a corresponding change in the actuarial gain and loss recorded in AOCI.

Pension Plan Actuarial Valuation

A new actuarial valuation of the OPG registered pension plan was filed with the Financial Services Commission of Ontario in September 2017 with an effective date of January 1, 2017. The annual funding requirements in accordance with the new actuarial valuation are $212 million for 2017, $215 million for 2018, and $219 million for 2019.

Recent Accounting Pronouncements Not Yet Adopted

Revenue from Contracts with Customers

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09, *Revenue from Contracts with Customers* (Topic 606), which supersedes nearly all existing revenue recognition guidance, including industry-specific guidance, under US GAAP. The core principle of Topic 606 is to recognize revenues when promised goods or services are transferred to customers in an amount that reflects the consideration to which an entity expects to be entitled for those goods or services. Either a full retrospective application or a modified retrospective application is required for annual periods beginning on or after January 1, 2018, including interim periods within that year. Early adoption is permitted.

OPG has assessed the impact of the standard on accounting for the Company's revenue streams and consolidated financial statements. OPG's major revenue streams include regulated generation revenue from base regulated prices and rate riders established by the OEB, as well as revenue from generation assets under long-term contractual arrangements with the IESO. OPG has completed its analyses of the impact of Topic 606 on all of its revenue streams, and has not identified any material differences in the timing or amount of revenue recognition for these streams.

The Company will apply the new revenue standard in its 2018 first quarter interim financial statements and is in the process of evaluating the additional disclosures required under the new standard.

Lease Accounting

In February 2016, the FASB issued ASU No. 2016-02, *Leases* (Topic 842). The update includes comprehensive changes to existing guidance for lease accounting, particularly for lessees, and aims to increase transparency and comparability among organizations by requiring the recognition of lease assets and lease liabilities on the balance sheet. The standard is effective for annual periods beginning after December 15, 2018, including interim periods within that year.

Under the current guidance, entities are required to use a modified retrospective approach for leases that exist, or are entered into, after the beginning of the earliest comparative period presented in the financial statements of the period of adoption. Under this method, Topic 842 would effectively be implemented by recognizing any adjustments stemming from the transition, as of beginning of the earliest comparative period presented in the entities' financial statements. Full retrospective application is prohibited. In January 2018, the FASB issued a proposed ASU wherein entities would be able to utilize an additional optional transition method of recording the cumulative impact of adopting the new lease standard to the opening balance in the initial period of adoption; with comparative periods continuing to be presented in accordance with the existing leasing standard, Topic 840 - *Leases*, including disclosures. [**MONITOR**] The Company will continue to monitor the status of this proposed ASU.

The FASB also issued ASU No. 2018-01, *Land Easement Practical Expedient for Transition to Topic 842* in January 2018. The amendments therein allows an entity to choose not to evaluate under Topic 842 land easements that exist or expired before the entity's adoption of the new leasing standard and that were not previously accounted for as leases under Topic 840.

The Company continues to implement and execute a comprehensive project governance framework, which comprises a Steering Committee, Implementation & Stakeholder Committee, Project Management Office, and various working groups in order to evaluate the implement the new standard. The working groups are represented by cross functional finance and non-finance stakeholders who will support the financial and operational implementation of the standard. The Company continues to evaluate the impact of the new leasing standard on its consolidated financial statements.

Recognition and Measurement of Financial Assets and Financial Liabilities

In January 2016, the FASB issued ASU No. 2016-01, *Financial Instruments – Overall: Recognition and Measurement of Financial Assets and Financial Liabilities*. Under the updated guidance, entities will have to measure equity investments at fair value and recognize any changes in fair value in net income. The update will be effective for OPG's 2018 fiscal year, including interim periods. As a result of this update, effective January 1, 2018, the AFS classification for securities will no longer be available, with any unrealized gains and losses related to such securities recognized in net income instead of OCI. Any unrealized gains and losses for AFS securities reported by OPG in AOCI as of the end of 2017 will be reclassified to retained earnings as of January 1, 2018. OPG's Hydro One share holdings are currently the Company's only AFS securities. As at December 31, 2017, these shares are valued on the consolidated balance sheet at $188 million (December 31, 2016 − $212 million), for which a loss of $8 million (2016 − $1 million) has been recorded in AOCI. OPG continues to evaluate whether the new standard will have any further impact on its consolidated financial statements.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost

In March 2017, the FASB issued ASU No. 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. Under the new guidance, employers that sponsor defined benefit plans for pensions and/or other postretirement benefits are required to present the service cost component of net periodic benefit cost in the same statement of income line item as other employee compensation costs arising from services rendered during the period. The other components of the net periodic benefit cost are to be presented separately from the line item that includes the service cost and outside of any subtotal of income from operations, if such a subtotal is presented. In addition, the new guidance requires that only the service cost component of net benefit cost be eligible for capitalization.

This guidance is effective for fiscal years beginning after December 15, 2017, including interim periods of those years. The guidance is not expected to have a material impact on OPG's consolidated financial statements, as OPG currently capitalizes only the service cost component of post-retirement benefits costs. Additionally, OPG already includes the service cost component of post-retirement benefit costs with other compensation costs, within the OM&A expenses line item in the consolidated statements of income, and does not show a subtotal of income from operations. As such, the new guidance is not expected to affect the presentation of OPG's consolidated financial statements.

4. PROPERTY, PLANT AND EQUIPMENT, INTANGIBLE ASSETS AND DEPRECIATION AND AMORTIZATION

PP&E as at December 31 consist of the following:

(millions of dollars)	**2017**	**2016**
Nuclear generating stations	**11,985**	11,057
Regulated hydroelectric generating stations	**9,566**	9,430
Contracted generation portfolio generating stations	**3,935**	3,751
Other property, plant and equipment	**372**	1,595
Construction in progress	**4,092**	3,482
	29,950	29,315
Less: accumulated depreciation		
Generating stations	**8,480**	7,948
Other property, plant and equipment	**148**	1,369
	8,628	9,317
	21,322	19,998

Construction in progress as at December 31 consists of the following:

(millions of dollars)	**2017**	**2016**
Darlington Refurbishment	**3,507**	2,563
Peter Sutherland Sr. GS	**17**	236
Other	**568**	683
	4,092	3,482

Intangible assets as at December 31 consist of the following:

(millions of dollars)	**2017**	**2016**
Nuclear generating stations	**122**	122
Regulated hydroelectric generating stations	**6**	7
Contracted generation portfolio generating stations	**5**	4
Computer software and other intangible assets	**393**	350
Development in progress	**39**	20
	565	503
Less: accumulated amortization		
Generating stations	**123**	120
Computer software and other intangible assets	**309**	284
	432	404
	133	99

Depreciation and amortization expenses, including amounts recognized in regulatory variance and deferral accounts authorized by the OEB, for the years ended December 31 consist of the following:

(millions of dollars)	**2017**	**2016**
Depreciation	**649**	602
Amortization of intangible assets	**30**	27
Amounts recognized in regulatory variance and deferral accounts	**-**	26
Amortization of regulatory assets and liabilities *(Note 5)*	**-**	602
	679	1,257

Interest capitalized to construction in progress during 2017 was $162 million (2016 – $141 million), at an average rate of five percent (2016 – five percent).

5. REGULATORY ASSETS AND LIABILITIES

OPG's May 2016 application with the OEB for new regulated prices included a request for new rate riders to recover or repay the December 31, 2015 balances in all of the Company's OEB-authorized variance and deferral accounts, with the exception of the Pension & OPEB Cash Versus Accrual Differential Deferral Account, less amounts previously approved for recovery or repayment for these accounts in 2016. The application also requested the continuation of all applicable existing variance and deferral accounts. In March 2017, the OEB approved a settlement agreement reached by OPG and intervenors on a limited set of issues in the application (Settlement Agreement). Among the settled issues, the agreement provided for the continuation of all applicable existing variance and deferral accounts and accepted a number of variance and deferral account balances for recovery, as requested in OPG's application. The periods of recovery or repayment for the accepted variance and deferral account balances were excluded from the scope of the Settlement Agreement.

In the OEB's December 2017 Decision and Order, the OEB accepted all applicable variance and deferral account balances for recovery that were not already accepted as part of the partial Settlement Agreement that was reached by OPG and intervenors. That OEB-approved Settlement Agreement also provided for the continuation of all applicable existing variance and deferral accounts effective June 1, 2017. The December 2017 decision and order allows for recovery of $305 million recorded in certain variance and deferral accounts as at December 31, 2015, without adjustments. OPG's draft Payment Amounts Order proposed the recovery period to be January 1, 2019 to December 31, 2021.

Consistent with the effective date of the OEB's December 2017 decision and order, for the period from January 1, 2017 to May 31, 2017, OPG continued to record additions to the existing variance and deferral accounts for the nuclear and regulated hydroelectric facilities pursuant to the OEB's previous decisions and orders. These additions reflected differences between actual and forecast amounts embedded in the regulated prices in effect prior to June 1, 2017.

In its December 2017 decision and order on OPG's rate application, the OEB granted OPG approval to request disposal of applicable audited deferral and variance account balances, including the Pension & OPEB Cash Versus Accrual Differential Account, in calendar year 2018. Under the requirements of US GAAP, the period of deferring amounts recorded in the Pension & OPEB Cash Versus Accrual Differential Deferral Account must not exceed five years from the time that they were incurred. Accordingly, such amounts recorded during November 2014 must begin to be recovered no later than November 2019 and must be fully recovered within 20 years of November 2014 or OPG will be required to write off the regulatory asset for these amounts.

The regulatory assets and liabilities recorded as at December 31 are as follows:

(millions of dollars)	**2017**	**2016**
Regulatory assets		
Variance and deferral accounts authorized by the OEB		
Pension and OPEB Cost Variance Account	**716**	716
Pension & OPEB Cash Versus Accrual Differential Deferral Account *(Note 11)*	**614**	497
Hydroelectric Surplus Baseload Generation Variance Account	**360**	210
Bruce Lease Net Revenues Variance Account	**121**	95
Other variance and deferral accounts	**124**	107
	1,935	1,625
Interim Period Revenue Shortfall Account	**544**	-
Pension and OPEB Regulatory Asset *(Note 11)*	**3,855**	3,392
Deferred Income Taxes	**897**	838
Total regulatory assets	**7,231**	5,855
Regulatory liabilities		
Variance and deferral accounts authorized by the OEB		
Hydroelectric Water Conditions Variance Account	**150**	51
Pension & OPEB Cash Variance Account	**140**	58
Impacts Resulting from Changes in Station End-of-Life Dates Deferral Account	**103**	71
Rate Smoothing Deferral Account	**63**	-
Other variance and deferral accounts	**138**	130
Total regulatory liabilities	**594**	310

The changes in the regulatory assets and liabilities during 2017 and 2016 are as follows:

(millions of dollars)	Pension and OPEB Cost Vari-ance	Pension & OPEB Cash vs Accrual Differen-tial Deferral	Hydro-electric Surplus Baseload Genera-tion Variance	Bruce Lease Net Reve-nues Variance	Water Condit-ions variance	Pension & OPEB Cash	Impact Resulting from Changes in Station End-of-Life Dates Deferral Account	Rate Smooth-ing Deferral Account	Other Vari-ance and Deferral (net)	Interim Period Revenue Shortfall Account	Pension and OPEB Regula-tory Asset	Deferred Income Taxes
Net regulatory assets (liabilities) January 1, 2016	865	315	114	95	(23)	28	-	-	260	-	3,362	792
Increase (decrease)	-	182	126	143	(33)	(86)	(71)	-	-	-	30	46
Interest	-	-	2	-	(1)	-	0	-	1	-	-	-
Amortization	(149)	-	(32)	(143)	6	-	0	-	(284)	-	-	-
Net regulatory assets (liabilities) December 31, 2016	716	497	210	95	(51)	(58)	(71)	-	(23)	-	3,392	838
Increase (decrease)	**-**	**117**	**146**	**25**	**(98)**	**(81)**	**(32)**	**(62)**	**10**	**544**	**463**	**59**
Interest	**-**	**-**	**4**	**1**	**(1)**	**(1)**	**0**	**(1)**	**(1)**	**-**	**-**	**-**
Net regulatory assets (liabilities) December 31, 2017	**716**	**614**	**360**	**121**	**(150)**	**(140)**	**(103)**	**(63)**	**(14)**	**544**	**3,855**	**897**

Pension and OPEB Cost Variance Account

As authorized by the OEB, for the period from March 1, 2011 to October 30, 2014, the Pension and OPEB Cost Variance Account recorded the differences between OPG's actual pension and OPEB costs for the regulated business determined on an accrual basis and related tax impacts, and corresponding forecast amounts reflected in the regulated prices then in effect. In its November 2014 decision, the OEB determined that the pension and OPEB amounts reflected in OPG's regulated prices established by that decision effective November 1, 2014 would be limited to the Company's estimated minimum contributions to its registered pension plan and a forecast of OPG's expenditures on the OPEB and supplementary pension plans. As such, the OEB ordered the Pension and OPEB Cost Variance Account to record only amortization beginning on November 1, 2014.

In its October 2015 order, the OEB approved the continuation of the previously authorized recovery of 10/12 of the account balance as at December 31, 2012 over a 144-month period to December 31, 2024. Amounts recorded in the account in 2013 and 2014 were approved for recovery over a 72-month period to June 30, 2021 by the OEB's October 2015 order. In OPG's draft payment amounts order, the recovery period was adjusted to extend beyond June 30, 2021 and December 31, 2024 to account for the break in recovery of the account in the 2017 and 2018 periods as proposed by OPG.

Pension & OPEB Cash Versus Accrual Differential Deferral Account

In its November 2014 decision and December 2014 order, the OEB established the Pension & OPEB Cash Versus Accrual Differential Deferral Account. Effective November 1, 2014, this deferral account records the difference between OPG's actual pension and OPEB costs for the regulated business determined on an accrual basis under US GAAP and OPG's corresponding actual cash expenditures for these plans. The balance in the account as at

December 31, 2017 represents the excess of costs calculated using the accrual basis over the cash basis for the period from November 1, 2014 to December 31, 2017. The Company has recognized the amount set aside in the deferral account as a regulatory asset.

The OEB's November 2014 decision indicated that the future recovery, if any, of amounts recorded in the deferral account would be subject to the outcome of the OEB generic proceeding on the regulatory treatment and recovery of pension and OPEB costs. On September 14, 2017, the OEB issued its final report on the guiding principles and the policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the Ontario electricity and natural gas sectors. The report establishes the accrual basis of accounting as the method of determining pension and OPEB amounts for rate-setting purposes, unless the OEB finds that this method does not result in just and reasonable rates in the circumstances of a particular utility. The OEB's September 2017 report and the OEB's December 2017 decision on OPG's application for new regulated prices require OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the Pension & OPEB Cash to Accrual Differential Deferral Account in effect since November 1, 2014, until such time as the OEB approves resumption of the accrual basis of recovery.

Consistent with the expectations set out in the OEB's December 2017 decision, in 2018, OPG plans to file an application with the OEB requesting disposition of the Pension & OPEB Cash Versus Accrual Differential Deferral Account balance.

Hydroelectric Surplus Baseload Generation Variance Account

The Hydroelectric Surplus Baseload Generation Variance Account records the impact of forgone production at OPG's regulated hydroelectric facilities due to surplus baseload generation conditions.

In its December 2017 Decision and Order, the OEB approved the disposition of the Hydroelectric Surplus Baseload Generation Variance Account balance as at December 31, 2015, as proposed. OPG has proposed a recovery period of January 1, 2019 to December 31, 2021.

Bruce Lease Net Revenues Variance Account

In accordance with *Ontario Regulation 53/05*, the OEB is required to include the difference between OPG's revenues and costs associated with the two nuclear generating stations on lease to Bruce Power in the determination of the regulated prices for production from OPG's regulated nuclear facilities. Based on *Ontario Regulation 53/05* requirements, the OEB has established a variance account that captures differences between OPG's actual revenues and costs related to these stations and the corresponding forecasts included in approved nuclear regulated prices, including the costs associated with OPG's Nuclear Liabilities and the earnings from the portion of the Nuclear Segregated Funds related to the Bruce stations.

In 2013, the OEB ordered the portion of the balance in the Bruce Lease Net Revenues Variance Account related to the impact of the derivative liability embedded in the terms of the lease agreement between OPG and Bruce Power related to the Bruce nuclear generating stations (Bruce Lease) in effect prior to December 2015 to be recovered on the basis of OPG's expected rent rebate payments to Bruce Power and associated income tax impacts. The OEB's October 2015 order reaffirmed this approach and included, in amounts authorized for recovery over the period to the end of 2016, amounts for the derivative liability. In December 2015, as a result of amendments to the Bruce Lease, OPG reversed the derivative liability, with a corresponding reduction to the regulatory asset for the Bruce Lease Net Revenue Variance Account. Amounts collected from customers for the derivative liability for periods after its reversal are subject to refund in the future and have been recognized as a regulatory liability as part of the variance account balance.

The regulatory asset balance for the Bruce Lease Net Revenues Variance Account as at December 31, 2017 reflects a net amount of $190 million recoverable from customers for non-derivative variances recorded in 2015 through 2017, which is partially offset by a liability of $69 million to customers for amounts recovered for the derivative liability

since its reversal in December 2015. Non-derivative amounts recorded during 2017 included those arising from the adjustment to the Nuclear Liabilities and related changes to the estimated service lives of OPG's nuclear stations, for accounting purposes, effective December 31, 2015 and the updated 2017 ONFA reference plan approved by the province.

In its December 2017 Decision and Order, the OEB approved the disposition of the Bruce Lease Net Revenues Account balance as at December 31, 2015, as proposed. OPG has proposed a recovery period of January 1, 2019 to December 31, 2021.

Interim Period Revenue Shortfall Account

The Interim Period Revenue Shortfall regulatory asset records the revenue shortfall between proposed Nuclear and Regulated Hydroelectric rates and existing Nuclear and Regulated Hydroelectric rates from June 1, 2017 through December 31 2017 based on actual production. The recovery of this account is expected to begin January 1, 2019 through to December 31, 2021. [**UPDATE**]

Pension and OPEB Regulatory Asset

The Pension and OPEB Regulatory Asset represents unamortized amounts in respect of OPG's pension and OPEB plans that have been recognized in OCI and not yet reclassified into the amortization component of the benefit costs in respect of these plans. These amounts are expected to be recovered from customers through future regulated prices. The regulatory asset is reversed as underlying unamortized balances are amortized as components of benefit costs. For further details, refer to Note 3 under the heading, *Rate Regulated Accounting*. The AOCI amounts related to pension and OPEB plans are presented in Note 11.

Deferred Income Taxes

OPG is required to record a regulatory asset or liability for the deferred income taxes that are expected to be recovered or refunded through future regulated prices charged to customers for generation from OPG's regulated facilities. In addition, OPG is required to recognize a deferred income tax liability or asset for the regulatory asset or liability for the amount of deferred income taxes expected to be included in future regulated prices and paid to, or recovered, from customers. Income taxes are discussed in Note 9.

Hydroelectric Water Conditions Variance Account

The Hydroelectric Water Conditions Variance Account captures the impact of differences in regulated hydroelectric electricity production due to differences between forecast water conditions underlying the production forecast approved by the OEB in setting regulated hydroelectric prices, and the actual water conditions.

In its December 2017 Decision and Order, the OEB approved the disposition of the Hydroelectric Water Conditions Variance Account balance as at December 31, 2015, as proposed. OPG has proposed a recovery period of January 1, 2019 to December 31, 2021.

Pension & OPEB Cash Payment Variance Account

The Pension & OPEB Cash Payment Variance Account was approved in EB-2013-0321 and continued in EB-2014-0370. The account records the difference between OPG's actual registered pension plan contributions and OPEB plan payments (including the long-term disability benefit plan) attributed to the prescribed generating facilities, and such forecast amounts reflected in the revenue requirement approved by the OEB.

In its December 2017 Decision and Order, the OEB approved the disposition of the Pension & OPEB Cash Payment Variance Account balance as at December 31, 2015, as proposed. OPG has proposed a recovery period of January 1, 2019 to December 31, 2021.

Impact Resulting from Changes in Station End-of-Life Dates Deferral Account

In December 2015, as required by the OEB's previous decisions and orders, OPG applied to the OEB for an accounting order to establish a new deferral account to record the revenue requirement impact on the Pickering and Darlington nuclear generating stations of changes to the Nuclear Liabilities and depreciation expense arising from extensions in the estimated useful lives of OPG's nuclear stations, for accounting purposes, effective December 31, 2015. These impacts were not reflected in the existing regulated prices. In March 2016, the OEB issued its final decision and order establishing the requested account, the Impact Resulting from Changes in Station End-of-Life Dates Deferral Account, effective January 1, 2016. The deferral account recorded these impacts until new regulated prices reflecting the above changes came into effect on June 1, 2017.

The extensions to the estimated useful lives of OPG's nuclear generating stations effective December 31, 2015, for accounting purposes, included those of the Bruce A GS and the Bruce B GS to reflect the estimated end-of-life dates per the updated refurbishment agreement between the IESO and Bruce Power announced in December 2015, a one-year extension for the Darlington GS to reflect the approval of the refurbishment schedule in 2015, and an extension of less than one year for the Pickering GS. To reflect these changes, OPG recognized a total increase of $2,330 million in the Nuclear Liabilities and a corresponding increase in the related asset retirement costs capitalized to PP&E, effective December 31, 2015.

Rate Smoothing Deferral Account

In accordance with section 5.5 of *Ontario Regulation 53/05*, OPG shall establish a Rate Smoothing Deferral Account. This account shall record, for each respective year, the difference between: (i) the total annual revenue requirement for the prescribed nuclear facilities approved by the OEB; and, (ii) the portion of that revenue requirement in (i) that is used in connection with setting the approved nuclear payment amounts in each year.

Consistent with the requirements of *Ontario Regulation 53/05*, OPG's overall production weighted payment amounts will be smoothed, with a resulting portion of the approved annual nuclear revenue requirements for the 2017-2021 period deferred in the Rate Smoothing Deferral Account for future collection. The non-deferred portion of each year's nuclear revenue requirement will be divided by the OEB-approved forecast of OPG's nuclear electricity generation for the corresponding year to determine the base nuclear regulated price. Per the regulation, the deferral account records interest at a long-term debt rate reflecting OPG's cost of long-term borrowing approved by the OEB, compounded annually. The regulation also requires the OEB to authorize recovery of the balance in the account on a straight line basis over a period not to exceed ten years following the end of the Darlington Refurbishment project. OPG recognizes positive amounts deferred under rate smoothing as an increase in net regulatory assets and an increase in revenue in the period to which the underlying approved revenue requirement relates. Negative amounts determined under rate smoothing are correspondingly recorded as a decrease in net regulatory assets and a decrease to revenue.

On January 17, 2018, OPG submitted a draft payment amounts order to the OEB that proposed nuclear base regulated prices for each year of the 2017-2021 period. The proposed regulated prices reflected the December 2017 decision's findings in calculating the 2017-2021 nuclear revenue requirements and reflected a rate smoothing proposal developed by OPG in accordance with *Ontario Regulation 53/05* and OEB's direction. As at December 31, 2017 OPG recorded a liability of $63 million and is expected to have a regulatory asset balance of approximately $750 million by 2021.

Other Variance and Deferral Accounts

Regulatory assets

As at December 31, 2017 and 2016, regulatory assets for Other variance and deferral accounts included amounts for the Nuclear Liability Deferral Account, the Nuclear and Hydroelectric Deferral and Variance Over/Under Recovery Variance Account, the Nuclear Development Account, and the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account and the Fitness for Duty Deferral Account.

Pursuant to *Ontario Regulation 53/05*, the Nuclear Liability Deferral Account has been authorized by the OEB in connection with changes to OPG's liabilities for nuclear used fuel management and nuclear decommissioning and L&ILW management associated with the nuclear facilities owned and operated by OPG, which are comprised of the Pickering and Darlington nuclear generating stations. The deferral account records the revenue requirement impact associated with the changes in these liabilities arising from an approved reference plan, in accordance with the terms of the ONFA.

The Nuclear and Hydroelectric Deferral and Variance Over/Under Recovery Variance Accounts records any shortfall or over-recovery of the approved variance and deferral account balances due to differences between actual and forecast nuclear and hydroelectric production respectively.

The Nuclear Development Variance Account records variances between the actual non-capital costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities and the corresponding forecasts reflected in the regulated prices approved by the OEB.

The Fitness for Duty Deferral Account was approved by the OEB in the EB-2016-0152 Decision and order, effective June 1, 2017. The account shall record the costs related to implementing the Canadian Nuclear Safety Commission (CNSC) Fitness for Duty program. The Fitness for Duty program is a drug, alcohol, psychological and physical testing program for employees in nuclear facilities, which is anticipated to be a license requirement of the CNSC.

Regulatory liabilities

As at December 31, 2017 and 2016, regulatory liabilities for Other variance and deferral accounts included amounts for the Ancillary Services Net Revenue Variance Account, the Income and Other Taxes Variance Account, the Hydroelectric Incentive Mechanism Variance Account, the SR&ED ITC Variance Account and the Capacity Refurbishment Variance Account.

The Ancillary Services Net Revenue Variance Account has been authorized by the OEB to capture differences between actual nuclear and regulated hydroelectric ancillary services net revenue and the forecast amounts of such revenue approved by the OEB in setting regulated prices.

The Income and Other Taxes Variance Account includes deviations in income taxes for the regulated business, from those approved by the OEB in setting regulated prices, caused by changes in tax rates and rules, as well as reassessments.

The Hydroelectric Incentive Mechanism Variance Account records a credit to customers equal to 50 percent of OPG's hydroelectric incentive mechanism revenues above a specified threshold for the regulated hydroelectric facilities.

As at December 31, 2017, regulatory liabilities for Other variance and deferral accounts also included the SR&ED ITC Variance Account and the Capacity Refurbishment Variance Account. The SR&ED ITC Variance Account was approved by the OEB in its EB-2016-0152 Decision, effective June 1, 2017. This account will record the tax expense impact for the nuclear facilities as a result of the difference between actual SR&ED ITCs (attributed to the nuclear facilities) as determined after any tax audits and the forecast SR&ED ITCs included in the nuclear revenue requirement approved by the OEB. Pursuant to *Ontario Regulation 53/05*, the OEB has authorized the Capacity Refurbishment Variance Account. The account captures variances from the forecasts reflected in the regulated prices for capital and non-capital costs incurred to increase the output of, refurbish, or add operating capacity to one or more of the regulated facilities. The balance in the account as at December 31, 2017 includes variances related to

the refurbishment of the Darlington nuclear generating station, life extension initiatives at the Pickering nuclear generation station, and other projects.

6. LONG-TERM DEBT AND NET INTEREST EXPENSE

Long-term debt consists of the following as at December 31: [1]

(millions of dollars)	**2017**	**2016**
Notes payable to the OEFC [2]		
Senior Notes		
bear interest at rates ranging from 3.12% to 5.44%; maturity dates ranging from 2018 to 2047	**3,195**	3,295
Medium Term Note Program [3]		
Senior Notes		
3.32% due 2027	**500**	-
UMH Energy Partnership [4]		
Senior Notes		
7.86% due 2041	**181**	184
PSS Generating Station Limited Partnership [5]		
Senior Notes		
4.90% due 2067	**245**	245
Lower Mattagami Energy Limited Partnership [6]		
Senior Notes		
bear interest at rates ranging from 2.4% to 5.26%; maturity dates ranging from 2021 to 2052	**1,595**	1,795
Fair Hydro Trust [7]		
Senior notes		
2.32% due 2019	**601**	-
Other	**19**	15
	6,336	5,534
Less: bond issuance fees	**(17)**	(14)
Less: due within one year	**(398)**	(1,103)
Long-term debt	**5,921**	4,417

[1] The interest rates disclosed reflect the effective interest rate of the debt, except for the Fair Hydro Trust notes which reflect the weighted average interest rate during the period the notes were outstanding from December 21 to December 31, 2017.

[2] OEFC is entitled to receive in full amounts owing in respect of the senior debt.

[3] These notes are direct unsecured obligations of OPG and rank *pari passu* with all other OPG's unsubordinated and unsecured obligations.

[4] These notes are secured by the assets of the Upper Mattagami and Hound Chute project. Principal repayments of $3 million per year are made on a semi-annual basis until maturity in 2041, at which time the remaining principal balance of $116 million becomes due.

[5] These notes are secured by the assets of the Peter Sutherland Sr. GS project. The notes have an interest-only feature until 2025 and will be amortized with blended semi-annual principal and interest payments thereafter until maturity in 2067, at which time the remaining principal balance of $49 million becomes due.

[6] These notes are secured by the assets of the Lower Mattagami River project, including existing and new operating facilities.

[7] The notes were issued under an $800 million two-year revolving warehouse facility discussed below and are secured by the assets of the Fair Hydro Trust.

In June 2016, OPG entered into a $700 million general corporate credit facility agreement with the OEFC, which expired on December 31, 2017. In September 2017, the agreement was amended, with the credit facility increased to $2,350 million and the expiry date extended to December 31, 2018. As of December 31, 2017, $800 million were outstanding from the credit facility.

In February 2017, OPG issued senior notes payable to the OEFC totalling $200 million and maturing in February 2047. The effective interest rate and coupon interest rate of these notes was 4.12 percent. In June 2017,

OPG issued senior notes payable to the OEFC totalling $100 million and maturing in June 2047. The effective interest rate and coupon interest rate of these notes was 3.65 percent. In August 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in August 2047. The effective interest rate and coupon interest rate of these notes was 3.86 percent. In September 2017, OPG issued senior notes payable to the OEFC totalling
$400 million and maturing in September 2047. The effective interest rate and coupon interest rate of these notes was 4.07 percent.

In October 2017, OPG issued $500 million of senior notes payable under a Medium Term Note Program. The notes bear a coupon interest rate of 3.32 percent and an effective rate of 3.43 percent, payable semi-annually until maturity in October 2027. The offering was made under OPG's $2 billion short form base shelf prospectus filed in September 2017.

In 2015, PSS, a subsidiary of OPG, issued long-term debt totalling $245 million in support of the Peter Sutherland Sr. Generating Station (GS) project. The majority of the debt proceeds, totalling $180 million, were invested in a structured deposit note with staggered maturity dates ranging from January 2016 to April 2017. As at December 31, 2017, the deposit note had matured.

In October 2016, Lower Mattagami Energy Limited Partnership (LME) issued senior notes totalling $220 million maturing in October 2026. The effective interest rate and coupon interest rate of these notes were 2.40 percent and 2.31 percent, respectively.

In December 2017, the Trust entered into an $800 million revolving warehouse facility agreement with an expiry date of December 21, 2019. As at December 31, 2017, there were outstanding senior notes of $601 million under this credit facility, which were used to finance 51 percent of the Trust's funding requirement for the acquisition of the first tranche of Investment Interest from the IESO in December 2017. The outstanding balance has been classified as long-term debt to reflect the terms and substance of the facility agreement. The interest incurred on this debt is recorded within Earnings from Fair Hydro Trust on the consolidated statements of income. Please refer to Note 17 for additional information on Fair Hydro Trust's financial information.

In February 2018, the Trust issued $500 million of senior notes payable with a coupon interest rate of 3.36 percent and an effective interest rate of 3.42 percent, payable semi-annually until maturity on May 15, 2033. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility issued by the Trust in December 2017. By the end of the first quarter of 2018, the Trust is expected to acquire another tranche of Investment Interest from the IESO, which it expects to fund using its revolving warehouse facility. **[MONITOR]**

The following table summarizes the net interest expense:

(millions of dollars)	December 31 **2017**	**2016**
Interest on long-term debt	**289**	290
Interest on short-term debt	**7**	8
Interest income	**(9)**	(7)
Interest capitalized to property, plant and equipment and intangible assets	**(162)**	(141)
Interest related to regulatory assets and liabilities [1]	**(30)**	(30)
Net interest expense	**95**	120

[1] Includes interest to recognize the cost of financing related to regulatory variance and deferral accounts, as authorized by the OEB, and interest deferred in the Bruce Lease Net Revenues Variance Account, the Capacity Refurbishment Variance Account, and the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account.

Interest paid in 2017 was $258 million (2016 – $269 million), of which $ 251 million (2016 – $261 million) relates to interest paid on long-term debt.

The net book value of the pledged assets of PSS, UMH, LME, and Lower Mattagami Limited Partnership against their debt as at December 31, 2017 was $3,645 million (2016 – $3,510 million).

7. SHORT-TERM DEBT

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. During 2017, OPG renewed and extended the expiry date of both tranches to May 2022. There were no amounts outstanding under the bank credit facility. There was $100 million of commercial paper outstanding under OPG's commercial paper program as at December 31, 2017. The Commercial paper program is used to provide short-term funding requirement for the Company, at rates of approximately one percent and are less than one year in duration.

As at December 31, 2017, the LME maintained a $400 million bank credit facility to support the funding requirements for the Lower Mattagami River project including support for LME's commercial paper program. The facility consists of a $300 million tranche maturing in August 2022 and a $100 million tranche maturing in August 2018. As at December 31, 2017, there was $160 million commercial paper outstanding under LME's commercial paper program (December 31, 2016 – nil). A letter of credit of $55 million was issued in July 2017 and remains outstanding as at December 31, 2017 under the first tranche of LME's credit facility.

As at December 31, 2017, OPG maintained $25 million of short-term, uncommitted overdraft facilities and $468 million of short-term, uncommitted credit facilities, which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other general corporate purposes. As at December 31, 2017, a total of $390 million of Letters of Credit had been issued under these facilities. This included $353 million for the supplementary pension plans, $36 million for general corporate purposes, and $1 million related to the operation of the PEC.

The Company has an agreement to sell an undivided co-ownership interest in its current and future accounts receivable to an independent trust. The maximum amount of co-ownership interest that can be sold under this agreement is $150 million, expiring on November 30, 2018. As at December 31, 2017, there were Letters of Credit outstanding under this agreement of $150 million (December 31, 2016 – $150 million), which were issued in support of OPG's supplementary pension plans.

UMH Energy Partnership has entered into an $8 million short-term, uncommitted overdraft facility and $16 million of irrevocable, standby Letters of Credit facilities in support of its operations. As at December 31, 2017, total Letters of Credit of $15 million had been issued under these facilities.

8. NUCLEAR FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT FUND AND FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT LIABILITIES

The liabilities for fixed asset removal and nuclear waste management on a present value basis as December 31, consist of the following:

(millions of dollars)	**2017**	**2016**
Liability for nuclear used fuel management	**11,970**	11,292
Liability for nuclear decommissioning and nuclear low and intermediate level waste management	**8,107**	7,811
Liability for non-nuclear fixed asset removal	**344**	381
Fixed asset removal and nuclear waste management liabilities	**20,421**	19,484

The changes in the fixed asset removal and nuclear waste management liabilities for the years ended December 31 are as follows:

(millions of dollars)	**2017**	**2016**
Liabilities, beginning of year	**19,484**	20,169
Increase in liabilities due to accretion [1]	**974**	1,024
Decrease in liabilities resulting from the ONFA reference plan update process	**-**	(1,567)
Net change in liabilities reflecting changes to the estimated useful lives *(Note 3)*	**158**	-
Increase in liabilities due to changes in estimates of nuclear used fuel and nuclear waste management expenses and other expenses [1]	**118**	133
Liabilities settled by expenditures on fixed asset removal and nuclear waste management	**(313)**	(275)
Liabilities, end of year	**20,421**	19,484

[1] Amounts shown exclude the impact of regulatory variance and deferral accounts.

OPG's fixed asset removal and nuclear waste management liabilities are comprised of expected costs to be incurred up to and beyond termination of operations and the closure of nuclear and thermal generating facilities, and other facilities. Costs will be incurred for activities such as preparation for safe storage and safe storage of the nuclear stations, dismantlement, demolition and disposal of facilities and equipment, remediation and restoration of sites, and the ongoing and long-term management of nuclear used fuel and L&ILW material.

The determination of the accrual for fixed asset removal and nuclear waste management costs requires significant assumptions since these programs are long-term in nature. The most recent comprehensive update of the cost estimates for the Nuclear Liabilities is contained in the 2017−2021 ONFA reference plan, which was finalized and approved by the Province in the fourth quarter of 2016 (2017 ONFA Reference Plan).

For the purposes of calculating OPG's Nuclear Liabilities, as at December 31, 2017, consistent with the current accounting end-of-life assumptions, nuclear station decommissioning activities are projected to occur over approximately the next 80 years. The estimates for the Nuclear Liabilities include cash flow estimates for decommissioning the nuclear stations for approximately 40 years after stations are shut down and to 2088 for placement of used fuel into the assumed long-term disposal repository, followed by extended monitoring.

The significant assumptions underlying operational, technical, and economic factors used in the calculation of the accrued Nuclear Liabilities are subject to periodic review. Changes to these assumptions, including changes to assumptions on the timing of the nuclear waste programs including construction of waste disposal facilities, station end-of-life dates, waste disposal methods, financial indicators, or the technology employed, may result in significant changes to the value of the accrued liabilities. With programs of this long-term duration and the evolving technology to handle the nuclear waste, there is a significant degree of inherent uncertainty surrounding the measurement of the costs for these programs. These costs may increase or decrease over time.

Liability for Nuclear Used Fuel Management Costs

The liability for nuclear used fuel management represents the cost of managing the highly radioactive used nuclear fuel bundles. The federal NFWA, proclaimed into force in 2002, required that Canada's nuclear fuel waste owners form a nuclear waste management organization, and that each waste owner establish a trust fund for used fuel management costs as specified in the NFWA. This organization, the NWMO, is responsible for the design and implementation of Canada's plan for the long-term management of nuclear used fuel waste. To estimate its liability for nuclear used fuel management costs, OPG has adopted an approach consistent with the Adaptive Phased Management concept approved by the Government of Canada, which assumes a deep geologic repository as part of the long-term management of nuclear used fuel, with an in-service date of 2043 at the earliest.

Liability for Nuclear Decommissioning and L&ILW Management Costs

The liability for nuclear decommissioning and L&ILW management represents the estimated costs of decommissioning the nuclear generating stations after the end of their service lives, as well as the cost of managing L&ILW generated by the stations. The significant assumptions used in estimating future nuclear fixed asset removal costs include a deferred dismantlement basis for decommissioning of the stations, whereby the reactors will be de-watered and de-fueled immediately after the station has ceased operations and thereafter will remain in a safe state condition for a 30-year period, prior to an approximate 10-year dismantlement period.

The life cycle costs of L&ILW management include the costs of processing and storage of such radioactive wastes during and following the operation of the nuclear stations, as well as the costs of the ultimate long-term management of these wastes. The current assumptions used to establish the accrued costs for the management of L&ILW include an L&ILW DGR to be owned and operated by OPG. Agreement was previously reached with local municipalities for OPG to develop a deep geologic repository for the long-term management of L&ILW adjacent to OPG's Western Waste Management Facility in Kincardine, Ontario.

Liability for Non-Nuclear Fixed Asset Removal Costs

The liability for non-nuclear fixed asset removal primarily represents the estimated costs of decommissioning OPG's thermal generating stations at the end of their services lives. The liability is based on third-party cost estimates following an in-depth review of plant sites and an assessment of required clean-up and restoration activities completed in 2017.

OPG performed a revaluation of the liability for non-nuclear fixed asset removal as at December 31, 2017. OPG recognized a decrease in the non-nuclear fixed asset removal liabilities of approximately $30 million, resulting in an decrease in asset retirement costs of $18 million capitalized as part of the carrying value of PP&E, and a gain of $12 million recorded to net income in 2017.

Ontario Nuclear Funds Agreement

In accordance with the ONFA, OPG sets aside and invests funds that are held in segregated custodian and trustee accounts specifically for discharging its life cycle obligation for nuclear decommissioning and long-term nuclear waste management. The Used Fuel Segregated Fund and the Decommissioning Segregated Fund were established under the ONFA for this purpose. OPG makes contributions to the Nuclear Segregated Funds based on the approved ONFA reference plan in effect. ONFA reference plans are subject to approval by the Province.

Since inception, OPG has been making quarterly payments to the Used Fuel Segregated Fund over the assumed lives of its nuclear generating stations, as specified in the ONFA, including contributions to the NFWA Trust established by OPG pursuant to the NFWA. The NFWA Trust forms part of the Used Fuel Segregated Fund, with any OPG contributions to the Used Fuel Segregated Fund, as well as any portion of the fund currently not in the trust, being able to be applied towards the NFWA Trust's annual contribution requirements pursuant to the NFWA. As a result, required funding of the Used Fuel Segregated Fund for 2017 was nil (2016 – $150 million). ONFA

requirements have resulted in the majority of the underlying used fuel management obligation being funded through OPG contributions over the initial estimated useful lives of the nuclear generating stations assumed in the ONFA, which did not reflect subsequent extensions to the nuclear station lives to reflect refurbishment and life extension decisions.

OPG has not been required to make contributions to the Decommissioning Segregated Fund, which was fully funded at its inception through an initial contribution made by the Province and, taking into account asset performance and changes in underlying funding obligation over time, at the time of every subsequent approved ONFA reference plan.

The 2017 ONFA Reference Plan was approved by the Province in December 2016, with an effective date of January 1, 2017. Based on the funded status of the Used Fuel Segregated Fund and the Decommissioning Segregated Fund reflecting the life cycle liability estimates per the 2017 ONFA Reference Plan, no overall contributions to either fund are currently required starting in 2017. Contributions may be required in the future should either or both of the funds be in an underfunded position when a new reference plan is prepared.

The *Nuclear Safety and Control Act* (Canada) requires OPG to have sufficient funds available to discharge its existing nuclear waste management and nuclear facilities decommissioning obligations. As required by the terms of the ONFA, the Province has provided a Provincial Guarantee to the CNSC since 2003, on behalf of OPG. The Provincial Guarantee provides for any shortfall between the CNSC consolidated financial guarantee requirement and the value of the Nuclear Segregated Funds. OPG pays the Province an annual guarantee fee of 0.5 percent of the amount of the Provincial Guarantee. The value of the Provincial Guarantee amount in effect through to the end of 2017 was $1,551 million. Based on this guarantee amount, OPG paid a guarantee fee of $8 million to the Province for each of 2017 and 2016.

Commented [DS1]: Realize that these financial statements are only through Dec. 31, 2017, but to be safe, wanted to flag the CNSC decision in November 2017 such that the Province no longer provides a Provincial Guarantee as of Jan. 1, 2018.

The investments in the Nuclear Segregated Funds include a diversified portfolio of equities and fixed income securities that are invested across geographic markets, as well as investments in infrastructure, real estate, and agriculture. The Nuclear Segregated Funds are invested to fund long-term liability requirements and, as such, the portfolio asset mix is structured to achieve the required return over a long-term horizon. While short-term fluctuations in market value will occur, managing the long-term return of the Nuclear Segregated Funds remains the primary goal. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

Decommissioning Segregated Fund

Under the ONFA, OPG is wholly responsible for cost estimate changes and investment returns in the Decommissioning Segregated Fund. As at December 31, 2017 and 2016, the Decommissioning Segregated Fund was in an overfunded position.

Upon termination of the ONFA, the Province has the sole right to any excess funds in the Decommissioning Segregated Fund, which is the excess of the fair market value of the fund's assets over the underlying estimated future costs, as per the most recently approved ONFA reference plan. Accordingly, when the Decommissioning Segregated Fund is overfunded, OPG limits the fund earnings recognized in the consolidated financial statements by recording an amount due to the Province, such that the asset recognized for the fund on the consolidated balance sheet is equal to the cost estimate of the liability based on the most recently approved ONFA reference plan. Additionally, OPG recognizes the portion of the surplus that it may direct to the Used Fuel Segregated Fund, which is possible when the surplus in the Decommissioning Segregated Fund is such that the underlying liabilities, as defined by the most recently approved ONFA reference plan, are at least 120 percent funded. In those circumstances, OPG may direct, at the time a new reference plan is approved, up to 50 percent of the surplus over 120 percent to the Used Fuel Segregated Fund, with the OEFC entitled to a distribution of an equal amount. Therefore, when the Decommissioning Segregated Fund is at least 120 percent funded, OPG recognizes 50 percent of the excess greater than 120 percent in income, up to the amount by which the Used Fuel Segregated Fund is underfunded. Based on the 2017 ONFA Reference Plan, the Used Fuel Segregated Fund was in a marginally overfunded position as at December 31, 2016, for the first time since inception. As a result, OPG recognized a due to the Province amount

such that the Decommissioning Segregated Fund asset on the consolidated balance sheet as at December 31, 2017 and 2016 was limited to the value of the underlying liability per the 2017 ONFA Reference Plan. The payable to the Province may be reduced in subsequent periods in the event that the Decommissioning Segregated Fund earns less than its target rate of return, a new ONFA reference plan is approved with a higher underlying funding liability, or the Used Fuel Segregated Fund changes to an underfunded status. When the Decommissioning Segregated Fund is underfunded, the earnings on the fund reflect actual fund returns based on the market value of the assets.

When the Decommissioning Segregated Fund is in an overfunded status at less than 120 percent, OPG recognized its annual earnings on the fund at 3.25 percent plus the long-term Ontario Consumer Price Index (CPI) specified in the most recently approved ONFA reference plan, which is the rate of growth in the underlying funding liability. The same treatment is applied to the Decommissioning Segregated Fund when it is in an overfunded status at greater than 120 percent, if the Used Fuel Segregated Fund is fully funded.

Used Fuel Segregated Fund

OPG is responsible for cost increases in the funding liability for used fuel waste management under the ONFA, subject to specified graduated liability thresholds, pursuant to which the Province limits OPG's total financial exposure for the first 2.23 million nuclear used fuel bundles at approximately $15.7 billion in present value dollars as at December 31, 2017. The graduated liability thresholds do not apply to used fuel bundles beyond the 2.23 million threshold.

Under the ONFA, the Province guarantees OPG's annual return in the Used Fuel Segregated Fund at 3.25 percent plus the change in the Ontario CPI, as defined by ONFA, for funding related to the first 2.23 million used fuel bundles, (committed return). OPG recognizes the committed return on the Used Fuel Segregated Fund as Earnings on the Nuclear Segregated Funds. The difference between the committed return and the actual market return determined based on the fair value of the fund assets related to the first 2.23 million used fuel bundles is recorded as due to or due from the Province. This amount due to or due from the Province represents the amount that would be paid to or received from the Province if the committed return were to be settled as at the consolidated balance sheets date. The 2.23 million threshold represents the estimated total life cycle fuel bundles based on the initial estimated useful lives of the nuclear stations assumed in the ONFA.

As prescribed under the ONFA, OPG's contributions for fuel bundles in excess of 2.23 million are not subject to the rate of return guaranteed by the Province, and earn a return based on changes in the market value of the assets of the Used Fuel Segregated Fund.

If there is a surplus in the Used Fuel Segregated Fund such that the liabilities, as defined by the most recently approved ONFA reference plan, are at least 110 percent funded, the Province, has the right, at any time, to access the excess amount greater than 110 percent. Upon termination of the ONFA, the Province is entitled to any surplus in the fund, which is the excess of the fair market value of the Used Fuel Segregated Fund assets over the estimated future costs, as per the most recently approved ONFA reference plan. Neither OPG nor the Province has a right to direct any amounts from the Used Fuel Segregated Fund to the Decommissioning Segregated Fund. Therefore, when the Used Fuel Fund is overfunded, OPG limits the earnings it recognizes by recording an amount due to the Province, such that the asset recognized for the fund on the consolidated balance sheets is equal to the cost estimate of the liability per the most recently approved ONFA reference plan. This results in OPG recognizing annual earnings on the fund at 3.25 percent plus the long-term Ontario CPI specified in the most recently approved ONFA reference plan, which is the rate of growth in the underlying funding liability, when the fund is overfunded.

As at December 31, 2017, the Used Fuel Segregated Fund was marginally overfunded in accordance with the 2017 ONFA Reference Plan, and OPG recognized a due to the Province amount of $55 million such that the asset recognized for the fund was limited to the value of the underlying funding liability. This payable to the Province may be reduced in subsequent periods in the event that the Used Fuel Segregated Fund earns less than its target rate of return or in the event that a new ONFA reference plan is approved with a higher underlying funding liability.

Nuclear Segregated Funds

The nuclear fixed asset removal and nuclear waste management funds as at December 31 consist of the following:

(millions of dollars)	Fair Value 2017	2016
Decommissioning Segregated Fund	**9,099**	8,317
Due to Province – Decommissioning Segregated Fund	**(1,933)**	(1,477)
	7,166	6,840
Used Fuel Segregated Fund [1]	**12,087**	11,082
Due to Province – Used Fuel Segregated Fund	**(2,529)**	(1,938)
	9,558	9,144
Total Nuclear Segregated Funds	**16,724**	15,984
Less: current portion	**23**	24
Non-current Nuclear Segregated Funds	**16,701**	15,960

[1] The Ontario NFWA Trust represents $3,882 million as at December 31, 2017 (2016 – $3,688 million) of the Used Fuel Segregated Fund on a fair value basis.

The fair value of the securities invested in the Nuclear Segregated Funds as at December 31 is as follows:

(millions of dollars)	Fair Value 2017	2016
Cash and cash equivalents and short-term investments	**227**	354
Alternative investments	**2,357**	1,989
Pooled funds	**1,713**	1,329
Marketable equity securities	**10,457**	9,503
Fixed income securities	**6,405**	6,181
Net receivables/payables	**27**	43
	21,186	19,399
Due to Province	**(4,462)**	(3,415)
	16,724	15,984

The historical cost, gross unrealized aggregate appreciation and depreciation of investment, gross unrealized foreign exchange gains, and fair value of the Nuclear Segregated Funds as at December 31, 2017 and 2016 are summarized as follows:

	2017		
(millions of dollars)	**Decommissioning Segregated Fund**	**Used Fuel Segregated Fund**	**Total**
Historical cost	**7,327**	**9,902**	**17,229**
Gross unrealized gains (losses)			
Aggregate appreciation	**1,789**	**2,188**	**3,977**
Aggregate depreciation	**(134)**	**(180)**	**(314)**
Foreign exchange	**117**	**177**	**294**
	9,099	**12,087**	**21,186**
Due to Province	**(1,933)**	**(2,529)**	**(4,462)**
Total fair value	**7,166**	**9,558**	**16,724**
Less: current portion	**5**	**18**	**23**
Non-current fair value	**7,161**	**9,540**	**16,701**

	2016		
(millions of dollars)	**Decommissioning Segregated Fund**	**Used Fuel Segregated Fund**	**Total**
Historical cost	6,896	9,385	16,281
Gross unrealized gains (losses)			
Aggregate appreciation	1,326	1,564	2,890
Aggregate depreciation	(165)	(222)	(387)
Foreign exchange	260	355	615
	8,317	11,082	19,399
Due to Province	(1,477)	(1,938)	(3,415)
Total fair value	6,840	9,144	15,984
Less: current portion	8	16	24
Non-current fair value	6,832	9,128	15,960

Net realized and unrealized gains or losses from investments for the years ended December 31, 2017 and 2016 are summarized as follows:

(millions of dollars)	2017 Decommissioning Segregated Fund	2017 Used Fuel Segregated Fund	2017 Total
Net realized gains			
Realized gains excluding foreign exchange	**198**	**245**	**443**
Realized foreign exchange gains	**54**	**65**	**119**
Net realized gains	**252**	**310**	**562**
Net unrealized gains			
Unrealized gains excluding foreign exchange	**494**	**666**	**1,160**
Unrealized foreign exchange losses	**(143)**	**(178)**	**(321)**
Net unrealized gains	**351**	**488**	**839**

(millions of dollars)	2016 Decommissioning Segregated Fund	2016 Used Fuel Segregated Fund	2016 Total
Net realized gains			
Realized gains excluding foreign exchange	84	180	264
Realized foreign exchange gains	30	41	71
Net realized gains	114	221	335
Net unrealized gains			
Unrealized gains excluding foreign exchange	360	442	802
Unrealized foreign exchange losses	(165)	(216)	(381)
Net unrealized gains	195	226	421

The change in the Nuclear Segregated Funds for the years ended December 31 is as follows:

(millions of dollars)	Fair Value 2017	Fair Value 2016
Decommissioning Segregated Fund, beginning of year	**6,840**	6,549
Increase in fund due to return on investments	**807**	505
Decrease in fund due to reimbursement of eligible expenditures	**(25)**	(22)
Increase in due to Province	**(456)**	(192)
Decommissioning Segregated Fund, end of year	**7,166**	6,840
Used Fuel Segregated Fund, beginning of year	**9,144**	8,587
Increase in fund due to contributions made	**-**	150
Increase in fund due to return on investments	**1,059**	690
Decrease in fund due to reimbursement of eligible expenditures	**(54)**	(48)
Increase in due to Province	**(591)**	(235)
Used Fuel Segregated Fund, end of year	**9,558**	9,144

The earnings from the Nuclear Segregated Funds during 2017 and 2016 were impacted by the Bruce Lease Net Revenues Variance Account authorized by the OEB. The earnings on the Nuclear Segregated Funds for the years ended December 31 are as follows:

(millions of dollars)	**2017**	**2016**
Decommissioning Segregated Fund	**351**	313
Used Fuel Segregated Fund	**468**	455
Bruce Lease Net Revenues Variance Account	**(18)**	(22)
Total earnings	**801**	746

9. INCOME TAXES

OPG follows the liability method of accounting for income taxes. The Company records an offsetting regulatory asset or liability for the deferred income taxes that are expected to be recovered or refunded through future regulated prices charged to customers for generation from OPG's regulated facilities.

A reconciliation between the statutory and the effective rate of income taxes is as follows:

(millions of dollars)	**2017**	**2016**
Income before income taxes	**1,090**	621
Combined Canadian federal and provincial statutory enacted income tax rates	**26.5%**	26.5%
Statutory income tax rates applied to accounting income	**289**	165
(Decrease) increase in income taxes resulting from:		
Income tax (recovery) expense deferred in regulatory assets and liabilities	**(20)**	65
Scientific Research and Experimental Development investment tax credits	**(47)**	(48)
Manufacturing and processing credit	**(16)**	(9)
Other	**3**	(5)
	(80)	3
Income tax expense	**209**	168
Effective rate of income taxes	**19.1%**	27.0%

Significant components of the income tax expense are presented in the table below:

(millions of dollars)	**2017**	**2016**
Current income tax expense	**190**	204
Deferred income tax expense (recovery)	**19**	(36)
Income tax expense	**209**	168

The income tax effects of temporary differences that give rise to deferred income tax assets and liabilities as at December 31 are as follows:

(millions of dollars)	**2017**	**2016**
Deferred income tax assets:		
Fixed asset removal and nuclear waste management liabilities	**5,096**	4,861
Other assets and liabilities	**2,057**	1,813
	7,153	6,674
Deferred income tax liabilities:		
Property, plant and equipment and intangible assets	**(1,923)**	(1,807)
Nuclear fixed asset removal and nuclear waste management funds	**(4,181)**	(3,996)
Other assets and liabilities	**(1,928)**	(1,700)
	(8,032)	(7,503)
Net deferred income tax liabilities	**(879)**	(829)

During 2017, OPG recorded an increase in the deferred income tax liability for the income taxes that are expected to be recovered or refunded through regulated prices charged to customers of $59 million (2016 – $46 million). Since these deferred income taxes are expected to be refunded through future regulated prices, OPG recorded a corresponding increase to the regulatory asset for deferred income taxes. As a result, the deferred income tax expense for 2017 and 2016 was not impacted.

The following table summarizes the deferred income tax liabilities recorded for the rate regulated operations that are expected to be recovered through future regulated prices:

(millions of dollars)	**2017**	**2016**
January 1:		
Deferred income tax liabilities on temporary differences related to regulated operations	**627**	592
Deferred income tax liabilities on temporary differences related to the regulatory asset for the deferred income tax liabilities	**211**	200
	838	792
Changes during the year:		
Increase in deferred income tax liabilities on temporary differences related to regulated operations	**44**	35
Increase in deferred income tax liabilities on temporary differences related to the regulatory asset for the deferred income tax liabilities	**15**	11
Balance as at December 31	**897**	838

The tax benefit associated with an income tax position is recognized only when it is more likely than not that such a position will be sustained upon examination by the taxing authorities based on the technical merits of the position. The current and deferred income tax benefit is equal to the largest amount, considering possible settlement outcomes, that is greater than 50 percent likely of being realized upon settlement with the taxing authorities.

A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

(millions of dollars)	**2017**	**2016**
Unrecognized tax benefits, beginning of year	**77**	72
Additions based on tax positions related to the current year	**21**	19
Additions for tax positions of prior years	**-**	2
Reductions for tax positions of prior years	**(20)**	(16)
Unrecognized tax benefits, end of year	**78**	77

As at December 31, 2017, OPG's unrecognized tax benefits were $78 million (2016 – $77 million), excluding interest and penalties, all of which, if recognized, would affect OPG's effective tax rate. Changes in unrecognized tax benefits over the next 12 months cannot be predicted with certainty.

OPG recognizes interest and penalties related to unrecognized tax benefits as income tax expense. As at December 31, 2017, OPG had recorded interest on unrecognized tax benefits of $8 million (2016 – $8 million). OPG considers its significant tax jurisdiction to be Canada. OPG remains subject to income tax examination for years after 2013.

OPG paid $195 million in income taxes (net of tax refunds) during 2017 (2016 – $98 million).

10. ACCUMULATED OTHER COMPREHENSIVE LOSS

The changes in the balance of each component of accumulated other comprehensive loss (AOCL), net of income taxes, are as follows:

	2017			
(millions of dollars)	**Unrealized Gains and Losses on Cash Flow Hedges [1]**	**Pension and OPEB [1]**	**Available-for-sale Securities [1]**	**Total [1]**
AOCL, beginning of year	**(87)**	**(207)**	**(1)**	**(295)**
Actuarial loss on re-measurement of liabilities for pension and OPEB	**-**	**(23)**	**-**	**(23)**
Unrealized loss on available-for-sale securities	**-**	**-**	**(8)**	**(8)**
Amounts reclassified from AOCL	**18**	**10**	**-**	**28**
Other comprehensive income (loss) for the year	**18**	**(13)**	**(8)**	**(3)**
Reclassification of non-controlling interest on change in ownership interest *(Note 22)*	**3**	**-**	**-**	**3**
AOCL, end of year	**(66)**	**(220)**	**(9)**	**(295)**

[1] All amounts are net of income taxes.

	2016			
(millions of dollars)	**Unrealized Gains and Losses on Cash Flow Hedges [1]**	**Pension and OPEB [1]**	**Available-for-sale Securities [1]**	**Total [1]**
AOCL, beginning of year	(106)	(213)	-	(319)
Actuarial loss on re-measurement of liabilities for pension and OPEB	-	(6)	-	(6)
Unrealized loss on available-for-sale securities	-	-	(1)	(1)
Amounts reclassified from AOCL	19	12	-	31
Other comprehensive income (loss) for the year	19	6	(1)	24
AOCL, end of year	(87)	(207)	(1)	(295)

[1] All amounts are net of income taxes.

The significant amounts reclassified out of each component of AOCL, net of income taxes, during December 31, 2017 and 2016 are as follows:

	Amount Reclassified from AOCL		
(millions of dollars)	**2017**	**2016**	**Statement of Income Line Item**
Amortization of losses from cash flow hedges			
Losses	**20**	21	Net interest expense
Income tax recovery	**(2)**	(2)	Income tax expense
	18	19	
Amortization of amounts related to pension and OPEB			
Actuarial losses and past service costs	**13**	16	See (1) below
Income tax recovery	**(3)**	(4)	Income tax expense
	10	12	
Total reclassifications for the year	**28**	31	

[1] These AOCL components are included in the computation of pension and OPEB costs (see Note 11 for additional details).

11. PENSION AND OTHER POST-EMPLOYMENT BENEFITS

Fund Assets

The OPG registered pension fund investment guidelines are stated in an approved Statement of Investment Policies and Procedures (SIPP). The SIPP is reviewed and approved by the Audit and Risk Committee of OPG's Board of Directors at least annually and includes a discussion of investment objectives and expectations, asset mix and rebalancing, and the basis for measuring the performance of the pension fund assets.

In accordance with the SIPP, investment allocation decisions are made with a view to achieve OPG's objective of meeting obligations of the plan as they come due. The pension fund assets are invested in four categories of asset classes. The first category is liability hedging assets, which are intended to hedge the inflation and interest rate sensitivity of the plan liabilities. The second category is return enhancing assets, which are intended to obtain higher investment returns compared to the returns expected for liability hedging assets. The third category is real assets, which offer exposure to the combined characteristics of liability hedging and return enhancing assets. The fourth category is return diversifying strategies, which are intended to improve the overall return of the pension fund while mitigating the downside market risk.

To achieve the above objective, OPG has adopted the following target strategic asset allocation:

	Target
Asset Class	
Liability Hedging Assets	34%
Return Enhancing Assets	31%
Real Assets	20%
Return Diversifying Assets	15%

The plan may use derivatives for risk management or strategic purposes, where such activity is consistent with the plan's investment objectives.

Significant Concentrations of Risk in Fund Assets

The assets of the pension fund are diversified to limit the impact of any individual investment. The pension fund is diversified across multiple asset classes. Fixed income securities are diversified among Canadian government bonds, government agency bonds, real return bonds, and corporate bonds. Equity securities are diversified across

Canadian, US, and Global stocks. There are also real estate, infrastructure, and agriculture portfolios that represent approximately 12 percent of the total pension fund assets as at December 31, 2017. Investments in the above asset classes are further diversified across funds, investment managers, strategies, vintages, sectors and geographies, depending on the specific characteristics of each asset class.

Credit risk with respect to the pension fund's fixed income securities is managed by risk tolerance guidelines, which requires that fixed income securities comply with various investment constraints that ensure prudent diversification and prescribed minimum required credit rating quality. Credit risk, as it relates to the pension fund's derivatives, is managed through the use of International Swap and Derivatives Association documentation and counterparty management performed by the fund's investment managers.

Risk Management

Risk management oversight with respect to the pension fund includes, but is not limited to, the following activities:

- Periodic asset/liability management and strategic asset allocation studies
- Monitoring of funding levels and funding ratios
- Monitoring compliance with asset allocation guidelines and investment management agreements
- Monitoring asset class performance against asset class benchmarks
- Monitoring investment manager performance against benchmarks
- Monitoring of risk tolerance guidelines

Expected Rate of Return on Plan Assets

The expected rate of return on plan assets is based on the fund's asset allocation, as well as the return expectations considering long-term risks and returns associated with each asset class within the plan portfolio. The asset management decisions consider the economic liabilities of the plan.

Fair Value Measurements

OPG is required to classify fair value measurements using a fair value hierarchy. This hierarchy groups financial instruments into three levels, based on the significance of inputs used in measuring the fair value of the assets and liabilities. Refer to Note 13 for a detailed discussion of fair value measurements and the fair value hierarchy.

The following tables present pension plan assets measured at fair value in accordance with the fair value hierarchy:

	December 31, 2017			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Cash and cash equivalents	**377**	**-**	**-**	**377**
Short-term investments	**-**	**9**	**-**	**9**
Fixed income				
Corporate debt securities	**-**	**521**	**-**	**521**
Government bonds	**-**	**3,476**	**-**	**3,476**
Equities				
Canadian	**1,441**	**329**	**-**	**1,770**
US	**1,551**	**-**	**-**	**1,551**
Global	**1,681**	**-**	**-**	**1,681**
Pooled funds	**459**	**105**	**-**	**564**
Other	**15**	**-**	**-**	**15**
	5,524	**4,440**	**-**	**9,964**
Investments measured at NAV [1]				**4,221**
				14,185 [2]

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to the total fair value of plan assets presented in tables following.

[2] The table above excludes pension fund receivables and payables.

	December 31, 2016			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Cash and cash equivalents	690	-	-	690
Fixed income				
Corporate debt securities	-	407	-	407
Government bonds	-	3,483	-	3,483
Equities				
Canadian	1,449	291	-	1,740
US	1,495	-	-	1,495
Global	1,643	-	-	1,643
Pooled funds	118	413	-	531
	5,395	4,594	-	9,989
Investments measured at NAV [1]				3,504
				13,493 [2]

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to the total fair value of plan assets presented in tables following.

[2] The table above excludes pension fund receivables and payables.

Plan Costs and Liabilities

Details of OPG's pension and OPEB obligations, pension fund assets and costs are presented in the following tables:

	Registered and Supplementary Pension Plans		Other Post-Employment Benefits	
	2017	**2016**	**2017**	**2016**
Weighted Average Assumptions – Benefit Obligations at Year-End				
Discount rate for projected benefit obligation	**3.57 %**	3.90 %	**3.60 %**	3.94 %
Salary schedule escalation rate - initial rate [1]	**1.90 %**	1.80 %	**1.90 %**	1.80 %
- thereafter	**2.50 %**	2.50 %	**2.50 %**	2.50 %
Rate of cost of living increase to pensions	**2.00 %**	2.00 %	**n/a**	n/a
Initial health care trend rate	**n/a**	n/a	**5.80 %**	5.90 %
Ultimate health care trend rate	**n/a**	n/a	**4.32 %**	4.32 %
Year ultimate health care trend rate reached	**n/a**	n/a	**2030**	2030
Rate of increase in disability benefits	**n/a**	n/a	**2.00 %**	2.00 %

[1] Per year to December 31, 2021.

	Registered and Supplementary Pension Plans		Other Post-Employment Benefits	
	2017	**2016**	**2017**	**2016**
Weighted Average Assumptions – Costs for the Year				
Expected return on plan assets, net of expenses	**6.00 %**	6.00 %	**n/a**	n/a
Discount rate for projected benefit obligation	**3.90 %**	4.10 %	**3.94 %**	4.13 %
Discount rate for current service cost	**4.15 %**	4.10 %	**4.03 %**	4.13 %
Discount rate for interest on projected benefit obligation	**3.37 %**	4.10 %	**3.53 %**	4.13 %
Discount rate for interest on current service cost	**3.95 %**	4.10 %	**3.85 %**	4.13 %
Salary schedule escalation rate - initial rate [1]	**1.80 %**	1.60 %	**1.80 %**	1.60 %
- thereafter	**2.50 %**	2.50 %	**2.50 %**	2.50 %
Rate of cost of living increase to pensions	**2.00 %**	2.00 %	**n/a**	n/a
Initial health care trend rate	**n/a**	n/a	**5.90 %**	6.00 %
Ultimate health care trend rate	**n/a**	n/a	**4.32 %**	4.33 %
Year ultimate health care trend rate reached	**n/a**	n/a	**2030**	2030
Rate of increase in disability benefits	**n/a**	n/a	**2.00 %**	2.00 %
Expected average remaining service life for employees (years)	**12**	12	**13**	13

[1] Per year to December 31, 2021.

(millions of dollars)	Registered Pension Plans 2017	2016	Supplementary Pension Plans 2017	2016	Other Post-Employment Benefits 2017	2016
Components of Cost Recognized for the year						
Current service costs	**274**	277	**7**	7	**67**	67
Interest on projected benefit obligation	**548**	634	**11**	12	**106**	133
Expected return on plan assets, net of expenses	**(766)**	(734)	**-**	-	**-**	-
Amortization of past service costs [1]	**-**	-	**-**	-	**1**	1
Amortization of net actuarial loss [1]	**183**	192	**6**	4	**-**	19
Recognition of LTD net actuarial loss (gain)	**-**	**-**	**-**	**-**	**11**	(52)
Costs recognized [2]	**239**	369	**24**	23	**185**	168

[1] The amortization of past service costs and net actuarial loss was recognized as an increase to OCI. This increase was partially offset by the impact of the Pension and OPEB Regulatory Asset discussed in Note 5.

[2] Excludes the impact of regulatory variance and deferral accounts discussed in Note 5.

Total benefit costs, including the impact of the Pension & OPEB Cash Payment Variance Account and the Pension & OPEB Cash Versus Accrual Differential Deferral Account, for the years ended December 31 are as follows:

(millions of dollars)	2017	2016
Registered pension plans	**239**	369
Supplementary pension plans	**24**	23
Other post-employment benefits	**185**	168
Pension & OPEB Cash Payment Variance Account *(Note 5)*	**81**	86
Pension & OPEB Cash Versus Accrual Differential Deferral Account *(Note 5)*	**(117)**	(182)
Pension and other post-employment benefit costs	**412**	464

The pension and OPEB obligations and the pension fund assets measured as at December 31 are as follows:

(millions of dollars)	Registered Pension Plans 2017	2016	Supplementary Pension Plans 2017	2016	Other Post-Employment Benefits 2017	2016
Change in Plan Assets						
Fair value of plan assets at beginning of year	**13,506**	13,160	**-**	-	**-**	-
Contributions by employer	**214**	255	**14**	15	**94**	93
Contributions by employees	**97**	85	**-**	-	**-**	-
Actual return on plan assets, net of expenses	**1,207**	714	**-**	-	**-**	-
Benefit payments	**(761)**	(708)	**(14)**	(15)	**(94)**	(93)
Fair value of plan assets at end of year	**14,263**	13,506	**-**	-	**-**	-
Change in Projected Benefit Obligations						
Projected benefit obligations at beginning of year	**16,199**	15,475	**336**	299	**2,992**	3,188
Employer current service costs	**274**	277	**7**	7	**67**	67
Contributions by employees	**97**	85	**-**	-	**-**	-
Interest on projected benefit obligation	**548**	634	**11**	12	**106**	133
Benefit payments	**(761)**	(708)	**(14)**	(15)	**(94)**	(93)
Net actuarial loss (gain)	**987**	436	**16**	33	**119**	(303)
Projected benefit obligations at end of year	**17,344**	16,199	**356**	336	**3,190**	2,992
Funded status – deficit at end of year	**(3,081)**	(2,693)	**(356)**	(336)	**(3,190)**	(2,992)

The following table provides the pension and OPEB liabilities and their classification on the consolidated balance sheets as at December 31:

(millions of dollars)	Registered Pension Plans 2017	2016	Supplementary Pension Plans 2017	2016	Other Post-Employment Benefits 2017	2016
Current liabilities	**-**	-	**(14)**	(17)	**(98)**	(95)
Non-current liabilities	**(3,081)**	(2,693)	**(342)**	(319)	**(3,092)**	(2,897)
Total liabilities	**(3,081)**	(2,693)	**(356)**	(336)	**(3,190)**	(2,992)

The accumulated benefit obligations for the registered pension plans and supplementary pension plans as at December 31, 2017 are $16,005 million and $333 million, respectively (2016 – $14,909 million and $293 million, respectively). The accumulated benefit obligation differs from the projected benefit obligation in that the accumulated benefit obligation includes no assumption about future compensation levels.

The following table provides the components of OPG's OCI related to pension and OPEB plans and the offsetting Pension and OPEB Regulatory Asset, discussed in Note 5, for the years ended December 31, on a pre-tax basis:

(millions of dollars)	Registered Pension Plans 2017	Registered Pension Plans 2016	Supplementary Pension Plans 2017	Supplementary Pension Plans 2016	Other Post-Employment Benefits 2017	Other Post-Employment Benefits 2016
Changes in plan assets and benefit obligations recognized in OCI						
Current year net actuarial loss (gain)	**546**	456	**16**	33	**108**	(251)
Amortization of net actuarial loss	**(183)**	(192)	**(6)**	(4)	**-**	(19)
Amortization of past service costs	**-**	-	**-**	-	**(1)**	(1)
Total decrease (increase) in OCI	**363**	264	**10**	29	**107**	(271)
Less: increase (decrease) in Pension and OPEB Regulatory Asset *(Note 5)*	**352**	253	**9**	27	**102**	(250)
Net decrease (increase) in OCI (pre-tax)	**11**	11	**1**	2	**5**	(21)

The following table provides the components of OPG's AOCL and the offsetting Pension and OPEB Regulatory Asset that have not yet been recognized as components of benefit costs as at December 31, on a pre-tax basis:

(millions of dollars)	Registered Pension Plans 2017	Registered Pension Plans 2016	Supplementary Pension Plans 2017	Supplementary Pension Plans 2016	Other Post-Employment Benefits 2017	Other Post-Employment Benefits 2016
Unamortized amounts recognized in AOCL						
Past service costs	**-**	-	**-**	-	**4**	5
Net actuarial loss	**3,650**	3,287	**116**	106	**378**	270
Total recognized in AOCL	**3,650**	3,287	**116**	106	**382**	275
Less: Pension and OPEB Regulatory Asset *(Note 5)*	**3,391**	3,039	**109**	100	**355**	253
Net recognized in AOCL (pre-tax)	**259**	248	**7**	6	**27**	22

The following table provides the components of OPG's AOCL and the offsetting Pension and OPEB Regulatory Asset as at December 31 (included in the table above) that are expected to be amortized as components of benefit costs and recognized as increases to OCI and reductions in the Pension and OPEB Regulatory Asset in 2018, on a pre-tax basis:

(millions of dollars)	Registered Pension Plans	Supplementary Pension Plans	Other Post-Employment Benefits
Past service costs	**-**	**-**	**1**
Net actuarial loss	**198**	**7**	**6**
Total increase in OCI	**198**	**7**	**7**
Less: estimated decrease in Pension and OPEB Regulatory Asset	**184**	**6**	**6**
Net increase in OCI (pre-tax)	**14**	**1**	**1**

The most recently filed actuarial valuation, for funding purposes, of the OPG registered pension plan, as at January 1, 2017, was filed with the FSCO in September 2017. The next filed funding valuation must have an effective date no later than January 1, 2020. For 2018, OPG's required contribution to its registered pension plan is expected to be $215 million. The amount of OPG's additional, voluntary contribution, if any, is revisited from time to time. OPG will continue to assess the requirements for contributions to the pension plan.

The supplementary pension plans are not funded, but are secured by Letters of Credit totalling $353 million as at December 31, 2017 (2016 – $349 million).

Estimated future benefit payments to participants in the pension and OPEB plans based on the assumptions used to measure the benefit obligations as at December 31, 2017 are as follows:

(millions of dollars)	Registered Pension Plans	Supplementary Pension Plans	Other Post-Employment Benefits
2018	676	15	98
2019	696	15	101
2020	722	15	105
2021	747	16	108
2022	764	16	111
2023 through 2027	4,397	86	633

A one percent increase or decrease in the health care trend rate would result in an increase in the current service and interest components of the 2017 OPEB costs of $40 million (2016 – $45 million) or a decrease in the service and interest components of the 2017 OPEB costs of $29 million (2016 – $33 million). A one percent increase or decrease in the health care trend rate would result in an increase in the projected OPEB obligation as at December 31, 2017 of $592 million (2016 – $560 million) or a decrease in the projected OPEB obligation as at December 31, 2017 of $451 million (2016 – $426 million).

12. RISK MANAGEMENT AND DERIVATIVES

OPG is exposed to risks related to changes in market interest rates on debt expected to be issued in the future and movements in foreign currency that affect the Company's assets, liabilities, and forecasted transactions. Select derivative instruments are used to manage such risks. Derivatives are used as hedging instruments, as well as for trading purposes.

Interest rate risk is the risk that the value of assets and liabilities can change due to movements in related interest rates. Interest rate risk for OPG arises with the need to refinance existing debt and/or undertake new financing. The management of these risks includes using derivatives to hedge the exposure in accordance with corporate risk management policies. OPG periodically uses interest rate swap agreements to mitigate elements of interest rate risk exposure associated with anticipated financing.

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are denominated in, or tied to, US dollars. OPG enters into foreign exchange derivatives and agreements with major financial institutions, when appropriate, in order to manage the Company's exposure to foreign currency movements.

The majority of OPG's revenues are derived from sales through the IESO administered spot market. Market participants in the IESO spot market provide collateral in accordance with the IESO prudential support requirements to cover funds that they might owe to the market. Although the credit exposure to the IESO represents a significant portion of OPG's accounts receivable, the Company's management accepts this risk due to the IESO's primary role in the Ontario electricity market. The remaining receivables exposure is to a diverse group of generally high quality counterparties. OPG's allowance for doubtful accounts as at December 31, 2017 was less than $1 million. OPG's fair value derivatives totalled a net liability of $20 million as at December 31, 2017 (December 31, 2016 − $24 million).

The following table shows the pre-tax amounts related to derivatives recorded in AOCL and net income for the years ended December 31:

(millions of dollars)	**2017**	**2016**
Cash flow hedges (recorded in AOCL)		
Reclassification of losses to net interest expense	**19**	21
Commodity derivatives (recorded in net income)		
Realized losses in revenue	**(9)**	(12)
Unrealized gains (losses) in revenue	**3**	(3)

Existing pre-tax net losses of $19 million deferred in AOCL as at December 31, 2017 are expected to be reclassified to net income within the next 12 months.

13. FAIR VALUE MEASUREMENTS

OPG is required to classify fair value measurements using a fair value hierarchy. This hierarchy groups financial assets and liabilities into three levels, based on the inputs used in measuring the fair value of the financial assets and liabilities. The fair value hierarchy has the following levels:

- Level 1: Valuation of inputs is based on unadjusted quoted market prices observed in active markets for identical assets or liabilities.
- Level 2: Valuation is based on inputs other than quoted prices under Level 1 that are observable for the asset or liability, either directly or indirectly.
- Level 3: Valuation is based on inputs for the asset or liability that are not based on observable market data.

The fair value of financial instruments traded in active markets is based on quoted market prices as at the consolidated balance sheet dates. A market is regarded as active if quoted prices are readily and regularly available from an exchange, dealer, broker, industry group, pricing service, or regulatory agency, and those prices represent actual and regularly occurring market transactions on an arm's length basis. The quoted market price used for financial assets held by OPG is the current bid price. These instruments are included in Level 1 and are comprised primarily of equity investments and fund investments.

For financial instruments for which quoted market prices are not directly available, fair values are estimated using forward price curves developed from observable market prices or rates. The estimation of fair value may include the use of valuation techniques or models, based wherever possible on assumptions supported by observable market prices or rates prevailing as at the consolidated balance sheet dates. This is the case for over-the-counter derivatives and securities, which include energy commodity derivatives, foreign exchange derivatives, interest rate swap derivatives, and fund investments. Pooled fund investments are valued at the unit values supplied by the pooled fund administrators. The unit values represent the underlying net assets at fair values, determined using closing market prices. Valuation models use general assumptions and market data and therefore do not reflect the specific risks and other factors that would affect a particular instrument's fair value. The methodologies used for calculating the fair value adjustments are reviewed on an ongoing basis to ensure that they remain appropriate. If all significant inputs required to fair value an instrument are observable, the instrument is included in Level 2.

The following is a summary of OPG's financial instruments and their fair value as at December 31, 2017 and December 31, 2016:

	Fair Value		Carrying Value [1]		
(millions of dollars)	**2017**	**2016**	**2017**	**2016**	**Balance Sheet Line Item**
Nuclear Segregated Funds (includes current portion) [2]	**16,724**	15,984	**16,724**	15,984	Nuclear fixed asset removal and nuclear waste management funds
Financing receivables	**1,179**	-	**1,179**	-	Financing receivables
Investment in Hydro One shares	**188**	212	**188**	212	Available-for-sale securities
Payable related to cash flow hedges	**(40)**	(48)	**(40)**	(48)	Long-term accounts payable and accrued charges
Long-term debt (includes current portion and medium) term notes)	**(6,835)**	(6,033)	**(5,735)**	(5,520)	Long-term debt
Long-term debt – Fair Hydro Trust	**(601)**	-	**(601)**	-	Long-term debt
Other financial instruments	**(16)**	(18)	**(16)**	(18)	Various

[1] The carrying values of other financial instruments included in cash and cash equivalents, receivables from related parties, other current assets, short-term debt, and accounts payable and accrued charges approximate their fair values due to the immediate or short-term maturity of these financial instruments.

[2] The Nuclear Segregated Funds are comprised of the Decommissioning Segregated Fund and the Used Fuel Segregated Fund.

The fair value of long-term debt instruments is determined based on a conventional pricing model, which is a function of future cash flows, the current market yield curve and term to maturity. These inputs are considered Level 2 inputs.

The fair value of the Trust debt and Medium Term Note Program debt (included in the Long-term debt line above) are based on unadjusted quoted active market prices, which are considered Level 1 inputs. All other long-term debt instruments is determined based on a conventional pricing model, which is a function of future cash flows, the current market yield curve and term to maturity. These inputs are considered Level 2 inputs. For the financing receivables related to the Investment Interest acquired from the IESO, fair value is estimated to equal the fair value of the underlying debt due to the direct relationship of the asset, and the debt instruments that financed the acquisition. The financing receivables are funded by both the senior and subordinated debt issued by the Trust. The long-term debt ranks as senior notes and has inputs that are based on unadjusted quoted active market prices, which are considered Level 1 inputs, while the portion funded by the subordinated debt has inputs that are based on indicative pricing from the market, which are considered Level 2 inputs.

If one or more of the significant inputs is not based on observable market data, the instrument is included in Level 3. Specific valuation techniques are used to value these instruments. Significant Level 3 inputs include: recent comparable transactions, comparable benchmark information, bid/ask spread of similar transactions, and other relevant factors.

Transfers into, out of, or between levels are deemed to have occurred on the date of the event or change in circumstances that caused the transfer to occur.

The following tables present financial assets and financial liabilities measured at fair value in accordance with the fair value hierarchy as at December 31, 2017 and December 31, 2016:

	December 31, 2017			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Used Fuel Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	**6,090**	**4,705**	**-**	**10,795**
Investments measured at NAV [1]				**1,292**
				12,087
Due to Province				**(2,529)**
Used Fuel Segregated Fund, net				**9,558**
Decommissioning Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	**4,547**	**3,487**	**-**	**8,034**
Investments measured at NAV [1]				**1,065**
				9,099
Due to Province				**(1,933)**
Decommissioning Segregated Fund, net				**7,166**
Investment in available-for-sale securities	**188**	**-**	**-**	**188**
Other financial assets	**5**	**3**	**6**	**14**
Liabilities				
Other financial liabilities	**(28)**	**(2)**	**-**	**(30)**

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to amounts presented on the consolidated balance sheets.

(millions of dollars)	December 31, 2016 Level 1	Level 2	Level 3	Total
Assets				
Used Fuel Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	5,602	4,394	-	9,996
Investments measured at NAV [1]				1,086
				11,082
Due to Province				(1,938)
Used Fuel Segregated Fund, net				9,144
Decommissioning Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	4,171	3,243	-	7,414
Investments measured at NAV [1]				903
				8,317
Due to Province				(1,477)
Decommissioning Segregated Fund, net				6,840
Investments in available-for-sale securities	212	-	-	212
Other financial assets	6	2	9	17
Liabilities				
Other financial liabilities	(29)	(6)	-	(35)

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to amounts presented on the consolidated balance sheets.

During the year ended December 31, 2017, there were no transfers between Level 1 and Level 2. In addition, there were no transfers into or out of Level 3.

The following table presents the changes in OPG's net assets measured at fair value that are classified as Level 3 financial instruments.

(millions of dollars)	Other financial instruments
Opening balance, January 1 2017	**9**
Unrealized losses included in revenue	**(3)**
Realized losses included in revenue	**(9)**
Purchases	**9**
Closing balance, December 31, 2017	**6**

Nuclear Segregated Funds

The fair value of the investments within the Nuclear Segregated Funds' alternative investment portfolio is determined using appropriate valuation techniques, such as recent arm's length market transactions, references to current fair values of other instruments that are substantially the same, discounted cash flow analyses, third-party independent appraisals, valuation multiples, or other valuation methods. Any control, size, liquidity or other discount premiums on the investments are considered in the determination of fair value. Alternative investments are measured at fair value using NAV as a practical expedient.

The process of valuing investments for which no published market price exists is based on inherent uncertainties and the resulting values may differ from values that would have been used had a ready market existed for these investments. The values may also differ from the prices at which the investments may be sold.

The following are the classes of investments within the Nuclear Segregated Funds that are reported on the basis of NAV as at December 31, 2017:

(millions of dollars except where noted)	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice
Alternative Investments				
Infrastructure	**1,330**	**798**	**n/a**	**n/a**
Real Estate	**936**	**440**	**n/a**	**n/a**
Agriculture	**90**	**97**	**n/a**	**n/a**
Pooled Funds				
Short-term Investments	**32**	**n/a**	**Daily**	**1 - 5 Days**
Fixed Income	**729**	**n/a**	**Daily**	**1 - 5 Days**
Equity	**952**	**n/a**	**Daily**	**1 - 5 Days**
Total	**4,069**	**1,335**		

The fair value of the pooled funds is classified as Level 2. Infrastructure, real estate and agriculture investments are measured using NAV as a practical expedient for determining their fair value.

Infrastructure

This asset class includes investments in funds and assets with an objective to generate a combination of long-term capital appreciation and current income, generally through private investments in sectors such as energy, transportation, communication and utilities. The fair values of investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in these investments. The investments in its respective funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests/shares to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Distributions from each infrastructure fund will be received based on the operations of the underlying investments and/or as the underlying investments of the infrastructure funds are liquidated. It is not possible to estimate when the underlying assets in this asset class will be liquidated.

Real Estate

This asset class includes investments in funds and assets with an objective is to generate a combination of long-term capital appreciation and current income, generally through investments in institutional-grade real estate property. The fair values of the investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in these investments. The investments in its respective funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Distributions from each real estate fund will be received based on the operations of the underlying investments and/or as the underlying investments of the real estate funds are liquidated. For investments in private real estate corporations, shares may be redeemed through a pre-established redemption process. It is not possible to estimate when the underlying assets in this asset class will be liquidated.

Agriculture

This asset class includes investments in funds and assets with an objective to provide a differentiated return source, income yield, and inflation protection, generally through private investments inglobal farmland and timberland. The fair values of the investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in these investments. The investments in its respective funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests/shares to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Distributions from each fund will be received based on the operations of the underlying investments and/or as the underlying investments of the funds are liquidated. It is not possible to estimate when the underlying assets in this asset class will be liquidated.

Pooled Funds

This asset class represents investments in pooled funds, which primarily include a diversified portfolio of fixed income securities, issued mainly by Canadian corporations, and diversified portfolios of Emerging Market listed equity. The investment objective of the pooled funds is to achieve capital appreciation and income through professionally managed portfolios. The fair value of the investments in this class has been estimated using NAV per share of the investments. There are no significant restrictions on the ability to sell the investments in this class.

14. SHARE CAPITAL

Common Shares

As at December 31, 2017 and 2016, OPG had 256,300,010 common shares issued and outstanding at a stated value of $5,126 million. OPG is authorized to issue an unlimited number of common shares without nominal or par value. Any issue of new shares is subject to the consent of OPG's shareholder.

Class A Shares

The Company's Articles of Amalgamation were amended effective December 1, 2017 to allow for the creation and issuance of non-voting Class A shares to the Province in exchange for its equity injections in OPG to be used solely for its investment in the Trust. All of the outstanding shares are owned directly by the Province and OPG is authorized to issue an unlimited number of Class A shares without nominal or par value. The Class A and common shares rank equally as to dividends on a share for share basis, and all dividends declared by OPG shall be declared in equal amounts per share on all outstanding shares without preference or distinction. Upon the liquidation, dissolution or wind-up of OPG, whether voluntary or involuntary, the holders of Class A shares and common shares are entitled to share equally, on a share for share basis, in all distributions of property and assets without preference or distinction. Any issue of new shares is subject to the consent of the Province. OPG is entitled to redeem outstanding shares in connection with the repayment of the Trust's debt or other purposes as may be approved by OPG's Board of Directors.

In December 2017, OPG issued 12,217,616 Class A shares at a price of $42.46 per share to the Province for its equity injection in OPG, generating proceeds of $519 million, which was used to fund 44 percent of the total funding requirement of the Trust's acquisition of Investment Interest from the IESO.

15. EARNINGS PER COMMON SHARE

Basic and diluted earnings per common share is calculated by dividing net income attributable to the Shareholder of OPG by the weighted average number of common shares outstanding.

Class A shares are included in the weighted average number of common shares outstanding. The weighted average number of shares outstanding as at December 31, 2017 was 256.7 million (2016 – 256.3 million). There were no dilutive securities during the years ended December 31, 2017 and 2016.

16. COMMITMENTS AND CONTINGENCIES

Litigation

On August 9, 2006, a Notice of Action and Statement of Claim filed with the Ontario Superior Court of Justice in the amount of $500 million was served against OPG and Bruce Power by British Energy Limited and British Energy International Holdings Limited (together British Energy). The action is for contribution and indemnity of any amounts British Energy was liable for in an arbitration against it by some of the owners of Bruce Power regarding an alleged breach of British Energy's representations and warranties to the claimants when they purchased British Energy's interest in Bruce Power (the Arbitration). Both the action and the Arbitration relate to corrosion to a steam generator unit discovered after OPG leased the Bruce nuclear generating stations to Bruce Power.

In 2012, the arbitrator found that British Energy was liable to the claimants for some of the damages they claimed. The final settlement amount was valued by British Energy at $71 million. In September 2014, British Energy amended its Statement of Claim (Amended Claim) to reduce the claim amount to $100 million to reflect that the purchasers of British Energy's interest in Bruce Power did not receive the full damages they originally claimed in the Arbitration. British Energy also added an allegation to its Amended Claim that OPG breached a covenant to maintain the steam generator between the time of the initial agreement to lease and the effective date of the lease in accordance with "Good Utility Practices".

In November 2016, British Energy obtained consent from Ontario Superior Court of Justice to a timetable for the remaining steps in the litigation, pursuant to which the matter must be set down for trial by December 31, 2018. OPG has delivered a statement of defence in accordance with an extension of the original June 30, 2017 delivery deadline set up in the timetable. [**MONITOR**]

Various other legal proceedings are pending against OPG or its subsidiaries covering a wide range of matters that arise in the ordinary course of business activities.

Each of these matters is subject to various uncertainties. Some of these matters may be resolved unfavourably. While it is not possible to determine the ultimate outcome of the various pending actions, it is the Company's belief that their resolution is not likely to have a material adverse impact on its financial position.

Guarantees

The Company and its joint venture partners have jointly guaranteed the financial performance of jointly owned entities related primarily to the payment of liabilities. As at December 31, 2017, the total amount of guarantees OPG provided to these entities was $82 million (December 31, 2016 − $83 million). OPG may terminate some of these guarantees within a short time frame by providing written notice to the counterparties at any time. Other guarantees have terms ending between 2019 and 2029. As at December 31, 2017, the potential impact of the fair value of these guarantees to income has been estimated to be negligible and OPG does not expect to make any payments associated with these guarantees.

Contractual Obligations

OPG's contractual obligations as at December 31, 2017, are as follows:

(millions of dollars)	2018	2019	2020	2021	2022	Thereafter	Total
Fuel supply agreements	158	125	115	88	67	67	620
Contributions to the OPG registered pension plan [1]	215	219	-	-	-	-	434
OPG long-term debt repayment	398	368	663	413	172	3,721	5,735
Interest on OPG long-term debt	244	226	204	175	161	3,006	4,016
Fair Hydro Trust senior debt repayment [2]	-	601	-	-	-	-	601
Interest on Fair Hydro Trust senior debt	15	15	-	-	-	-	30
Commitments related to Darlington Refurbishment project [3]	473	-	-	-	-	-	473
Commitments related to Ranney Falls GS project	29	5	-	-	-	-	34
Operating licences	40	41	24	28	28	87	248
Operating lease obligations	28	24	24	22	22	79	199
Unconditional purchase obligations	59	58	56	5	-	-	178
Accounts payable and accrued charges	957	8	-	-	-	16	981
Other	57	30	2	1	1	64	155
Total	2,673	1,720	1,088	732	451	7,040	13,704

[1] The pension contributions include ongoing funding requirements and additional funding requirements towards the deficit, in accordance with the actuarial valuation of the OPG registered pension plan as at January 1, 2017. The next actuarial valuation of the OPG registered pension plan must have an effective date no later than January 1, 2020. The pension contributions are affected by various factors including market performance, changes in actuarial assumptions, plan experience, changes in the pension regulatory environment, and the timing of funding valuations. Funding requirements after 2019 are excluded due to significant variability in the assumptions required to project the timing of future cash flows. The amount of OPG's additional, voluntary contribution, if any, is revisited from time to time.

[2] The notes were issued by the Fair Hydro Trust under an $800 million two-year revolving warehouse facility in December 2017. In February 2018, the Trust issued $500 million of senior notes payable to repay the majority of the outstanding balance of the revolving warehouse facility.

[3] Represents estimated currently committed costs to close the project, including accruals for completed work, demobilization of project staff and cancellation of existing contracts and material orders.

Other Commitments

Collective Agreements

As of December 31, 2017, OPG had approximately 9,212 regular employees. Most of OPG's regular employees are represented by two unions:

- **The PWU** – This union represents approximately 4,849 OPG employees or approximately 53 percent of OPG's regular workforce as at December 31, 2017. Union membership includes operators, technicians, skilled trades, clerical, and security personnel. The current collective agreement between OPG and the PWU has a three-year term, expiring on March 31, 2018.
- **The Society** – This union represents approximately 3,259 OPG employees or approximately 35 percent of OPG's regular workforce as at December 31, 2017. Union membership includes supervisors, professional engineers, scientists, and other professionals. The current collective agreement between OPG and The Society has a three-year term, expiring on December 31, 2018.

In addition to the regular workforce, construction work is performed through 19 craft unions with established bargaining rights at OPG facilities. These bargaining rights are established either through the Electrical Power Systems Construction Association or directly with OPG. Collective agreements between the Company and its construction unions are negotiated either directly or through EPSCA. All of these collective agreements currently have multi-year terms, expiring on April 30, 2020.

17. BUSINESS SEGMENTS

Effective in the fourth quarter of 2017, OPG has the following six reportable business segments:

- Regulated – Nuclear Generation
- Regulated – Nuclear Waste Management
- Regulated – Hydroelectric
- Contracted Generation Portfolio
- Services, Trading, and Other Non-Generation
- Fair Hydro Trust

Regulated – Nuclear Generation Segment

The Regulated – Nuclear Generation business segment operates in Ontario, generating and selling electricity from the Pickering GS and the Darlington GS, both owned and operated by OPG. The business segment also includes revenue under the terms of a long-term lease arrangement and related agreements with Bruce Power related to the Bruce nuclear generating stations. This revenue includes lease revenue, fees for nuclear waste management, and revenue from heavy water sales and detritiation services. The segment also earns revenue from isotope sales and ancillary services supplied by OPG-operated nuclear stations. Ancillary revenues are earned through voltage control and reactive support. Revenues under the agreements with Bruce Power, including a portion of heavy water sales, and from isotope sales and ancillary services are included by the OEB as a credit to customers in the determination of the regulated prices for production from OPG's nuclear facilities, which has had the effect of reducing these prices.

Regulated – Nuclear Waste Management Segment

OPG's Regulated – Nuclear Waste Management segment reports the results of the Company's operations associated with the management of nuclear used fuel and L&ILW, the decommissioning of OPG's nuclear generating stations including the stations on lease to Bruce Power and other waste management facilities, the management of the Nuclear Segregated Funds, and related activities including the inspection and maintenance of the waste storage facilities. Accordingly, accretion expense, which is the increase in the Nuclear Liabilities carried on the consolidated balance sheets in present value terms due to passage of time, and earnings from the Nuclear Segregated Funds are reported under this segment.

As the nuclear generating stations operate over time, OPG incurs incremental costs related to used nuclear fuel and low and intermediate level wastes, which increase the Nuclear Liabilities. OPG charges these incremental costs to current operations in the Regulated – Nuclear Generation segment to reflect the cost of producing energy from the Pickering and Darlington nuclear generating stations and earning revenue under the Bruce Lease and related agreements. Since the incremental costs increase the Nuclear Liabilities in the Regulated – Nuclear Waste Management segment, OPG records an inter-segment charge between the Regulated – Nuclear Generation and the Regulated – Nuclear Waste Management segments. The impact of the inter-segment charge is eliminated in the consolidated statements of income and balance sheets.

The Regulated – Nuclear Waste Management segment is considered rate regulated because OPG's costs associated with the Nuclear Liabilities have been included in the determination of regulated prices for production from the Pickering and Darlington nuclear generating stations, in accordance with the methodology applied by the OEB since its 2008 decision on OPG's first application for regulated prices.

Regulated – Hydroelectric Segment

OPG's Regulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from most of the Company's hydroelectric generating stations. The business segment includes the results of the Sir Adam Beck 1, 2 and Pump generating stations, the DeCew Falls 1 and 2 generating stations, and the R.H. Saunders GS

that were prescribed for rate regulation prior to 2014, and the 48 hydroelectric stations prescribed for rate regulation effective in 2014.

In addition, the business segment includes ancillary and other revenues from OPG's regulated hydroelectric stations. Ancillary revenues are earned through offering available generating capacity as operating reserve and through the supply of other ancillary services including voltage control and reactive support, certified black start facilities, regulation service, and other services. These ancillary revenues and other revenues are included by the OEB as a credit to ratepayers in the determination of the regulated prices for production from OPG's prescribed hydroelectric facilities, which has had the effect of reducing these prices.

Contracted Generation Portfolio Segment

The Contracted Generation Portfolio business segment operates in Ontario, generating and selling electricity from the Company's generating stations that are not prescribed for rate regulation. The segment primarily includes generating facilities that are under an ESA with the IESO or other long-term contracts.

The Contracted Generation Portfolio segment also includes OPG's share of equity income from its 50 percent ownership interests in the PEC and Brighton Beach stations.

The business segment also includes ancillary revenues and other revenues from the stations included in the segment, which are earned through offering available generating capacity as operating reserve, and the supply of other ancillary services including voltage control and reactive support, certified black start facilities, regulation service, and other services.

Services, Trading, and Other Non-Generation Segment

The Services, Trading, and Other Non-Generation segment is a non-generation segment that is not subject to rate regulation. It includes the revenue and expenses related to OPG's trading and other non-hedging activities. As part of these activities, OPG transacts with counterparties in Ontario and neighbouring energy markets in predominantly short-term trading activities of typically one year or less in duration. These activities relate to electricity that is purchased and sold at the Ontario border, financial energy trades, financial risk management energy product revenues, and sales of energy-related products. In addition, OPG has a wholly owned trading subsidiary that transacts solely in the US market. The results of this subsidiary are reported in this segment. All contracts that are not designated as hedges are recorded as assets or liabilities at fair value on the consolidated balance sheets with changes in fair value recorded in the revenue of this segment. In addition, the segment includes revenue from real estate rentals and non-regulated services, non-regulated business development activities, and, prior to OPG's decision to decommission the stations, preservation costs related to the former coal-fired Lambton GS and the Nanticoke GS sites.

OM&A expenses of the generation business segments include an inter-segment service fee for the use of certain PP&E and intangible assets held within Service, Trading, and Other Non-Generation segment. The total service fee is recorded as a reduction to the segment's OM&A expenses.

The service fee included in OM&A expenses by segment in 2017 and 2016 was as follows:

(millions of dollars)	**2017**	**2016**
Regulated – Nuclear Generation	**36**	34
Regulated – Hydroelectric	**7**	7
Contracted Generation Portfolio	**4**	4
Reduction to Services, Trading, and Other Non-Generation	**47**	45

Fair Hydro Trust Segment

The Trust was established on December 20, 2017 and was established as a non-generation segment that is not subject to rate regulation. It includes OPG's earnings from the Trust, which includes the financial results of the Trust, as well as revenues and expenses related to OPG's role as Financial Services Manager of the Fair Hydro Trust and holder of subordinated debt issued by the Trust. Revenues include recovery of related to third-party costs and fees for financial management and ongoing administration services. OM&A expenses include incurred third-party and other recoverable incurred costs related to the management and administration of the Trust. Net interest expense (income) include interest income from OPG's investment in subordinated debt of the Trust of up to 49 percent of the Trust's total outstanding debt, partially offset by interest costs on debt issued by OPG to fund five percent of the subordinated investment in the Trust.

The earnings from the Trust is comprised of the following:

For the year ended December 31 *(millions of dollars)*	**2017**
Revenues	**(8)**
OM&A expenses	**8**
Net interest expense (income)	**(1)**
Earnings from Fair Hydro Trust	**(1)**

Segment Income (Loss) for the Year Ended December 31, 2017 *(millions of dollars)*	Nuclear Generation	Regulated Nuclear Waste Management	Hydro-Electric	Unregulated Contracted Generation Portfolio	Unregulated Services, Trading, and Other Non-Generation	Fair Hydro Trust	Elimination	Total
Revenue	**3,095**	**121**	**1,436**	**579**	**43**	**-**	**(116)**	**5,158**
Fuel expense	**284**	**-**	**351**	**53**	**1**	**-**	**-**	**689**
Gross margin	**2,811**	**121**	**1,085**	**526**	**42**	**-**	**(116)**	**4,469**
Operations, maintenance and administration	**2,293**	**129**	**330**	**169**	**18**	**1**	**(116)**	**2,824**
Depreciation and amortization	**431**	**-**	**139**	**79**	**30**	**-**	**-**	**679**
Accretion on fixed asset removal and nuclear waste management liabilities	**-**	**943**	**-**	**9**	**8**	**-**	**-**	**960**
Earnings on nuclear fixed asset removal and nuclear waste management funds	**-**	**(801)**	**-**	**-**	**-**	**-**	**-**	**(801)**
Earnings from Fair Hydro Trust						**(1)**		**(1)**
Income from investments subject to significant influence	**-**	**-**	**-**	**(38)**	**-**	**-**	**-**	**(38)**
Property taxes	**26**	**-**	**1**	**7**	**6**	**-**	**-**	**40**
Other (gains) losses	**4**	**-**	**1**	**-**	**(384)**	**-**	**-**	**(379)**
Income (loss) before interest and income taxes	**57**	**(150)**	**614**	**300**	**364**	**-**	**-**	**1,185**
Net interest expense								**95**
Income before income taxes								**1,090**
Income tax expense								**209**
Net income								**881**

Segment Income (Loss) for the Year Ended December 31, 2016 *(millions of dollars)*	Nuclear Generation	Regulated Nuclear Waste Management	Hydroelectric	Unregulated Contracted Generation Portfolio	Unregulated Services, Trading, and Other Non-Generation	Elimination	Total
Revenue	3,481	138	1,527	573	68	(134)	5,653
Fuel expense	315	-	353	58	1	-	727
Gross margin	3,166	138	1,174	515	67	(134)	4,926
Operations, maintenance and administration	2,210	146	325	178	22	(134)	2,747
Depreciation and amortization	925	-	225	75	32	-	1,257
Accretion on fixed asset removal and nuclear waste management liabilities	-	912	-	9	8	-	929
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(746)	-	-	-	-	(746)
Income from investments to significant influence	-	-	-	(37)	-	-	(37)
Property taxes	26	-	1	7	12	-	46
Restructuring	-	-	-	-	6	-	6
Other (gains) losses	1	-	(19)	1	-	-	(17)
Income (loss) before interest and taxes	4	(174)	642	282	(13)	-	741
Net interest expense							120
Income before income taxes							621
Income tax expense							168
Net income							453

Selected Consolidated Balance Sheet information as at December 31, 2017 *(millions of dollars)*	Nuclear Gener-ation	Regulated Nuclear Waste Manage-ment	Hydro-electric	Unregulated Contracted Generation Portfolio	Unregulated Services, Trading, and Other Non-Generation	Fair Hydro Trust	Total
Segment property, plant and equipment in-service, net	**6,167**	**-**	**7,359**	**3,480**	**224**	**-**	**17,230**
Segment construction in progress	**3,839**	**-**	**157**	**78**	**18**	**-**	**4,092**
Segment property, plant and equipment, net	**10,006**	**-**	**7,516**	**3,558**	**242**	**-**	**21,322**
Segment intangible assets in-service, net	**4**	**-**	**1**	**5**	**84**	**-**	**94**
Segment development in progress	**16**	**-**	**-**	**-**	**23**	**-**	**39**
Segment intangible assets, net	**20**	**-**	**1**	**5**	**107**	**-**	**133**
Segment fuel inventory	**265**	**-**	**-**	**44**	**-**	**-**	**309**
Segment materials and supplies inventory, net:							
Current	**102**	**-**	**-**	**1**	**-**	**-**	**103**
Long-term	**351**	**-**	**-**	**4**	**-**	**-**	**355**
Nuclear fixed asset removal and nuclear waste management funds (current and non-current portions)	**-**	**16,724**	**-**	**-**	**-**	**-**	**16,724**
Financing receivables Fair Hydro Trust	**-**	**-**	**-**	**-**	**-**	**1,179**	**1,179**
Fixed asset removal and nuclear waste liabilities	**-**	**(20,077)**	**-**	**(151)**	**(193)**	**-**	**(20,421)**

Selected Consolidated Balance Sheet Information as at December 31, 2016 *(millions of dollars)*	Nuclear Generation	Regulated Nuclear Waste Management	Hydro-electric	Unregulated Contracted Generation Portfolio	Unregulated Services, Trading, and Other Non-Generation	Total
Segment property, plant and equipment in-service, net	5,653	-	7,355	3,282	226	16,516
Segment construction in progress	2,988	-	166	301	27	3,482
Segment property, plant and equipment, net	8,641	-	7,521	3,583	253	19,998
Segment intangible assets in-service, net	7	-	2	4	66	79
Segment development in progress	3	-	-	1	16	20
Segment intangible assets, net	10	-	2	5	82	99
Segment fuel inventory	276	-	-	34	-	310
Segment materials and supplies inventory, net:						
Current	99	-	-	1	-	100
Long-term	340	-	1	4	-	345
Nuclear fixed asset removal and nuclear waste management funds (current and non-current portions)	-	15,984	-	-	-	15,984
Fixed asset removal and nuclear waste management liabilities	-	(19,103)	-	(160)	(221)	(19,484)

Selected Capital Expenditure Information	Regulated		Unregulated				
(millions of dollars)	**Nuclear Generation**	**Nuclear Waste Manage-ment**	**Hydro-electric**	**Contracted Generation Portfolio**	**Services, Trading, and Other Non-Generation**	**Fair Hydro Trust**	**Total**
Year ended December 31, 2017							
Investment in property, plant and equipment, and intangible assets	**1,631**	**-**	**148**	**73**	**74**	**-**	**1,926**
Year ended December 31, 2016							
Investment in property, plant and equipment, and intangible assets	1,338	-	132	198	36	-	1,704

Shareholder Declarations and Shareholder Resolutions to Sell Certain Non-Core Real Estate Properties

In December 2015, OPG received a Shareholder Declaration and a Shareholder Resolution requiring the Company to sell its head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street in Toronto, Ontario. The sale was completed in April 2017 with a gain on sale of $283 million, which is net of tax effects of $95 million, recognized in net income during the year ended December 31, 2017. The pre-tax gain on sale was recorded as an item of Other gains in the consolidated statement of income in the Services, Trading and Other Non-Generation segment. Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. The amount of designated proceeds transferred into the Consolidated Revenue Fund ~~will~~ are expected to approximate ~~be equal to~~ the after-tax gain on sale. [**MONITOR**] The transfer is expected to take place ~~as early as~~ in the first quarter of 2018, through a special dividend authorized by OPG's Board of Directors in March 2018. **[MONITOR]**

Commented [DS2]: The amount of designated proceeds will be determined by regulation and therefore uncertain until the regulation is filed and made public.

In June 2016, OPG received a Shareholder Declaration and a Shareholder Resolution that requires the Company to sell its former Lakeview GS site located in Mississauga, Ontario. The Lakeview GS site assets were fully depreciated prior to June 2017. OPG entered into a purchase and sale agreement with a purchaser with the sale scheduled to close in March 2018. An estimated after-tax gain on sale of approximately $200 million will be recognized in net income upon completion of the transaction in the first quarter of 2018. **[MONITOR]** Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. In accordance with the Shareholder Resolution, approximately one-third of the site is to be transferred to the City of Mississauga, by the purchaser, for parkland, institutional, and cultural uses. **[MONITOR]**

18. NET CHANGES IN NON-CASH WORKING CAPITAL BALANCES

(millions of dollars)	December 31 2017	2016
Receivables from related parties	**60**	116
Prepaid expenses	**(14)**	(6)
Other current assets [1]	**(28)**	(32)
Fuel inventory	**1**	34
Materials and supplies	**(3)**	(4)
Income taxes payable	**2**	57
Accounts payable and accrued charges	**36**	15
	54	180

[1] Represents other accounts receivable.

19. RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One, the IESO and the OEFC. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly-owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions for the years ended December 31 are summarized below:

(millions of dollars)	2017 Revenue	2017 Expense	2016 Revenue	2016 Expense
Hydro One				
Electricity sales	**8**	**-**	6	-
Services	**1**	**10**	1	5
Dividends	**7**	**-**	6	-
Province of Ontario				
Change in Decommissioning Segregated Fund amount due to Province [1]	**-**	**456**	-	192
Change in Used Fuel Segregated Fund amount due to Province [1]	**-**	**591**	-	235
Hydroelectric gross revenue charge	**-**	**110**	-	120
ONFA guarantee fee	**-**	**8**	-	8
Other	**-**	**2**	-	-
OEFC				
Hydroelectric gross revenue charge	**-**	**216**	-	203
Interest expense on long-term notes	**-**	**158**	-	169
Income taxes, net of investment tax credits	**-**	**246**	-	104
IESO				
Electricity related revenue	**4,802**	**-**	5,082	-
Fair Hydro Trust	**4**	**3**	-	-
	4,822	**1,800**	5,095	1,036

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at December 31, 2017 and December 31, 2016, the Nuclear Segregated Funds were reported net of amounts due to the Province of $4,462 million and $3,415 million, respectively.

The receivable, AFS securities, payable and long-term debt balances between OPG and its related parties are summarized below:

(millions of dollars)	**December 31 2017**	**December 31 2016**
Receivables from related parties		
Hydro One	**1**	1
IESO − Electricity related receivables	**354**	421
IESO − Fair Hydro Trust [1]	**7**	-
OEFC	**-**	1
PEC	**4**	4
Province of Ontario	**3**	2
Financing receivables		
IESO − Fair Hydro Trust	**1,179**	-
Available-for-sale securities		
Hydro One shares	**188**	212
Accounts payable and accrued charges		
Hydro One	**1**	-
OEFC	**52**	61
Province of Ontario	**9**	2
IESO − Electricity-related payables	**5**	2
IESO − Fair Hydro Trust	**3**	-
Long-term debt (including current portion)		
Notes payable to OEFC	**3,195**	3,295

[1] Balance consists of unbilled revenue.

OPG holds interest-bearing Province of Ontario bonds in the Nuclear Segregated Funds and the OPG registered pension fund. As at December 31, 2017, the Nuclear Segregated Funds held $1,503 million of interest-bearing Province of Ontario bonds. As at December 31, 2016, the Nuclear Segregated Funds and the registered pension fund held $1,652 million and $284 million of interest-bearing Province of Ontario bonds, respectively. These bonds are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

In December 2017, the Trust purchased its first tranche of Investment Interest from the IESO for an exchange amount of $1.18 billion, which has been classified as a financing receivable on OPG's consolidated balance sheet. The transaction was settled in cash using proceeds from the Trust's issuance of senior and subordinated debt. Pursuant to the general regulation of the Act, the IESO is required to pay and remit carrying costs of the Trust, excluding repayment of principal on any debt obligations, up to July 31, 2021. Commencing May 1, 2021, Specified Consumers will be invoiced by their local distribution company for the Clean Energy Adjustment to pay financing and other costs of the Trust. These funds will be remitted to the Trust through the IESO and will be used to settle all funding and other related expenses of the Trust that underlie the financing receivable.

As at December 31, 2017, OPG's consolidated balance sheet included approximately $7 million of unbilled revenue from the IESO primarily for OPG's general fee for 2017 as Financial Services Manager relating to incurred third-party and certain direct labour costs. In February 2018, OPG submitted to the OEB its proposed general fee for 2017 in the amount of approximately $6 million for review pursuant to the requirements of the general regulation of the Fair Hydro Act. Once approved, the fees will be remitted to the Trust by the IESO and the Trust will pay OPG's fees as Financial Services Manager.

20. INVESTMENTS SUBJECT TO SIGNIFICANT INFLUENCE

Investments subject to significant influence consist of OPG's 50 percent ownership interest in the jointly controlled entities of the PEC gas-fired combined cycle generating station and the Brighton Beach, which are accounted for using the equity method. Details of the balances as at December 31, 2017 and December 31, 2016 are as follows:

(millions of dollars)	**2017**	**2016**
PEC		
Current assets	**20**	18
Long-term assets	**240**	256
Current liabilities	**(10)**	(8)
Long-term liabilities	**(6)**	(5)
Brighton Beach		
Current assets	**5**	5
Long-term assets	**160**	168
Current liabilities	**(17)**	(16)
Long-term liabilities	**(9)**	(7)
Long-term debt	**(74)**	(90)
Investments subject to significant influence	**309**	321

21. RESEARCH AND DEVELOPMENT

For the year ended December 31, 2017, research and development expenses of $106 million (2016 – $95 million) were charged to operations.

22. NON-CONTROLLING INTEREST

PSS Generating Station LP

PSS is a limited partnership between OPG, Coral Rapids Power Corporation (CRP) and PSS Generating Station Inc. (PSS GS Inc.). The principal business of the partnership is the development, construction, ownership, operation and maintenance of the 28 Megawatt (MW) Peter Sutherland Sr. hydroelectric GS on the New Post Creek. OPG and PSS GS Inc. are general partners and CRP is a limited partner in the partnership. CRP is a wholly owned subsidiary of the Taykwa Tagamou Nation.

The Peter Sutherland Sr. GS was placed in-service in March 2017 and, in April 2017, CRP increased its interest in PSS to 33 percent under the partnership agreement, by making contributions of $21 million, reducing OPG's interest to 67 percent. CRP's 33 percent interest in PSS is reported as non-controlling interest. As a result of CRP increasing its interest in the partnership, PSS's AOCL and partner's deficit were proportionately allocated to CRP as a reduction to its non-controlling interest.

Nanticoke Solar LP

In March 2016, Nanticoke Solar LP (NSLP), a partnership between OPG, SunEdison Canadian Construction LP (SECCLP) and a subsidiary of the Six Nations of the Grand River Development Corporation, was selected through IESO's Large Renewal Procurement program to construct a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands. In the first quarter of 2017, OPG acquired all of SECCLP's interests in NSLP, which represented 25 percent of the equity interest in NSLP. Subsequent to the acquisition, OPG owns 90 percent of the equity interest in NSLP, with an approximate value of $2 million. OPG consolidates the results of the NSLP in its consolidated financial statements and reports the equity interest of the other partner as non-controlling interest.

From: Ronald Kwan
To: John Kim
Cc: Usman Zahid
Subject: RE: OPG Q4 2017 Submission to Province
Date: Monday, February 26, 2018 5:52:32 PM

Hi John,

Go ahead and consolidate my comments with the other ones. I won't have time to review the F/S and AIF documents today, so please get back to OPG ASAP.

Thanks,
Ron

From: John Kim
Sent: February-26-18 17:38
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Usman Zahid <Usman.Zahid@ofina.on.ca>
Subject: FW: OPG Q4 2017 Submission to Province

Hi Ron,

Would you have any issues adding these edits to your comments (or vice versa)?

Thanks,

John

From: John Kim
Sent: Saturday, February 24, 2018 11:31 AM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Usman Zahid <Usman.Zahid@ofina.on.ca>; Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>; Darren Scanlan <Darren.Scanlan@ofina.on.ca>
Subject: RE: OPG Q4 2017 Submission to Province

Hi Ron,

Pls. see attached. No issue on the NR.

Thanks,

John

Z:\Users\CEF\Hydro 2018\OPG\Financials\Q4 2017

From: HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
Sent: February-16-18 5:11 PM

To: Shruti.Talwar@ontario.ca; Manu.Sud@ontario.ca; John Kim <John.Kim@ofina.on.ca>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: GORE Michael -FIN & C CTRL <michael.gore@opg.com>; PAN Rebecca -FIN & C CTRL <rebecca.pan@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>
Subject: OPG Q4 2017 Submission to Province

Hi All,

Please find attached OPG's draft Q4 2017 Financial Results Press Release, Management's Discussion and Analysis (MD&A), Annual Information Form (AIF) and Financial Statements for the Province's review.

We would greatly appreciate comments on the above **no later than Thursday, Feb 22nd**.

These documents will be filed with the Ontario Securities Commission on **Thursday, March 8th** following OPG's Board of Directors meeting.

Kindly forward all comments directly to Philip Ho – philip.ho@opg.com.

To assist the review process, the following are the key items in the Q4 2017 MD&A:

Highlights	
Recent Developments	MD&A p.13-19
OEB's Decision on OPG's Application for New Regulated Prices	MD&A p.13-15
Darlington Refurbishment	MD&A p.16-17; 28-30
Ontario's Fair Hydro Plan	MD&A p.17-18

Philip Ho, CPA, CA | Senior Manager, External Reporting & Accounting Policy | Ontario Power Generation
700 University Avenue, Toronto ON M5G 1X6 | Phone: (416) 592-3320| E-mail: philip.ho@opg.com

From: Ronald Kwan
To: John Kim
Subject: RE: OPG Q4 2017 Submission to Province
Date: Monday, February 26, 2018 2:09:49 PM
Attachments: Q4 2017 MDA - DRAFT - Feb 16 - PROVINCE MAILING_Markup.docx
Q4 2017 Press Release - PROVINCE MAILING_Markup.docx

Hi John,

Have comments been put together for OPG? I did a quick review and had a few comments. Has SIFB reviewed the ONFA parts?

Ron

From: HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
Sent: February-16-18 17:11
To: Shruti.Talwar@ontario.ca; Manu.Sud@ontario.ca; John Kim <John.Kim@ofina.on.ca>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: GORE Michael -FIN & C CTRL <michael.gore@opg.com>; PAN Rebecca -FIN & C CTRL <rebecca.pan@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>
Subject: OPG Q4 2017 Submission to Province

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Philip Ho, CPA, CA | Senior Manager, External Reporting & Accounting Policy | Ontario Power Generation
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ONTARIO POWER GENERATION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

DECEMBER 31, 2017

[DRAFT]

2017 YEAR-END REPORT

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ONTARIO POWER GENERATION INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) should be read in conjunction with the audited consolidated financial statements and accompanying notes of Ontario Power Generation Inc. (OPG or Company) as at and for the year ended December 31, 2017. OPG's consolidated financial statements are prepared in accordance with United States generally accepted accounting principles (US GAAP) and are presented in Canadian dollars.

As required by *Ontario Regulation 395/11*, as amended, a regulation under the *Financial Administration Act* (Ontario) (FAA), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. In 2014, the Ontario Securities Commission (OSC) approved an exemption which allows OPG to apply US GAAP up to January 1, 2019. The term of the exemption is subject to certain conditions, which may result in the expiry of the exemption prior to January 1, 2019. For details, refer to the section, *Critical Accounting Policies and Estimates* under the heading, *Exemptive Relief for Reporting under US GAAP*. This MD&A is dated March 8, 2018.

FORWARD-LOOKING STATEMENTS

The MD&A contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could", and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

All forward-looking statements involve inherent assumptions, risks, and uncertainties, including those set out in the section, *Risk Management,* and forecasts discussed in the section, *Core Business, Strategy, and Outlook.* All forward-looking statements could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's generating station performance and availability, fuel costs, surplus baseload generation (SBG), cost of fixed asset removal and nuclear waste management, performance and earnings of investment funds, refurbishment of existing facilities, development and construction of new facilities, pension and other post-employment benefit (OPEB) obligations and funds, income taxes, proposed new legislation, the ongoing evolution of Ontario's electricity industry, environmental and other regulatory requirements, health, safety and environmental developments, business continuity events, the weather, financing and liquidity, applications to the Ontario Energy Board (OEB) for regulatory prices, the impact of regulatory decisions by the OEB, Ontario's Fair Hydro Plan (Fair Hydro Plan or the Plan) and forecasts of earnings, cash flows, Funds from Operations (FFO) Adjusted Interest Coverage, Return on Common Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI), Total Generating Cost (TGC) and capital expenditures. Accordingly, undue reliance should not be placed on any forward-looking statement. The forward-looking statements included in this MD&A are made only as of the date of this MD&A. Except as required by applicable securities laws, OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events, or otherwise.

THE COMPANY

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG was established under the *Business Corporations Act* (Ontario) (OBCA) and is wholly owned by the Province of Ontario (Province or Shareholder).

As at December 31, 2017, OPG's electricity generation portfolio had an in-service capacity of 16,210 megawatts (MW). OPG operates two nuclear generating stations, 66 hydroelectric generating stations, three thermal generating stations, and one wind power turbine. In addition, OPG and TransCanada Energy Ltd. co-own the 550 MW Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS). OPG and ATCO Power Canada Ltd. co-own the 560 MW Brighton Beach gas-fired combined cycle GS (Brighton Beach). OPG's 50 percent share of the in-service capacity and generation volume of these co-owned facilities is included in the generation portfolio statistics set out in this report. The income from the co-owned facilities is accounted for using the equity method of accounting, and OPG's share of income is presented as income from investments subject to significant influence in the Contracted Generation Portfolio segment.

OPG also owns two other nuclear generating stations, the Bruce A GS and the Bruce B GS, which are leased on a long-term basis to Bruce Power LP (Bruce Power). Income from these leased stations is included in revenue under the Regulated – Nuclear Generation segment. The leased stations are not included in the generation portfolio statistics set out in this report.

All of OPG's owned and co-owned generating facilities are located in Ontario. OPG does not operate PEC, Brighton Beach, the Bruce A GS and the Bruce B GS.

OPG's Reporting Structure

Effective in the fourth quarter of 2017, following the establishment of the Fair Hydro Trust (the Trust) as the financing entity to implement the Fair Hydro Plan under the *Ontario Fair Hydro Plan Act, 2017* (the Fair Hydro Act or the Act), OPG has modified its reportable business segments to include the Fair Hydro Trust segment. Through its control over the key activities of the Trust and its obligation to absorb losses through ownership of the Trust's subordinated debt, the Company consolidates the financial results of the Trust in accordance with US GAAP. The Fair Hydro Trust segment reports the income related to OPG's role as Financial Services Manager under the Act and holder of subordinated debt issued by the Trust, including the financial results of the Trust. The Fair Hydro Plan and the Fair Hydro Trust are discussed in the section, *Recent Developments* and in the section, *Core Business, Strategy, and Outlook* under the heading, *Business Segments*.

The composition of OPG's reportable business segments is as follows:

- Regulated – Nuclear Generation
- Regulated – Nuclear Waste Management
- Regulated – Hydroelectric
- Contracted Generation Portfolio
- Services, Trading, and Other Non-Generation
- Fair Hydro Trust.

OPG receives regulated prices for electricity generated from most of its hydroelectric facilities and all of the nuclear facilities that it operates (collectively, prescribed facilities or regulated facilities). The regulated facilities comprise 54 hydroelectric generating stations across a number of major river systems in the province, the Pickering Nuclear GS (Pickering GS) and Darlington Nuclear GS (Darlington GS).

The operating results related to these regulated facilities are described under the Regulated – Nuclear Generation, Regulated – Nuclear Waste Management, and Regulated – Hydroelectric segments. For the remainder of OPG's operating generating facilities, the operating results are described under the Contracted Generation Portfolio segment. A description of all OPG's segments is provided under the section, *Business Segments*.

In-Service Generating Capacity

OPG's in-service generating capacity by business segment as of December 31 was as follows:

(MW)	**2017**	**2016**
Regulated – Nuclear Generation [1]	**5,728**	5,728
Regulated – Hydroelectric	**6,426**	6,421
Contracted Generation Portfolio [2]	**4,056**	4,028
Total	**16,210**	16,177

[1] The in-service generating capacity as of December 31, 2017 and December 31, 2016 excludes Unit 2 of the Darlington GS. The unit, which has a generating capacity of 878 MW, was taken offline in mid-October 2016 and is currently undergoing refurbishment.

[2] Includes OPG's share of in-service generating capacity of 275 MW for PEC and 280 MW for Brighton Beach.

The total in-service capacity as at December 31, 2017 increased by 33 MW compared to 2016. The increase was primarily due to the completion of the 28 MW Peter Sutherland Sr. hydroelectric GS, which was placed in-service in the first quarter of 2017, and the upgrade of Unit 10 of the Sir Adam Beck 1 hydroelectric GS, which was completed in June 2017. Further details on the Peter Sutherland Sr. GS project are found in the section, *Core Business, Strategy, and Outlook* under the heading, *Project Excellence*.

REVENUE MECHANISMS FOR REGULATED AND NON-REGULATED GENERATION

Regulated Generation

The OEB sets the prices for electricity generated from OPG's regulated nuclear and regulated hydroelectric facilities. The following table presents the OEB-authorized regulated prices for electricity generated from these facilities during the periods from January 1, 2016 to May 30, 2017, as well as new regulated prices retrospectively effective June 1, 2017 that OPG has calculated and submitted to the OEB, based on the OEB's decision on OPG's 2017-2021 application for new regulated prices issued on December 28, 2017:

($/MWh)	2017		2016
	January 1 to May 31	**June 1 to December 31** [1]	
Regulated – Nuclear Generation			
Base regulated price	**59.29**	**80.65**	59.29
Variance and deferral account rate rider	**-**	**-**	10.84 [2]
	59.29	**80.65**	70.13
Regulated – Hydroelectric			
Base regulated price	**40.72**	**41.67**	40.72
Variance and deferral account rate rider	**-**	**-**	3.19 [2]
	40.72	**41.67**	43.91

[1] Regulated prices for the June 1, 2017 to December 31, 2017 period were calculated and submitted to the OEB by OPG in January 2018 based on the OEB's December 28, 2017 decision on OPG's 2017-2021 application for new regulated prices. The final regulated prices will be determined by the OEB as part of the final payment amounts order process, which is expected to be completed in the first half of 2018. As part of the process, the OEB is expected to authorize separate rate riders to allow for the recovery of the shortfall between the new regulated prices and the previous regulated prices that OPG continues to receive during the period between June 1, 2017 and the implementation date of the new regulated prices pending the issuance of the final payment amounts order. The incremental revenue for the period between June 1, 2017 and December 31, 2017 arising from this retrospective application of new regulated prices was accrued in 2017. **[MONITOR]**

[2] The OEB authorized interim period rate riders for the period from October 1, 2015 to December 31, 2016 to allow for the recovery of the riders effective July 1, 2015 for the period from July 1, 2015 to September 30, 2015. The nuclear interim period rate rider was $2.17 per megawatt hour (MWh) and the regulated hydroelectric interim period rate rider was $0.64/MWh. These interim period rate riders have not been included in the above table. All rate riders in effect during 2016 expired on December 31, 2016.

Based on the OEB's December 2017 decision, the new base regulated prices are determined on an incentive ratemaking methodology for the hydroelectric operations and under a custom incentive regulation framework for the nuclear operations. For the hydroelectric facilities, the new base regulated price is determined using a formula that annually escalates the previous regulated prices, subject to some adjustments, based on inflation less a stretch factor to incent additional innovation and efficiency. For the nuclear facilities, the new regulated price is determined under a rate smoothing approach that defers a portion of the approved nuclear revenue requirement for future collection, with the aim of making more stable changes in OPG's production-weighted regulated prices year over year. The nuclear revenue requirement is based on the OEB-approved forecasts of operating costs as reduced by a stretch factor and a return on rate base. Rate base for OPG represents the average net level of investment in regulated fixed and intangible assets in service and an allowance for working capital. The OEB's December 2017 decision and OPG's new regulated prices are discussed further in the section, *Recent Developments*.

The base regulated prices in effect during 2016 were established by the OEB's November 2014 decision and December 2014 order, effective November 1, 2014, using a forecast cost-of-service methodology based on the OEB-approved revenue requirements for the 2014 to 2015 period, taking into account the OEB-approved forecasts of production and operating costs for the regulated facilities and a return on rate base.

The increase in base regulated prices for the Regulated – Nuclear Generation segment from those last approved in 2014 is impacted by lower production for Darlington GS for the duration of Unit 2's refurbishment. The increase also

reflects OPG's ability to earn a return on higher in-service capital and recover costs to enable Pickering to operate beyond 2020 in line with the Long-Term Energy Plan (LTEP).

Rate riders for OPG are typically established to recover or repay approved balances in OEB-authorized regulatory variance and deferral accounts (regulatory accounts). Variance and deferral accounts typically capture, for subsequent review and approval, differences between actual costs and revenues and the corresponding forecast amounts approved by the OEB in setting regulated prices, or record the impact of items not reflected in the approved regulated prices. The rate riders in effect to the end of 2016 were established by the OEB's October 2015 order on OPG's 2014 application to recover the December 31, 2014 variance and deferral account balances. Revenue received from the recovery of variance and deferral account balances is largely offset by amortization expense related to these balances.

Non-Regulated Generation

Electricity generated from most of OPG's non-regulated assets is subject to Energy Supply Agreements (ESAs) with the Independent Electricity System Operator (IESO).

During 2017, ESAs were in effect for the following thermal generating facilities:

- Lennox GS: Capacity and production provided by the station are subject to an ESA for the period from January 1, 2013 to September 30, 2022
- Atikokan GS: Capacity and production provided by the station are subject to a ten-year ESA expiring in July 2024
- Thunder Bay GS: Capacity and production provided by the station are subject to a five-year ESA expiring in January 2020.

In addition, long-term hydroelectric ESAs are in place for the following facilities, with expiry dates ranging from 2059 to 2067:

- Lac Seul and Ear Falls generating stations
- Healey Falls GS
- Sandy Falls, Wawaitin, Lower Sturgeon, and Hound Chute generating stations
- Little Long, Harmon, Smoky Falls, and Kipling generating stations (collectively the Lower Mattagami River generating stations)
- Peter Sutherland Sr. GS, which was placed in-service in March 2017.

HIGHLIGHTS

Overview of Results

This section provides an overview of OPG's operating results for the years ended December 31, 2017 and December 31, 2016.

(millions of dollars – except where noted)	**2017**	**2016**
Revenue	**5,158**	5,653
Fuel expense	**689**	727
Gross margin	**4,469**	4,926
Operations, maintenance and administration	**2,824**	2,747
Depreciation and amortization	**679**	1,257
Accretion on fixed asset removal and nuclear waste management liabilities	**960**	929
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(801)**	(746)
Earnings from Fair Hydro Trust	**(1)**	-
Income from investments subject to significant influence	**(38)**	(37)
Property taxes	**40**	46
Restructuring	**-**	6
	3,663	4,202
Income before other gains, interest, and income taxes	**806**	724
Other gains	**379**	17
Income before interest and income taxes	**1,185**	741
Net interest expense	**95**	120
Income before income taxes	**1,090**	621
Income tax expense	**209**	168
Net income	**881**	453
Net income attributable to the Shareholder	**860**	436
Net income attributable to non-controlling interest [1]	**21**	17
Electricity production (TWh) [2]	**74.1**	78.2
Cash flow		
Cash flow provided by operating activities	**944**	1,817

[1] Relates to the 25 percent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in the Lower Mattagami Limited Partnership, the 33 percent interest of Coral Rapids Power Corporation (CRP), a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership (PSS), and the 10 percent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP. CRP increased its partnership interest to 33 percent in April 2017.

[2] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach and excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS was excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

Net income attributable to the Shareholder was $860 million for 2017, representing an increase of $424 million compared to 2016. Income before interest and income taxes was $1,185 million for 2017, representing an increase of $444 million compared to 2016. The following summarizes the significant factors which contributed to the variance:

Significant factors that increased income before interest and income taxes:

- Higher revenue from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments of approximately $480 million recorded in the fourth quarter of 2017 to reflect the OEB's decision on OPG's application for new regulated rates issued in December 2017 with a retrospective effective date of June 1,

2017. This revenue increase for the June 1, 2017 to December 31, 2017 period was recorded as an increase in regulatory assets, based on new regulated prices for that period proposed in OPG's January 2018 submission to the OEB based on the findings in the December 2017 decision, net of a regulatory liability recognized in relation to OPG's nuclear rate smoothing proposal included in that submission. The new regulated prices, the future collection period for the retrospective revenue increase, and the rate smoothing proposal are pending the OEB's approval through the payment amounts order process, which typically follows the OEB's issuance of a decision on a major rates application. The OEB's approval of the final payment amounts order, including determinations on the new regulated prices and rate smoothing, are not expected to have a material impact on the total revenue recorded for the June 1, 2017 to December 31, 2017 period. The OEB is expected to issue the final payment amounts order in the first half of 2018. **[MONITOR]**

- Higher earnings of $377 million from the Services, Trading, and Other Non-Generation segment, primarily as a result of the gain on sale of OPG's head office premises and associated parking facility, a non-core asset of the business. A gain on sale of $283 million, which is net of tax effects of $95 million, was recognized in net income upon completion of the transaction in the second quarter of 2017. The sale was undertaken pursuant to a Shareholder Declaration and a Shareholder Resolution. Further details can be found under the heading, *Recent Developments – Shareholder Declarations and Shareholder Resolutions to Sell Certain Non-Core Real Estate Properties*.
- Higher earnings of $24 million from the Regulated – Nuclear Waste Management segment, primarily due to higher earnings from the nuclear fixed asset removal and nuclear waste management funds (Nuclear Segregated Funds), partially offset by an increase in accretion expense on the nuclear fixed asset removal and nuclear waste management liabilities (Nuclear Liabilities).

Significant factors that reduced income before interest and income taxes:

- Lower revenue of approximately $285 million, partially offset by a decrease in fuel expense of $31 million, reflecting lower electricity generation of 4.9 terawatt hours (TWh) from the Regulated – Nuclear Generation segment. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS since October 2016, partially offset by an increase in generation from the Pickering GS. The increase in generation from the Pickering GS was primarily due to outage cycle optimization, favourable unit conditions and execution of planned outage work resulting in fewer unplanned and planned outage days at the station.
- Higher operations, maintenance and administration (OM&A) expenses of $77 million, mainly in the Regulated – Nuclear Generation segment, reflecting planned expenditures related to the major maintenance activities occurring at the nuclear stations.
- Higher depreciation and amortization expense of $22 million in the Regulated – Nuclear Generation segment, excluding amortization expense related to balances in regulatory accounts, primarily due to new assets in service.
- A gain of $22 million recorded in the first quarter of 2016 to reflect the OEB's decision on OPG's motion asking the OEB to review and vary parts of its November 2014 decision on OPG's regulated prices.

The expiry of rate riders for the recovery of OEB-approved balances in regulatory accounts on December 31, 2016 contributed to the decrease in revenue in 2017, compared to 2016, but was largely offset by a decrease in the amortization expense related to regulatory account balances.

Net interest expense decreased by $25 million in 2017, compared to 2016, primarily due to a higher amount of interest costs capitalized for the Darlington Refurbishment project.

Income tax expense increased by $41 million in 2017, compared to 2016, primarily due to higher income before income taxes, partially offset by a higher amount of income tax expense deferred in regulatory assets in 2017.

Segment Results

The following table summarizes OPG's income before interest and income taxes by business segment. Significant factors which contributed to the higher income during 2017, compared to 2016, are discussed above. A detailed discussion of OPG's performance by reportable segment is included in the section, *Discussion of Operating Results by Business Segment*.

(millions of dollars)	**2017**	**2016**
Income (loss) before interest and income taxes		
Regulated – Nuclear Generation	**57**	4
Regulated – Hydroelectric	**614**	642
Contracted Generation Portfolio	**300**	282
Total electricity generation business segments	**971**	928
Regulated – Nuclear Waste Management	**(150)**	(174)
Services, Trading, and Other Non-Generation	**364**	(13)
Fair Hydro Trust	**-**	-
	1,185	741

Electricity Generation

Electricity generation for 2017 and 2016 was as follows:

(TWh)	**2017**	**2016**
Regulated – Nuclear Generation	**40.7**	45.6
Regulated – Hydroelectric	**30.7**	29.5
Contracted Generation Portfolio [1]	**2.7**	3.1
Total OPG electricity generation	**74.1**	78.2
Total electricity generation by other generators in Ontario [2]	**70.5**	72.7

[1] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

[2] Non-OPG generation is calculated as the Ontario electricity demand plus net exports, as published by the IESO, minus OPG electricity generation.

Total OPG electricity generation decreased by 4.1 TWh in 2017, mainly due to lower electricity generation of 4.9 TWh from the Regulated – Nuclear Generation segment. As expected, this was primarily the result of the removal from service of Unit 2 at the Darlington GS for the duration of the unit's refurbishment, which began in October 2016. This decrease in electricity generation was partially offset by an increase in generation from the Pickering GS, primarily due to outage cycle optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of outage days at the station, as well as higher electricity generation from the Regulated – Hydroelectric segment.

The higher electricity generation from the Regulated – Hydroelectric segment in 2017 was due to higher water flows primarily on the eastern Ontario river systems, net of forgone electricity generation as a result of SBG conditions, discussed below.

The lower electricity generation from the Contracted Generation Portfolio segment was primarily due to higher SBG conditions.

OPG's operating results are affected by changes in grid-supplied electricity demand resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. Ontario's electricity demand as reported

by the IESO was 132.1 TWh in 2017 and 137.0 TWh and 2016, respectively, which excludes electricity exports out of the province.

Power that is surplus to the Ontario market is managed by the IESO, mainly through generation reductions at hydroelectric and nuclear stations and other grid-connected renewable resources. Reducing hydroelectric production is a measure used by the IESO to manage SBG conditions. Baseload generation supply surplus in Ontario was more prevalent in 2017 than in 2016, mainly due to higher water flows and reduced electricity demand in the province during 2017. During 2017 and 2016, OPG lost 5.9 TWh and 4.7 TWh of hydroelectric generation due to SBG conditions, respectively. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions in 2017 and 2016 was offset by the impact of a regulatory variance account authorized by the OEB. OPG did not forgo any electricity production at its nuclear stations due to SBG conditions.

Average Sales Prices

The majority of OPG's generation is from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments. The regulated prices authorized by the OEB for electricity generated from OPG's nuclear and regulated hydroelectric generating stations are discussed in the section, *Revenue Mechanisms for Regulated and Non-Regulated Generation*.

The average sales price for the Regulated – Nuclear Generation segment during 2017 was 7.1 cents per kilowatt hour (¢/kWh), compared to 6.9 ¢/kWh during 2016. The increase in this average sales price was primarily due to an increase in revenue for the period June 1, 2017 to December 31, 2017 recorded in the fourth quarter of 2017 to reflect the OEB's December 2017 decision on OPG's application for new regulated prices, with an effective date of June 1, 2017. The increase was partially offset by the expiry of an OEB-authorized nuclear rate rider of $10.84 per MWh, on December 31, 2016, for the recovery of variance and deferral account balances. The average sales price for the Regulated – Hydroelectric segment during 2017 was 4.2 ¢/kWh, compared to 4.4 ¢/kWh during 2016. The decrease in this average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized regulated hydroelectric rate rider of $3.19/MWh for the recovery of variance and deferral account balances, partially offset by the impact of an increase in revenue for the period June 1, 2017 to December 31, 2017 recorded in the fourth quarter of 2017 to reflect the OEB's December 2017 decision. The rate riders that expired on December 31, 2016 were established to recover approved balances recorded in the variance and deferral accounts in prior years. As such, the year-over-year changes in revenue from the rate riders were largely offset by changes in amortization expense related to these balances.

Cash Flow from Operations

Cash flow provided by operating activities for 2017 was $944 million, compared to $1,817 million for 2016. The decrease in cash flow provided by operating activities was expected and primarily due to lower generation revenue receipts reflecting lower generation from the Regulated – Nuclear Generation segment as a result of the ongoing refurbishment of Unit 2 at the Darlington GS and the expiry, on December 31, 2016, of the OEB-authorized rate riders for nuclear and regulated hydroelectric generation. The decrease in cash flow was also due to higher income tax instalments during 2017, compared to 2016.

The decrease in cash flow provided by operating activities was partly offset by lower contributions to the Used Fuel Segregated Fund in 2017. Both the Used Fuel Segregated Fund and the Decommissioning Segregated Fund were determined to be fully funded based on an updated estimate of OPG's nuclear waste management and nuclear facilities decommissioning obligations pursuant to an Ontario Nuclear Funds Agreement (ONFA) reference plan approved by the Province, effective January 1, 2017. Pursuant to the ONFA, the reference plan is required to be updated at least once every five years. Contributions to either or both of the Nuclear Segregated Funds may be required in the future should the funds be in an underfunded position at the time of the next ONFA reference plan update. The decrease in cash flow compared to the prior year also was partially offset by the payment of a supplemental rent rebate to Bruce Power in the first quarter of 2016 in relation to a period in 2015. The lease

agreement for the Bruce nuclear generating stations was amended in late 2015 to eliminate this rebate provision going forward.

Funds from Operations Adjusted Interest Coverage

FFO Adjusted Interest Coverage is an indicator of OPG's ability to meet interest obligations from operating cash flow. The indicator is measured over a 12-month period. The FFO Adjusted Interest Coverage was 3.3 times for 2017 compared to 5.1 times for 2016. FFO Adjusted Interest Coverage in 2017 reflected a year-over-year decrease in FFO before interest due to lower cash flow provided by operating activities and changes to non-cash working capital balances, offset by the impact of a lower adjusted interest expense due to a decrease in the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets.

The decrease in the excess of interest on pension and OPEB benefit obligations over expected return on pension plan assets in 2017 was primarily due to the change in the method used to estimate the interest cost and service cost component of pension and OPEB costs prospectively adopted as of January 1, 2017. The change in the method is discussed in the section, *Critical Accounting Policies and Estimates* under the heading, *Pension and Other Post-Employment Benefits*.

Return on Common Equity Excluding Accumulated Other Comprehensive Income

ROE Excluding AOCI is an indicator of OPG's performance consistent with the Company's strategy to provide value to the Shareholder. ROE Excluding AOCI is measured over a 12-month period. ROE Excluding AOCI for 2017 was 7.5 percent, compared to 4.2 percent for 2016. ROE Excluding AOCI increased for 2017, compared to 2016, primarily due to higher net income attributable to the Shareholder as a result of the gain on the sale of OPG's head office premises and associated parking facility recorded during the second quarter of 2017 and an increase in revenue for the period June 1, 2017 to December 31, 2017 recorded in the fourth quarter of 2017 to reflect the OEB's December 2017 decision on OPG's application for new regulated prices, with an effective date of June 1, 2017. The increase in net income attributable to the Shareholder was partially offset by the impact of lower nuclear electricity generation reflecting the Unit 2 refurbishment outage at the Darlington GS.

Enterprise Total Generating Cost per Megawatt-Hour

The Enterprise TGC per megawatt-hour (MWh) was $50.66 for the year ended December 31, 2017, compared to $48.45 for the same period in 2016. The increase in Enterprise TGC per MWh was expected and primarily due to lower nuclear electricity generation as a result of the Unit 2 refurbishment outage at the Darlington GS and higher sustaining capital expenditures, partially offset by higher SBG-adjusted hydroelectric electricity generation reflecting higher water flows.

If Unit 2 at the Darlington GS was not currently undergoing refurbishment and had continued to operate in a manner consistent with the performance of the remaining units at the station, adjusting for generation constraints on these units related to the transition of the station toward refurbishment, the Enterprise TGC would have been approximately $4 to $5 per MWh lower for the year ended December 31, 2017. This sensitivity was calculated using the estimated incremental electricity generation and associated fuel cost that are expected to have had resulted in the absence of the refurbishment.

Nuclear Total Generating Cost per Megawatt-Hour

The Nuclear TGC per MWh was $70.95 for the year ended December 31, 2017, compared to $62.30 for the same period in 2016. The increase in Nuclear TGC per MWh was expected and primarily due to the decrease in nuclear electricity generation primarily as a result of the Unit 2 refurbishment outage at the Darlington GS and higher sustaining capital expenditures.

Hydroelectric Total Generating Cost per Megawatt-Hour

The Hydroelectric TGC per MWh was $23.91 for the year ended December 31, 2017, compared to $25.49 for the same period in 2016. The improvement in the Hydroelectric TGC per MWh was primarily due to higher SBG-adjusted hydroelectricity generation reflecting higher water flows.

ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are not measurements in accordance with US GAAP and should not be considered alternative measures to net income, cash flow provided by operating activities, or any other performance measure under US GAAP. OPG believes that these non-GAAP financial measures are effective indicators of its performance and are consistent with the Company's strategic imperatives and related objectives. The definition and calculation of ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are found in the section, *Supplementary Non-GAAP Financial Measures*.

Recent Developments

OEB's Decision on OPG's Application for New Regulated Prices

The OEB's decision on OPG's May 2016 five-year application for new regulated prices for its nuclear and regulated hydroelectric generation was issued on December 28, 2017, following a public hearing process. The OEB set an effective date for OPG's new regulated prices of June 1, 2017. OPG had requested an effective date of January 1, 2017. The decision reflected the terms of an OEB-approved partial settlement agreement reached by OPG and intervenors on a limited set of issues in the first quarter of 2017 (Settlement Agreement). For the first time since OPG's prescribed facilities became subject to rate regulation, the new prices have been determined on an incentive ratemaking methodology for the hydroelectric operations and a custom incentive regulation framework for the nuclear operations.

For the hydroelectric facilities, effective June 1, 2017, the base regulated prices in effect prior to June 1, 2017, with some adjustments, will be escalated for each of years 2017 to 2021 using a formula equal to an industry-specific weighted inflation factor based on indices published annually by the OEB for use in incentive regulation formulas, less a stretch factor adjustment. The OEB accepted OPG's proposal to set the annual stretch factor adjustment at 0.3 percent. Based on the approved formula, the 2017 increase in the base regulated price for the regulated hydroelectric facilities is 1.4 percent as of June 1, 2017 and the 2018 increase is 0.9 percent as of January 1, 2018. For the 2019-2021 period, the base regulated price for the regulated hydroelectric facilities will be determined annually before the beginning of each year using the approved formula and inflation indices published by the OEB.

For the nuclear operations, a revenue requirement is determined for each of the years 2017 to 2021 based on the OEB-allowed level of OPG's forecast operating costs, reduced by a stretch factor amount, as well as a return on rate base determined using OEB's generic prescribed rate of return and an OPG-specific deemed capital structure. OPG has calculated that the findings of the OEB's December 2017 decision with respect to the forecast operating costs, rate base and deemed capital structure for the nuclear generating facilities will result in nuclear revenue requirements totalling $15.9 billion over the five years.

The OEB's findings with respect to the nuclear revenue requirement include approval for inclusion in rate base of in-service amounts related to the Darlington Refurbishment of $5.5 billion by 2021, including $4.8 billion forecast in the first quarter of 2020 upon return to service of Unit 2, $0.4 billion forecast for pre-requisite projects excluding the Heavy Water Storage and Drum Handling Facility (HWSF) over the 2016-2021 period and $0.3 billion for pre-requisite projects placed in service prior to 2016. The OEB is expected to review the HWSF project as part of a future application. In the decision, the OEB concluded that it is appropriate to evaluate OPG's performance on the Darlington Refurbishment project at an overall level rather by individual cost component, with recovery of any increases over the approved in-service amounts subject to a future prudence review. The revenue requirement impact of differences between the approved in-service additions and the actual in-service additions will be recorded in

the Capacity Refurbishment Variance Account authorized by the OEB pursuant to *Ontario Regulation 53/05*. The $4.8 billion forecast in-service amount upon return to service of Unit 2 includes expenditures incurred during the definition and planning phase of the project.

The OEB also approved OPG's requested forecast costs of approximately $292 million for activities to enable Pickering operations beyond 2020 and agreed to inclusion of operating cost and generation impacts associated with continued operation of Pickering in 2021 in nuclear regulated prices. The differences between approved forecast enabling costs for continued Pickering operations and the actual amounts will be recorded in the Capacity Refurbishment Variance Account for future review and disposition by the OEB.

Excluding amounts that otherwise would have been recorded in OEB-authorized regulatory accounts for repayment to, or recovery from, customers in the future, the OEB's decision reduced OPG's proposed five-year nuclear revenue requirement by $0.6 billion. The main adjustments made by the OEB included a reduction of $100 million per year to requested OM&A costs, a reduction of 10 percent per year to forecast non-Darlington refurbishment capital in-service additions entering rate base over the 2017-2021 period, an increase and expansion of the scope of the stretch factor for nuclear costs that further reduced the revenue requirement, and a rejection of OPG's request to increase the equity component of the existing deemed capital structure of 45 percent equity and 55 percent debt. The OEB increased and expanded the annual stretch factor to 0.6 percent to most of OPG's OM&A expenses incurred directly for, or allocated to, the nuclear facilities, as well as to non-Darlington refurbishment capital in-service additions. The stretch factor is applied starting in 2018 and compounds in each year to 2021.

In accordance with *Ontario Regulation 53/05*, the nuclear revenue requirement continues to be adjusted by the amount of OPG's revenues, net of costs, from leasing the Bruce nuclear generating stations to Bruce Power. As directed by the OEB, OPG's revenues and costs related to the Bruce nuclear generating stations continue to be determined in accordance with US GAAP for the purposes of establishing the nuclear revenue requirement and are subject to the Bruce Lease Net Revenues Variance Account in accordance with *Ontario Regulation 53/05*. This includes costs related to the portion of the Nuclear Liabilities associated with the Bruce nuclear generating stations. The OEB's decision maintained the previously approved cost recovery methodology for the costs of the Nuclear Liabilities for the prescribed facilities and for the Bruce facilities, directing OPG to file a future study examining such methodologies jurisdictionally and for OPG's assets specifically. The decision fully incorporated the impacts of the updated estimate of OPG's obligations for nuclear waste management and nuclear facilities decommissioning as at December 31, 2016, including through a new ONFA reference plan effective January 1, 2017 and the change in the Nuclear Liabilities recorded on December 31, 2016.

As proposed by OPG, the OEB set recovery of pension and OPEB costs in the nuclear revenue requirement on the basis of OPG's cash payments for pension and OPEB plans, with differences between pension and OPEB accrual costs and cash payments continuing to be recorded in the Pension & OPEB Cash to Accrual Differential Deferral Account. The regulatory treatment of pension and OPEB costs is discussed further under the heading, *OEB's Report on Regulatory Treatment of Pension and OPEB Costs*.

The OEB accepted all variance and deferral account balances proposed for recovery that were not already accepted as part of the Settlement Agreement, resulting in approval of recovery of $305 million recorded in variance and deferral variance accounts as at December 31, 2015, without adjustments. The Settlement Agreement provided for the continuation of all applicable existing variance and deferral accounts. In addition to the Rate Smoothing Deferral Account discussed below, the OEB established, as of the effective date of the new regulated prices, new variance and deferral accounts to record costs related to implementing the Canadian Nuclear Safety Commission's (CNSC) Fitness for Duty program and to record differences between forecast and actual amount of Scientific Research & Experimental Development investment tax credits attributable to the nuclear facilities.

Consistent with the requirements of *Ontario Regulation 53/05*, OPG's overall production-weighted regulated prices will be smoothed, with a resulting portion of the approved annual nuclear revenue requirements for the 2017-2021 period deferred in the Rate Smoothing Deferral Account for future collection. The non-deferred portion of each year's

nuclear revenue requirement is divided by the OEB-approved forecast of OPG's nuclear electricity generation for the corresponding year to determine the base nuclear regulated price. The OEB approved the nuclear electricity generation forecast as requested by OPG.

As amended in March 2017, *Ontario Regulation 53/05* requires rate smoothing to be applied in a manner that makes changes in OPG's weighted-average nuclear and hydroelectric regulated prices more stable year over year. Previously, the regulation required that rate smoothing be applied with a view of making more stable year-over-year changes in OPG's nuclear regulated prices only. Per the regulation, the deferral account records interest at a long-term debt rate reflecting OPG's cost of long-term borrowing approved by the OEB, compounded annually. The regulation requires the OEB to authorize recovery of the balance in the account on a straight line basis over a period not to exceed ten years following the end of the Darlington Refurbishment project. OPG recognizes positive amounts deferred under rate smoothing as an increase in net regulatory assets and an increase in revenue in the period to which the underlying approved revenue requirement relates. Negative amounts determined under rate smoothing are correspondingly recorded as a decrease in net regulatory assets and a decrease to revenue.

On January 17, 2018, OPG submitted a draft payment amounts order to the OEB that proposed nuclear base regulated prices for each year of the 2017-2021 period, including a rate smoothing proposal, based on the December 2017 decision's findings. The rate smoothing proposal takes into account the near-term and future impacts on customers, while seeking to ensure that resulting nuclear regulated prices allow for sufficient cash flow to maintain the Company's investment grade credit rating and support availability of cost effective funding, while taking into account both near-term and future impacts on customers. Based on the OEB's direction, the draft payment amounts order also included proposed periods for recovery, through interim period shortfall rate riders, of the retrospective revenue shortfall for the period between June 1, 2017 and the implementation date of the new regulated prices based on proposed new regulated prices that would have been in effect during that period. The draft payment amounts also included proposed recovery periods, through variance and deferral account rate riders, for regulatory account balances approved for recovery in this application. **[MONITOR]**

To reflect the OEB's decision, in the fourth quarter of 2017, OPG recorded incremental revenue of approximately $480 million for the period June 1, 2017 to December 31, 2017 based on the draft payment amounts order. The revenue was recorded as an increase in regulatory assets for the June 1, 2017 to December 31, 2017 revenue shortfall based on proposed new regulated prices for nuclear facilities and regulated hydroelectric facilities, net of a regulatory liability recognized in relation to OPG's rate smoothing proposal. The OEB's approval of the final payment amounts order, including the allocation of the approved revenue requirement between nuclear regulated prices and rate smoothing deferrals, is not expected to have a material impact on the net revenue increase recorded in the fourth quarter of 2017. The OEB is expected to issue the final payment amounts order and implement new regulated prices in the first half of 2018. **[MONITOR]**

Consistent with the effective date of the OEB's December 2017 decision, for the period from January 1, 2017 to May 31, 2017, OPG continued to record additions to the existing variance and deferral accounts for the nuclear and regulated hydroelectric facilities pursuant to the OEB's previous decisions and orders. These additions reflected differences between actual and forecast amounts embedded in the regulated prices in effect prior to the June 1, 2017 effective date.

In January 2018, OPG filed a motion asking the OEB to review and vary the effective date of the new regulated prices to January 1, 2017. The motion did not impact OPG's financial results for the year ended December 31, 2017.

Ontario's 2017 Long-Term Energy Plan

On October 26, 2017, Ontario's Ministry of Energy issued the 2017 LTEP that outlines the Province's plans for the future development of Ontario's electricity system. The 2017 LTEP focuses on the affordability, reliability and flexibility of a clean energy supply in the province. The 2017 LTEP replaces the previous LTEP issued in 2013.

As it relates to the supply of electricity, the 2017 LTEP recognizes the refurbishment of Ontario's nuclear generating stations as the most cost-effective option for producing emission-free baseload generation to meet Ontario's needs and reaffirms the Province's support for the refurbishment of the four units at the Darlington GS and the six units at the Bruce generating stations, subject to the principles established in the 2013 LTEP. The 2017 LTEP also recognizes the value to customers of continuing to operate the Pickering GS until 2024, as planned. With respect to hydroelectric electricity generation, the 2017 LTEP highlights the opportunity to continue to invest in optimizing existing hydroelectric facilities, noting that pumped hydroelectric storage could play an important role in the reliability of the electricity system.

Additionally, the 2017 LTEP discusses the potential impact of a number of innovative technologies on the future of the electricity system. Among others, these include the increased electrification of the transportation sector, the emergence of energy storage, and the opportunity for Ontario to foster nuclear innovation technologies. OPG continues to assess how best to capitalize on potential business opportunities in these and other areas. The 2017 LTEP also recognizes the importance of Indigenous peoples' continuing role in shaping Ontario's energy planning, projects and policies.

Darlington Refurbishment

In October 2016, OPG commenced the refurbishment of the first Darlington GS unit, Unit 2, as part of the Darlington Refurbishment project. The de-fuelling of the reactor and islanding of Unit 2, the physical separation of the unit under refurbishment from the three operating units, were completed in the first half of 2017.

The disassembly of reactor components commenced in the third quarter of 2017, with the removal of feeder tubes completed in September 2017. The removal of fuel channel assemblies commenced in October 2017. As part of the fuel channel assemblies, the removal of pressure tubes is in progress and will be followed by the removal of calandria tubes. The second major segment and the removal of all reactor components is expected to be completed by mid-2018.

All of the pre-requisite projects, including construction of facilities, infrastructure upgrades and installation of safety enhancements, with the exception of the HWSF, have been completed and placed in service. The completion of the HWSF has been delayed due to challenges with construction, with construction activities suspended for a portion of 2017. Construction to complete the facility recommenced in the fourth quarter of 2017, including work to preserve and protect the facility during winter. The HWSF is expected to be completed by the second quarter of 2019 and is not on the critical path for the Darlington Refurbishment project, which continues to track on schedule. The increase in the cost estimate for the HWSF will be accommodated within the overall Darlington Refurbishment budget of $12.8 billion. Taking into account the execution performance of the Unit 2 refurbishment, the overall Darlington Refurbishment project continues to track on budget.

On November 21, 2017, the Financial Accountability Office of Ontario issued a report, "*An Assessment of the Financial Risks of the Nuclear Refurbishment Plan*". The report assesses the impact of OPG and Bruce Power's nuclear refurbishments on customers and the Province based on mechanisms in place for the recovery of the costs to refurbish and subsequently operate the nuclear stations. The report concludes that refurbishment of the four units at the Darlington GS and the six units at the Bruce nuclear generating stations provides the most cost effective, low emission generation source available to meet Ontario's baseload electricity requirements.

The Darlington Refurbishment project is discussed further in the section, *Core Business, Strategy, and Outlook* under the heading, *Project Excellence*.

Canadian Nuclear Safety Commission Safety Rating for the Darlington GS and the Pickering GS

The CNSC publishes an annual report on the safety performance of Canada's nuclear power plants. The report assesses how well plant operators are meeting regulatory requirements and program expectations in the areas of operational performance, safety analysis, radiation protection, waste management and conventional health and

safety. On September 8, 2017, the CNSC issued an executive summary of its 2016 annual report, giving both the Darlington GS and the Pickering GS the highest possible safety rating of "Fully Satisfactory". The Darlington GS achieved this rating for the eighth consecutive year, while the Pickering GS achieved this rating for the second consecutive year.

Ontario's Fair Hydro Plan

On March 2, 2017, the Province announced the Fair Hydro Plan aimed at reducing electricity bills for residential, farm, small businesses and other eligible consumers (Specified Consumers) in the province by refinancing a portion of the Global Adjustment costs over a longer period of time. The Global Adjustment includes the difference between Ontario's electricity market clearing price used to dispatch generation and the prices paid to contracted and regulated generators in the province, and the cost of conservation and demand management programs. On June 1, 2017, the Fair Hydro Act received Royal Assent and the associated general regulation came into force in June 2017. The Act established a framework under which the costs and benefits associated with the Government of Ontario's clean energy initiatives are to be allocated between present and future consumers of electricity under the Fair Hydro Plan. The general regulation provides details on the structural, operational and financial elements required to implement the Fair Hydro Plan.

Pursuant to the Act, effective May 1, 2017, the IESO began to defer a portion of the Global Adjustment costs. The Act allows the IESO to transfer a portion of the deferred balance to a financing entity that would fund the deferral in exchange for an irrevocable right to recover the balance and associated financing and other costs from Specified Consumers in the future (Investment Interest). The legislation appointed OPG as the Financial Services Manager under the Act and conveyed upon the Financial Services Manager statutory obligations, including the creation of one or more financing entities that may acquire Investment Interests from the IESO.

In November 2017, OPG's Board of Directors provided its final approval regarding OPG's involvement with the Trust on commercial terms following the fulfilment of all conditions it established in May 2017. Accordingly, the Fair Hydro Trust was established as the financing entity contemplated by the Act in December 2017. The majority unitholder and beneficiary of the Trust is a wholly-owned subsidiary of OPG. The Trust is structured to be bankruptcy remote and ring fenced from OPG in order to protect the Company's assets and operations.

In order for the Trust to finance the Investment Interest acquired from the IESO, it will incur senior debt from capital markets and subordinated debt from OPG. The Trust's investment will attract financing amounts and other related fees, which, under the general regulation, will be payable by the IESO as carrying costs until July 2021 and by Specified Consumers through the Clean Energy Adjustment to be invoiced by local distribution companies commencing in May 2021, with the three-month lag in 2021 intended to cover the billing and collection lag from the introduction of the Clean Energy Adjustment. The carrying costs include all financing and third-party costs other than payment of principal on debt.

Concurrent with every issuance of the Trust's senior notes, it is expected that OPG will purchase subordinated debt of the Trust in an aggregate amount not to exceed 49 percent of the Trust's total outstanding debt, with 44 percent of the funding to be provided by the Province through equity injections and five percent to be provided by OPG. The subordination level may vary over time, but must at least equal to, or be greater than 35 percent of all outstanding debt. Through OPG's control over the key activities of the Trust and its obligation to absorb losses through ownership of the Trust's subordinated debt, the Company consolidates the financial results of the Trust in accordance with US GAAP.

On December 21, 2017, the Trust purchased its first tranche of Investment Interest from the IESO in the amount of approximately $1.18 billion. Fifty-one percent of the funding requirement or $601 million was financed by the Trust through a revolving warehouse facility ranked as senior notes, and the remaining 49 percent was funded through the issuance of short-term subordinated debt to OPG. The Investment Interest has been classified as a financing receivable on OPG's consolidated balance sheet.

OPG's subordinated debt investment in the Trust was funded through the following sources:

- The Province provided 44 percent of the total funding requirement or $519 million, through an equity injection in OPG in exchange for approximately 12.2 million non-voting Class A common shares at a price of $42.46 per share. The Company's Articles of Amalgamation were amended effective December 1, 2017 to allow for the creation and issuance of Class A shares. Refer to Note 14 of OPG's 2017 audited consolidated financial statements for further details; and
- OPG provided five percent of the total funding requirement or approximately $60 million.

In February 2018, the Trust issued $500 million of senior notes payable with a coupon interest rate of 3.36 percent and an effective interest rate of 3.42 percent, payable semi-annually until maturity on May 15, 2033. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility issued in December 2017. By the end of the first quarter of 2018, the Trust is expected to acquire another tranche of Investment Interest from the IESO, which it expects to fund using its revolving warehouse facility.

Refer to the section, *Liquidity and Capital Resources* under the heading, *Financing Activities* for further details on the Trust's financing arrangements and OPG's public debt offering.

OEB's Report on Regulatory Treatment of Pension and OPEB Costs

On September 14, 2017, the OEB issued its final report on the guiding principles and policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the Ontario electricity and natural gas sectors. The report establishes the accrual basis of accounting as the method of determining pension and OPEB amounts for rate-setting purposes, unless the OEB finds that this method does not result in just and reasonable rates in the circumstances of a particular utility. The report also provides for the establishment of a generic variance account to record asymmetric carrying charges in favour of ratepayers on the differences between the accrual costs recovered and cash payments made by a utility in respect of pension and OPEB plans. Carrying charges on this differential are to be assessed at the OEB's prescribed interest rate, on a prospective basis from the effective date of the new variance account. For OPG, this differential will include amounts going back to November 1, 2014, with the charges calculated on the portion of the differential that has been recovered through regulated prices. None of this differential has been recovered to date. The prescribed interest rate is set quarterly by the OEB based on the quarterly return of a mid-term corporate bond index yield.

The OEB's September 2017 report and the OEB's December 2017 decision on OPG's application for new regulated prices require OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the Pension & OPEB Cash to Accrual Differential Deferral Account in effect since November 1, 2014, until such time as the OEB approves resumption of the accrual basis of recovery for OPG. The future recovery of amounts recorded in the account will be subject to this approval. The OEB's report did not impact OPG's financial results for the year ended December 31, 2017.

The Company recognizes the amount set aside in the Pension & OPEB Cash Versus Accrual Differential Deferral Account as a regulatory asset. As at December 31, 2017, the regulatory asset had a balance of $614 million. Consistent with the expectations set out in the OEB's December 2017 decision, in 2018, OPG plans to file an application with the OEB requesting disposition of the Pension & OPEB Cash Versus Accrual Differential Deferral Account balance as well as balances accumulated since December 31, 2015 in other regulatory accounts.

Shareholder Declarations and Shareholder Resolutions to Sell Certain Non-Core Real Estate Properties

In December 2015, OPG received a Shareholder Declaration and a Shareholder Resolution requiring the Company to sell its head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street in Toronto, Ontario. The sale was completed in April 2017, with a gain on sale of $283 million, which is net of tax effects of $95 million, recognized in net income in the second quarter of 2017. The pre-tax gain on sale was recorded

as an item of Other gains in the consolidated statement of income in the Services, Trading and Other Non-Generation segment. Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. The amount of designated proceeds transferred into the Consolidated Revenue Fund will be equal to the after-tax gain on sale. The transfer is expected to take place as early as in the first quarter of 2018, through a special dividend authorized by OPG's Board of Directors in March 2018. **[MONITOR]**

In June 2016, OPG received a Shareholder Declaration and a Shareholder Resolution that requires the Company to sell its former Lakeview GS site located in Mississauga, Ontario. OPG has entered into a purchase and sale agreement with a purchaser with the sale scheduled to close in March 2018. An estimated after-tax gain on sale of approximately $200 million is expected to be recognized in net income upon completion of the transaction in the first quarter of 2018. **[MONITOR]** Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. OPG anticipates the amount of designated proceeds transferred into the Consolidated Revenue Fund to approximate the after-tax gain on the sale. In accordance with the Shareholder Resolution, approximately one-third of the site is to be transferred to the City of Mississauga, by the purchaser, for parkland, institutional, and cultural uses.

CORE BUSINESS, STRATEGY, AND OUTLOOK

OPG's mission is to provide low cost power in a safe, clean, reliable and sustainable manner for the benefit of its customers and its Shareholder. OPG also seeks to pursue, on a commercial basis, generation development projects and other business expansion opportunities to the benefit of the Shareholder.

OPG's four key strategic imperatives are as follows:

- Operational Excellence
- Project Excellence
- Financial Strength
- Social Licence.

Operational Excellence

Operational excellence at OPG is accomplished by the safe and environmentally responsible generation of reliable and cost-effective electricity from the Company's generating assets through a highly trained and engaged workforce.

Workplace Safety and Public Safety

Workplace safety and public safety are fundamental core values at OPG. OPG is committed to operating all of its facilities in a safe, secure, and reliable manner that minimizes risks to a reasonably achievable level. Safety is an overriding priority in all activities performed at OPG's generating and other facilities, and all employees and contractors are expected to conduct themselves in manner that ensures workplace safety and public safety in line with the Company's safety culture.

In the area of workplace safety, OPG is committed to achieving excellent performance through continuous improvement and a strong safety culture, with the ultimate goal of zero injuries. OPG utilizes an integrated health and safety management system and a set of operational risk control procedures to ensure continued monitoring of health and safety performance and to support continuous learning and improvement in this area. Over the past five years, OPG has repeatedly stood in the top quartile of its comparator Canadian electrical utilities in various safety performance metrics.

Workplace safety performance is measured using two primary indicators at OPG, All Injury Rate (AIR) and Accident Severity Rate (ASR). OPG's AIR and ASR results for employee workplace safety were as follows for the year ended December 31:

	2017	2016
AIR *(injuries per 200,000 hours worked)*	**0.48**	0.56
ASR *(days lost per 200,000 hours)*	**3.57**	2.59

In 2017, OPG's AIR improved from 2016 and was the third-best performance year in the Company's history. For those employee injuries that caused lost time from work, the total time lost from work in 2017 was greater than the previous year. OPG's analysis of the underlying safety events indicated that major contributors to the injuries and near misses included inadequate situational awareness and attention to detail, and suboptimal risk-based decisions, rather than missing or inadequate standards or programs. OPG continues to implement a number of initiatives to target the injury trends based on the analysis of the safety events, with a focus on the use of human performance tools including increased field supervisory oversight, situational awareness, communication, and procedural use and adherence.

In order to strengthen its safety performance, OPG continues to progress an organization-wide "iCare Enough to Act" initiative launched in 2016 and aimed at renewing employees' commitment to their own and each other's safety and well-being. Approaches to supervisory oversight, communication and safe work planning are being modified and updated to further strengthen safety as a foundational element of the Company's values-based culture.

Contractors are required to conduct work safely at OPG sites. In support of this requirement, OPG utilizes an independent contractor pre-qualification process, provides on-site safety support for many of its major projects, and works with contract partners to improve their health and safety programs to meet OPG's requirements. In the past nine years, OPG has consistently shown a Construction Contractor AIR that is markedly better than the Infrastructure Health and Safety Association Contractor AIR, a metric of construction contractor safety performance across Ontario. OPG has maintained this performance while engaging in the refurbishment of the Darlington GS, one of the largest infrastructure projects in Canada. The hours worked by contractors in 2017 were the largest in OPG's history, largely attributable to this project.

OPG continues to maintain a strong focus on the nuclear safety program and to invest in nuclear safety systems. To ensure continued public safety, radiation exposure to members of the public resulting from the operation of OPG's nuclear generating stations is estimated on an annual basis for individuals living or working near the stations. The annual dose to the public resulting from operations of each nuclear facility is expressed in microsieverts (µSv), which is an international unit of radiation dose measurement. For 2016, the annual public doses resulting from the Darlington GS operations and the Pickering GS operations were 0.6 µSv and 1.5 µSv, respectively, which is less than 0.1 and 0.2 percent of the annual legal limit of 1,000 µSv, respectively. While the public doses from OPG's nuclear operations for the 2017 operating year will not be finalized until the second quarter of 2018, they are not expected to differ significantly from the 2016 levels.

In June 2016 and August 2016, the CNSC released sampling results from its independent environmental monitoring program, which confirmed that the public and the environment around OPG's nuclear generating stations continued to be safe. In September 2017, the CNSC issued an executive summary of its 2016 annual report on the safety performance of Canada's nuclear power plants, which gave both the Pickering GS and the Darlington GS the highest possible safety rating of "Fully Satisfactory". For further details, refer to the CNSC safety rating discussion in the section, *Highlights* under the heading, *Recent Developments*.

OPG remains committed to high standards of public safety on waterways around hydroelectric generating stations and dams, and continues to make investments in waterway and dam safety upgrades. The Company's practices in this area are routinely reviewed by an independent panel comprised of internationally recognized experts, who have

concluded that OPG's Dam Safety Program is industry leading in a number of areas. During 2017, OPG continued its water safety campaign with a series of public service announcements illustrating the danger of water near hydroelectric dams and hydroelectric generating stations.

Electricity Generation Production and Reliability

Key strategic initiatives in support of operational excellence, specific to each of OPG's core generating operations, are discussed below. Generation and reliability performance for 2017 is discussed by operating segment in the section, *Discussion of Operating Results by Business Segment*.

Nuclear Operations

OPG is pursuing a number of strategic initiatives aimed at the continued safe and reliable operation of the Pickering GS and targeting top performance at the Darlington GS.

OPG's objective is to maximize the safe and reliable operating life of the Pickering units. As announced in 2016 and approved by the Province, OPG is continuing to execute on a plan to extend safe and reliable operation of the Pickering GS to 2024. In addition to providing Ontario with a clean, reliable source of baseload electricity during nuclear unit refurbishments at the Darlington GS and the Bruce nuclear generating stations, extending operations at the Pickering GS will provide continued employment for up to 4,000 full-time employees at OPG and help to reduce approximately 17 million tonnes of carbon dioxide emissions, which is equivalent to removing approximately 3.4 million cars from Ontario's roads.

As part of the plan to extend Pickering operations, OPG has been continuing to undertake the required technical work to confirm that the station's pressure tubes, a key life-limiting component of the station, will remain fit for service for operation to 2024. In the fourth quarter of 2017, OPG has confirmed that technical assessments completed to date provide sufficient confidence in the programs and provisions in place to assure fitness-for-service of fuel channel components in line with the planned extended operations period. This evaluation is consistent with the safety case reflected in OPG's operating licence renewal application for the Pickering GS submitted to the CNSC in 2017, discussed below. Taking these factors into account, OPG revised the accounting end-of-life assumptions for the Pickering GS from December 31, 2020 for all units to December 31, 2022 for Units 1 and 4 and December 31, 2024 for Units 5 to 8, effective December 31, 2017.

The change in the Pickering GS accounting end-of-life assumptions did not impact OPG's net income in 2017. The change is expected to decrease depreciation expense by $77 million in 2018, including the associated impact on the nuclear asset retirement obligation (ARO) recorded as of December 31, 2017 but before the impact of regulatory accounts. Regulatory accounts, including a new deferral account proposed by OPG in a December 2017 application to the OEB, are expected to largely offset the decrease in depreciation expense. The change in the nuclear ARO recorded in the fourth quarter of 2017 is discussed in the section, *Critical Accounting Policies and Estimates* under the heading, *Asset Retirement Obligation*. On December 29, 2017, OPG applied for an accounting order to establish a variance account to record, from January 1, 2018 until the effective date of the OEB's next payment amounts order, the revenue requirement impact of changes to nuclear liabilities and depreciation and amortization expense resulting from changes to station end-of-life dates for OPG's Pickering prescribed nuclear facilities that will be effective December 31, 2017. Pending the OEB's review of the application, an interim order was issued January 31, 2018 establishing the proposed variance account effective January 1, 2018. The OEB's final decision for the account is expected later in 2018.

OPG's current five-year operating licence for the Pickering GS was approved by the CNSC in 2013 and expires on August 31, 2018. This current licence was issued assuming that the station would shut down in 2020. On June 28, 2017, OPG confirmed to the CNSC that it intends to cease commercial operation of all Pickering units on December 31, 2024. On August 28, 2017, OPG submitted a ten-year licence renewal application to the CNSC. The requested licence term spans the planned extended commercial operations period, through to the planned period of de-fuelling,

de-watering and beginning to place the station in a safe storage state in 2028. In support of the licence renewal, OPG undertook a Periodic Safety Review (PSR), a comprehensive assessment of the station's design and operation to confirm that there is a high level of safety throughout the operating life and to determine what reasonable and practical enhancements can be made to further improve safety. The PSR also includes a component condition assessment of the station to identify the work required to support the station's continued operation. The PSR has confirmed that extending operations of the Pickering units will continue to pose minimal risk to the health, safety and security of workers, the public and the environment. The final major component of the PSR was submitted to the CNSC in November 2017. The CNSC's review of the PSR submission and licence application is in progress. Based on the evidence and documentation submitted to the CNSC, OPG is confident in obtaining a licence renewal that would support its extended operations plan for Pickering GS.

OPG's nuclear operations are regularly benchmarked against top performing nuclear facilities around the world. This allows OPG to identify, develop and implement initiatives to further improve performance. In September 2016, OPG hosted a team of experts from the International Atomic Energy Agency (IAEA) at the Pickering GS to conduct a standard Operational Safety Review Team mission. The team conducted an in-depth review of performance and adherence to international safety standards. In the second quarter of 2017, the IAEA's Operational Safety Review Team released the final report and confirmed that the Pickering GS demonstrates strong commitment to safety. In December 2017, OPG hosted a World Association of Nuclear Operators (WANO) peer evaluation for the Pickering GS, which focused on the safe and reliable operation of the station while evaluating the plant material condition, functional and cross-functional areas of the organization. Pickering showed significant improvement since its last review and has sustained its strong rating in 2018, resulting in its best ever WANO peer review.

OPG remains focused on improving reliability and increasing electricity generation output from its nuclear fleet. This includes improving equipment reliability, optimizing outages, implementing integrated asset management planning and enhancing maintenance programs. Improved equipment reliability generally results in fewer generation interruptions. Nuclear inspection and testing programs are largely driven by maintenance and regulatory requirements, and are designed to ensure that equipment is performing safely and reliably. Execution of this and other outage work continues to be a high priority. As part of its commitment to operational excellence, OPG continues to focus on improving the planning, execution, monitoring, and reporting of outage work.

OPG continues to make investments in the performance of the Pickering GS, with a focus on improving plant reliability and maximizing the value of the asset over its remaining life through implementing equipment modifications and fuel handling reliability improvements, reducing equipment maintenance backlogs, and completing critical and high priority work. OPG also continues to make investments in the Darlington GS necessary to sustain safe and reliable operations for the next three decades and aimed at positioning the station for industry-leading operating and cost performance in the longer term. This includes investments in life cycle and aging management projects, facility upgrades as well as work in support of regulatory commitments.

Delivering solutions that provide the best combination of safety, cost and effectiveness, as well as establishing challenging financial targets based on comprehensive benchmarking and taking into account the operating environment of the nuclear stations, continues to be a vital part of OPG's strategy to improve performance of the nuclear business unit. Financial and staffing targets continue to be reviewed and adjusted where necessary to reduce operating costs, while ensuring safety and reliability are not compromised.

In 2016, OPG submitted applications with the CNSC seeking a ten-year licence renewal for the Western Waste Management Facility (WWMF), located at the Bruce generating stations' site, to May 31, 2027, and a ten-year licence renewal for the Pickering Waste Management Facility (PWMF) to August 31, 2028. The licence renewal applications were presented to the CNSC at public hearings in April 2017. On May 30, 2017, the CNSC announced that the WWMF licence was renewed for a ten-year period and will be valid until May 31, 2027. On February 7, 2018, the CNSC announced that the PWMF licence was renewed for a ten-year period and will be valid until August 31, 2028.

In 2017, the CNSC approved regulatory document *REGDOC 2.2.4 – Fitness for Duty – Managing Alcohol and Drug Use* for use at Canadian nuclear power plants. This document sets out requirements for managing fitness for duty of workers in relation to alcohol and drug use at high-security sites, including for-cause alcohol and drug testing for workers in positions identified as safety-sensitive or safety-critical and random alcohol and drug testing for workers holding safety-critical positions. OPG intends to enhance its existing Fitness for Duty program to comply with these new requirements. OPG is working with its partners in the Canadian nuclear industry to develop a program suitable for Canada and its workers.

Hydroelectric Operations

The objectives of OPG's hydroelectric operations include operating and maintaining the generating facilities in a safe, efficient and cost-effective manner, while increasing the output from the facilities and pursuing opportunities to increase capacity. OPG aims to increase the facilities' output by improving operational flexibility, enhancing reliability, optimizing outage planning and, subject to water conditions, increasing availability to meet electricity system demand. OPG continues to evaluate and implement plans to increase capacity, maintain and improve operational performance, and extend the operating life of its hydroelectric generating assets.

OPG's hydroelectric operations are regularly benchmarked against peer utilities in North America. Based on 2016 data, 19 of the OPG's 25 large regulated hydroelectric facilities benchmarked in the top two quartiles for unit energy costs. This group of 19 facilities represents 94 percent of the energy delivered from the regulated hydroelectric fleet. Similarly, 18 of 25 large regulated hydroelectric facilities benchmarked in the top two quartiles for availability based on 2016 data. OPG continues to pursue innovation and technology-based improvements in its asset management and equipment maintenance strategies in order to increase reliability and further reduce costs of the hydroelectric fleet.

As part of OPG's ongoing strategy to reduce costs and increase operational efficiency, the operations of the Company's hydroelectric and thermal assets were previously combined into one organization, with five regional operations groups. In 2017, OPG reduced the number of regional operations groups to four, by integrating the Central Operations work centres into three of the other existing regional operations groups. In addition, during the third quarter of 2017, OPG opened an amalgamated control room located at the Saunders hydroelectric GS, combining the Chenaux and Saunders control rooms. The amalgamated control room will control all operational activities at the ten hydroelectric stations along the Madawaska, Ottawa and St. Lawrence rivers.

OPG's plans for its existing hydroelectric generating stations are accomplished through multi-year capital investment and other programs, including replacements and upgrades of turbine runners, and refurbishment or replacement of existing generators, transformers, and controls. The aim of OPG's runner replacement and upgrade program is to increase hydroelectric station capacity by leveraging efficiency enhancements in runner design. Where economical and practical, OPG also pursues opportunities to refurbish, expand or redevelop its existing hydroelectric stations. Over the next four years, OPG plans to increase the total capacity of its hydroelectric generating fleet by approximately 150 MW, which, in addition to the runner replacement and upgrade program, includes the Ranney Falls GS and Sir Adam Beck frequency conversion projects. OPG is also planning to repair, rehabilitate, or replace a number of aging civil hydroelectric structures.

As part of its commitment to operational excellence, OPG continues to make investments in its existing hydroelectric generating fleet. During 2017, OPG continued to execute a number of projects, including:

- Completion of the overhaul and upgrade of Unit 10 of the Sir Adam Beck 1 GS, which increased the station's capacity by 6 MW
- Continued work on the overhaul and rehabilitation of Unit 1 of the Sir Adam Beck Pump GS to ensure reliable unit operation for approximately the next 20 years
- Completion of the replacement of the Shebandowan Lake Control Dam at the Kakabeka Falls GS, which will maintain structural integrity and enhance dam safety for another 100 years

- Continued work on the overhaul and upgrade of Unit 1 of the Harmon GS with completion of the turbine upgrade, generator rehabilitation and upgrade of protection and control systems
- Continued work on the overhaul and upgrade of Unit 2 of the DeCew Falls GS, with turbine and generator rehabilitation and upgrade of protection and control systems completed during the year, and, in the fourth quarter of 2017, commencement of the overhaul and upgrade of Unit 2 of the Little Long GS
- Continued work on the overhaul and rehabilitation of Unit 2 of the Lower Notch GS, with generator rehabilitation completed during the year, and in the fourth quarter of 2017, commencement of the overhaul and rehabilitation of Unit 6 of the Sir Adam Beck Pump GS
- Commencement of definition phase work for the Water Conveyance System project to rehabilitate the Sir Adam Beck 1 GS canal and associated structures, ensuring their continued safe and reliable operations for approximately the next 50 years.

In 2018, OPG plans to commence execution of several major sustaining projects across the hydroelectric fleet, including the overhaul and upgrade of Unit 5 of the Sir Adam Beck 1 GS, the rehabilitation of Caribou Falls Block Dam No.2, and automatic sluicegates system replacement at the Whitedog Falls GS. Definition phase activities on several other major projects are also expected to commence in 2018, including frequency conversion of Units 1 and 2 of the Sir Adam Beck 1 GS and the overhaul and upgrade of the R.H. Saunders GS units.

Thermal Operations

OPG's thermal operations consist of biomass-fuelled generating units at each of Atikokan GS and Thunder Bay GS, and the oil/gas dual-fuelled Lennox GS.

These stations, which operate as peaking facilities under their respective energy supply requirements, provide Ontario's electricity system with the flexibility to meet changing daily system demand and capacity requirements and enable the system to accommodate the expansion of Ontario's renewable generation portfolio. The continued operation of these stations will continue to provide Ontario with over 2,000 MW of peaking generation capacity. The stations operate under their respective ESAs.

OPG's biomass-fuelled generating units are among the world's leading in their innovation. The Atikokan GS is the largest generating station in North America fuelled by 100 percent biomass, while the Thunder Bay GS unit uses advanced biomass that is thermally treated to allow it to be stored outdoors and withstand exposure to the weather.

Former thermal stations that are no longer available to generate electricity are included in the Services, Trading, and Other Non-Generation segment once they are removed from service. This includes the Lambton GS and Nanticoke GS sites, which ceased operations in 2013. Over 2015 and 2016, OPG announced that these stations would be decommissioned safely, securely and in an environmentally responsible manner. The costs of the decommissioning are charged to a previously established decommissioning provision.

During 2017, OPG substantially completed the demolition of the Nanticoke coal yard equipment and structures and issued a contract for the demolition of the Nanticoke powerhouse and associated structures. In the fourth quarter of 2017, the demolition contractor had been mobilized to prepare for the removal of the powerhouse and associated structures and initiated the preparatory work for the demolition of the stacks. The demolition of the stacks took place in February 2018. **[MONITOR]** A competitive bidding process for the demolition of the Lambton GS is in progress, with a contract for the removal of the powerhouse and associated structures expected to be issued during 2018. The decommissioning plan for the Nanticoke GS accommodates the construction and operation of the Nanticoke solar facility.

An update of the asset retirement obligations related to the Nanticoke and Lambton sites has been completed. For a discussion of the revaluation of this liability for non-nuclear fixed asset removal as at December 31, 2017, refer to the section, *Critical Accounting Policies and Estimates* under the heading, *Asset Retirement Obligations*.

Environmental Performance

OPG's Environmental Policy states that "OPG shall meet compliance obligations, including any environmental commitments that it makes, with the objective of exceeding these compliance obligations where it makes business sense". This policy commits OPG to:

- maintain an ISO 14001-registered environmental management system (EMS)
- work to prevent or mitigate adverse impacts on the environment with a long-term objective of continual improvement
- strive to be a leader in climate change mitigation
- manage sites in a manner that strives to maintain, or enhance where it makes business sense, significant natural areas and associated species of concern.

In 2017, OPG maintained the ISO 14001 registration of its company-wide EMS. Within the EMS, OPG has planning, operational control, and monitoring programs to manage the Company's positive and negative impacts on the environment. Significant environmental aspects of OPG's operations include: spills, chemical and thermal emissions to water, water flow and level changes, radiological emissions, low and intermediate level radioactive waste (L&ILW), enhancement and disruption of wildlife habitat, displacement of fossil fuels, and fish impingement and entrainment. Further details regarding OPG's environmental risks can be found in the section, *Risk Management* under the heading, *Environmental Risk*.

Environmental performance targets are set as part of the annual business planning process. These targets are based on past performance and external benchmarking to promote continual improvement. OPG met or outperformed its 2017 targets for spills, environmental infractions, carbon-14 emissions to air, and L&ILW. Targets for tritium emissions to air and water were not achieved due to equipment performance issues; however, emissions remained less than one percent of the regulatory limit. There were no significant environmental events during 2017.

In 2016, the Government of Ontario passed the *Climate Change Mitigation and Low-Carbon Economy Act, 2016* and the associated *Cap and Trade Program Regulation*. The legislation provides the foundation for regulating greenhouse gas (GHG) emissions in Ontario and establishes a cap and trade program, with the first compliance period being from January 1, 2017 to December 31, 2020.

The cap and trade program is a market mechanism intended to give Ontarians an incentive to reduce GHG emissions by putting a price on carbon. OPG has an internal program to meet its GHG emissions compliance obligations. With OPG's low GHG emitting fleet, these obligations are not expected to have a material financial impact on the Company.

OPG monitors actions being taken by the Government of Ontario and the Government of Canada to reduce GHG emission levels and transition to a low-carbon economy. In support of efforts to mitigate climate change, the Company continues to evaluate and implement plans to increase the generation capacity of its hydroelectric generating fleet, where economical, invest in other low-carbon technologies, and take a leadership role in the electrification of Ontario's transportation sector.

OPG has developed biodiversity management plans that identify priority natural areas, conservation goals, threats, and proposed actions to sustain biodiversity at its properties. To maximize benefits and manage impacts, initiatives include biodiversity monitoring, site naturalization, habitat creation, and control of invasive species.

OPG works with community partners to support regional ecosystems and biodiversity across Ontario. In 2017, OPG continued efforts to protect and restore habitat, promote biodiversity education and awareness, and help the recovery of species at risk. In November 2017, OPG's biodiversity program was recognized by the Canadian Electricity Association with the 2017 Sustainable Electricity award for Commitment to Continuous Performance Improvement.

OPG communicates its environmental performance internally to employees and to external stakeholders, including the Ontario Ministry of the Environment and Climate Change (MOECC), Environment and Climate Change Canada, the CNSC, and local communities. Details of OPG's environmental performance and initiatives to fulfill the Company's Environmental Policy can be found in OPG's 2016 Sustainability Report, available on the Company's website at www.opg.com.

Improving Efficiency and Reducing Costs

As part of its commitment to operational excellence, OPG remains strongly focused on reducing costs by pursuing sustainable efficiency and productivity improvements across operating business units and support functions, while ensuring that there is no adverse impact on the safety, reliability and environmental sustainability of the Company's operations. Building on significant efficiency achieved since 2011 under a more scalable, centre-led organizational model, this includes streamlining of processes, simplifying governance, upgrading technology, optimizing service delivery models, and continuing to leverage attrition to achieve human resource targets aligned with business requirements. Strategies to improve cost performance and organizational capability are being implemented at the enterprise and business unit level. These strategies are supported by continuing to embed an outcomes-driven culture that reinforces cost effectiveness, efficiency and organizational agility as part of business decision-making.

OPG is proceeding with an enterprise-wide process to evaluate the impact of the eventual shutdown of the Pickering GS on the Company's operating cost structure. This multi-year initiative, known as OPG25, involves identifying and implementing a coordinated set of plans and targets to ensure the optimization of the Company's longer-term operating model, business strategies and organizational design between now and the planned end of Pickering commercial operations. The overall aim of the initiative is to ensure ongoing cost effectiveness of the Company's operations after the eventual shutdown of the Pickering GS and to mitigate the cost impacts associated with the shutdown. Through this work and a continued focus on productivity enhancements, OPG expects to deliver increased value to customers and achieve improvement in outcomes of future applications for regulated prices under the OEB's incentive regulation framework.

In 2017, OPG also launched a strategy to accelerate the pace of digital transformation across the enterprise. The strategy is focused on making investments to modernize information technology infrastructure, enhance mobility, connectivity and field and office productivity, and improve equipment reliability and station performance through data management and data analysis. The strategy will increase operational efficiency, reduce operating costs and help to enable optimization initiatives in support of OPG25.

People and Culture

A well trained and engaged workforce is fundamental to the achievement of OPG's strategic imperatives. To succeed in a demanding business environment, OPG is focused on building a diverse, healthy, engaged workforce and fostering a culture of collaboration, accountability and innovation. OPG also continues to communicate and implement the values and behaviours expected from its employees in order to maintain a strong focus on safety, performance excellence, continuous improvement, and corporate citizenship.

The Company continues to focus on improving the capability of its workforce through leadership development, knowledge management, diversity and inclusion programs, and hiring in critical areas. Ability to secure the right talent mix in order to effectively meet the Company's immediate and longer term business needs on a timely basis is supported through workforce planning, resourcing and on-boarding strategies, both to acquire external talent into the organization and to develop existing employees. The goal of workforce planning and resourcing strategies is to ensure that the Company has a diverse workforce with the right skill set and capability for the safe and effective operation of the generating facilities and successful delivery of major projects, including the Darlington Refurbishment. These strategies take into account changes in anticipated staffing requirements leading up and subsequent to the end of planned commercial operations of the Pickering GS and the period to de-fuel, de-water and

place the station in a safe state condition after shutdown. The end of commercial operations at the Pickering GS is expected to lead to a significant reduction in OPG's workforce.

As part of the strategy to develop and engage employees and to build leadership talent in support of the Company's long-term success, OPG has an active succession planning program with a focus on accelerating development. This includes a company-wide high-potential leadership development program for qualified internal candidates. This 14-month cross-functional, competitive-entry program is designed to identify and develop candidates for future leadership positions while they are relatively early in their careers. OPG also has a talent management monitoring process to proactively assess staffing risks, challenges and opportunities.

Electricity generation involves complex technologies that require highly skilled and trained workers. Many positions at OPG have significant educational prerequisites and rigorous requirements for continuous training and periodic requalification. In addition to maintaining its internal training infrastructure, OPG relies on partnerships with government agencies, other electrical industry partners and educational institutions to meet the required level of qualification. Training delivery models are evaluated for effectiveness and efficiency.

Effective January 1, 2017, OPG implemented an Executive Compensation Program that is compliant with *Ontario Regulation 304/16: Executive Compensation Framework*, introduced in September 2016. While the Province released two subsequent amendments, *Ontario Regulation 187/17* and *Ontario Regulation 400/17* in June 2017 and November 2017, respectively, OPG's Executive Compensation Program continues to be subject to the original regulation's requirements. The regulation sets out how all employers designated under the *Broader Public Sector Executive Compensation Act, 2014*, including OPG, must establish and post compensation programs for executives. The program must include the compensation philosophy, salary and performance-related pay caps, comparative analysis details, and a description of other elements of compensation. OPG's Executive Compensation Program, which applies to employees at the Vice President level and higher, is designed to provide compensation that is at the 50th percentile of the market and focused on at-risk, performance based pay. The program will better enable OPG to attract, align and retain the executive talent critical to delivering Shareholder and customer value, while ensuring continued safe and reliable operations.

Project Excellence

OPG is pursuing a number of generation development and other major projects in support of Ontario's electricity planning initiatives. OPG also continues to plan and execute maintenance and capital improvement projects related to its existing assets. OPG strives for excellence in the planning and delivery of all projects across the Company.

OPG's vision for project excellence is to be an industry leader in project management capability and performance. As part of its commitment to project excellence, OPG continues to enhance and streamline its approach to project planning and execution, with the goal of delivering all projects safely, on time, on budget, and with high quality. Achieving project excellence at OPG involves, among other things, implementing a common, scalable project delivery model across all business units, establishing qualified project management teams, optimizing contracting strategies, engaging qualified and experienced vendors, and effectively monitoring and controlling performance.

The status updates for OPG's major projects as of December 31, 2017 are outlined below.

Project	Capital expenditures		Approved budget	Expected in-service date	Current status
(millions of dollars)	Year-to-date	Life-to-date			
Darlington Refurbishment	1,249	4,434	12,800 [1]	First unit - 2020 Last unit - 2026	All Unit 2 feeder tubes were removed safety in the fourth quarter of 2017 and the removal of fuel channel assemblies is in progress. Construction activities on the HWSF have recommenced in the fourth quarter. Planning and procurement activities for the refurbishment of Unit 3 are continuing. The overall project is tracking on schedule and on budget.
Peter Sutherland Sr. Hydroelectric GS	41	277	300	2017	The station was placed in-service on March 31, 2017, ahead of the originally planned schedule, and is expected to close below the approved budget. Project close-out activities are in progress.
Sir Adam Beck Pump GS Reservoir Refurbishment	3	49	58	2017	The refurbishment was completed and the reservoir was returned to service in February 2017, ahead of the originally planned in-service date and below the approved budget.
Ranney Falls Hydroelectric GS	25	28	77	2019	Excavation has been completed and construction is continuing in the expanded forebay, powerhouse and spillway area. Concrete placement of the new powerhouse and the spillway integrated structure is in progress. The project is tracking on schedule and on budget.
Nanticoke Solar Facility	2	3	107	2019	Significant contracts for equipment and engineering construction services have been executed, with construction planned to commence in the first quarter of 2018. **[MONITOR]**
Deep Geologic Repository (DGR) for L&ILW	9 [2]	204 [2]			On August 21, 2017, the federal Minister of Environment and Climate Change requested further information related to the project's environmental assessment (EA). OPG is working on a response to this information request.

[1] The total project budget of $12.8 billion is for the refurbishment of all four units at the Darlington GS.
[2] Expenditures are charged against the Nuclear Liabilities.

Darlington Refurbishment

The Darlington generating units are approaching their originally designed end-of-life. Refurbishment of the four generating units is expected to extend the operating life of the station by approximately 30 years. The approved budget for the four-unit refurbishment is $12.8 billion, which includes the costs of the pre-requisite projects in support of the execution phase of the refurbishment. The first refurbished unit is scheduled to be returned to service in the first quarter of 2020 and the last unit is scheduled to be completed by 2026. The project continues to track on schedule.

The Darlington Refurbishment project is a multi-phase program comprising the following five major sub-projects:

- **Retube and Feeder Replacement**, which includes the removal and replacement of fuel channel assemblies and feeder tubes in each reactor
- **Turbines and Generators**, which consists of inspections and repairs of turbine generator sets and the replacement of analog control systems with digital control systems
- **De-fuelling and Fuel Handling**, which involves the de-fuelling of the reactors and the refurbishment of the fuel handling equipment
- **Steam Generators**, which includes mechanical cleaning, water lancing, and inspection and maintenance work on the generators
- **Balance of Plant**, which consists of work on smaller projects to replace or repair certain other station components.

In 2016, the Darlington Refurbishment project transitioned from the planning phase to the execution phase, as OPG commenced the refurbishment of the first unit, Unit 2, in October 2016 as planned. The unit was taken offline on October 15, 2016. De-fuelling of the reactor was completed in January 2017, with a total of 480 fuel channels de-fuelled. Islanding of Unit 2, the physical separation of the unit under refurbishment from the three operating units, was completed in April 2017, signifying the completion of the first major segment of the project.

The second major segment includes preparatory work to support the removal of feeder tubes and fuel channel assemblies, followed by the removal of reactor components. The preparatory work was completed in the second quarter of 2017. The Re-tube Tooling Platform for hosting the tooling for the removal, inspection and installation activities, and the setup of specialized tooling and equipment needed for the removal and replacement of the reactor components were completed in the third quarter of 2017. The disassembly of reactor components commenced in August 2017, with the removal of all 960 feeder tubes completed safely in September 2017. The removal of fuel channel assemblies commenced in October 2017. As part of the fuel channel assemblies, the removal of pressure tubes is in progress and will be followed by the removal of calandria tubes. The second major segment and the removal of all reactor components is expected to be completed by mid-2018. Key projects in the second major segment finished in 2018 include the completion of the primary side steam generator layup and installation of steam generator access ports to support future inspections. Other key project activities being executed during the second segment include the continuation of the major turbine generator overhaul, which will be completed in the second quarter of 2018, and continued execution of the major electrical scope. OPG is also continuing to execute work to support the requirements set out in the CNSC-approved Integrated Implementation Plan for the station.

Most of the pre-requisite projects, including construction of facilities, infrastructure upgrades and installation of safety enhancements, have been completed and placed in-service. The Re-tube Waste Processing Building was completed in November 2017. Completion of the HWSF has been delayed due to challenges with construction. OPG suspended the project in the second quarter of 2017 to evaluate the best approach to optimize cost and schedule and complete the project. Construction to complete the facility recommenced in the fourth quarter of 2017. The HWSF is expected to be completed by the second quarter of 2019 and is not on the critical path for the Darlington Refurbishment project, which continues to track on schedule. The increase in the cost estimate for the HWSF will be accommodated within the overall Darlington Refurbishment budget of $12.8 billion. Taking into account the execution performance of the Unit 2 refurbishment, the overall Darlington Refurbishment project continues to track on budget.

In addition to the execution of refurbishment activities on Unit 2, OPG is continuing planning activities for the refurbishment of the second unit, Unit 3, and is entering into associated commitments to procure major components that require long lead times. As of December 31, 2017, $93 million has been invested in planning activities related to the refurbishment of the second unit, Unit 3. These planning activities are being undertaken in accordance with the refurbishment project schedule. In February 2018, the Province confirmed its commitment to proceed with Darlington's Unit 3 refurbishment in 2020. **[MONITOR]**

Peter Sutherland Sr. Hydroelectric GS

In March 2017, the project to construct the 28 MW two-unit Peter Sutherland Sr. hydroelectric GS successfully completed final testing and commissioning of the turbine and generator units, and both units were declared substantially complete. On March 31, 2017, the project received a permit from the MOECC to take water for operations to allow the station to operate commercially. This in-service date was well ahead of the originally planned schedule of the first half of 2018. The project's schedule was accelerated to take advantage of favourable weather conditions. The project is expected to close below the approved budget of $300 million. Project close-out activities are in progress. OPG began to receive contracted revenue for the project following the IESO's confirmation of the station's commercial operations as of March 31, 2017, under a hydroelectric ESA.

Under the partnership agreement, as the unit is placed in-service, the CRP, a corporation wholly owned by the Taykwa Tagamou Nation, may acquire up to a 33 percent partnership interest through its investment in PSS. In April 2017, the CRP acquired a 33 percent interest in PSS.

Sir Adam Beck Pump GS Reservoir Refurbishment

The Sir Adam Beck Pump GS refurbishment construction began in April 2016 and the 300-hectare reservoir was returned to service in February 2017 upon completion of the reservoir commissioning program. The Sir Adam Beck Pump GS facility allows OPG to pump and store water diverted from the Sir Adam Beck generating complex during periods of low electricity demand, to be used to generate up to 600 MW of electricity during subsequent periods of high electricity demand. The work on the project included installation of a new partial liner and construction of a grout curtain in the bedrock foundation of the reservoir dyke. The refurbishment is expected to add approximately 50 more years to the reservoir's life. The project was completed ahead of the originally planned in-service date of April 2017 and below the approved budget of $58 million. The Sir Adam Beck Pump GS is reported in the Regulated – Hydroelectric segment.

Ranney Falls Hydroelectric GS

In 2017, OPG began construction work on a 10 MW single-unit powerhouse on the existing Ranney Falls GS site, as part of the Regulated – Hydroelectric segment. The new unit will replace an existing unit that reached its end of life in 2014. The existing forebay structure has been demolished and the new concrete structure has been completed. Excavation has been completed and construction continues in the expanded forebay, powerhouse and spillway area. The new forebay concrete wall has been completed, and concrete placement of the new powerhouse and the spillway integrated structure is in progress. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget.

Nanticoke Solar Facility

The construction of a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands under a Large Renewable Procurement contract with the IESO, through Nanticoke Solar LP, a partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation, is planned to commence in the first quarter of 2018. During 2017, the partnership continued work to obtain approvals and permits required to enable the commencement of construction. Significant contracts for equipment and engineering construction services were executed in the first quarter of 2018. The facility is expected to be completed in the first quarter of 2019, with a budget of $107 million. **[MONITOR]**

Deep Geologic Repository for Low and Intermediate Level Waste

OPG has proposed a deep geologic repository as the preferred solution for the safe long-term management of the L&ILW produced from the continued operation of OPG-owned nuclear generating stations. Agreement has been reached with local municipalities for OPG to develop the L&ILW DGR on lands adjacent to the WWMF in Kincardine, Ontario. The environmental effects of the proposed L&ILW DGR were examined by the CNSC and Canadian Environmental Assessment Agency (CEAA)-appointed Joint Review Panel (JRP) to meet the requirements of the *Canadian Environmental Assessment Act*. The JRP submitted its report on the EA to the federal Minister of Environment in May 2015, concluding that, given mitigation, there is unlikely to be significant environmental impact from the project and recommending that the Minister approve the EA. In December 2016, at the request of the federal Minister of Environment and Climate Change, OPG submitted additional information on certain aspects of the EA, including information related to alternate locations for the project. Following its review of OPG's submission and a period of public comment, the CEAA requested further information that OPG subsequently provided in May 2017. In June 2017, the CEAA notified OPG that it had sufficient and adequate information to proceed with the next step of the environmental assessment process and advised that a draft report and updated terms and conditions would be prepared for public review.

On August 21, 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of potential cumulative effects of the project on the Saugeen Ojibway Nation's (SON) physical and cultural heritage, including a description of the potential effects of the project on the Nation's spiritual and cultural connection to the land, taking into account the results of the SON Community Process. OPG is working closely with the SON to formulate a response to the information request.

The L&ILW DGR at the WWMF site remains OPG's preferred solution for the safe long-term management of the L&ILW. The in-service date of the L&ILW DGR is expected to be approximately six to seven years from the start of construction.

Financial Strength

As a commercial enterprise, OPG's financial priority is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future expansion. Inherent in this priority are four objectives:

- Increasing revenue, reducing costs and achieving appropriate return
- Ensuring availability of cost effective funding for operational needs, generation development projects and other business opportunities, and long-term obligations
- Pursuing opportunities to expand the existing core business and capitalize on new growth paths
- Managing risks, which is discussed in the section, *Risk Management*.

Increasing Revenue, Reducing Costs and Achieving Appropriate Return

In line with its commercial mandate, OPG is focused on increasing revenue and net income and achieving an appropriate rate of return on the Shareholder's investment, while taking into account the impact on Ontario electricity customers by seeking further efficiencies in the Company's cost structure.

For the regulated operations, achievement of the above objectives is largely dependent on outcomes of rate applications to the OEB and growth of the asset base earning a return as part of the regulated prices.

With respect to rate application outcomes, OPG has been focused on demonstrating in its rate applications that the costs required to operate and invest in the assets are reasonable and being prudently incurred, and should be fully recovered, and that the Shareholder's investment in these assets should earn an appropriate rate of return. While the OEB's decision on OPG's 2017-2021 application for new regulated prices reduced OPG's forecasted costs used to set new regulated prices, the decision will result in a substantial increase in revenue and net income compared to

existing regulated prices. The existing base regulated prices were set in 2014 to allow the Company to recover its approved nuclear costs over a higher nuclear production volume, based on the 2014 and 2015 outage profile that did not include a Darlington refurbishment outage.

The OEB's decision to reduce recovery of OPG's forecasted cost levels, including through the use of stretch factors under an incentive rate-making model, will negatively impact OPG's ability to earn an appropriate return on the Shareholder's investment in the regulated assets. To improve the financial strength of the regulated operations, OPG will continue to focus on optimizing operational performance and outage plans across the generating fleet and on pursuing further efficiency improvements in the Company's cost structure and operating model. OPG's cost and productivity improvement strategies are discussed further in the section, *Core Business, Strategy and Outlook* under the heading, *Operational Excellence – Improving Efficiency and Reducing Costs*.

OPG continues to invest in the regulated asset base, with the Darlington Refurbishment project being the single largest such capital investment. In its decision on OPG's 2017-2021 application for new regulated prices, the OEB has allowed inclusion of a total of $5.5 billion in Darlington Refurbishment in-service capital additions by 2021, including pre-requisite projects other than HWSF and including in-service amounts upon planned return to service of Unit 2 in the first quarter of 2020. Once in-service, these assets will attract a return on equity of approximately 8.8 percent during the 2017-2021 period set by the OEB, based on a deemed capital structure of 45 percent equity and 51 percent debt. The average OEB-approved cost of deemed debt for the 2017-2021 period is approximately 4.6 percent. OPG also continues to pursue an extensive capital program across its regulated hydroelectric operations that includes expansion, redevelopment and life extension of the generating facilities, where economic. These renewable assets have long service lives and, with either maintenance efforts or rebuilding, will continue to supply electricity for the foreseeable future. The OEB's decision on OPG's application for new regulated prices is discussed further in the section, *Highlights* under the heading, *Recent Developments*.

For generation assets that do not form part of the assets regulated by the OEB, OPG's strategy has been to secure appropriate long-term revenue arrangements. In line with this strategy, virtually all of OPG's non-regulated operating facilities and assets under construction are subject to long-term ESAs or other long-term contracts with the IESO. This includes the Peter Sutherland Sr. GS, which was placed in service and began receiving contracted revenue under a hydroelectric ESA as of March 31, 2017. The Peter Sutherland Sr. GS ESA expires in 2067.

OPG's capital structure currently reflects lower levels of debt than the deemed capital structure reflected in the Company's existing regulated prices and maintained by the OEB's December 2017 decision on new regulated prices. OPG continues to evaluate strategies to enhance Shareholder returns by optimizing the Company's capital structure through better alignment with the deemed capital structure, taking into account the overall financial strength of the Company and the potential impact on the Company's investment grade credit rating.

Ensuring Availability of Cost Effective Funding

OPG actively monitors its funding requirements and forecasts availability of funds to ensure that it can meet the Company's operational needs, project commitments and long-term obligations. OPG utilizes multiple sources of funds, including funds generated from operations, commercial paper, securitization of assets, letters of credit, credit facilities, long-term corporate debt (sourced from both the OEFC and public debt offerings), credit facilities with the OEFC, private placement project financing, and equity issuance. The Company's financing strategy leverages the strength of its balance sheet to obtain cost effective long-term corporate debt. OPG also accesses the capital markets for private placement project financing, secured by the assets of the project, where the characteristics of the project support such financing. Maintaining an investment grade credit rating is critical to OPG's ability to access cost effective financing.

In April 2017, DBRS Limited (DBRS) re-affirmed the long-term credit rating on OPG's debt at 'A (low)' and OPG's commercial paper rating at 'R-1 (low)'. All ratings from DBRS have a stable outlook. In July 2017, S&P Global

Ratings (S&P) re-affirmed OPG's long-term credit rating at 'BBB+' with a stable outlook. S&P's commercial paper rating for OPG is 'A-1 (low)'.

OPG intends to continue to access the capital markets, where appropriate, to obtain cost effective financing for future generation development projects. The Company continues to evaluate arrangements that would appropriately support its financing needs, its capital expenditure programs, its financing of OPG's subordinated debt investment in the Trust, and the Trust's acquisition of Investment Interest from the IESO. OPG's liquidity and capital resources are discussed in the section, Liquidity and Capital Resources.

Building Our Business

Through pursuit of commercial-based opportunities to expand its business, OPG strives to be a leader in the North American transition toward a low carbon future while maintaining and expanding the Company's scale and energy industry leadership. This strategy considers the Company's financial position and anticipated future changes in the generating fleet, including the eventual end of Pickering commercial operations. The strategy is also informed by industry, technological, environmental, social, and economic external factors. Opportunities are evaluated using financial and risk-based analyses as well as strategic considerations.

Currently, OPG's strategy primarily focuses on the renewal and expansion of the Company's portfolio of generating assets in Ontario, including the redevelopment and expansion of existing sites and potential new developments. The strategy leverages OPG's operating and project development expertise as well as the Company's existing diverse physical asset base. Acquisition opportunities are considered as they arise, taking into account operating synergies, strategic benefits, financial returns and risk profile. OPG's current major generation development projects and asset life extension initiatives are discussed in the section, *Core Business, Strategy, and Outlook* under the headings, *Operational Excellence* and *Project Excellence*.

OPG also actively seeks to expand beyond its core generation business through investments in innovation and emergent low-carbon technologies, including selective solar generation, nuclear innovation, energy storage, distributed generation, electric vehicle infrastructure and other development. Additionally, OPG continues to consider potential paths to extend its business through broader electricity sector opportunities, within and outside Ontario. Business expansions opportunities may be pursued in partnership with other commercial entities where appropriate synergies exist and are aligned with OPG's business objectives.

Social Licence

As the largest electricity generator in Ontario with diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust. OPG is committed to maintaining high standards of public safety and corporate citizenship, including environmental stewardship, transparency, community engagement, and Indigenous relations. OPG works to maintain public trust with stakeholders by engaging site communities, sharing information, and being transparent about performance. In addition, OPG's operations are subject to extensive regulatory oversight, with public participation, by the CNSC, the OEB, and other bodies. OPG's commitment to safety is discussed in the section, *Core Business, Strategy, and Outlook* under the heading, *Workplace and Public Safety*.

OPG is focused on building long-term, mutually beneficial working relationships with Indigenous communities, businesses and organizations across Ontario, and continues to support procurement, employment and educational opportunities with its Indigenous community partners. The Company seeks to establish these relationships based on a foundation of respect for the languages, customs, and political, social and cultural organizations of the Indigenous communities.

OPG's commitment in this area includes pursuing generation-related development partnerships on the basis of long-term commercial arrangements, such as the construction of the Peter Sutherland Sr. GS in partnership with Taykwa Tagamou Nation and the development of the Nanticoke solar facility in partnership with the Six Nations of the Grand

River. During 2017, OPG also continued to engage with Indigenous communities regarding the Company's nuclear waste management operations, through regularly scheduled meetings and ongoing dialogue in connection with OPG's proposed L&ILW DGR, the re-licensing of the PWMF and the WWMF, and the Pickering GS re-licensing. Engagement was also conducted with First Nations in southwestern Ontario regarding the demolition of the Lambton and Nanticoke generating stations and with the Mississaugas of New Credit regarding the Shareholder-directed sale of the former Lakeview GS site.

OPG is also committed to improving Indigenous access to procurement and employment opportunities, including increasing the profile of the nuclear generation industry in Indigenous communities. In 2017, OPG launched an Indigenous Business Engagement (IBE) Initiative. The purpose of this initiative is to increase access to procurement opportunities for Indigenous businesses interested in supplying materials and services to OPG. The IBE Initiative is based on a strategy that will identify opportunities in contracts, scopes of work and business plans for potential Indigenous business engagement; include criteria related to suppliers' ability to engage or partner with Indigenous people or businesses in assessing procurement proposals; and invest in relationships with Indigenous communities by increasing outreach efforts to enhance understanding of how to do business with OPG. OPG has been engaging with Indigenous businesses and communities as well as its suppliers to promote the IBE Initiative, including the Mohawk Council of Akwesasne as well as the Williams Treaties First Nations, located proximate to the Pickering and Darlington nuclear generating stations.

OPG has been actively developing recruitment plans targeting Indigenous peoples. As part of this initiative, during the fourth quarter of 2017, OPG participated in several Indigenous-specific career fairs, hosted a Day in the Trades event for Indigenous students and job seekers as part of an open house at the Darlington Energy Centre, and approved plans aimed at increasing the number of Indigenous apprentices as part of the nuclear operations' recruitment program.

OPG also contributes to the well-being of its host communities through the Company's Corporate Citizenship Program (CCP), which supports charitable and non-profit grassroots initiatives in the areas of environment, education, and community involvement, including support for Indigenous initiatives. In 2017, OPG's CCP provided support to over 800 initiatives, of which 84 were Indigenous.

OPG has a strategy to help position the Company as a leader in transportation electrification in the province. The strategy aims to leverage the Company's clean, reliable and cost-effective electricity to power transportation, capitalize on future commercial growth opportunities, and enhance the Company's social licence. OPG is pursuing initiatives to increase the use of electric vehicles within its operations, and is assessing vehicle grid integration and hydrogen applications for the transportation sector. Ontario's climate change plan aims for electric and hydrogen passenger vehicles to represent five percent of new vehicle sales in the province by 2020.

As part of its commitment to help de-carbonize Ontario's transportation sector, OPG is a founding sponsor of Plug'n Drive, a non-profit organization working to accelerate the adoption of electric vehicles and to maximize their environmental and economic benefits. In May 2017, Plug'n Drive announced the opening of the world's first experiential learning facility dedicated to electric vehicle education and awareness, with OPG sponsoring the Centre's training facility.

Further details regarding OPG's commitment to sustainable development, including information regarding the Company's environmental and social performance and initiatives, are provided in OPG's 2016 Sustainability Report available on the Company's website at www.opg.com.

Outlook

The financial performance of OPG's regulated operations is driven, in large part, by the outcome of applications for regulated prices to the OEB. Subject to the OEB's issuance of the final payment amounts order expected in the first half of 2018, the OEB's December 2017 decision on OPG's application for new regulated prices provides substantial

price certainty for the regulated business for the 2017 to 2021 period. During this period, OPG will continue to focus on optimizing operational performance and outage plans across the generating fleet and on pursuing further efficiency improvements in the Company's cost structure and operating model.

The OEB's decision established June 1, 2017 as the effective date of the new regulated prices, which negatively affected OPG's net income and ROE Excluding AOCI in 2017 relative to OPG's requested effective date of January 1, 2017. The full-year effect of new regulated prices in 2018 is expected to contribute to an improvement in net income and ROE Excluding AOCI over the 2017 results.

Subject to the OEB's final determination on nuclear rate smoothing as part of the payment amounts order process, OPG expects an improvement in cash flow from operating activities in 2018, compared to 2017. This will reflect OPG beginning to receive revenue from the IESO based on new regulated prices following the OEB's implementation of these prices, expected in the first half of 2018. Additionally, the Fair Hydro Trust segment will begin to contribute positive cash flow from operating activities in 2018. OPG expects to continue to have the necessary financial capacity and sufficient access to cost effective financing sources to continue to fund its capital requirements and other disbursements, including the financing of the Fair Hydro Trust.

Several OEB-authorized regulatory variance and deferral accounts currently in place contribute to reducing the relative variability of the Company's net income and ROE Excluding AOCI. Among others, the regulatory accounts include those related to the revenue impact of variability in water flows and forgone production due to SBG conditions at the regulated hydroelectric stations. As there are no variance or deferral accounts in place related to the impact of generation performance of the nuclear stations on revenue from base regulated prices, the Regulated – Hydroelectric segment generally is expected to produce overall more predictable earnings. OPG continues to operate and maintain its nuclear facilities with a view to optimize their performance and availability, while focusing on improving the overall reliability and predictability of the fleet.

Electricity generated from most of OPG's non-regulated assets is subject to ESAs or other long-term contracts with the IESO. Based on these agreements, OPG expects the Contracted Generation Portfolio segment to continue to contribute a generally stable level of earnings and cash flow from operating activities going forward.

Lower nuclear generation due to the Darlington Refurbishment outages will continue, as planned, to negatively impact the Enterprise TGC and Nuclear TGC metrics for the duration of the refurbishment project. Lower hydroelectric generation due to outages related to various refurbishment and operational projects may negatively impact Enterprise TGC and Hydroelectric TGC for the duration of these projects. Variability in sustaining capital investment expenditures and nuclear outage profile may also impact TGC metrics in future periods.

OPG's total forecast capital expenditures for the 2018 year are approximately $2.1 billion. **[CONFIRM]** This includes amounts for the Darlington Refurbishment project, hydroelectric and other development projects including the Ranney Falls GS redevelopment and construction of the Nanticoke solar facility, and sustaining capital investments across the generating fleet. OPG's major projects are discussed in the section, *Project Excellence*.

In addition to the operating and financial performance of the electricity generation business, OPG's results are affected by the earnings on the Nuclear Segregated Funds, which are reported in the Regulated – Nuclear Waste Management segment. While the Nuclear Segregated Funds are managed to achieve, in the long term, the target rate of return based on the discount rate specified in the ONFA, the rates of return earned in a given period can be subject to various external factors including financial market conditions and, for the portion of the Used Fuel Segregated Fund guaranteed by the Province under the ONFA, changes in the Ontario consumer price index (CPI). In the near term, these factors can be volatile and cause fluctuations in the Company's income. This volatility is partially mitigated by the impact of the OEB-authorized Bruce Lease Net Revenues Variance Account and the funded status of the two segregated funds, discussed below.

As OPG does not have the right to withdraw surplus amounts from the Nuclear Segregated Funds, OPG limits the amount of Nuclear Segregated Funds assets reported on the balance sheet to the present value of the underlying life cycle funding liabilities per the most recently approved ONFA Reference Plan. This reduces the volatility of earnings on the Nuclear Segregated Funds reflected in net income when the funds are in a fully funded or overfunded position. As at December 31, 2017, the Decommissioning Segregated Fund was overfunded by approximately 27 percent, and the Used Fuel Segregated Fund was marginally overfunded, by less than one percent, based on the 2017 ONFA Reference Plan. Variability in asset performance due to volatility inherent in financial markets and changes in Ontario CPI, or changes in funding liability estimates, may result in either or both funds becoming underfunded in the future.

OPG's results are also affected by the earnings from the Fair Hydro Trust segment. Management expects an increase in 2018 earnings from the segment, primarily related to interest income from OPG's investment in subordinated debt of the Trust. OPG's involvement with the Fair Hydro Plan over time is expected to put downward pressure on ROE Excluding AOCI as a result of increases in shareholder's equity through future issuances of Class A common shares to partially fund OPG's subordinated debt investment in the Trust.

KEY OPERATING AND FINANCIAL PERFORMANCE INDICATORS

OPG evaluates the performance of its generating stations using a number of key indicators. Key operating performance indicators aligned with corporate strategic imperatives are measures of production reliability, cost effectiveness, environmental performance, and safety performance. Certain of the measures used vary depending on the generating technology.

Enterprise TGC, Nuclear TGC, Hydroelectric TGC, ROE Excluding AOCI, and FFO Adjusted Interest Coverage ratio discussed below are not measurements in accordance with US GAAP. They should not be considered as alternative measures to net income or any other measure of performance under US GAAP. However, OPG believes that these non-GAAP financial measures are effective indicators of its performance and are consistent with the Company's strategic imperatives and related objectives. The definition and calculation of Enterprise TGC per MWh, Nuclear TGC per MWh, Hydroelectric TGC per MWh, ROE Excluding AOCI, and FFO Adjusted Interest Coverage are found in the section, *Supplementary Non-GAAP Financial Measures*.

Enterprise Total Generating Cost per Megawatt-Hour

Enterprise TGC per MWh is used to measure OPG's overall organizational cost performance. Enterprise TGC per MWh is defined as OM&A expenses (excluding the Darlington Refurbishment project and other generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to OPG's electricity generation business), fuel expense for OPG-operated stations including hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures (excluding the Darlington Refurbishment project and other generation development projects) incurred during the period, divided by total electricity generation from OPG-operated generating stations plus electricity generation forgone due to SBG conditions during the period.

Nuclear Total Generating Cost per Megawatt-Hour

Nuclear TGC per MWh is used to measure the cost performance of OPG's nuclear generating assets. Nuclear TGC per MWh is defined as OM&A expenses of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to OPG's nuclear electricity generation business), nuclear fuel expense for OPG-operated stations (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs) incurred during the period, divided by nuclear electricity generation for the period.

Hydroelectric Total Generating Cost per Megawatt-Hour

Hydroelectric TGC per MWh is used to measure the cost performance of OPG's hydroelectric generating assets. Hydroelectric TGC per MWh is defined as OM&A expenses of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segments (excluding generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the hydroelectric electricity generation business), hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding expenditures related to the Peter Sutherland Sr. GS, Ranney Falls GS, and other hydroelectric generation development projects) incurred during the period, divided by total hydroelectric electricity generation plus hydroelectric electricity generation forgone due to SBG conditions during the period. OPG reports hydroelectric gross revenue charge and water rental payments as fuel expense.

Nuclear Unit Capability Factor

OPG's nuclear stations are baseload facilities that are not designed for fluctuating production levels to meet peaking demand. The nuclear Unit Capability Factor is a key measure of nuclear station performance. It measures the amount of energy that the unit(s) generated over a period of time, adjusted for externally imposed constraints such as transmission or demand limitations, as a percentage of the amount of energy that would have been produced over the same period had the unit(s) produced maximum generation. Capability factors are primarily affected by planned and unplanned outages. By industry definition, capability factors exclude production losses beyond plant management's control, such as grid-related unavailability. The nuclear Unit Capability Factor also excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS is excluded from the measure effective October 15, 2016, when the unit was taken offline as part of the Darlington Refurbishment project.

Hydroelectric Availability

OPG's hydroelectric stations operate as baseload, intermediate, or peaking stations. Hydroelectric Availability represents the percentage of time the generating unit is capable of providing service, whether or not it is actually generating electricity, compared to the total time for the respective period.

Thermal Equivalent Forced Outage Rate

Equivalent Forced Outage Rate (EFOR) is an index of the reliability of a generating unit at OPG's thermal stations. It is measured by the ratio of time a generating unit is forced out of service by unplanned events, including any forced deratings, compared to the amount of time the generating unit was available to operate.

Return on Common Equity Excluding Accumulated Other Comprehensive Income

ROE Excluding AOCI is an indicator of OPG's performance consistent with its objective to deliver value to the Shareholder. ROE Excluding AOCI is defined as net income attributable to the Shareholder for the period divided by average equity attributable to the Shareholder excluding AOCI for that period, and is measured over a period of 12 months.

Funds from Operations Adjusted Interest Coverage

The FFO Adjusted Interest Coverage ratio is an indicator of OPG's ability to meet interest obligations from operating cash flow and is consistent with the Company's objective of ensuring availability of cost effective funding. The FFO Adjusted Interest Coverage ratio is defined as FFO before interest divided by adjusted interest expense, and is measured over a period of 12 months.

Other Key Indicators

In addition to production reliability, cost effectiveness, and financial performance indicators, OPG has identified certain environmental and safety performance measures. These measures are discussed in the section, *Core Business, Strategy, and Outlook*.

BUSINESS SEGMENTS

Effective in the fourth quarter of 2017, OPG has the following six reportable business segments:

- Regulated – Nuclear Generation
- Regulated – Nuclear Waste Management
- Regulated – Hydroelectric
- Contracted Generation Portfolio
- Services, Trading, and Other Non-Generation
- Fair Hydro Trust.

Regulated – Nuclear Generation Segment

The Regulated – Nuclear Generation business segment operates in Ontario, generating and selling electricity from the Pickering GS and the Darlington GS, both owned and operated by OPG. The business segment also includes revenue under the terms of a long-term lease arrangement and related agreements with Bruce Power related to the Bruce nuclear generating stations. This revenue includes lease revenue, fees for nuclear waste management, and revenue from heavy water sales and detritiation services. The segment also earns revenue from isotope sales and ancillary services supplied by OPG from the nuclear stations it operates. Ancillary revenues are earned through voltage control and reactive support. Revenues under the agreements with Bruce Power, including a portion of heavy water sales, and from existing isotope sales contracts and ancillary services are included by the OEB in the determination of the regulated prices for production from OPG's nuclear facilities, which has the effect of reducing these prices.

Regulated – Nuclear Waste Management Segment

OPG's Regulated – Nuclear Waste Management segment reports the results of the Company's operations associated with the management of nuclear used fuel and L&ILW, the decommissioning of OPG's nuclear generating stations including the stations on lease to Bruce Power and other facilities, the management of the Nuclear Segregated Funds, and related activities including the inspection and maintenance of the waste storage facilities. Accordingly, accretion expense, which is the increase in the Nuclear Liabilities carried on the consolidated balance sheets in present value terms due to the passage of time, and earnings from the Nuclear Segregated Funds are reported under this segment.

As the nuclear generating stations operate over time, OPG incurs incremental costs related to used nuclear fuel and L&ILW, which increase the Nuclear Liabilities. OPG charges these incremental costs to current operations in the Regulated – Nuclear Generation segment to reflect the cost of producing energy from the Pickering and Darlington nuclear generating stations and earning revenue under the Bruce Power lease arrangement and related agreements. Since the incremental costs increase the Nuclear Liabilities reported in the Regulated – Nuclear Waste Management segment, OPG records an inter-segment charge between the Regulated – Nuclear Generation and the Regulated – Nuclear Waste Management segments. The impact of the inter-segment charge is eliminated in the consolidated statements of income and balance sheets.

The Regulated – Nuclear Waste Management segment is considered rate regulated because OPG's costs associated with the Nuclear Liabilities are included in the OEB's determination of regulated prices for production from the Pickering and Darlington nuclear generating stations.

Regulated – Hydroelectric Segment

OPG's Regulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from most of the Company's hydroelectric generating stations. The business segment comprises the results of 54 hydroelectric generation stations across a number of major river systems in the province.

In addition, the business segment includes ancillary and other revenues from OPG's regulated hydroelectric stations. Ancillary revenues are earned through offering available generating capacity as operating reserve and through the supply of other ancillary services including voltage control and reactive support, certified black start facilities, regulation service, and other services. These ancillary revenues and other revenues are included by the OEB in the determination of the regulated prices for production from OPG's prescribed hydroelectric facilities, which has the effect of reducing these prices.

Contracted Generation Portfolio Segment

The Contracted Generation Portfolio business segment operates in Ontario, generating and selling electricity from the Company's generating stations that are not prescribed for rate regulation. The segment primarily includes generating facilities that are under an ESA with the IESO or other long-term contracts.

The Contracted Generation Portfolio segment also includes OPG's share of equity income from its 50 percent ownership interests in the PEC and Brighton Beach stations. Brighton Beach operates under an energy conversion agreement between Brighton Beach and Shell Energy North America (Canada) Inc., and the PEC station is operated under the terms of an Accelerated Clean Energy Supply contract with the IESO. OPG's share of the in-service generating capacity and generation volume from its interests in the PEC and Brighton Beach stations are reported in this segment.

The business segment also includes ancillary revenues and other revenues from the stations included in the segment, which are earned through offering available generating capacity as operating reserve, and the supply of other ancillary services including voltage control and reactive support, certified black start facilities, regulation service, and other services.

Services, Trading, and Other Non-Generation Segment

The Services, Trading, and Other Non-Generation segment is a non-generation segment that is not subject to rate regulation. It includes the revenue and expenses related to OPG's trading and other non-hedging activities. As part of trading activities, OPG transacts with counterparties in Ontario and neighbouring energy markets in predominantly short-term trading activities of typically one year or less in duration. These activities relate to electricity that is purchased and sold at the Ontario border, financial energy trades, financial risk management energy product revenues, and sales of energy-related products. In addition, OPG has a wholly owned trading subsidiary that transacts solely in the United States (US) market. The results of this subsidiary are reported in this segment. All contracts that are not designated as hedges are recorded as assets or liabilities at fair value on the consolidated balance sheets, with changes in fair value recorded in the revenue of this segment.

In addition, the segment includes revenue from real estate rentals and non-regulated services, gains or losses on disposition of non-regulated real estate assets, costs associated with non-regulated business development activities, and costs related to the Lambton GS and Nanticoke GS sites.

Fair Hydro Trust Segment

The Fair Hydro Trust segment is a non-generation segment that is not subject to rate regulation. It includes OPG's earnings from the Fair Hydro Trust, which includes the financial results of the Trust, as well as income related to OPG's role as Financial Services Manager of the Fair Hydro Trust and holder of subordinated debt issued by the Trust. Earnings include interest income from OPG's investment in subordinated debt of the Trust of up to 49 percent of the Trust's total outstanding debt, recovery of third-party costs and fees for financial management and ongoing administration services, partially offset by interest costs on debt issued by OPG to fund five percent of the subordinated investment in the Trust, incurred third-party costs, and other incurred costs related to the management and administration of the Trust.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

Regulated – Nuclear Generation Segment

(millions of dollars)	**2017**	**2016**
Revenue	**3,095**	3,481
Fuel expense	**284**	315
Gross margin	**2,811**	3,166
Operations, maintenance and administration	**2,293**	2,210
Depreciation and amortization	**431**	925
Property taxes	**26**	26
Income before other losses, interest, and income taxes	**61**	5
Other gains	**4**	1
Income before interest and income taxes	**57**	4

Income before interest and income taxes from the segment increased by $53 million in 2017, compared to 2016. Segment earnings were favourably affected by the OEB's decision on OPG's application for new regulated prices issued in December 2017 with a retrospective effective date of June 1, 2017. The revenue increase of approximately $465 million in relation to the June 1, 2017 to December 31, 2017 period resulting from the OEB's decision was recorded as an increase in net regulatory assets in the fourth quarter of 2017. This revenue increase was based on new regulated prices for that period proposed in OPG's January 2018 submission to the OEB based on the findings in the decision and is net of a regulatory liability recognized in relation to OPG's nuclear rate smoothing proposal in that submission.

Segment earnings were unfavourably affected by a reduction in electricity generation of 4.9 TWh in 2017, compared to 2016. This reduced revenue by approximately $285 million, partially offset by a decrease in fuel expense. The lower electricity generation was primarily due to the ongoing Unit 2 refurbishment outage at the Darlington GS that began in October 2016, partially offset by the higher electricity generation from the Pickering GS. The income impact of OEB-approved regulatory accounts also contributed to the decrease in income for the year.

The increase in OM&A expenses of $83 million in 2017, compared to 2016, reflected planned expenditures related to the major maintenance activities and higher project expenditures occurring at the nuclear stations. Depreciation and amortization expenses, excluding amortization expense related to regulatory account balances, increased by $22 million primarily due to new assets in service in 2017.

The expiry of a nuclear rate rider for the recovery of OEB-approved balances in regulatory accounts on December 31, 2016 contributed to the decrease in segment revenue in 2017, compared to 2016, but was largely offset by a decrease in amortization expense related to these balances.

The Unit Capability Factors for the Darlington GS and Pickering GS for 2017 and 2016 were as follows:

	2017	2016
Unit Capability Factor *(%)* [1]		
Darlington GS	**85.2**	89.5
Pickering GS	**80.0**	75.2

[1] The nuclear Unit Capability Factor excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS was excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

The lower Unit Capability Factor at the Darlington GS in 2017, compared to 2016, reflected the higher number of planned outage days in 2017, largely driven by constraints related to the transition of the station's operating units toward refurbishment.

The increase in the Unit Capability Factor at the Pickering GS in 2017, compared to 2016, was primarily due to outage cycle optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station compared to 2016.

The definition of the nuclear Unit Capability Factor is found in the section, *Key Operating and Financial Performance Indicators.*

Regulated – Nuclear Waste Management Segment

(millions of dollars)	2017	2016
Revenue	**121**	138
Operations, maintenance and administration	**129**	146
Accretion on nuclear fixed asset removal and nuclear waste management liabilities	**943**	912
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(801)**	(746)
Loss before interest and income taxes	**(150)**	(174)

Earnings from the segment improved by $24 million in 2017 compared to 2016. The improvement was primarily due to higher earnings from the Nuclear Segregated Funds, partially offset by an increase in accretion expense on the Nuclear Liabilities. Accretion expense represents a financing cost due to the increase in the present value of the underlying liabilities with the passage of time.

The year-over-year increase in the earnings from the funds was primarily due to a reduction in the earnings recorded in the fourth quarter of 2016 to reflect an accounting adjustment to limit Nuclear Segregated Funds assets reported on the consolidated balance sheet to the underlying funding liabilities based on an updated ONFA reference plan approved by the Province. The updated ONFA reference plan resulted in a reduction in the funding liabilities. As both the Decommissioning Segregated Fund and the Used Fuel Fund have been in an overfunded position since the beginning of 2017, the earnings on the funds recognized in net income during the year reflected the growth rate in the present value of the funding liabilities and were not impacted by market returns and the rate of return guaranteed by the Province for the portion of the Used Fuel Segregated Fund. Further details on the accounting for the Nuclear Segregated Funds can be found in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

The year-over-year increase in accretion on nuclear fixed removal and nuclear waste management liabilities in 2017, compared to 2016, was primarily due to the impact on accretion expense related to the increase in asset retirement obligation associated with the life extension of the Bruce nuclear assets from the agreement executed between Bruce Power and the Province in late 2015. This increase was offset in 2016 due to the Bruce Lease Net Revenues Variance Account but is reflected in accretion with the resetting of base rates in 2017. This increase was partially

offset by the impact of the decrease in Nuclear Liabilities to reflect an updated estimate as part of the ONFA reference plan update process.

As of December 31, 2016, OPG recorded a decrease of approximately $1,570 million to the Nuclear Liabilities and associated asset retirement costs capitalized as part of the carrying value of the nuclear generating stations to reflect an updated estimate of OPG's obligations for nuclear waste management and nuclear facilities decommissioning determined as part of the ONFA reference plan update process. The resulting year-over-year decreases in accretion expense recorded in the Regulated – Nuclear Waste Management segment and depreciation and fuel expenses recorded in the Regulated – Nuclear Generation segment were offset by the impact of the OEB-authorized Bruce Lease Net Revenues Variance Account and Nuclear Liability Deferral Account recorded in the corresponding segments for the period up to May 31, 2017, and by the retrospective revenue impact of the OEB's decision for the period from June 1, 2017 to December 31, 2017 recorded in the Regulated – Nuclear Generation segment.

Regulated – Hydroelectric Segment

(millions of dollars)	**2017**	**2016**
Revenue [1]	**1,436**	1,527
Fuel expense	**351**	353
Gross margin	**1,085**	1,174
Operations, maintenance and administration	**330**	325
Depreciation and amortization	**139**	225
Property tax	**1**	1
Income before other gains, interest and income taxes	**615**	623
Other losses (gains)	**1**	(19)
Income before interest and income taxes	**614**	642

[1] During 2017 and 2016, the Regulated – Hydroelectric segment revenue included incentive payments of $12 million and $14 million, respectively, related to the OEB-approved hydroelectric incentive mechanism. The mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers.

The decrease in income before interest and income taxes of $28 million in 2017, compared to 2016, was primarily due to a gain of $22 million recognized during the first quarter of 2016 to reflect the OEB's January 2016 decision reversing a portion of an earlier capital cost disallowance related to the Niagara Tunnel project expenditures, in response to a motion by OPG. The income impact of OEB-approved regulatory accounts and higher OM&A expenses also contributed to the decrease in income for the year. The higher OM&A expenses were primarily related to overhaul work and civil repairs completed during the year.

These factors were partially offset by the recognition of a revenue increase of approximately $15 million in the fourth quarter of 2017 to reflect the OEB's decision on OPG's application for new regulated prices. This incremental revenue was in relation to the June 1, 2017 to December 31, 2017 period based on the June 1, 2017 retrospective effective date of the new regulated prices and was recorded as an increase to regulatory assets.

The decrease in revenue from the segment for the year ended December 31, 2017, compared to the same period in 2016, was largely due to the expiry of an OEB-authorized hydroelectric rate rider on December 31, 2016. As the rate rider allowed for the recovery of approved balances in OEB-authorized regulatory accounts, this decrease in revenue was largely offset by lower amortization expense related to these balances.

The Hydroelectric Availability for the stations included in the Regulated – Hydroelectric segment was as follows:

	2017	2016
Hydroelectric Availability *(%)*	**88.0**	89.0

The Hydroelectric Availability decreased during 2017, compared to 2016, primarily due to a higher number of unplanned outage days at the Northwestern Ontario, Niagara, and Eastern Ontario regions' hydroelectric stations, partially offset by higher availability from the Sir Adam Beck Pump GS due to a higher number of planned outages days in 2016 as a result of the refurbishment of the station's reservoir.

The definition of Hydroelectric Availability is found in the section, *Key Operating and Financial Performance Indicators*.

Contracted Generation Portfolio Segment

(millions of dollars)	2017	2016
Revenue	**579**	573
Fuel expense	**53**	58
Gross margin	**526**	515
Operations, maintenance and administration	**169**	178
Depreciation and amortization	**79**	75
Accretion on fixed asset removal liabilities	**9**	9
Property taxes	**7**	7
Income from investments subject to significant influence	**(38)**	(37)
Income before other losses, interest, and income taxes	**300**	283
Other losses	**-**	1
Income before interest and income taxes	**300**	282

Income before interest and income taxes increased by $18 million during 2017, compared to 2016. The increase in earnings primarily resulted from revenues from the Peter Sutherland Sr. GS that was placed in-service at the end of the first quarter of 2017 and lower OM&A expenses, partially offset by lower revenues from the Lower Mattagami River hydroelectric generating stations and Atikokan GS. The lower OM&A expenses were mainly due to the prospective adoption of the full yield curve approach to the estimation of the service and interest cost components of pension and OPEB costs starting in 2017.

The Hydroelectric Availability and the Thermal EFOR for the Contracted Generation Portfolio segment were as follows:

	2017	2016
Hydroelectric Availability *(%)*	**74.6**	77.3
Thermal EFOR *(%)*	**2.4**	1.6

Lower Hydroelectric Availability during 2017, compared to 2016, was primarily due to an increase in the number of planned outage days at the Lower Mattagami River hydroelectric generating stations.

The higher thermal EFOR in 2017, compared to 2016, was primarily due to a higher number of unplanned outage days at a Lennox GS unit as a result of a transmission outage and a generator-related outage in 2017.

The definitions of Hydroelectric Availability and Thermal EFOR are found in the section, *Key Operating and Financial Performance Indicators*.

Services, Trading, and Other Non-Generation Segment

(millions of dollars)	2017	2016
Revenue	**43**	68
Fuel expense	**1**	1
Gross margin	**42**	67
Operations, maintenance and administration	**18**	22
Depreciation and amortization	**30**	32
Accretion on fixed asset removal liabilities	**8**	8
Property taxes	**6**	12
Restructuring	**-**	6
Loss before other gain, interest, and income taxes	**(20)**	(13)
Other gains	**(384)**	-
Income before interest and income taxes	**364**	(13)

Segment earnings improved by $377 million in 2017 compared to 2016. The increase in earnings mainly reflected the gain on the sale of OPG's head office premises and associated parking facility recorded during the second quarter of 2017 of $283 million, which is net of tax effects of $95 million, partially offset by a decrease in rental revenue due to the sale of the head office premises.

The year-over-year decrease in OM&A expenses in 2017 reflected higher expenses incurred in 2016 prior to the decision taken in the fourth quarter of 2016 to proceed with the decommissioning of the Lambton GS, largely offset by a higher write-off of previously incurred project expenditures in 2017.

During the fourth quarter of 2017, OPG recorded $12 million in Other gains related to the revaluation of the asset retirement obligations for Lambton and Nanticoke generating stations in line with the current decommissioning plans and cost estimates. During each of 2017 and 2016, OPG recorded a charge against earnings to adjust the scrap value estimate for the Lambton GS, as a reduction to Other gains.

Fair Hydro Trust Segment

(millions of dollars)	2017
Operations, maintenance and administration	**1**
Earnings from Fair Hydro Trust	**(1)**
Income before interest and income taxes	**-**

The Fair Hydro Trust was established on December 20, 2017. The Fair Hydro Trust segment includes the revenue and expenses related to OPG's role as Financial Services Manager of the Fair Hydro Trust and holder of subordinated debt issued by the Trust, including the financial results of the Trust. Earnings from Fair Hydro Trust were $1 million in 2017, primarily due to net interest income earned on OPG's subordinated debt investment for the 11-day period following the acquisition of the first tranche of Investment Interest from the IESO on December 21, 2017. The earnings were offset by an allocation of OM&A expenses for labour costs relating to OPG's employees that are not exclusively dedicated to the segment but who provided services to set up the Trust during the year. Pursuant to the general regulation of the Fair Hydro Act, such labour costs are not recoverable as part of OPG's fees for 2017. Refer to the section, *Recent Developments* under the heading, *Ontario's Fair Hydro Plan* and the section, *Business Segments* under the heading, *Fair Hydro Trust Segment* for further details on the Fair Hydro Trust.

LIQUIDITY AND CAPITAL RESOURCES

OPG's primary sources of liquidity and capital are funds generated from operations, bank financing, credit facilities provided by the Ontario Electricity Financial Corporation (OEFC), long-term corporate debt, including public debt offerings and notes payable to the OEFC, private placement project financing, and equity issuance. These sources are used for multiple purposes including: to invest in plants and technologies, to undertake major projects, to fund long-term obligations such as contributions to the pension fund and the Nuclear Segregated Funds, to make payments under the OPEB plans, to fund expenditures on Nuclear Liabilities not eligible for reimbursement from the Nuclear Segregated Funds, and to service and repay long-term debt, to provide general working capital, and to fund a portion of OPG's subordinated debt investment in the Fair Hydro Trust and the Trust's acquisition of Investment Interest from the IESO.

Changes in cash and cash equivalents for 2017 and 2016 were as follows:

(millions of dollars)	**2017**	**2016**
Cash and cash equivalents, beginning of period	**186**	464
Cash flow provided by operating activities	**944**	1,817
Cash flow used in investing activities	**(2,478)**	(1,919)
Cash flow provided by (used in) financing activities	**1,582**	(176)
Net increase (decrease) in cash and cash equivalents	**48**	(278)
Cash and cash equivalents, end of period	**234**	186

For a discussion regarding cash flow provided by operating activities and the FFO Adjusted Interest Coverage ratio, refer to the details in the section, *Highlights* under the heading, *Overview of Results*.

Investing Activities

Electricity generation is a capital-intensive business. It requires continued investment in plants and technologies to maintain and improve operating performance including asset reliability, safety and environmental performance, to increase the generating capacity of existing stations, and to invest in the development of new generating stations, emerging technologies and other business growth opportunities.

Cash flow used in investing activities in 2017 increased by $834 million compared to 2016. The increase in net cash flow used in investing activities was primarily due to the Trust's acquisition of the first tranche of Investment Interest from the IESO in the amount of approximately $1.18 billion in December 2017 and higher expenditures on the Darlington Refurbishment project in 2017.

The increase in net cash flow used in investing activities was partially offset by the receipt of proceeds from the sale of OPG's head office premises and associated parking facility in 2017 and the acquisition of nine million common shares of Hydro One Limited (Hydro One) in 2016. OPG acquired the Hydro One shares for investment purposes, to mitigate the risk of future price volatility related to the Company's future share delivery obligations under the current collective agreements with the Power Workers' Union (PWU) and The Society of Energy Professionals (The Society).

Financing Activities

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. In the second quarter of 2017, OPG renewed and extended the expiry date of both tranches from May 2021 to May 2022. There were no amounts outstanding under the bank credit facility as at December 31, 2017.

There was $100 million of commercial paper outstanding under OPG's commercial paper program as at December 31, 2017.

As at December 31, 2017, OPG also maintained $25 million of short-term, uncommitted overdraft facilities, and a further $468 million of short-term, uncommitted credit facilities which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other general corporate purposes. As at December 31, 2017, a total of $390 million of Letters of Credit had been issued under these facilities. This included $353 million for the supplementary pension plans, $36 million for general corporate purposes, and $1 million related to the operation of the PEC.

The Company has an agreement to sell an undivided co-ownership interest in its current and future accounts receivable to an independent trust, expiring on November 30, 2018. The maximum amount of co-ownership interest that can be sold under this agreement is $150 million. As at December 31, 2017, no borrowings were issued under this agreement and there were Letters of Credit outstanding under this agreement of $150 million, which were issued in support of OPG's supplementary pension plans.

As at December 31, 2017, Lower Mattagami Energy Limited Partnership (LME) maintained a $400 million bank credit facility to support the funding requirements for the Lower Mattagami River project including support for LME's commercial paper program. The facility consists of a $300 million tranche maturing in August 2022 and a $100 million tranche maturing in August 2018. As at December 31, 2017, there was $160 million commercial paper outstanding under LME's commercial paper program. A letter of credit of $55 million was issued in July 2017 and remains outstanding as at December 31, 2017 under the $300 million tranche of LME's credit facility.

In June 2016, OPG entered into a $700 million general corporate credit facility agreement with the OEFC, with an expiry date of December 31, 2017. During 2017, the agreement was amended to increase the credit facility to $2,350 million and to extend its expiry date to December 31, 2018. As at December 31, 2017, there were outstanding long-term borrowings of $800 million under this credit facility.

In February 2017, OPG issued senior notes payable to the OEFC totalling $200 million and maturing in February 2047. The effective interest rate and coupon interest rate of these notes was 4.12 percent. In June 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in June 2047. The effective interest rate and coupon interest rate of these notes was 3.65 percent. In August 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in August 2047. The effective interest rate and coupon interest rate of these notes was 3.86 percent. In September 2017, OPG issued senior notes payable to the OEFC totalling $400 million and maturing in September 2047. The effective interest rate and coupon interest rate of these notes was 4.07 percent.

In October 2017, OPG issued $500 million of senior notes payable under a Medium Term Note Program. The notes bear a coupon interest rate of 3.32 percent and an effective rate of 3.43 percent, payable semi-annually until maturity on October 4, 2027. The offering was made under OPG's $2 billion short form base shelf prospectus dated September 12, 2017. The net proceeds will be used for general corporate purposes.

In December 2017, the Fair Hydro Trust entered into an $800 million revolving warehouse facility agreement with an expiry date of December 21, 2019. As at December 31, 2017, there were outstanding senior notes of $601 million under this credit facility, which were used to finance 51 percent of the Trust's funding requirement for the acquisition of the first tranche of Investment Interest from the IESO in December 2017.

In February 2018, the Trust issued $500 million of senior notes payable with a coupon interest rate of 3.36 percent and an effective interest rate of 3.42 percent, payable semi-annually until maturity on May 15, 2033. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility issued by the Trust in December 2017. By the end of the first quarter of 2018, the Trust is expected to acquire another tranche of Investment Interest from the IESO, which it expects to fund using its revolving warehouse facility.

As at December 31, 2017, OPG's long-term debt outstanding was $5,735 million, including $398 million due within one year and excluding Fair Hydro Trust's senior debt included in OPG's consolidated balance sheets. The Fair Hydro Trust's senior debt outstanding was $601 million as at December 31, 2017.

Contractual Obligations

OPG's contractual obligations as at December 31, 2017, are as follows:

(millions of dollars)	2018	2019	2020	2021	2022	Thereafter	Total
Fuel supply agreements	158	125	115	88	67	67	620
Contributions to the OPG registered pension plan [1]	215	219	-	-	-	-	434
OPG long-term debt repayment	398	368	663	413	172	3,721	5,735
Interest on OPG long-term debt	244	226	204	175	161	3,006	4,016
Fair Hydro Trust senior debt repayment [2]	-	601	-	-	-	-	601
Interest on Fair Hydro Trust senior debt	15	15	-	-	-	-	30
Commitments related to Darlington Refurbishment project [3]	473	-	-	-	-	-	473
Commitments related to Ranney Falls GS project	29	5	-	-	-	-	34
Operating licences	40	41	24	28	28	87	248
Operating lease obligations	28	24	24	22	22	79	199
Unconditional purchase obligations	59	58	56	5	-	-	178
Accounts payable and accrued charges	957	8	-	-	-	16	981
Other	57	30	2	1	1	64	155
Total	2,673	1,720	1,088	732	451	7,040	13,704

[1] The pension contributions include ongoing funding requirements and additional funding requirements towards the deficit, in accordance with the actuarial valuation of the OPG registered pension plan as at January 1, 2017. The next actuarial valuation of the OPG registered pension plan must have an effective date no later than January 1, 2020. The pension contributions are affected by various factors including market performance, changes in actuarial assumptions, plan experience, changes in the pension regulatory environment, and the timing of funding valuations. Funding requirements after 2019 are excluded due to significant variability in the assumptions required to project the timing of future cash flows. The amount of OPG's additional, voluntary contribution, if any, is revisited from time to time.

[2] The notes were issued by the Fair Hydro Trust under an $800 million two-year revolving warehouse facility in December 2017. In February 2018, the Trust issued $500 million of senior notes payable to repay the majority of the outstanding balance of the revolving warehouse facility.

[3] Represents estimated currently committed costs to close the project, including accruals for completed work, demobilization of project staff and cancellation of existing contracts and material orders.

Other Commitments

Collective Agreements

As of December 31, 2017, OPG had approximately 9,200 regular employees. Most of OPG's regular employees are represented by two unions:

- The PWU – This union represents approximately 4,850 OPG employees or approximately 53 percent of OPG's regular workforce as at December 31, 2017. Union membership includes operators, technicians, skilled trades, clerical, and security personnel. The current collective agreement between OPG and the PWU has a three-year term, expiring on March 31, 2018. Negotiations for a new labour agreement with the PWU are underway. **[MONITOR]**
- The Society – This union represents approximately 3,250 OPG employees or approximately 35 percent of OPG's regular workforce as at December 31, 2017. Union membership includes supervisors, professional engineers, scientists, and other professionals. The current collective agreement between OPG and The Society has a three-year term, expiring on December 31, 2018.

In addition to the regular workforce, construction work is performed through 19 craft unions with established bargaining rights at OPG facilities. These bargaining rights are established either through the Electrical Power Systems Construction Association (EPSCA) or directly with OPG. Collective agreements between the Company and its construction unions are negotiated either directly or through EPSCA. All of these collective agreements currently have multi-year terms, expiring on April 30, 2020.

BALANCE SHEET HIGHLIGHTS

The following section provides other highlights of OPG's audited consolidated financial position using selected balance sheet data as at December 31:

(millions of dollars)	**2017**	**2016**
Property, plant and equipment – net	**21,322**	19,998
The increase was primarily due to capital expenditures on the Darlington Refurbishment project, partially offset by depreciation expense.		
Nuclear fixed asset removal and nuclear waste management funds *(current and non-current portions)*	**16,724**	15,984
The increase was primarily due to earnings on the Nuclear Segregated Funds, partially offset by reimbursement of eligible expenditures on nuclear fixed asset removal and nuclear waste management activities.		
Regulatory assets and liabilities – net *(current and non-current portions)*	**6,637**	5,545
The increase was primarily due to the addition of the Interim period revenue shortfall account, increases in the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB AOCI regulatory asset. In addition, there was no amortization recorded in 2017 consistent with OPG's proposal in the Draft Payment Amounts Order filed with the OEB in January 2018.		
Long-term debt *(current and non-current portions)*	**6,319**	5,520
The increase was primarily due to the issuance of senior notes payable by the Trust to finance the acquisition of an Investment Interest in the shortfall from the rate reductions mandated by the Fair Hydro Act of $601 million, issuance of senior notes payable totaling $804 million during 2017 primarily with the OEFC, and issuance of senior notes totaling $500 million under the Medium Term Note Program. The balance is offset by the debt repayment of $1 billion in 2017.		
Fixed asset removal and nuclear waste management liabilities	**20,421**	19,484
The increase was primarily a result of accretion expense representing the increase in the present value liabilities due to the passage of time, and an increase in the estimate for the nuclear ARO of $188 million recorded in 2017, which is discussed in *Critical Accounting Policies and Estimates* under the heading, Asset Retirement *Obligation*. The increase was partially offset by expenditures on nuclear fixed asset removal and waste management activities.		
Pension liabilities	**3,423**	3,012
The increase was primarily due to the re-measurement of the liabilities at the end of 2017 reflecting lower discount rates, partially offset by the excess of actual returns on pension plan assets over interest costs on the liabilities during 2017, as discussed in the section, *Critical Accounting Policies and Estimates* under the *heading, Pension and Other Post-Employment Benefits.*		
Other post-employment benefit liabilities	**3,092**	2,897
The increase was primarily due to the remeasurement of the liabilities at the end of 2017 reflecting lower discount rates, partially offset by the updated lower per capital health care claims costs assumption as part of the 2017 actuarial valuation.		

Off-Balance Sheet Arrangements

In the normal course of operations, OPG engages in a variety of transactions that, under US GAAP, are either not recorded in the Company's interim consolidated financial statements or are recorded in the Company's interim consolidated financial statements using amounts that differ from the full contract amounts. Principal off-balance sheet activities for OPG include guarantees and long-term contracts.

Guarantees

As part of normal business, OPG and certain of its subsidiaries and joint ventures enter into various agreements to provide financial or performance assurance to third parties. Such agreements include guarantees, standby Letters of Credit and surety bonds. For more details on guarantees issued by the company, refer to Note 15 of OPG's audited consolidated financial statements.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

OPG's significant accounting policies, including the impact of major recent accounting pronouncements, are outlined in Note 3 of the audited consolidated financial statements. Certain of these policies are recognized as critical accounting policies by virtue of the subjective and complex judgments and estimates required around matters that are inherently uncertain and could result in materially different amounts being reported under different conditions or assumptions. The critical accounting policies and estimates that affect OPG's US GAAP consolidated financial statements are highlighted below.

Exemptive Relief for Reporting under US GAAP

As required by *Ontario Regulation 395/11,* as amended, under the FAA, OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. Since January 1, 2012, OPG also has received exemptive relief from the OSC from the requirements of section 3.2 of National Instrument 52-107 *Acceptable Accounting Policies and Auditing Standards* (NI 52-107). The exemption allows OPG to file consolidated financial statements with the OSC based on US GAAP, rather than International Financial Reporting Standards (IFRS), without becoming a U.S. Securities and Exchange Commission registrant.

The current OSC exemption, received in 2014, will terminate on the earliest of the following:

- January 1, 2019
- The financial year that commences after OPG ceases to have activities subject to rate regulation
- The effective date prescribed by the International Accounting Standards Board (IASB) for the mandatory application of a standard within IFRS specific to entities with rate-regulated activities.

As a result of OPG's 2011 decision to adopt US GAAP, as required by the FAA regulation, OPG's earlier plan to convert to IFRS, effective January 1, 2012, was discontinued. OPG had substantively completed its IFRS conversion project, which included separate diagnostic, development, and implementation phases, when it suspended the project. If a future transition to IFRS for the purposes of OPG's consolidated financial statements is required, conversion work can be effectively restarted with sufficient lead time to evaluate and conclude on changes that occurred subsequent to the decision to suspend the project. OPG continues to monitor the IASB's current standard-setting project related to entities with rate-regulated activities and is evaluating alternatives with respect to the Company's future financial reporting.

Rate Regulated Accounting

The *Ontario Energy Board Act, 1998* and *Ontario Regulation 53/05* provide that OPG receives regulated prices for electricity generated from 54 hydroelectric generating stations and the Pickering and Darlington nuclear generating stations. OPG's regulated prices for these facilities are determined by the OEB.

The OEB is a self-funding Crown corporation. Its mandate and authority come from the *Ontario Energy Board Act, 1998*, the *Electricity Act, 1998*, and a number of other provincial statutes. The OEB is an independent, quasi-judicial tribunal that reports to the Legislature of the Province through the Ontario Ministry of Energy. It regulates market participants in Ontario's natural gas and electricity industries. The OEB carries out its regulatory functions through public hearings and other more informal processes such as consultations.

US GAAP recognizes that rate regulation can create economic benefits and obligations that are required by the regulator to be obtained from, or settled with, the customers. When the Company assesses that there is sufficient assurance that incurred costs in respect of the regulated facilities will be recovered in the future, those costs are deferred and reported as a regulatory asset. When the Company is required to refund amounts to customers in the future in respect of the regulated facilities, including amounts related to costs that have not been incurred and for which the OEB has provided recovery through regulated prices, the Company records a regulatory liability.

Certain of the regulatory assets and liabilities recognized by the Company relate to variance and deferral accounts authorized by the OEB, including those authorized pursuant to *Ontario Regulation 53/05.* The measurement of these regulatory assets and liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of *Ontario Regulation 53/05* and the OEB's decisions. The estimates and assumptions made in the interpretation of the regulation and the OEB's decisions are reviewed as part of the OEB's regulatory process.

Regulatory assets and liabilities for variance and deferral account balances approved by the OEB for inclusion in regulated prices are amortized based on approved recovery or repayment periods.

In addition to regulatory assets and liabilities for variance and deferral accounts, OPG recognizes regulatory assets and liabilities for unamortized amounts recorded in AOCI in respect of pension and OPEB obligations, and deferred income taxes, in order to reflect the expected recovery or repayment of these amounts through future regulated prices charged to customers. There are measurement uncertainties related to these balances due to the assumptions made in the determination of pension and OPEB obligations and deferred income taxes that are attributed to rate regulated business segments.

The regulatory asset for unamortized pension and OPEB amounts recorded in AOCI has reflected the OEB's use, since April 1, 2008, of the accrual basis of accounting for including pension and OPEB amounts in approved regulated prices for OPG. This is also the manner in which these costs are recognized in OPG's consolidated financial statements. Therefore, unamortized amounts in respect of OPG's pension and OPEB plans recognized in AOCI generally would not be reflected in regulated prices until they have been reclassified from AOCI and recognized as amortization components of the benefit costs for these plans.

Since November 1, 2014, the OEB has limited amounts for pension and OPEB costs included in the approved revenue requirements and regulated prices to the regulated business portion of the Company's cash expenditures for its pension and OPEB plans. The difference between actual pension and OPEB costs determined using the accrual method applied in OPG's audited consolidated financial statements and OPG's corresponding actual cash expenditures for these plans is captured in OEB-authorized Pension & OPEB Cash Versus Accrual Differential Deferral Account for future consideration. In 2017, the OEB issued a report outlining the guiding principles and policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the Ontario electricity and natural gas sectors. The report establishes the accrual basis of accounting as the method of determining pension and OPEB amounts for rate-setting purposes, unless the OEB finds that this method does not result in just and reasonable rates in the circumstances of a particular utility. The OEB's report and the OEB's December 2017 decision on OPG's

application for new regulated prices require OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the existing deferral account, until such time as the OEB approves resumption of the accrual basis of recovery for OPG. The future recovery of amounts recorded in the account will be subject to this approval. Further details on the OEB's 2017 report can be found in the section, *Highlights* under the heading, *Recent Developments – OEB's Decision on OPG's Application for New Regulated Prices*.

It remains the Company's position that, taken collectively, OEB's decisions on OPG's applications for regulated prices and the OEB's 2017 report in this area do not constitute a change in the basis of OPG's rate recovery of pension and OPEB costs. The Company continues to believe that there is sufficient likelihood that unamortized pension and OPEB amounts that have not yet been reclassified from AOCI will be included in future regulated prices, or in an OEB-authorized regulatory account for future recovery, as they are recognized in benefit costs. Similarly, the Company continues to believe that there is sufficient likelihood that amounts recorded in the Pension & OPEB Cash Versus Accrual Differential Deferral Account will be recovered, and consistent with the expectations set out in the OEB's December 2017 decision, plans to file an application with the OEB in 2018 requesting recovery of the account balance. Therefore, the Company continues to recognize regulatory assets for the above amounts.

See Notes 3, 5, 8, 9, and 11 of OPG's 2017 audited consolidated financial statements for additional disclosures related to the OEB's decisions, regulatory assets and liabilities, and rate regulated accounting.

Useful Lives of Long-Lived Assets

OPG reviews estimated station useful lives for its generating assets on a regular basis.

Nuclear Generating Stations

For the nuclear stations, this process involves reviewing major life limiting components (such as pressure tubes, feeders and steam generators) to determine an appropriate end-of-life date for the station. Useful lives are set such that, with normal and customary maintenance activities, stations are expected to be operational until such time as their life-limiting component's threshold is expected to be reached.

Hydroelectric and Thermal Generating Stations

Although there is a link between the age of a facility and the capital investment required to maintain that facility, age does not establish an upper limit on the expected useful life of hydroelectric facilities and dams. Regular maintenance and the replacement of specific components typically allow hydroelectric stations to operate for very long periods. For hydroelectric generating stations, an upper age limit of 100 years have been set.

Thermal generating stations reported in the Contracted – Generation Portfolio business segment primarily have useful lives that are in line with the term of the Energy Supply Agreements with the IESO.

Financing Receivables

Financing receivables consist of the current and irrevocable right of the Fair Hydro Trust to collect payments from Specified Consumers in the future in accordance with the Fair Hydro Act and associated general regulation. These amounts are measured at the transaction price entered into with the IESO on market terms upon acquisition and subsequently measured on an amortized cost basis. The basis of amortization follows the effective interest method.

Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

In accordance with the ONFA, OPG sets aside and invests funds that are held in segregated custodian and trustee accounts specifically for discharging its obligation for nuclear facilities decommissioning and long-term nuclear waste management. The Decommissioning Segregated Fund was established to fund the future costs of nuclear fixed asset removal and long-term L&ILW management, and certain costs of used fuel storage incurred after the stations are shut down. The Used Fuel Segregated Fund was established to fund the future costs of long-term nuclear used

fuel management and certain costs of used fuel storage incurred after the stations are shut down. Costs for L&ILW management and used fuel storage incurred during station operation are not funded by the Nuclear Segregated Funds. They are funded through the Company's operating cash flow or other sources of liquidity.

Based on the current approved ONFA reference plan, starting in 2017, OPG is not currently required to make overall contributions to the Used Fuel Segregated Fund or the Decommissioning Segregated Fund. Prior to 2017, OPG made contributions to the Used Fuel Segregated Fund quarterly, including a one-time special payment in earlier years, as required by the ONFA. These contributions reflected ONFA requirements to fund the majority of the underlying used fuel liability by the end of the initial estimated useful lives of the nuclear stations assumed in the ONFA, resulting in significantly higher contributions to the Used Fuel Segregated Fund in the earlier years of OPG's existence. OPG has not been required to make contributions to the Decommissioning Segregated Fund, which was fully funded at its inception through the initial contribution made by the Ontario Electricity Financial Corporation (OEFC), an agency of the Province, and, taking into account asset performance and changes in underlying funding obligations over time, at the time of every subsequent approved ONFA reference plan. Contributions to either or both funds may be required in the future should the funds be in an underfunded position when a new reference plan is prepared. Such may be the case as a result of variability in asset performance due to volatility inherent in financial markets and, for the portion of the Used Fuel Segregated Fund guaranteed by the Province, changes in the Ontario CPI. Future contribution levels also are dependent on changes in baseline cost and liability estimates and underpinning assumptions used to establish the funding obligations in subsequent ONFA reference plans.

Decommissioning Segregated Fund

Upon termination of the ONFA, the Province has the sole right to any excess funds in the Decommissioning Segregated Fund. Accordingly, when the Decommissioning Segregated Fund is overfunded, OPG limits the fund earnings it recognizes in the consolidated financial statements by recording an amount due to the Province, such that the fund asset recognized on the consolidated balance sheet is equal to the cost estimate of the liability based on the most recently approved ONFA reference plan. Additionally, OPG recognizes the portion of the surplus that it may direct to the Used Fuel Segregated Fund, which is possible when the surplus is such that the underlying liabilities, as defined by the most recently approved ONFA reference plan, are at least 120 percent funded. In those circumstances, OPG may direct, at the time a new or amended reference plan is approved, up to 50 percent of the surplus over 120 percent to the Used Fuel Segregated Fund, with the OEFC entitled to a distribution of an equal amount. Therefore, when the Decommissioning Segregated Fund is at least 120 percent funded, OPG recognizes 50 percent of the excess greater than 120 percent in income, up to the amount by which the Used Fuel Segregated Fund is underfunded.

The amount due to the Province in respect of the Decommissioning Segregated Fund could be reduced in subsequent periods in the event that the fund earns less than is target rate of return, a new ONFA reference plan is approved with a higher underlying liability, or the amount of the underfunding in the Used Fuel Segregated Fund increases.

When the Decommissioning Segregated Fund is underfunded, the earnings on the fund reflect actual fund returns based on the market value of the assets.

Used Fuel Segregated Fund

Under the ONFA, the Province guarantees OPG's annual return in the Used Fuel Segregated Fund at 3.25 percent plus the change in the Ontario CPI, as defined in the ONFA, for funding related to the first 2.23 million used fuel bundles ("committed return"). OPG recognizes the committed return on the Used Fuel Segregated Fund as earnings on the Nuclear Segregated Funds. The difference between the committed return and the actual market return determined based on the fair value of the fund's assets related to the first 2.23 million used fuel bundles is recorded as due to or due from the Province. This amount represents the amount OPG would pay to, or receive from, the Province if the committed return were to be settled as of the consolidated balance sheet date. Upon approval of a

new or amended ONFA reference plan, the Province is obligated to make an additional contribution to the Used Fuel Segregated Fund in relation to the first 2.23 million used fuel bundles if the fund's assets earned a rate of return that is less than the guaranteed rate of return. If the return on the fund's assets exceeds the Province's guaranteed rate of return, the Province is entitled to withdraw any portion of the excess related to the 2.23 million used fuel bundles, upon approval of a new or amended ONFA reference plan. The 2.23 million threshold represents the estimated total life cycle fuel bundles based on the initial estimated useful lives of the nuclear stations assumed in the ONFA.

As prescribed under the ONFA, OPG's contributions attributed to the used fuel bundles in excess of 2.23 million are not subject to the rate of return guaranteed by the Province, and earn a return based on changes in the market value of the assets of the Used Fuel Segregated Fund.

If there is a surplus in the Used Fuel Segregated Fund such that the funding liabilities, as defined by the most recently approved ONFA Reference Plan, are at least 110 percent funded, the Province has the right, at any time, to access the excess amount greater than 110 percent. Upon termination of the ONFA, the Province is entitled to any surplus in the fund. Accordingly, when the Used Fuel Segregated Fund is overfunded, OPG limits the fund earnings it recognizes in the consolidated financial statements by recording an amount due to the Province, such that the balance of the fund is equal to the cost estimate of the liability based on the most recently approved ONFA reference plan. In accordance with the ONFA, neither OPG nor the Province have a right to direct any amounts from the Used Fuel Segregated Fund to the Decommissioning Segregated Fund.

Provincial Guarantee

In accordance with the *Nuclear Safety and Control Act* (Canada), the CNSC requires OPG to have sufficient funds available to discharge its existing nuclear waste management and nuclear decommissioning obligations. The CNSC process requires the CNSC financial guarantee requirement to be updated once every five years and for OPG to provide an annual report to the CNSC on the assumptions, asset values, and resulting financial guarantee requirements. The CNSC financial guarantee requirement calculation takes into account nuclear waste expected to be generated to the end of each year.

In November 2017, the CNSC accepted OPG's proposed 2018-2022 CNSC financial guarantee requirement to be satisfied by the forecast fair market value of the Nuclear Segregated Funds without the requirement of a Provincial Guarantee for the 2018-2022 period. As ~~required~~provided for by the terms of the ONFA, the Province is committed to provide a Provincial Guarantee to the CNSC as required, on behalf of OPG, should there be a shortfall between the CNSC financial guarantee requirement and the fair market value of the Nuclear Segregated Funds in the 2018-2022 period, as it has done in the past. OPG pays the Province an annual guarantee fee equal to 0.5 percent of the outstanding amount, if any, of the Provincial Guarantee.

The value of the Provincial Guarantee in effect through to the end of 2017 was $1,551 million. Based on this guarantee amount, OPG paid a guarantee fee of $8 million to the Province for each of 2016 and 2017.

Pension and Other Post-Employment Benefits

The determination of OPG's pension and OPEB costs and obligations is based on accounting policies and assumptions, as discussed below.

Accounting Policy

OPG's post-employment benefit programs consist of a contributory defined benefit registered pension plan, a defined benefit supplementary pension plan, and other post retirement benefits (OPRB) including group life insurance and health care benefits, and long-term disability (LTD) benefits. Post-employment benefit programs also are provided by the Nuclear Waste Management Organization (NWMO), which is consolidated into OPG's financial results. Unless otherwise noted, information on the Company's post-employment benefit programs is presented on a consolidated basis.

OPG accrues its obligations under pension and OPEB plans in accordance with US GAAP. The obligations for pension and OPRB are determined using the projected benefit method pro-rated on service. The obligation for LTD benefits is determined using the projected benefit method on a terminal basis. Pension and OPEB obligations are impacted by factors including interest rates, adjustments arising from plan amendments, demographic assumptions, experience gains or losses, salary levels, inflation, and health care cost escalation assumptions. Pension and OPEB costs and obligations are determined annually by independent actuaries using management's best estimate assumptions.

Pension fund assets include equity securities, corporate and government debt securities, pooled funds, real estate, infrastructure and other investments. These assets are managed by professional investment managers. The pension fund does not invest in equity or debt securities issued by OPG. Pension fund assets are valued using market-related values for purposes of determining the amortization of actuarial gains or losses and the expected return on plan assets. The market-related value recognizes gains and losses on equity assets relative to a six percent assumed real return over a five-year period.

Pension and OPEB costs include current service costs, interest costs on the obligations, the expected return on pension plan assets, adjustments for plan amendments and adjustments for actuarial gains or losses, which result from changes in assumptions and experience gains and losses. Past service costs or credits arising from pension and OPRB plan amendments are amortized on a straight-line basis over the expected average remaining service life to full eligibility of the employees covered by the corresponding plan. Past service costs or credits arising from amendments to LTD benefits are immediately recognized as OPEB costs in the period incurred. Due to the long-term nature of pension and OPRB liabilities, the excess of the net cumulative unamortized gain or loss, over 10 percent of the greater of the benefit obligation and the market-related value of the plan assets (the corridor) for each plan is amortized over the expected average remaining service life of the employees covered by the plan, which represents the period during which the associated economic benefits are expected to be realized by the Company. Actuarial gains or losses for LTD benefits are immediately recognized as OPEB costs in the period incurred.

OPG recognizes the funded status of its defined benefit plans on the consolidated balance sheets. The funded status is measured as the difference between the fair value of plan assets and the benefit obligation, on a plan-by-plan basis.

Actuarial gains or losses and past service costs or credits arising during the year that are not recognized immediately as components of benefit costs are recognized as increases or decreases in other comprehensive income (OCI), net of income taxes. These unamortized amounts in AOCI are subsequently reclassified and recognized as amortization components of pension and OPRB costs as described above.

As at December 31, 2017, the unamortized net actuarial loss and unamortized past service costs for the pension and OPEB plans totalled $4,148 million (2016 – $3,668 million). Details of the unamortized net actuarial loss and unamortized past service costs as at December 31, 2017 and 2016 are as follows:

(millions of dollars)	Registered Pension Plans 2017	2016	Supplementary Pension Plans 2017	2016	Other Post-Employment Benefits 2017	2016
Net actuarial gain not yet subject to amortization due to use of market-related values	**(418)**	(570)	**-**	-	**-**	-
Net actuarial loss not subject to amortization due to use of the corridor	**1,735**	1,619	**36**	34	**299**	267
Net actuarial loss subject to amortization	**2,333**	2,238	**80**	72	**79**	3
Unamortized net actuarial loss	**3,650**	3,287	**116**	106	**378**	270
Unamortized past service costs	**-**	-	**-**	-	**4**	5

OPG records an offsetting regulatory asset or liability for the portion of the adjustments to AOCI that is attributable to the regulated operations in order to reflect the expected recovery or refund of these amounts through future regulated prices charged to customers. For the recoverable or refundable portion attributable to regulated operations, OPG records a corresponding change in this regulatory asset or liability for the amount of the increases or decreases in OCI and for the reclassification of AOCI amounts into benefit costs during the period.

When the recognition of the transfer of employees and employee-related benefits gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement. A curtailment is the loss by employees of the right to earn future benefits under the plan. A settlement is the discharge of a plan's liability.

Accounting Assumptions

Assumptions are significant inputs to actuarial models that measure pension and OPEB obligations and related effects on operations. Discount rate, inflation rate and changes in salary levels are three critical assumptions in the determination of benefit costs and obligations. In addition, the expected long-term rate of return on plan assets is a critical assumption in the determination of registered pension plan cost, and the health care cost trend rate is a critical assumption in the determination of OPEB cost and obligations. These assumptions, as well as other assumptions involving demographic factors such as retirement age, mortality, and employee turnover, are evaluated periodically by management in consultation with independent actuaries. During the evaluation process, the assumptions are updated to reflect past experience and expectations for the future. Actual results in any given year will often differ from actuarial assumptions because of economic and other factors giving rise to actuarial gains and losses.

The discount rates, which are representative of the AA corporate bond yields, are used to calculate the present value of the expected future cash flows on the measurement date in order to determine the projected benefit obligations for the Company's employee benefit plans. A lower discount rate increases the benefit obligations. The weighted-average discount rate used to determine the projected pension and OPEB benefit obligations as at December 31, 2017 was 3.6 percent. This represents a decrease compared to the 3.9 percent discount rate that was used to determine the obligations as at December 31, 2016.

In 2016 and prior years, benefit costs were calculated using the same single weighted-average discount rates as reflected in the calculation of the benefit obligations. Effective January 1, 2017, OPG adopted a full yield curve approach to the estimation of the service and interest cost components of pension and OPEB costs, by applying the specific spot rates along the yield curve used in the determination of the projected benefit obligations to the relevant projected cash flows. The change improves the correlation between projected benefit cash flows and the corresponding yield curve spot rates, and provides a more precise measurement of service and interest costs. This change in the method was accounted for prospectively, as a change in estimate. The resulting reduction in pension and OPEB costs is estimated at approximately $135 million for the twelve months ended December 31, 2017. Approximately 90 percent of this reduction in pension and OPEB costs was attributed to the Company's regulated

business segments and therefore was offset by the impact of OEB-authorized regulatory accounts. The change does not affect the measurement of the total benefit obligation as the change in the current service and interest cost components from the previous method is offset by a corresponding change in the actuarial gain or loss recorded in AOCI.

The expected rate of return on plan assets is determined based on the pension fund's asset allocation and the expected return considering long-term risks and returns associated with each asset class within the plan portfolio. A lower expected rate of return on plan assets increases pension cost.

A new actuarial valuation of the OPG registered pension plan was filed with the Financial Services Commission of Ontario in September 2017 with an effective date of January 1, 2017. The annual funding requirements in accordance with the new actuarial valuation are outlined in the section, *Liquidity and Capital Resources* under the heading, *Contractual and Commercial Commitments*. OPG conducted a comprehensive actuarial valuation for accounting purposes of its pension and OPEB plans in 2017, using demographic data as at January 1, 2017 consistent with the new funding valuation and using assumptions as at December 31, 2017. As part of the valuation, the plans' demographic and other assumptions were reviewed and revised, as necessary, by independent actuaries.

The deficit for the registered pension plan, for accounting purposes, increased from $2,693 million as at December 31, 2016 to $3,081 million as at December 31, 2017. This increase was largely due to a re-measurement of the liabilities at the end of 2017 reflecting lower discount rates, partially offset by the excess of actual returns on the pension plan assets over interest costs on the liabilities during the year.

The projected benefit obligations for OPEB increased from $2,992 million as at December 31, 2016 to $3,190 million as at December 31, 2017. This increase was largely due to a re-measurement of the liabilities at the end of 2017 reflecting a decrease in the discount rates, partially offset by the updated, lower per capita health care claims costs assumption as part of the 2017 actuarial valuation.

A change in the following assumptions, holding all other assumptions constant, would increase (decrease) pension and OPEB costs for the year ended December 31, 2017 as follows:

(millions of dollars)	**Registered Pension Plans [1]**	**Supplementary Pension Plans [1]**	**Other Post-Employment Benefits [1]**
Expected long-term rate of return			
0.25% increase	(32)	n/a	n/a
0.25% decrease	32	n/a	n/a
Discount rate			
0.25% increase	(56)	(1)	(2)
0.25% decrease	59	1	13
Inflation			
0.25% increase	98	1	-
0.25% decrease	(91)	(1)	-
Salary increases			
0.25% increase	22	3	-
0.25% decrease	(20)	(2)	-
Health care cost trend rate			
1% increase	n/a	n/a	77
1% decrease	n/a	n/a	(29)

n/a – change in assumption not applicable.

[1] Excludes the impact of regulatory accounts.

Asset Retirement Obligation

OPG recognizes ARO for fixed asset removal and nuclear waste management liabilities, discounted for the time value of money. OPG estimates both the amount and timing of future cash expenditures based on the plans for fixed asset removal and nuclear waste management. The ARO is comprised of expected costs to be incurred up to and beyond termination of operations and the closure of nuclear and thermal generating plant facilities and other facilities. Costs are expected to be incurred for activities such as preparation for safe storage and safe storage of nuclear stations, dismantlement, demolition and disposal of facilities and equipment, remediation and restoration of sites, and the ongoing and long-term management of nuclear used fuel bundles and L&ILW material. The liabilities associated with the decommissioning of the nuclear generating stations and the long-term management of used nuclear fuel comprise the most significant amounts of the total obligation.

The nuclear decommissioning liability includes the estimated costs of closing the nuclear stations after the end of their service lives, which includes preparation and placement of the stations into a safe state condition followed by an assumed 30-year safe store period prior to station dismantlement and site restoration. Activities associated with the placement of stations into a safe state condition include de-fuelling and de-watering of the nuclear reactors. OPG is responsible for the nuclear waste management and nuclear decommissioning obligations associated with the Bruce nuclear generating stations and includes the associated costs in its ARO. Pursuant to the lease agreement, Bruce Power must return the two Bruce stations to OPG together, in a de-fuelled and de-watered state. As such, these de-watering and de-fuelling costs are not part of OPG's ARO.

The life cycle costs of L&ILW management include the costs of processing and storage of such radioactive wastes during and following the operation of the nuclear stations, as well as the costs of the ultimate long-term management of these wastes. The current assumptions used to establish the obligation for these costs include an L&ILW DGR facility to be constructed and operated by OPG, as discussed in the section, *Core Business, Strategy, and Outlook* under the heading, *Project Excellence*. To estimate the liability for nuclear used fuel management, OPG has adopted an approach consistent with the Adaptive Phased Management concept approved by the Government of Canada, which assumes a deep geologic repository for the long-term management of Canada's nuclear used fuel waste. The NWMO is responsible for the design and implementation of Canada's plan for the long-term management of used nuclear fuel.

The following costs are recognized as a liability on OPG's consolidated balance sheets:

- the present value of the costs of decommissioning the nuclear and thermal production facilities and other facilities after the end of their useful lives
- the present value of the fixed cost portion of nuclear waste management programs that are required based on the total volume of waste expected to be generated over the assumed lives of the stations
- the present value of the variable cost portion of nuclear waste management programs taking into account waste volumes generated to date.

The significant assumptions underlying operational and technical factors used in the calculation of the accrued liabilities are subject to periodic review. Changes to these assumptions, including changes to assumptions on the timing of the programs including construction of assumed waste disposal facilities, station end-of-life dates, waste disposal methods, financial indicators, decommissioning strategy, and the technology employed may result in significant changes to the value of the accrued liabilities. With programs of such long-term duration and the evolving technology to handle nuclear waste, there is a significant degree of inherent uncertainty surrounding the measurement of the costs for these programs. These costs may increase or decrease over time.

The estimates for the Nuclear Liabilities are reviewed on an ongoing basis as part of the overall nuclear waste management program. A comprehensive reassessment of all underlying assumptions and baseline cost estimates is performed periodically, at least once every five years, in line with the required ONFA reference plan update process. Changes in the Nuclear Liabilities resulting from changes in assumptions or estimates that impact the amount or

timing of the estimated undiscounted future cash flows are recorded as an adjustment to the liabilities. Upward revisions in the Nuclear Liabilities represent the present value of a net increase in future undiscounted cash flows determined using a current credit-adjusted risk-free rate. Downward revisions in the Nuclear Liabilities represent the present value of a net decrease in future undiscounted cash flows determined using the weighted average discount rate reflected in the existing liability. Resulting changes in the related asset retirement costs are capitalized as part of the carrying amount of nuclear fixed assets in service.

As of December 31, 2017, OPG recorded an increase of $188 million in the Nuclear Liabilities and associated asset retirement costs capitalized as part of carrying value of property, plant and equipment (PP&E) reflecting the change in the Pickering GS accounting end-of-life assumptions from December 31, 2020 for all operating units to December 31, 2022 for Units 1 and 4 and December 31, 2024 for Units 5 to 8. The increase in the liabilities is primarily due to higher fixed costs associated with the Used Fuel Disposal and L&ILW Storage programs, discounted using the current credit-adjusted risk-free rate of 2.94 percent. The adjustment did not impact net income for 2017. The adjustment is not expected to have a material impact on net income in 2018 as the associated impact on expenses is expected to be largely offset by OEB-authorized regulatory accounts. The change in accounting end-of-life assumptions for the Pickering GS are discussed in further detail in the section, *Core Business, Strategy, and Outlook* under the heading, *Operational Excellence – Electricity Generation Production and Reliability*.

For the purposes of calculating OPG's Nuclear Liabilities, as at December 31, 2017, consistent with the current accounting end-of-life assumptions, nuclear station decommissioning activities are projected to occur over approximately the next 80 years.

The liability for nuclear fixed asset removal and nuclear waste management on a present value basis as at December 31, 2017 was $20,077 million (2016 – $19,103 million). As at December 31, 2017, the undiscounted cash flows of expenditures for OPG's Nuclear Liabilities in 2017 dollars are as follows:

(millions of dollars)	**2018**	**2019**	**2020**	**2021**	**2022**	**Thereafter**	**Total**
Expenditures for nuclear fixed asset removal and nuclear waste management [1]	323	326	323	311	598	40,513	42,394

[1] The majority of the expenditures are expected to be reimbursed by the Nuclear Segregated Funds established by the ONFA. Any contributions required under the ONFA are not included in these undiscounted cash flows. Accounting for the Nuclear Segregated Funds is discussed in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

The liability for non-nuclear fixed asset removal was $344 million as at December 31, 2017 (2016 – $381 million). This liability primarily represents the present value of estimated costs of decommissioning OPG's thermal generating stations at the end of their service lives. OPG has updated the asset retirement obligations for the thermal generating stations as of December 31, 2017, based on a review of required decommissioning, clean-up and restoration activities, underlying economic assumptions and anticipated timing of these activities in line with current accounting end-of-life assumptions for the operating sites. For the shutdown Nanticoke and Lambton generating stations, the update reflects the estimated cost of executing current decommissioning plans. For the currently operating sites, OPG recognized a decrease of $18 million in the non-nuclear fixed asset removal liabilities and associated asset retirement costs capitalized as part of the carrying value of PP&E as at December 31, 2017. For the Nanticoke and Lambton sites, a reduction in the non-nuclear fixed asset removal liabilities and a gain of approximately $12 million was recorded in net income in the fourth quarter of 2017, in the, Services, Trading, and Other Non-Generation segment.

For the purpose of measuring the non-nuclear fixed asset removal liability, asset removal activities are assumed to take place approximately over the next one to 12 years. The amount of undiscounted estimated future cash flows associated with the thermal liabilities is approximately $400 million.

OPG has no legal obligation associated with the decommissioning of its hydroelectric generating facilities and the costs cannot be reasonably estimated because of the long service life of these assets. With either maintenance efforts or rebuilding, the water control structures are assumed to be used for the foreseeable future. Accordingly, OPG has not recognized a liability for the decommissioning of its hydroelectric generating facilities.

Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly arm's-length transaction between market participants at the measurement date. Fair value measurements are required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model.

The fair value of financial assets and liabilities for which quoted prices in an active market are available, including exchange traded derivatives and other financial instruments, are determined directly from those quoted market prices.

For financial instruments for which quoted market prices are not directly available, fair values are estimated using forward price curves developed from observable market prices or rates. The estimation of fair value may include the use of valuation techniques or models, based wherever possible on assumptions supported by observable market prices or rates prevailing at the consolidated balance sheet dates. This is the case for over-the-counter derivatives and securities, which include energy commodity derivatives, foreign exchange derivatives, interest rate swap derivatives, and fund investments. Pooled fund investments are valued at the unit values supplied by the pooled fund administrators. The unit values represent the underlying net assets at fair values, determined using closing market prices. Valuation models use general assumptions and market data and therefore do not reflect the specific risks and other factors that may affect a particular instrument's fair value. The methodologies used for calculating the fair value adjustments are reviewed on an ongoing basis to ensure that they remain appropriate. If the valuation technique or model is not based on observable market data, specific valuation techniques are used, primarily based on recent comparable transactions, comparable benchmark information, bid/ask spread of similar transactions, and other relevant factors.

For the financing receivables related to the Investment Interest acquired from the IESO, fair value is estimated to equal the fair value of the underlying debt due to the direct relationship of the asset, and the debt instruments that financed the acquisition.

OPG's use of financial instruments exposes the Company to certain risks, including credit risk, foreign currency risk and interest rate risk. A discussion of how OPG manages these and other risks is found under the section, *Risk Management*.

Recent Accounting Pronouncements Not Yet Adopted

The recent US GAAP accounting pronouncements related to revenue recognition, leases, and financial instruments are described below. Other recent accounting pronouncements applicable to OPG are outlined in Note 3 of the audited consolidated financial statements.

Revenue from Contracts with Customers

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09, *Revenue from Contracts with Customers* (Topic 606), which supersedes nearly all existing revenue recognition guidance, including industry-specific guidance, under US GAAP. The core principle of Topic 606 is to recognize revenues when promised goods or services are transferred to customers in an amount that reflects the consideration to which an entity expects to be entitled for those goods or services. Either a full retrospective

application or a modified retrospective application is required for annual periods beginning on or after January 1, 2018, including interim periods within that year. Early adoption is permitted.

OPG has assessed the impact of the standard on accounting for the Company's revenue streams and consolidated financial statements. OPG's major revenue streams include regulated generation revenue from base regulated prices and rate riders established by the OEB, as well as revenue from generation assets under long-term contractual arrangements with the IESO. OPG has completed its analyses of the impact of Topic 606 on all of its revenue streams, and has not identified any material differences in the timing or amount of revenue recognition for these streams.

The Company will apply the new revenue standard in its 2018 first quarter interim financial statements and is in the process of evaluating the additional disclosures required under the new standard.

Lease Accounting

In February 2016, the FASB issued ASU No. 2016-02, *Leases* (Topic 842). The update includes comprehensive changes to existing guidance for lease accounting, particularly for lessees, and aims to increase transparency and comparability among organizations by requiring the recognition of lease assets and lease liabilities on the balance sheet. The standard is effective for annual periods beginning after December 15, 2018, including interim periods within that year.

Under the current guidance, entities are required to use a modified retrospective approach for leases that exist, or are entered into, after the beginning of the earliest comparative period presented in the financial statements of the period of adoption. Under this method, Topic 842 would effectively be implemented by recognizing any adjustments stemming from the transition, as of beginning of the earliest comparative period presented in the entities' financial statements. Full retrospective application is prohibited. In January 2018, the FASB issued a proposed ASU wherein entities would be able to utilize an additional optional transition method of recording the cumulative impact of adopting the new lease standard to the opening balance in the initial period of adoption; with comparative periods continuing to be presented in accordance with the existing leasing standard, Topic 840 - *Leases*, including disclosures. [**MONITOR**] The Company will continue to monitor the status of this proposed ASU.

The FASB also issued ASU No. 2018-01, *Land Easement Practical Expedient for Transition to Topic 842* in January 2018. The amendments therein allows an entity to choose not to evaluate under Topic 842 land easements that exist or expired before the entity's adoption of the new leasing standard and that were not previously accounted for as leases under Topic 840.

The Company continues to implement and execute a comprehensive project governance framework, which comprises a Steering Committee, Implementation & Stakeholder Committee, Project Management Office, and various working groups in order to evaluate the implement the new standard. The working groups are represented by cross functional finance and non-finance stakeholders who will support the financial and operational implementation of the standard. The Company continues to evaluate the impact of the new leasing standard on its consolidated financial statements.

Recognition and Measurement of Financial Assets and Financial Liabilities

In January 2016, the FASB issued ASU No. 2016-01, *Financial Instruments – Overall: Recognition and Measurement of Financial Assets and Financial Liabilities*. Under the updated guidance, entities will have to measure equity investments at fair value and recognize any changes in fair value in net income. The update will be effective for OPG's 2018 fiscal year, including interim periods. As a result of this update, effective January 1, 2018, the available-for-sale (AFS) classification for equity securities will no longer be available, with any unrealized gains and losses related to such securities recognized in net income instead of OCI. Any unrealized gains and losses for AFS securities reported by OPG in AOCI as of the end of 2017 will be reclassified to retained earnings as of January 1, 2018. OPG's equity shareholdings in Hydro One are currently the Company's only AFS securities. As at December

31, 2017, these shares are valued on the consolidated balance sheet at $188 million, for which a loss of $8 million has been recorded in AOCI. OPG does not expect the new standard to have any other significant impact on its consolidated financial statements.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost

In March 2017, the FASB issued ASU No. 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. Under the new guidance, employers that sponsor defined benefit plans for pensions and/or other postretirement benefits are required to present the service cost component of net periodic benefit cost in the same statement of income line item as other employee compensation costs arising from services rendered during the period. The other components of the net periodic benefit cost are to be presented separately from the line item that includes the service cost and outside of any subtotal of income from operations, if such a subtotal is presented. In addition, the new guidance requires that only the service cost component of net benefit cost be eligible for capitalization.

This guidance is effective for fiscal years beginning after December 15, 2017, including interim periods of those years. The guidance is not expected to have a material impact on OPG's consolidated financial statements, as OPG currently capitalizes only the service cost component of post-retirement benefits costs. Additionally, OPG already includes the service cost component of post-retirement benefit costs with other compensation costs, within the operations, maintenance and administration expenses line item in the consolidated statements of income, and does not show a subtotal of income from operations. As such, the new guidance is not expected to affect the presentation of OPG's consolidated financial statements.

RISK MANAGEMENT

Overview

OPG faces various risks that could significantly impact the achievement of its strategic imperatives. The objective of risk management is to identify, assess and mitigate key risks, and to preserve and increase the value of the Shareholder's investment in the Company.

The Audit and Risk Committee is mandated to fulfill the oversight responsibilities of the Board of Directors for matters relating to the identification and management of the Company's key business risks. OPG's Enterprise Risk Management framework is designed to identify and evaluate risks on the basis of their potential impact on the Company's strategic imperatives and business plan objectives. Formal risk management policies, procedures and systems are in place to identify, assess and mitigate risks to the Company. Senior management also establishes set limits for the market risk, credit risk and energy trading activities of the Company.

The key risks to OPG's strategic imperatives are briefly described below. These are key risks that management believes could materially affect its business, revenues, net income, assets or capital resources. There may be further risks and uncertainties that are not presently known, or that are not currently believed to be material, that may in the future adversely affect the Company's performance or financial condition.

Risks to Achieving Operational Excellence

OPG is exposed to variable output from its existing generating stations that could adversely impact its financial performance. The operational risks of a station are generally a function of its age, human performance, and the technology used.

Asset Conditions and Generation Variability

The uncertainty associated with electricity production by OPG's generating units is primarily driven by the condition of station components and systems, which are subject to the effects of aging and the manner in which the units operate. To safely operate the units to meet electricity system requirements, a unit could be derated resulting in reduced generation. The primary implications of these risks may include additional safety requirements, lower than expected generation and revenues, and higher operating or capital costs. To respond to this risk, OPG continues to:

- monitor performance, implement extensive inspection and maintenance programs;
- identify future work required to sustain and, as appropriate, upgrade a station equipment; and
- undertake projects required to reliably operate within design and operating parameters.

Extension of Commercial Operations at Pickering to 2024

In January 2016, the Province of Ontario announced its approval of OPG's plan to pursue the continued safe and reliable operation of the Pickering GS to 2024. Under OPG's plan, the six operating units at the Pickering GS would operate until 2022, at which point two units would be shut down and the remaining four units would continue to operate until 2024. The current operating licence for the Pickering GS, which expires in August 2018, was issued in 2013 assuming that the station would shut down in 2020. Technical assessments have been completed to determine the ability of the Pickering units to continue to be fit for service to support extended operations. There is high technical confidence in the programs and provisions in place to operate the station to the end of 2024.

Inability to extend operations as planned would result in a reduction of OPG's future generation revenue and cash flows and lead to the advancement of station shutdown and decommissioning expenditures.

Risk factors for extended operations include the discovery of unexpected conditions, equipment failures, the state of critical plant components that are reaching end-of-life and a requirement for significant plant modifications. To mitigate these risks, OPG has implemented actions recommended from the technical assessments as part of the outage work program. OPG has also incorporated those actions into the comprehensive inspection and maintenance program under the Life Cycle Management Plan.

Supply Chain

OPG's ability to operate effectively is in part dependent upon timely access to equipment, materials, and service suppliers. Loss of key equipment, materials and service suppliers, particularly for the nuclear business, could affect OPG's operations and execution of major capital projects. OPG mitigates this risk, to the extent possible, through contract negotiations, contract terms, vendor monitoring, diversification of supplier base and business continuity plans.

Cyber Security

OPG's operations depend in part, on the efficient operation and management of the Company's complex information technology and operational systems in a secure, vigilant and resilient manner that minimizes cyber risks. Cyber security incidents may have an adverse impact on OPG's reputation, energy production, and public and employee safety.

Cyber security incidents have been on the rise for the past few years and this trend is only expected to intensify as global reliance on technology increases. OPG has strategies in place to prepare for, respond to, and recover from cyber security incidents. OPG continuously monitors, assesses, and improves the effectiveness of its strategies and program considering leading industry practices and remains proactive in information and intelligence sharing to learn and adapt to the changing cyber environment. In 2017, the media reported several worldwide cyber-attacks, such as WannaCry and Petya, which impacted multiple sectors including power and utilities. OPG's operational responses to those cyber-attacks were timely and effective resulting in no or low operational impact to OPG.

As a registered Ontario market participant, OPG must comply with reliability standards that apply to the Bulk Electric System elements specified under North American Electric Reliability Corporation and the relevant Bulk Power System facilities as determined by the Northeast Power Coordinating Council. In addition, OPG's nuclear cyber assets are subject to CNSC licensing conditions and regulatory requirements. For other cyber assets not subject to applicable regulatory requirements, OPG has adopted a risk-based approach based on the National Institute of Standards and Technology cyber security framework to manage its cyber security. Policies are in place to manage the Company's cyber risks and programs which are subject to oversight by management and the Board.

Regulatory Compliance

OPG is subject to extensive federal and provincial legislation and regulations by various entities such as the OEB, CNSC and the IESO.

The uncertainty associated with nuclear regulatory compliance is driven by plant aging, changes to technical codes, and challenges raised by the public at regulatory hearings, particularly in the areas of safety, environment and emergency preparedness. Addressing these requirements could add to the cost of operations, including replacement or modification of a station component or additional requirements for waste management. In some instances, these requirements may result in a reduction or elimination of the productive capacity of a station.

The Provincial agency, Office of the Fire Marshal and Emergency Management (OFMEM) is required to periodically update the Provincial Nuclear Emergency Response Plan (PNERP). In 2016, the CNSC advised the OFMEM to consider more severe accidents in the update to the PNERP, which may result in potential changes to the planning basis. Potentially, these changes may include new protective requirements and expansion of the emergency plan requirements for Pickering. In December 2017, the Province approved the updated PNERP Master Plan. The development of a detailed Implementing Plan for the Pickering GS is in progress. To date, there is no significant impact on OPG from the updated PNERP.

In December 2015, the CNSC granted the Darlington GS a ten-year operating licence, valid until November 30, 2025. The new licence spans most of the planned duration of the Darlington Refurbishment project, which provides greater regulatory stability and reduces regulatory risk. As discussed in the section, *Core Business, Strategy and Outlook*, under the heading, *Nuclear Operations*, the plan to extend Pickering operations to 2024 is subject to the CNSC's approval of the Pickering licence renewal application and other regulatory requirements as set out by the CNSC.

Nuclear Waste Management

The handling, storage and disposal of nuclear waste exposes OPG to various risks that it manages in accordance with the applicable regulatory requirements. Additionally, the interim storage of nuclear waste is subject to rigorous oversight and monitoring.

Currently, there are no licenced facilities in Canada for the permanent disposal of used nuclear fuel or L&ILW. The risks to OPG's proposed L&ILW DGR for the safe long-term management of L&ILW are discussed below under the heading, *Risks to Achieving Project Excellence – Deep Geologic Repository for Low and Intermediate Level Waste*.

Human Resources and Organizational Structure

The development of new leaders and retention of staff in critical roles is a key factor to OPG's success. The risk associated with the alignment and availability of skilled and experienced resources continues to exist for OPG in specific areas, including leadership and project management positions. To mitigate this risk, OPG continues to focus on succession planning, leadership development and knowledge management programs to improve the capability of its workforce. OPG expects to meet the human resource needs of the business by developing existing employees and hiring in specific areas, while continuing to leverage attrition through realignment of work and streamlining of processes, where appropriate.

Labour Relations

As of December 31, 2017, approximately 88 percent of OPG's regular labour force was represented by a union. The collective agreements with the PWU and The Society are due for renewal in 2018. There is a risk that OPG may not be able to negotiate terms that allow for compensation levels consistent with its rate orders.

OPG's current collective agreements with the PWU expires on March 31, 2018 and renewal negotiations began in early 2018. In the event of a labour disruption by the PWU, OPG could face financial or reputational implications. OPG has contingency plans in place to minimize the impact. **[MONITOR]**

The collective agreement between OPG and The Society expires on December 31, 2018 and renewal negotiations are expected to begin in mid-2018. The parties do not have the right to strike or lock-out. If the parties are unable to reach an agreement, the terms of the new collective agreement would be decided through interest mediation/arbitration.

Health and Safety

OPG's operations involve inherent occupational safety risks and hazards that could impact the achievement of the Company's health and safety goals. OPG is committed to continuous improvement and achievement of its ultimate goal of zero injuries through a formal enterprise-wide safety management system and by continuing to foster a strong health and safety culture among its employees and contractors. The safety management system serves to focus the Company on proactively managing safety risks and hazard exposures to employees and contractors. OPG also strategically engages with external parties for benchmarking and auditing. This ensures that OPG's management system achieves its intended results and maximizes the opportunity to incorporate program improvements.

Business Continuity and Emergency Management

OPG may be exposed to natural, technological or human-caused hazards including significant events against which it is not fully insured or indemnified; or to parties that fail to meet their indemnification obligations. These hazards have the potential to disrupt operations resulting in decreased generation revenue or additional costs to repair damages and restore operations.

OPG's business continuity program provides a framework to build resilience into critical business processes to ensure continued operation of critical business functions. OPG's emergency management program is designed to ensure that the Company can manage an emergency in a timely and effective manner. OPG's plans and implementation procedures identify immediate response actions to be taken to protect the health and safety of workers and the public, and to limit the impact of the incident on site security, production capability and the environment. The program elements are designed to meet legal and regulatory requirements.

Risks to Achieving Project Excellence

OPG is undertaking several capital intensive projects with significant investments. There may be an adverse effect on the Company if it is unable to: obtain necessary approvals; raise the necessary funds; effectively manage the projects on time and on budget; or fully recover capital costs and earn an appropriate return on investment. These projects may also have a significant impact on OPG's borrowing capacity and credit rating. Some projects may be ultimately reassessed as being uneconomic. The risks associated with OPG's current major projects are described below.

Darlington Refurbishment

There are financial and reputational risk exposures for OPG if actual costs exceed the budget or if OPG does not meet the project schedule. In addition, failure to achieve the objectives of the refurbishment project may result in future forced outages and more complex planned outages, potentially impacting the post-refurbishment performance or useful life of the units. Failure to carry out the refurbishment of the first unit as planned may result in the Province

exercising an off-ramp for the refurbishment of the remaining units. In January 2018, Refurbishment senior management met with the Minister of Energy, Cabinet and Treasury Board to provide an update on the status of the Darlington Refurbishment project and to request a decision to not exercise the Unit 3 off-ramp. The request was based on the performance to date on the Unit 2 project. Additionally, OPG continues to apply lessons learned that have been captured on the execution of Unit 2 into the planning of future units.

Commented [RK1]: Is Energy okay with this wording? Does such disclosure normally reference meetings of Cabinet or its committees?

There are a number of specific risks that OPG is managing and mitigating in relation to the Darlington Refurbishment project, which include OPG and vendor performance risks, delay or productivity risks, financial risks related to escalation of costs, technical risks such as equipment conditions resulting in additional scope and execution risks. A large portion of the costs for the Darlington Refurbishment project is being paid to contractors and suppliers, including vendors that will engineer, procure and construct components of the project. There is a risk that, as the volume of work increases significantly, vendor capability, capacity and performance shortfalls may impact project objectives and deliverables.

OPG systematically manages the risks associated with the Darlington Refurbishment project through robust risk management practices to achieve project deliverables on time and budget with quality. OPG engaged in an extensive five-year project planning phase to determine the project scope and to rigorously estimate costs. During this phase, OPG also took into account major lessons learned from other nuclear refurbishments and large scale, complex projects. In order to fully define the scope and material requirements for the project, the planning phase included the completion of detailed designs before proceeding with the execution of the unit refurbishments. Further risk mitigation has been implemented through the construction of a full scale model training reactor, which allows for simulations and training for unit refurbishment execution tasks.

OPG's risk management strategy aims to ensure that contractors are held accountable and appropriate incentives and disincentives are in place. There is also an increased risk of contractor initiated safety events, which may impact OPG's reputation. Mitigating actions include:

- Collaborative training and planning with vendors on executing work safely;
- An enhanced human performance program;
- Increased field presence by supervisory staff; and
- Collaboration with Bruce Power to streamline processes and reduce burden on vendors.

OPG is also managing other ongoing risks that could potentially impact the project, including those related to continuity of skilled leaders within OPG and its vendor partners, as well as the availability of technical resources to support the project through execution.

Both management and Board of Directors have engaged Independent, third-party oversight for the execution phase of the project.

Deep Geologic Repository for Low and Intermediate Level Waste

OPG, with the support of Bruce County municipalities, is proposing to construct and operate a deep geologic repository for the safe long-term management of L&ILW. While broad local community support for the proposed L&ILW DGR is stable, OPG continues its engagement with the SON towards securing support for the project.

In August 2017, the federal Minister of Environment and Climate Change wrote to OPG and commended OPG for its collaborative work with the SON and for the practical demonstration of reconciliation practices. In light of that work, the Minster requested OPG to update its analysis of the potential cumulative effects of the DGR project on the physical and cultural heritage of the SON, taking into account the results of the SON Community Process. OPG continues to work with the SON, however the timing and outcome of the SON Community Process and the EA decision by the Minister are uncertain.

Risks to Maintaining Financial Strength

Risks related to rate regulation, financial markets and long-term obligations could significantly impact OPG's financial performance. The Company is also exposed to risks such as weak electricity demand, displacement of generation by competitors and financial risk associated with energy trading.

Rate Regulation

There is an inherent risk that regulated prices established by the OEB may not provide for the recovery of actual costs incurred by OPG's regulated operations or allow the regulated operations to earn an appropriate rate of return. This could occur if, in setting regulated prices, the OEB makes adjustments to forecasts submitted by OPG, if actual production and costs significantly differ from the forecasts approved by the OEB, or if OPG is unable to achieve OEB-approved stretch factors included in regulated prices under incentive ratemaking. Differences between OPG's actual and forecast production and costs could be due to factors such as outages or project execution risks. In providing evidence in support of its applications for regulated prices, OPG aims to clearly demonstrate to the OEB that the costs for the regulated operations are reasonable, prudently incurred and should be fully recovered from customers.

Certain differences between elements of OEB-approved revenue requirements and OPG's actual results are recorded in OEB-approved variance and deferral accounts for future review by the OEB. Additionally, these accounts may be subject to an OEB prudence review. There is uncertainty associated with the outcomes of future proceedings for the recovery or refund of these balances.

Nuclear Rate Smoothing Proposal

Consistent with the requirements of *Ontario Regulation 53/05*, OPG's nuclear rates will be smoothed as a result of OPG deferring a portion of the approved annual nuclear revenue requirements during the period from January 1, 2017 to the end of the Darlington Refurbishment project in a Rate Smoothing Deferral Account.

There is a risk that the magnitude of the deferral ordered by the OEB will result in regulated prices that do not provide sufficient cash flow to the Company for meeting its financial objectives in an optimal manner, including ensuring sufficient liquidity, cost effectively funding the Darlington Refurbishment project and other expenditures and maintaining the Company's investment grade credit rating. Maintaining adequate levels of credit metrics will support OPG's investment grade credit rating. As such, OPG requested the OEB to consider the impact on its credit rating when smoothing the nuclear base rates. **[MONITOR]**

Post-Employment Benefit Obligations Risk

OPG's post-employment benefit obligations include pension, group life insurance, health care benefits, and LTD benefits. OPG's post-employment benefit obligations and costs and pension plan contributions could be materially affected in the future by numerous factors including: changes in discount rates, inflation rates and other actuarial assumptions; future investment returns; experience gains and losses; the funded status of the pension plans; changes in benefits; changes in the regulatory environment including potential changes to the *Pension Benefits Act* (Ontario); changes in OPG's operations and the measurement uncertainty incorporated into the actuarial valuation process.

The OPG registered pension plan, which covers most of OPG's employees and retirees, is a contributory defined benefit plan that is indexed to inflation up to a certain maximum. Contributions to the OPG registered pension plan are determined by actuarial valuations, which are filed with the appropriate regulatory authorities at least every three years. Future actuarial valuations could increase OPG's funding requirements due to market and economic-related conditions. A significant decline in the financial markets could trigger an immediate requirement to update the actuarial valuation based on declines in the funded status. OPG continues to assess the requirements for contributions to the registered pension plan, including the timing of future actuarial valuations. OPG's OPEB

obligations are not funded and the associated employee benefits are paid from cash flows provided by operating activities or other sources of liquidity.

Nuclear Liabilities and Nuclear Segregated Funds

As required by the CNSC, OPG is responsible for the management of used nuclear fuel and L&ILW and the decommissioning of its nuclear stations and waste management facilities. The cost estimates for OPG's nuclear waste management and decommissioning obligations are based on multiple underlying assumptions and estimates that are inherently uncertain and may evolve over time. The assumptions include station end-of-life dates, waste volumes, waste disposal methods, the timing of construction of assumed waste disposal facilities, waste packaging systems, decommissioning strategy and financial indicators. To address the inherent uncertainty, OPG undertakes to perform a comprehensive review of the underlying assumptions and baseline cost estimates at least once every five years, in line with the required ONFA Reference Plan update process.

The most recent comprehensive update of the nuclear waste management and decommissioning obligations was approved by the Province in December 2016 as part the 2017 ONFA Reference Plan. An approved ONFA Reference Plan determines OPG's contributions to the Nuclear Segregated Funds. Based on the 2017 ONFA Reference Plan, no contributions are currently required to the Nuclear Segregated Funds. Additional contributions may be required should the Nuclear Segregated Funds be in an underfunded position in the future.

Nuclear Funds are segregated under ONFA in order to fund the long-term waste management, used fuel management and decommissioning expenditures. These funds are managed to achieve, in the long term, the target rate of return based on the discount rate specified in the ONFA. Investments in the Nuclear Segregated Funds are allocated to certain asset classes including fixed income securities, domestic and international equity securities, pooled funds, infrastructure, agriculture and real estate. The rates of return earned on these segregated funds may vary depending on current and future financial market conditions. The asset mix of the funds is determined jointly by OPG and the Province in accordance with the ONFA.

Under ONFA, OPG bears the market risk related to the portion of the Nuclear Segregated Funds set aside for:

- decommissioning of Pickering and Darlington nuclear generating stations; and
- long-term management of the irradiated used fuel bundles in excess of the first 2.23 million bundles and L&ILW after the respective Pickering GS and Darlington GS shut down.

A significant drawdown in the Nuclear Funds would first reduce the surplus in the respective funds before impacting OPG's net income. As such, the income statement impact of this risk is reduced when the Nuclear Segregated Funds are in a fully funded position.

Liquidity

OPG operates in a capital intensive business. Significant financial resources are required to fund major development and other capital improvement projects, including the Darlington Refurbishment project. In addition, the Company has other significant disbursement requirements including pension contributions, payments towards OPEB and other benefit plans, funding ongoing operations, debt maturities with the OEFC, OPG's investment in the Fair Hydro Plan and investments in new generating capacity and other business development opportunities. OPG must ensure that it has the financial capacity and sufficient access to cost effective financing sources to fund its capital requirements and other disbursements. In support of this objective, OPG utilizes multiple sources and forecasts availability of funds, actively monitors funding requirements and is focused on maintaining its investment grade credit rating. The Company's ability to arrange sufficient and cost-effective debt financing could be adversely affected by a number of factors, including, financial market and general economic conditions, the regulatory environment in Ontario, the Company's results of operations and financial conditions, the ratings assigned to the Company by credit rating agencies and the current timing of debt maturities.

A discussion of corporate liquidity is included in the section, *Liquidity and Capital Resources*.

Commodity Markets

Changes in the market price of fuels used to produce electricity can adversely impact OPG's earnings and cash flow from operations.

To manage the risk of unpredictable increases in the price of fuels, the Company has fuel hedging programs, which include using fixed price and indexed contracts.

The percentages hedged of OPG's fuel requirements are shown in the following table. These amounts are based on yearly forecasts of generation and supply mix and, as such, are subject to change as these forecasts are updated.

	2018	2019	2020
Estimated fuel requirements hedged [1]	72.9%	68.2%	65.3%

[1] Represents the approximate portion of megawatt-hours of expected generation production (and year-end inventory targets) from each type of OPG-operated facility (nuclear, hydroelectric and thermal) for which the Company has entered into contractual arrangements or obligations in order to secure the price of fuel, or which is subject to regulation. In the case of hydroelectric generation, this represents the gross revenue charge and water rental charges. Excess fuel inventories (nuclear and thermal) in a given year are attributed to the next year for the purpose of measuring hedge ratios.

Foreign Exchange

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are primarily denominated in, or tied to US dollars (USD). To manage this risk, OPG employs various financial instruments such as forwards and other derivative contracts, in accordance with approved risk management policies. As at December 31, 2017, OPG had total foreign exchange contracts outstanding with a notional value of USD $5 million.

Trading

OPG's financial performance can be affected by its trading activities. OPG's electricity trading operations are closely monitored, with total exposures measured and reported to senior management on a daily basis. The main metric used to measure the financial risk of trading activity is Value at Risk (VaR). VaR is defined as a probabilistic maximum potential future loss expressed in monetary terms for a portfolio based on normal market conditions over a set period of time. During 2017, the VaR utilization ranged between $0.1 million and $0.4 million, compared to between nil and $1.5 million in 2016.

Credit

The Company's credit risk exposure is a function of its electricity sales, trading and hedging activities, treasury activities including investing and commercial transactions with various suppliers of goods and services. OPG's credit risk exposure relating to electricity sales is considered low as the majority of sales are through the IESO-administered spot market. The IESO oversees the credit worthiness of all market participants. In accordance with the IESO's prudential support requirements, market participants are required to provide collateral to cover funds that they might owe to the market.

The following table summarizes OPG's credit exposure to all counterparties from electricity transactions and trading as at December 31, 2017:

	All Counterparties		Largest Counterparties	
Credit Rating [1]	**Number of Counterparties** [2]	**Potential Exposure** [3] *(millions of dollars)*	**Number of Counterparties**	**Potential Exposure** *(millions of dollars)*
Investment grade	15	18	5	14
IESO [4]	1	360	1	360
Total	16	378	6	374

[1] Credit ratings are based on OPG's own analysis, taking into consideration external rating agency analysis where available, as well as recognizing explicit credit support provided through parental guarantees, Letters of Credit or other forms of security.

[2] OPG's counterparties are defined on the basis of individual master agreements.

[3] Potential exposure is OPG's statistical assessment of maximum exposure over the life of each transaction at a 95 percent confidence interval.

[4] Credit exposure is an estimate of the short-term receivable amount arising from OPG's electricity sales into the IESO market. The credit exposure and associated receivable vary each month based on electricity sales. The monthly receivable from the IESO is typically paid to OPG in the subsequent month as per the IESO payment schedule.

Other major components of OPG's credit risk exposure include those associated with vendors that are contracted to provide services or products. OPG manages its exposure to various suppliers or counterparties by evaluating their financial condition and ensuring that the Company holds appropriate collateral or other forms of security.

Contracted Generation

The Company's generating stations that operate under ESAs with the IESO or other long-term contracts are subject to several obligations, including but not limited to:

- availability targets;
- monthly and annual reporting; and
- must offer obligations, as specified in their respective contracts.

OPG could incur penalties up to and including termination of the respective contract if these facilities fail to meet their contractual obligations. This risk is mitigated through:

- education of staff who work with these facilities;
- continuous communication between staff managing the contracts and staff managing the stations;
- processes that monitor and address contractual obligations and milestones; and
- the implementation of maintenance, capital investment (approved by the IESO when required by the contracts) and other programs.

OPG's owned and co-owned thermal generating stations operate under ESAs with the IESO or other long-term agreements. While OPG expects that its thermal generating stations will continue to provide capacity to the market over the term of the respective agreements, there is a risk that, upon expiry of the current agreements, subsequent contracts for these stations may not be available or may not be financially viable. The Thunder Bay Biomass ESA is the first such contract to reach the end of its term, scheduled for early 2020.

Ontario Electricity Market

OPG's revenue can be impacted by external factors related to the electricity market including: the entrance of new participants into the Ontario market; the competitive actions of market participants; Ontario electricity demand; changes in the regulatory environment; and wholesale electricity prices in the interconnected markets.

The IESO is in the preliminary stages of a Market Renewal Program, which is expected to result in a fundamental redesign of Ontario's electricity markets and may impact OPG depending on the market design that is implemented. To mitigate this risk, OPG is actively participating in Market Renewal stakeholder committees as well as continuing to collaborate with the IESO.

Ownership by the Province

The Province owns all of OPG's issued and outstanding common shares. Accordingly, the Province, as represented by the Ontario Ministry of Energy, has the authority to make appointments to OPG's Board of Directors. OPG could be subject to Shareholder direction, under Section 108 of the OBCA that can directly influence major decisions. These directions could include those related to project development, timing and strategy of applications for regulated prices, acquisitions and asset divestitures, financing and capital structure. As a result, OPG could be required to undertake activities that result in increased expenditures, or that reduce revenues or cash flows relative to the business activities or strategies that would have otherwise been undertaken. In addition, the obligation of OPG's Shareholder to respond to a broad range of matters in its role as the Government of Ontario may compete with OPG's commitment to maximize the return on the Shareholder's investment in the Company. This includes, but is not limited to, the Province's response to mitigate the impact of rising electricity prices on consumers.

Government Legislation and Regulation Change

OPG's core business and strategy may be impacted by changes in federal and provincial legislation and regulations. Matters that are subject to regulation include, among others, rate regulation, electricity generating operations, nuclear waste management and nuclear decommissioning, the Ontario electricity market and taxation. Regulatory bodies may change or enact regulations or rules that could increase OPG's costs, decrease OPG's revenue, or limit the Company's ability to recover appropriate costs or earn a return on the assets.

The next Ontario provincial election is set to take place in June 2018 and electricity rates are a focus of each party's platform. Depending on the outcome of the election, there may be significant legislative changes that could impact OPG.

Since legal requirements are subject to change and to interpretation, OPG is unable to predict the impact of such changes on the Company and its operations. To mitigate legislative risks, OPG continues to monitor and actively engage with the federal and provincial governments in order to determine if future legislation will impact the Company.

Litigation

OPG or its subsidiaries are involved in various legal proceedings covering a range of matters arising out of their business activities. Each of these matters is subject to various uncertainties and some of these matters may be resolved unfavourably. Refer to Note 16 of OPG's 2017 audited consolidated financial statements under the heading, *Litigation* for further details.

Risks to Maintaining Social Licence

OPG is exposed to risks associated with its social licence and public profile due to changes in the opinions of:

- Various stakeholders, including Ontario electricity customers, local communities, government agencies; and
- Indigenous communities.

Maintaining public trust and meeting stakeholders and Indigenous communities' expectations are critical to OPG's success. OPG focuses on building and maintaining its social licence and corporate reputation through safe, reliable, environmentally-responsible operations as well as corporate citizenship initiatives across the province. The inability to maintain safe, reliable operations could negatively impact OPG's reputation and result in a loss of public support.

Ontario Fair Hydro Plan Act

The Fair Hydro Act received Royal Assent and came into force on June 1, 2017. As the Financial Services Manager under the Act, OPG's reputation could potentially be adversely impacted through this involvement and through stakeholder opinions related to this involvement.

Indigenous Communities

The quality of OPG's relationships and the outcome of negotiations with Indigenous communities may impact OPG's project and financial performance, as well as its social licence to operate.

OPG may be subject to claims by Indigenous communities. These claims stem from projects and generation development related to the operations of OPG and historic operations of OPG's predecessor company, Ontario Hydro, which may have impacted the Aboriginal and/or Treaty rights of Indigenous communities.

OPG has an Indigenous Relations Policy, which sets out the Company's commitment to proactively build and maintain positive relationships with Indigenous communities. OPG has been successful in working collaboratively with Indigenous communities to resolve a number of past grievances. However, the outcome of ongoing and any future negotiations depends on a number of factors, including legislation and regulations and precedents created by court rulings, which are subject to change over time. OPG pursues generation-related developments in partnerships with Indigenous communities on the basis of long-term mutually beneficial commercial arrangements.

Environmental Risks

OPG's operations and facilities are subject to environmental compliance obligations at the municipal, provincial and federal levels that include protection of land, water, air, living organisms and natural systems. A failure to comply with applicable environmental laws may result in enforcement actions, remediation actions or restrictions to operations. Changes in compliance obligations can result in new operational requirements and increased costs.

OPG has an ISO 14001 registered EMS to manage its environmental responsibilities. For further information, see discussion in the section, *Core Business, Strategy, and Outlook* under the heading, *Environmental Performance*.

OPG recognizes that efforts are required to plan for the impacts of climate change and has identified climate change adaptation as a strategic priority for the company. OPG monitors developments in climate science, adaptation activities, and potential changes to policy and regulatory requirements. OPG continues to work with stakeholders to better define adaptation requirements through analysis and understanding of impacts on watersheds, equipment and the electricity market. OPG undertakes a risk-based analysis to determine the extent of adaptation requirements to reduce the impact of climate change on its operations, and also collaborates with all levels of government and industry to increase the resiliency of the electricity infrastructure.

A carbon cap and trade program became effective in Ontario in January 2017. The program is not expected to have a material adverse economic impact on OPG due to the Company's low GHG emissions. Further details can be found in the section, *Core Business, Strategy and Outlook* under the heading, *Environmental Performance*.

RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One, the IESO and the OEFC. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly-owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions for the years ended December 31 are summarized below:

	2017		2016	
(millions of dollars)	**Revenue**	**Expense**	**Revenue**	**Expense**
Hydro One				
Electricity sales	**8**	**-**	6	-
Services	**1**	**10**	1	5
Dividends	**7**	**-**	6	-
Province of Ontario				
Change in Decommissioning Segregated Fund amount due to Province [1]	**-**	**456**	-	192
Change in Used Fuel Segregated Fund amount due to Province [1]	**-**	**591**	-	235
Hydroelectric gross revenue charge	**-**	**110**	-	120
ONFA guarantee fee	**-**	**8**	-	8
Other	**-**	**2**	-	-
OEFC				
Hydroelectric gross revenue charge	**-**	**216**	-	203
Interest expense on long-term notes	**-**	**158**	-	169
Income taxes, net of investment tax credits	**-**	**246**	-	104
IESO				
Electricity related revenue	**4,802**	**-**	5,082	-
Fair Hydro Trust	**4**	**3**	-	-
	4,822	**1,800**	5,095	1,036

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at December 31, 2017 and December 31, 2016, the Nuclear Segregated Funds were reported net of amounts due to the Province of $4,462 million and $3,415 million, respectively.

The receivable, AFS securities, payable and long-term debt balances between OPG and its related parties are summarized below:

(millions of dollars)	**December 31 2017**	**December 31 2016**
Receivables from related parties		
Hydro One	**1**	1
IESO – Electricity related receivables	**354**	421
IESO – Fair Hydro Trust [1]	**7**	-
OEFC	**-**	1
PEC	**4**	4
Province of Ontario	**3**	2
Financing receivables		
IESO – Fair Hydro Trust	**1,179**	-
Available-for-sale securities		
Hydro One shares	**188**	212
Accounts payable and accrued charges		
Hydro One	**1**	-
OEFC	**52**	61
Province of Ontario	**9**	2
IESO – Electricity-related payables	**5**	2
IESO – Fair Hydro Trust	**3**	-
Long-term debt (including current portion)		
Notes payable to OEFC	**3,195**	3,295

[1] Balance consists of unbilled revenue.

OPG holds interest-bearing Province of Ontario bonds in the Nuclear Segregated Funds and the OPG registered pension fund. As at December 31, 2017, the Nuclear Segregated Funds held $1,503 million of interest-bearing Province of Ontario bonds. As at December 31, 2016, the Nuclear Segregated Funds and the registered pension fund held $1,652 million and $284 million of interest-bearing Province of Ontario bonds, respectively. These bonds are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

In December 2017, the Trust purchased its first tranche of Investment Interest from the IESO for an exchange amount of $1.18 billion, which has been classified as a financing receivable on OPG's consolidated balance sheet. The transaction was settled in cash using proceeds from the Trust's issuance of senior and subordinated debt. Pursuant to the general regulation of the Act, the IESO is required to pay and remit carrying costs of the Trust, excluding repayment of principal on any debt obligations, up to July 31, 2021. Commencing May 1, 2021, Specified Consumers will be invoiced by their local distribution company for the Clean Energy Adjustment to pay financing and other costs of the Trust. These funds will be remitted to the Trust through the IESO and will be used to settle all funding and other related expenses of the Trust that underlie the financing receivable.

As at December 31, 2017, OPG's consolidated balance sheet included approximately $7 million of unbilled revenue from the IESO primarily for OPG's general fee for 2017 as Financial Services Manager relating to incurred third-party and certain direct labour costs. In February 2018, OPG submitted to the OEB its proposed general fee for 2017 in the amount of approximately $6 million for review pursuant to the requirements of the general regulation of the Fair Hydro Act. Once approved, the fees will be remitted to the Trust by the IESO and the Trust will pay OPG's fees as Financial Services Manager.

INTERNAL CONTROLS OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

Management, including the President and Chief Executive Officer (President and CEO) and the Chief Financial Officer (CFO), are responsible for maintaining Disclosure Controls and Procedures (DC&P) and Internal Controls over Financial Reporting (ICOFR). DC&P is designed to provide reasonable assurance that all relevant information is gathered and reported to senior management, including the President and CEO and the CFO, on a timely basis so that appropriate decisions can be made regarding public disclosure. ICOFR is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the financial statements in accordance with US GAAP.

There were no changes in OPG's ICOFR during the year ended December 31, 2017 that have materially affected or are reasonably likely to materially affect OPG's ICOFR.

Management, including the President and CEO and the CFO, concluded that, as of December 31, 2017, OPG's DC&P and ICOFR (as defined in National Instrument 52-109 – *Certification of Disclosure in Issuers' Annual and Interim Filings*) were effective.

FOURTH QUARTER

Discussion of Results

(millions of dollars) (unaudited)	Three Months Ended December 31 2017	2016
Revenue	**1,619**	1,388
Fuel expense	**171**	186
Gross margin	**1,448**	1,202
Operations, maintenance and administration	**770**	686
Depreciation and amortization	**162**	316
Accretion on fixed asset removal and nuclear waste management liabilities	**251**	233
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(222)**	(126)
Earnings from Fair Hydro Trust	**(1)**	-
Income from investments subject to significant influence	**(9)**	(9)
Property taxes	**10**	11
Restructuring	**-**	6
Income before other losses, interest, and income taxes	**487**	85
Other losses	**1**	6
Income before interest and income taxes	**486**	79
Net interest expense	**39**	28
Income before income taxes	**447**	51
Income tax expense	**81**	59
Net income (loss)	**366**	(8)
Net income (loss) attributable to the Shareholder	**362**	(13)
Net income attributable to non-controlling interest	**4**	5

Net income attributable to the Shareholder for the fourth quarter was $362 million, compared to a net loss of $13 million for the same quarter in 2016.

Income before interest and income taxes was $486 million during the fourth quarter of 2017, an increase of $407 million compared to income before interest and income taxes of $85 million during the same period in 2016. The following summarizes the significant factors which contributed to the variance:

Significant factors that increased income before interest and income taxes:

- Higher revenue from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments totaling approximately $480 million recorded in the fourth quarter of 2017 to reflect the OEB's decision on OPG's application for new regulated rates issued in December 2017 with a retrospective effective date of June 1, 2017.
- Higher earnings of $77 million from the Regulated – Nuclear Waste Management segment, primarily due to higher earnings from the Nuclear Segregated Funds reflecting the growth rate in the present value of the funding liabilities, partially offset by an increase in accretion expense on the Nuclear Liabilities.

Significant factors that decreased income before interest and income taxes:

- Lower revenue from the nuclear base regulated price of approximately $55 million, partially offset by a decrease in fuel expense of $9 million, reflecting lower electricity generation of 0.9 terawatt hours (TWh) from the Regulated – Nuclear Generation segment. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS since October 2016, partially offset by an increase in generation from the Pickering GS. The increase in generation from the Pickering GS was primarily due to outage cycle optimization, favourable unit conditions and execution of planned outage work resulting in fewer unplanned and planned outage days at the station.
- Higher OM&A expenses of $55 million, mainly in the Regulated – Nuclear Generation segment, reflected planned expenditures related to the major maintenance expenditures occurring at the nuclear stations.

The increase in income tax expense during the fourth quarter of 2017, compared to the same quarter in 2016, was primarily due to higher income before income taxes, partially offset by a higher amount of tax expense deferred in regulatory assets in 2017.

Average Sales Prices

The average sales price for the Regulated – Nuclear Generation segment during the fourth quarter of 2017 was 11.0 ¢/kWh, compared to 6.9 ¢/kWh during the same quarter in 2016. The increase in the average sales price was primarily due to the OEB ruling issued in December 2017, in which OPG received a base rate increase, retroactive to June 1, 2017. The average sales price for the Regulated – Hydroelectric segment during 2017 was 4.3 ¢/kWh, compared to 4.4 ¢/kWh during 2016. The decrease in this average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized regulated hydroelectric rate rider of $3.19/MWh for the recovery of variance and deferral account balances. The rate riders were established to recover approved balances recorded in the variance and deferral accounts in prior years. As such, the year-over-year changes in revenue from the rate riders were largely offset by changes in amortization expense related to these balances.

Electricity Generation

OPG's electricity generation for the three months ended December 31, 2017 and 2016 was as follows:

(TWh)	Three Months Ended December 31 2017	2016
Regulated – Nuclear Generation	**10.1**	11.0
Regulated – Hydroelectric	**7.2**	6.7
Contracted Generation Portfolio [1]	**0.8**	0.6
Total OPG electricity generation	**18.1**	18.3
Total electricity generation by all other generators in Ontario [2]	**18.8**	18.9

[1] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

[2] Non-OPG generation is calculated as the Ontario electricity demand plus net exports, as published by the IESO, minus OPG electricity generation.

The decrease in OPG's electricity generation of 0.2 TWh during the fourth quarter of 2017, compared to the same quarter in 2016, was mainly due to lower electricity generation of 0.9 TWh from the Regulated – Nuclear Generation segment. This was mainly the result of more planned outage days at Pickering in 2017 as well as the refurbishment of Unit 2 at the Darlington GS, which began in mid-October 2016 and continued for all of 2017. This was largely offset by higher production from the Regulated - Hydroelectric and Contracted Generation Portfolio segments mainly due to higher water flows on the eastern Ontario river systems.

Ontario's electricity demand as reported by the IESO was 33.6 TWh during the fourth quarter of 2017, compared to 33.2 TWh during the fourth quarter of 2016.

Liquidity and Capital Resources

Cash flow provided by operating activities during the three months ended December 31, 2017 was $246 million, compared to $606 million for the same period in 2016. The decrease in cash flow was primarily due to lower generation revenue receipts and higher OM&A expenditures during the fourth quarter of 2017.

Cash flow used in investing activities during the three months ended December 31, 2017 was $1,758 million, compared to $666 million during the same period in 2016. The increase was primarily due to the acquisition of the Fair Hydro Trust financing receivables and higher expenditures on the Darlington Refurbishment project in 2017.

Cash flow provided by financing activities during the three months ended December 31, 2017 was $1,466 million, compared to cash flow used in financing activities of $180 million for the same period in 2016. The increase in cash flow provided by financing activities was primarily due to higher net issuance of long-term debt and short-term notes by the Trust, as well as issuance of Class A shares in the four quarter of 2017. The increase was partially offset by the repayment of short term notes.

QUARTERLY FINANCIAL HIGHLIGHTS

The following tables set out selected annual financial information for the last three years and financial information for each of the eight most recently completed quarters. This information is derived from OPG's unaudited interim consolidated financial statements and the audited consolidated financial statements, and has been prepared in accordance with US GAAP.

Annual Financial Information

(millions of dollars – except where noted)	**2017**	**2016**	**2015**
Revenue	**5,158**	5,653	5,476
Net income attributable to the Shareholder	**860**	436	402
Earnings per common share *(dollars)*	**$3.35**	$1.70	$1.57
Total assets	**48,822**	44,372	44,250
Total long-term liabilities	**34,933**	31,460	32,404
Weighted average common shares outstanding *(millions)*	**256.7**	256.3	256.3

Quarterly Financial Information

(millions of dollars – except where noted) *(unaudited)*	**2017 Quarters Ended**				
	December 31	**September 30**	**June 30**	**March 31**	**Total**
Revenue	**1,619**	**1,217**	**1,146**	**1,176**	**5,158**
Net income	**366**	**140**	**307**	**68**	**881**
Less: Net income attributable to non-controlling interest	**4**	**9**	**4**	**4**	**21**
Net income attributable to the Shareholder	**362**	**131**	**303**	**64**	**860**
Earnings per common share, attributable to the Shareholder *(dollars)*	**$1.41**	**$0.51**	**$1.18**	**$0.25**	**$3.36**

Quarterly Financial Information

(millions of dollars – except where noted) *(unaudited)*	**2016 Quarters Ended**				
	December 31	**September 30**	**June 30**	**March 31**	**Total**
Revenue	1,388	1,400	1,387	1,478	5,653
Net (loss) income	(8)	198	135	128	453
Less: Net income attributable to non-controlling interest	5	4	3	5	17
Net (loss) income attributable to the Shareholder	(13)	194	132	123	436
Per common share, attributable to the Shareholder *(dollars)*	($0.05)	$0.76	$0.51	$0.48	$1.70

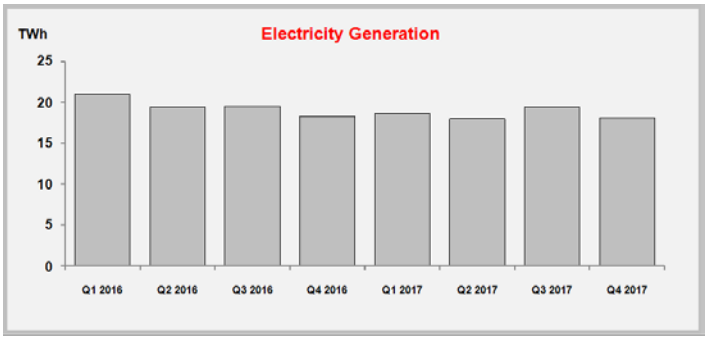
Trends

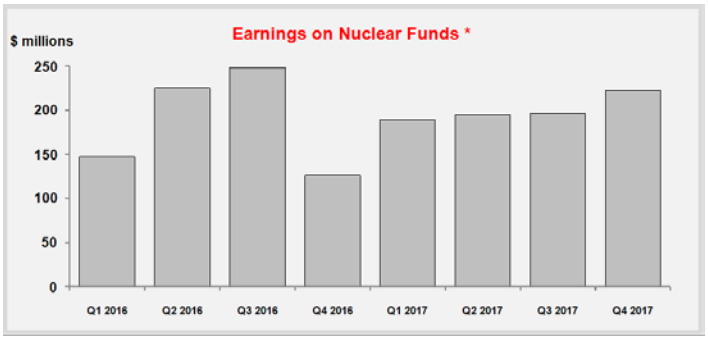
OPG's quarterly results are affected by changes in grid-supplied electricity demand, primarily resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. Weather conditions affect water flows, electricity demand, and prevalence of SBG conditions. Historically, OPG's revenues have been higher in the first quarter of a fiscal year as a result of winter heating demands and in the third quarter due to air conditioning and cooling demands. The financial impact of forgone production due to SBG conditions at the regulated hydroelectric stations and the financial impact of differences between forecast water flows reflected in OEB-approved regulated prices and the actual water flows are offset by regulatory variance accounts authorized by the OEB.

The timing of planned outages at a nuclear generating station during the year can cause variability in year-over-year operating results for partial periods of a fiscal year, including the impact on revenue and OM&A expenses, but is not a significant driver of variability for full fiscal year results.

OPG's electricity generation was reduced as a result of the Unit 2 refurbishment outage at the Darlington GS, which began in October 2016 and is expected to continue until early 2020.

OPG's financial results are also affected by the earnings on the Nuclear Segregated Funds, net of the impact of the Bruce Lease Net Revenues Variance Account. The volatility of the earnings on the Nuclear Segregated Funds is mitigated by their funded status.





*net of regulatory variance account

SUPPLEMENTARY NON-GAAP FINANCIAL MEASURES

In addition to providing net income and other financial information in accordance with US GAAP, certain non-GAAP financial measures are also presented in OPG's MD&A. These non-GAAP measures do not have any standardized meaning prescribed by US GAAP and, therefore, may not be comparable to similar measures presented by other issuers. OPG utilizes these measures to make operating decisions and assess performance. Readers of the MD&A would utilize these measures in assessing the Company's financial performance from ongoing operations. The Company believes that these indicators are important since they provide additional information about OPG's performance, facilitate comparison of results over different periods, and present measures consistent with the Company's strategies to provide value to the Shareholder, improve cost performance, and ensure availability of cost effective funding. These non-GAAP financial measures have not been presented as an alternative to net income, cash flow provided by operating activities, or any other measure in accordance with US GAAP, but as indicators of operating performance.

The definitions of the non-GAAP financial measures are as follows:

(1) ROE Excluding AOCI is defined as net income attributable to the Shareholder divided by average equity attributable to the Shareholder excluding AOCI, for the period.

ROE Excluding AOCI is measured over a 12-month period and is calculated as follows for the period ended December 31:

(millions of dollars – except where noted) (unaudited)	**2017**	**2016**
ROE Excluding AOCI		
Net income attributable to the Shareholder	**860**	436
Divided by: Average equity attributable to the Shareholder, excluding AOCI	**11,498**	10,442
ROE Excluding AOCI *(percent)*	**7.5**	4.2

(2) **FFO Adjusted Interest Coverage** is defined as FFO before interest divided by adjusted interest expense. FFO before interest is defined as cash flow provided by operating activities adjusted for interest paid, interest capitalized to fixed and intangible assets, and changes to non-cash working capital balances for the period. Adjusted interest expense is calculated as net interest expense plus interest income, interest capitalized to fixed and intangible assets, interest related to regulatory assets and liabilities, and the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets, for the period.

FFO Adjusted Interest Coverage is measured over a 12-month period and is calculated as follows for the period ended December 31:

(millions of dollars – except where noted) (unaudited)	**2017**	**2016**
FFO before interest		
Cash flow provided by operating activities	**944**	1,817
Add: Interest paid	**258**	269
Less: Interest capitalized to fixed and intangible assets	**(162)**	(141)
Less: Changes to non-cash working capital balances	**(54)**	(180)
FFO before interest	**986**	1,765
Adjusted interest expense		
Net interest expense	**95**	120
Add: Interest income	**9**	7
Add: Interest capitalized to fixed and intangible assets	**162**	141
Add: Interest related to regulatory assets and liabilities	**30**	30
Add: Excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets [1]	**-**	45
Adjusted interest expense	**296**	343
FFO Adjusted Interest Coverage *(times)*	**3.3**	5.1

[1] A value of nil is used in the calculation when interest on pension and OPEB projected benefit obligations is equal to, or lower than, expected return on pension plan assets.

(3) **Enterprise Total Generating Cost per MWh** is used to measure OPG's overall organizational cost performance. Enterprise TGC per MWh is defined as OM&A expenses (excluding the Darlington Refurbishment project and other generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to OPG's electricity generation business), fuel expense for OPG-operated stations including hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures (excluding the Darlington Refurbishment project and other generation development projects) incurred during the period, divided by total electricity generation from OPG-operated generating stations plus electricity generation forgone due to SBG conditions during the period.

Enterprise TGC per MWh is calculated as follows for the 12-month period ended December 31:

(millions of dollars – except where noted)	**2017**	**2016**
Enterprise TGC		
Total OM&A expenses	**2,824**	2,747
Total fuel expense	**689**	727
Total capital expenditures	**1,926**	1,704
Less: Darlington Refurbishment capital and OM&A costs	**(1,285)**	(1,022)
Less: Other generation development project capital and OM&A costs	**(65)**	(163)
Add: OM&A and fuel expenses (refundable through) deferred in regulatory variance and deferral accounts	**(1)**	62
Less: Nuclear fuel expense for non OPG-operated stations	**(57)**	(67)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**69**	49
Less: OM&A expenses ancillary to electricity generation business	**(18)**	(28)
Other adjustments	**(43)**	(19)
	4,039	3,990
Adjusted electricity generation *(TWh)*		
Total OPG electricity generation	**74.1**	78.2
Adjust for electricity generation forgone due to SBG conditions and OPG's share of electricity generation from co-owned facilities	**5.6**	4.1
	79.7	82.3
Enterprise TGC per MWh *($/MWh)* [1]	**50.66**	**48.45**

[1] Amounts may not calculate due to rounding.

(4) **Nuclear Total Generating Cost per MWh** is used to measure the cost performance of OPG's nuclear generating assets. Nuclear TGC per MWh is defined as OM&A expenses of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the nuclear electricity generation business), nuclear fuel expense for OPG-operated stations (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs) incurred during the period, divided by nuclear electricity generation for the period.

Nuclear TGC per MWh is calculated as follows for the 12-month period ended December 31:

(millions of dollars – except where noted)	**2017**	**2016**
Nuclear TGC		
Regulated – Nuclear Generation OM&A expenses	**2,293**	2,210
Regulated – Nuclear Generation fuel expense	**284**	315
Regulated – Nuclear Generation capital expenditures	**1,631**	1,338
Less: Darlington Refurbishment capital and OM&A costs	**(1,285)**	(1,022)
Add: Regulated – Nuclear Generation OM&A and fuel expenses deferred in regulatory variance and deferral accounts	**35**	81
Less: Nuclear fuel expense for non OPG-operated stations	**(57)**	(67)
Less: Regulated – Nuclear Generation OM&A expenses ancillary to electricity generation business	**(6)**	(10)
Other adjustments	**(10)**	(4)
	2,885	2,841
Nuclear electricity generation *(TWh)*	**40.7**	45.6
Nuclear TGC per MWh *($/MWh)* [1]	**70.95**	62.30

[1] Amounts may not calculate due to rounding.

(5) **Hydroelectric Total Generating Cost per MWh** is used to measure the cost performance of OPG's hydroelectric generating assets. Hydroelectric TGC per MWh is defined as OM&A expenses of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the hydroelectric electricity generation business), hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding expenditures related to the Peter Sutherland Sr. GS, Ranney Falls GS, and other hydroelectric generation development projects) incurred during the period, divided by total hydroelectric electricity generation plus hydroelectric electricity generation forgone due to SBG conditions during the period. OPG reports hydroelectric gross revenue charge and water rental payments as fuel expense.

Hydroelectric TGC per MWh is calculated as follows for the 12-month period ended December 31:

(millions of dollars – except where noted)	**2017**	**2016**
Hydroelectric TGC		
Regulated – Hydroelectric OM&A expenses	**330**	325
Regulated – Hydroelectric fuel expense	**351**	353
Contracted Generation Portfolio OM&A expenses	**169**	178
Contracted Generation Portfolio fuel expense	**53**	58
Regulated – Hydroelectric and Contracted Generation Portfolio capital expenditures	**226**	330
Less: Regulated – Hydroelectric and Contracted Generation Portfolio Generation Portfolio generation development project capital and OM&A costs	**(63)**	(158)
Less: Thermal OM&A and fuel expenses and capital expenditures in the Contracted Generation Portfolio	**(166)**	(177)
Less: Regulated – Hydroelectric OM&A and fuel expenses refundable through regulatory variance and deferral accounts	**(36)**	(24)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**69**	49
Other adjustments	**(1)**	(1)
	932	933
Adjusted hydroelectric electricity generation *(TWh)*		
Regulated – Hydroelectric electricity generation	**30.7**	29.5
Contracted Generation Portfolio electricity generation	**2.7**	3.1
Adjust for hydroelectric electricity generation forgone due to SBG conditions and non-hydroelectric electricity generation of the Contracted Generation Portfolio, including OPG's share of electricity generation from co-owned facilities	**5.5**	4.0
	38.9	36.6
Hydroelectric TGC per MWh *($/MWh)* [1]	**23.91**	25.49

[1] Amounts may not calculate due to rounding.

(6) **Gross margin** is defined as revenue less fuel expense**.**

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[DRAFT]

Mar. 8, 2018

OPG REPORTS 2017 FINANCIAL RESULTS

OPG records increase in net income for third consecutive year

[Toronto]: – Ontario Power Generation Inc. (OPG or Company) today reported net income attributable to the Shareholder of $860 million for 2017, compared to $436 million in 2016.

"As stewards of Ontario's publicly-owned generating assets, I am pleased with our strong 2017 financial results, which marks the third year-over-year increase in net income. OPG's major focus remains on the largest clean energy project in Canada, the refurbishment of the Darlington Generating Station. This ten-year project will extend the life of this asset and ensure a safe, reliable, and clean source of electricity for another 30 years," said Jeff Lyash, OPG President and CEO. "Darlington's Unit 2 recently passed the halfway point, based on work performed, while remaining on time and on budget due to the hard work and dedication of our employees and partners. This success was recognized by our shareholder, the Province of Ontario, whe~~i~~ich has confirmed its commitment to proceed with Darlington's Unit 3 refurbishment in 2020."

Commented [RK1]: Comment for Energy: Has MENE signed off on this wording?

Lyash continued, "The Peter Sutherland Sr. Generating Station was completed in 2017, on budget and ahead of schedule, and is the latest example of OPG's commitment to working closely in partnership with Indigenous communities."

"Pickering Generating Station significantly improved its operating performance over last year by increasing its capability factor to 80 per cent in 2017. By continuing to operate this important asset to 2024, we will ensure a safe and clean source of reliable power during the refurbishment of Darlington. OPG has applied to its regulator, the Canadian Nuclear Safety Commission, for a licen~~c~~se to keep Pickering online until 2024 and expects a decision on this application in 2018," added Lyash.

The Ontario Energy Board's (OEB) decision on OPG's new regulated rates was issued in December 2017, establishing new rates to be applied with an effective date of June 1, 2017. OPG recognized the impact of the newly established base regulated rates for OPG's nuclear and most of its hydroelectric generation for the year resulting in additional net revenues of approximately $480 million **[MONITOR]**. Net income was negatively impacted by the planned reduction in nuclear electricity generation, primarily due to the Darlington Refurbishment, in conjunction with the continued application of previously established interim rates for the period in 2017 prior to the effective date of the new base regulated rates.

The OEB's approval of the final payment amounts order, including determinations on

the new regulated prices and rate smoothing, are not expected to have a material impact on the total revenue recorded for the June 1, 2017 to December 31, 2017 period. The OEB is expected to issue the final payment amounts order in the first half of 2018 **[MONITOR]**. OPG continues to provide electricity at a price that is 40 per cent less than other generators and is the only electricity generator in Ontario that has its prices set through a public hearing process by the OEB.

Commented [RK2]: The average of?

The gain of $283 million on the sale of OPG's head office building and parking facility recorded in the second quarter of 2017 and higher earnings on the nuclear fixed asset removal and nuclear waste management segregated funds of $24 million during 2017 compared to 2016 offset the year-to-date reduction in generation revenue.

The Fair Hydro Trust (the Trust) was established in December 2017 in accordance with the *Ontario Fair Hydro Act*, 2017, (the Fair Hydro Act), which appointed OPG as the Financial Services Manager of the Trust. The Fair Hydro Act established a framework under which the costs of clean energy investments [and benefits] associated with the ~~Government~~Province of Ontario's clean energy initiatives are to be allocated more fairly between present and future consumers of electricity under the Fair Hydro Plan. In December 2017, the Trust purchased its first tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $1.2 billion. In February 2018, the Trust issued $500 million of senior notes payable maturing on May 15, 2033.

Commented [RK3]: Is Energy okay with this wording?

Generating and Operating Performance

Electricity generated in 2017 decreased to 74.1 terawatt hours (TWh) from 78.2 TWh in 2016. The decrease in electricity generation reflected the expected lower generation from the Darlington GS and lower generation from the contracted plants. The decrease was partially offset by higher generation from the Pickering GS, primarily due to fewer outage days, and higher generation from the regulated hydroelectric stations.

Regulated – Nuclear Generation Segment

Lower nuclear generation of 4.9 TWh during 2017 was primarily due to the removal from service of Unit 2 at the Darlington GS for the duration of the unit's refurbishment that began in October 2016 and is expected to continue until early 2020. Offsetting the reduction in generation from the Darlington GS was an increase in generation of 1.5 TWh from the strong performance of the Pickering GS during 2017.

For 2017, the unit capability factor for the operating units at the Darlington GS was 85.2 per cent, compared to 89.5 per cent for 2016. The decrease was primarily a result of a higher number of planned outage days at the station in 2017, largely driven by the planned transition of the station towards refurbishment.

At the Pickering GS, the unit capability factor increased to 80.0 per cent for 2017, compared to 75.2 per cent for 2016, primarily due to outage cycle optimization and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station in 2017.

Regulated – Hydroelectric Segment

Higher generation from the regulated hydroelectric stations of 1.2 TWh during 2017

compared to 2016, was due to higher water flows, primarily on the eastern Ontario river systems.

The availability of 88.0 per cent at these stations in 2017 was slightly lower than 89.0 per cent for 2016. The marginal decrease in the availability was primarily due to a higher number of unplanned outage days at the Northwestern Ontario, Niagara and Eastern Ontario region hydroelectric stations, partially offset by higher availability from the Sir Adam Beck Pump GS due to a higher number of planned outages days in 2016 as a result of the refurbishment of the station's reservoir.

Contracted Generation Portfolio Segment

Lower generation from the Contracted Generation Portfolio of 0.4 TWh during 2017 compared to 2016, was mainly due to higher surplus baseload generation conditions.

The availability of these hydroelectric stations for 2017 was 74.6 per cent, compared to 77.3 per cent for 2016. The decrease in the availability was primarily due to an increase in the number of planned outage days at the Lower Mattagami River hydroelectric generating stations.

Total Generating Cost

The Enterprise Total Generating Cost per megawatt hour (MWh) for 2017 was $50.66, compared to $48.45 for 2016. The increase was expected and mainly a result of lower electricity generation due to the Unit 2 refurbishment outage at the Darlington GS and higher sustaining capital expenditures, which was partially offset by higher hydroelectric electricity generation adjusted for surplus baseload generation.

If Unit 2 at the Darlington GS were~~as~~ not currently undergoing refurbishment and had continued to operate in a manner consistent with the performance of the remaining units at the station, adjusted for generation constraints on these units related to the transition of the station toward refurbishment, the Enterprise Total Generating Cost would have been approximately $4 to $5 per MWh lower for 2017. This sensitivity was calculated using the estimated incremental electricity generation and associated fuel cost that are expected to have resulted in the absence of the refurbishment.

Generation Development

OPG is undertaking a number of generation development and life extension projects in support of Ontario's electricity planning initiatives. Significant developments during 2017 were as follows:

Darlington Refurbishment

The Darlington Refurbishment project is expected to extend the operating life of the four-unit Darlington GS by approximately 30 years. The approved budget for the four-unit refurbishment is $12.8 billion, which includes the costs of the pre-requisite projects in support of the execution phase of the refurbishment. In October 2016, OPG commenced the refurbishment of the first unit, Unit 2. The de-fuelling of the reactor and islanding of Unit 2 were completed in the first half of 2017. The Re-tube Tooling Platform for hosting the tooling for the removal, inspection and installation activities, and the setup of specialized tooling and equipment needed for the removal and

replacement of the reactor components were completed in the third quarter of 2017. The disassembly of reactor components began in August 2017, with the removal of all 960 feeder tubes completed in September 2017. The removal of fuel channel assemblies commenced in October 2017. As part of the fuel channel assemblies, the removal of pressure tubes is in progress and will be followed by the removal of calandria tubes. The second major segment and the removal of all reactor components is expected to be completed in mid-2018.

Most of the pre-requisite projects, including construction of facilities, infrastructure upgrades and installation of safety enhancements, have been completed and placed in service. The Re-tube Waste Processing Building was completed in November 2017. Construction activities for the Heavy Water Storage and Drum Handling Facility (HWSF) have recommenced following the substantial completion of the Re-tube Waste Processing Building. This sequencing ensured that the necessary resources were available to support the execution of both projects. The HWSF is expected to be completed by the second quarter of 2019 and is not on the critical path for the Darlington Refurbishment project, which continues to track on schedule. The increase in the cost estimate for the HWSF will be accommodated within the overall Darlington Refurbishment budget of $12.8 billion. Taking into account the execution performance of the Unit 2 refurbishment, the overall Darlington Refurbishment project continues to track on budget.

In addition to the execution of refurbishment activities on Unit 2, OPG is continuing planning activities for the refurbishment of the second unit, Unit 3, and is entering into associated commitments to procure major components that require long lead times. As of December 31, 2017, $93 million has been invested in planning activities related to the refurbishment of the second unit.

Total life-to-date capital expenditures on the project were approximately $4.4 billion as at December 31, 2017.

Ranney Falls Hydroelectric GS

In 2017, OPG began construction work on a 10 MW single-unit powerhouse on the existing Ranney Falls GS site, as part of the Regulated – Hydroelectric segment. The new unit will replace an existing unit that reached its end of life in 2014. The existing forebay structure has been demolished and the new concrete structure has been completed. Excavation has been completed and construction continues in the expanded forebay, powerhouse and spillway area. The new forebay concrete wall has been completed, and concrete placement of the new powerhouse and the spillway integrated structure is in progress. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget.

Nanticoke Solar Facility

The construction of a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands, through Nanticoke Solar LP, a partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation, is planned to commence in the first quarter of 2018. During 2017, the partnership continued work to obtain approvals and permits required to enable the commencement of construction. Significant contracts for equipment and engineering construction services were executed in the first quarter of 2018. The facility, to operate under a contract with the IESO, is

expected to be completed in the first quarter of 2019, with a budget of $107 million. **[MONITOR]**

FINANCIAL AND OPERATIONAL HIGHLIGHTS

(millions of dollars – except where noted)	**2017**	**2016**
Revenue	**5,158**	5,653
Fuel expense	**689**	727
Gross margin	**4,469**	4,926
Operations, maintenance and administration	**2,824**	2,747
Depreciation and amortization	**679**	1,257
Accretion on fixed asset removal and nuclear waste management liabilities	**960**	929
Earnings on Nuclear Segregated Funds - (a reduction to expenses)	**(801)**	(746)
Earnings from Fair Hydro Trust - (a reduction to expenses)	**(1)**	-
Income from investments subject to significant influence	**(38)**	(37)
Other net (gains) expenses	**(339)**	35
Income before interest and income taxes	**1,185**	741
Net interest expense	**95**	120
Income tax expense	**209**	168
Net income	**881**	453
Net income attributable to the Shareholder	**860**	436
Net income attributable to non-controlling interest [1]	**21**	17
Income before interest and income taxes		
Electricity generation business segments	**971**	928
Regulated – Nuclear Waste Management	**(150)**	(174)
Services, Trading, and Other Non-Generation	**364**	(13)
Fair Hydro Trust	**-**	-
Total income before interest and income taxes	**1,185**	741
Cash flow		
Cash flow provided by operating activities	**944**	1,817
Electricity generation (TWh)		
Regulated – Nuclear Generation	**40.7**	45.6
Regulated – Hydroelectric	**30.7**	29.5
Contracted Generation Portfolio [2]	**2.7**	3.1
Total electricity generation	**74.1**	78.2
Nuclear unit capability factor (per cent) [3]		
Darlington Nuclear GS	**85.2**	89.5
Pickering Nuclear GS	**80.0**	75.2
Availability (per cent)		
Regulated – Hydroelectric	**88.0**	89.0
Contracted Generation Portfolio – hydroelectric stations	**74.6**	77.3
Equivalent forced outage rate		
Contracted Generation Portfolio – thermal stations	**2.4**	1.6
Enterprise Total Generating Cost (TGC) per MWh for the twelve months ended December 31, 2017 and 2016 ($/MWh) [4]	**50.66**	48.45
Return on Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI) for the twelve months ended December 31, 2017 and 2016 (%) [4]	**7.5**	4.2
Funds from Operations (FFO) Adjusted Interest Coverage for the twelve months ended December 31, 2017 and 2016 (times) [4]	**3.3**	5.1

[1] Relates to the 25 per cent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation in the Lower Mattagami Limited Partnership, the 33 per cent interest of Coral Rapids Power Corporation (CRP), a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership, and the 10 per cent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP. CRP increased its partnership interest to 33 percent in April 2017.

[2] Includes OPG's share of generation volume from its 50 per cent ownership interests in the Portlands Energy Centre and Brighton Beach GS.

[3] Nuclear unit capability factor excludes unit(s) during the period in which they are undergoing refurbishment. Unit 2 of the Darlington GS is excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

[4] Enterprise TGC per MWh, ROE Excluding AOCI, and FFO Adjusted Interest Coverage are non-GAAP financial measures and do not have any standardized meaning prescribed by US GAAP. Additional information about the non-GAAP measures is provided in OPG's Management's Discussion and Analysis for the year ended December 31, 2017, in the sections *Highlights – FFO Adjusted Interest Coverage*, *Highlights – Return on Common Equity Excluding Accumulated Other Comprehensive Income*, and *Highlights – Enterprise Total Generating Cost per MWh*, as well as *Supplementary Non-GAAP Financial Measures.*

Ontario Power Generation Inc. is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. Our mission is providing low cost power in a safe, clean, reliable and sustainable manner for the benefit of our customers and shareholder.

Ontario Power Generation Inc.'s audited consolidated financial statements and Management's Discussion and Analysis as at and for the year ended December 31, 2017 can be accessed on OPG's web site (www.opg.com), the Canadian Securities Administrators' web site (www.sedar.com), or can be requested from the Company.

For further information, please contact: Investor Relations 416-592-6700
webmaster@opg.com

Media Relations 416-592-4008
1-877-592-4008

- 30 -

From:	Ronald Kwan
To:	John Kim
Subject:	RE: OPG Q4 2017 Submission to Province
Date:	Monday, February 26, 2018 11:01:38 AM

Thanks John.

Ron

From: John Kim
Sent: February-26-18 10:57
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Subject: RE: OPG Q4 2017 Submission to Province

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Philip Ho, CPA, CA | Senior Manager, External Reporting & Accounting Policy | Ontario Power Generation

700 University Avenue, Toronto ON M5G 1X6 | Phone: (416) 592-3320| E-mail: philip.ho@opg.com

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To: Ronald Kwan
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Subject:	RE: OPG Q4 2017 Submission to Province
Date:	Sunday, February 25, 2018 3:09:01 PM
Attachments:	Q4 2017 OPG MD&A - DRAFT - Feb 25_230PM_RPT excerpt for Prov.docx Q4 2017 OPG FS Feb 25_230PM_RPT excerpt for Prov.docx

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ONTARIO POWER GENERATION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

DECEMBER 31, 2017

[DRAFT]

RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One, the IESO and the OEFC. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly-owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions for the years ended December 31 are summarized below:

	2017		2016	
(millions of dollars)	**Income**	**Expense**	**Income**	**Expense**
Hydro One				
Electricity sales	**8**	**-**	6	-
Services	**1**	**10**	1	5
Dividends	**7**	**-**	6	-
Province of Ontario				
Change in Decommissioning Segregated Fund amount due to Province [1]	**-**	**456**	-	192
Change in Used Fuel Segregated Fund amount due to Province [1]	**-**	**591**	-	235
Hydroelectric gross revenue charge	**-**	**110**	-	120
ONFA guarantee fee	**-**	**8**	-	8
Other	**-**	**2**	-	-
OEFC				
Hydroelectric gross revenue charge	**-**	**216**	-	203
Interest expense on long-term notes	**-**	**158**	-	169
Income taxes, net of investment tax credits	**-**	**246**	-	104
IESO				
Electricity related revenue	**4,802**	**-**	5,082	-
Earnings from Fair Hydro Trust	**1**	**-**	-	-
	4,819	**1,797**	5,095	1,036

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at December 31, 2017 and December 31, 2016, the Nuclear Segregated Funds were reported net of amounts due to the Province of $4,462 million and $3,415 million, respectively.

The receivable, AFS securities, payable and long-term debt balances between OPG and its related parties are summarized below:

(millions of dollars)	December 31 2017	December 31 2016
Receivables from related parties		
Hydro One	**1**	1
IESO – Electricity related receivables	**354**	421
IESO – Fair Hydro Trust [1]	**7**	-
OEFC	**-**	1
PEC	**4**	4
Province of Ontario	**3**	2
Financing receivables		
IESO – Fair Hydro Trust	**1,179**	-
Available-for-sale securities		
Hydro One shares	**188**	212
Accounts payable and accrued charges		
Hydro One	**1**	-
OEFC	**52**	61
Province of Ontario	**9**	2
IESO – Electricity-related payables	**5**	2
IESO – Fair Hydro Trust	**3**	-
Long-term debt (including current portion)		
Notes payable to OEFC	**3,195**	3,295

[1] Balance consists of unbilled revenue.

OPG holds interest-bearing Province of Ontario bonds in the Nuclear Segregated Funds and the OPG registered pension fund. As at December 31, 2017, the Nuclear Segregated Funds held $1,503 million of interest-bearing Province of Ontario bonds, while the registered pension fund had no such holdings. As at December 31, 2016, the Nuclear Segregated Funds and the registered pension fund held $1,652 million and $284 million of interest-bearing Province of Ontario bonds, respectively. These bonds are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

In December 2017, the Fair Hydro Trust purchased its first tranche of Investment Interest from the IESO for an exchange amount of $1.18 billion, which has been classified as a financing receivable on OPG's consolidated balance sheet. The transaction was settled in cash using proceeds from the Trust's issuance of senior and subordinated debt. Pursuant to the general regulation of the Fair Hydro Act, the IESO is required to pay and remit carrying costs of the Trust, excluding repayment of principal on any debt obligations, up to July 31, 2021. Commencing May 1, 2021, Specified Consumers will be invoiced by their local distribution company for the Clean Energy Adjustment to pay the carrying costs of the Trust. These funds will be remitted to the Trust through the IESO and will be used to settle all funding and other related expenses of the Trust that underlie the financing receivable.

As at December 31, 2017, OPG's consolidated balance sheet included approximately $7 million of unbilled revenue from the IESO, primarily for OPG's general fee for 2017 as the Financial Services Manager under the Act relating to incurred third-party and certain direct labour costs.

Under one of the Trust's program agreements, the Province has provided a limited guarantee to specified creditors in the event that the Trust's ability to receive amounts in respect of its Investment Interest to pay for certain funding obligations is adversely affected due to the occurrence of any one of the following: the Province changes the Fair

Hydro Act or any other legislation or regulation; Ontario's electricity market significantly changes due to actions undertaken by the Province; or the Act is declared invalid or unconstitutional.

ONTARIO POWER GENERATION INC.

CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2017

[DRAFT]

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[1] Balance consists of unbilled revenue.

OPG holds interest-bearing Province of Ontario bonds in the Nuclear Segregated Funds and the OPG registered pension fund. As at December 31, 2017, the Nuclear Segregated Funds held $1,503 million of interest-bearing Province of Ontario bonds, while the registered pension fund had no such holdings. As at December 31, 2016, the Nuclear Segregated Funds and the registered pension fund held $1,652 million and $284 million of interest-bearing Province of Ontario bonds, respectively. These bonds are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

In December 2017, the Fair Hydro Trust purchased its first tranche of Investment Interest from the IESO for an exchange amount of $1.18 billion, which has been classified as a financing receivable on OPG's consolidated balance sheet. The transaction was settled in cash using proceeds from the Trust's issuance of senior and subordinated debt. Pursuant to the general regulation of the Fair Hydro Act, the IESO is required to pay and remit carrying costs of the Trust, excluding repayment of principal on any debt obligations, up to July 31, 2021. Commencing May 1, 2021, Specified Consumers will be invoiced by their local distribution company for the Clean Energy Adjustment to pay the carrying costs of the Trust. These funds will be remitted to the Trust through the IESO and will be used to settle all funding and other related expenses of the Trust that underlie the financing receivable.

As at December 31, 2017, OPG's consolidated balance sheet included approximately $7 million of unbilled revenue from the IESO, primarily for OPG's general fee for 2017 as the Financial Services Manager under the Act relating to incurred third-party and certain direct labour costs.

Under one of the Trust's program agreements, the Province has provided a limited guarantee to specified creditors in the event that the Trust's ability to receive amounts in respect of its Investment Interest to pay for certain funding obligations is adversely affected due to the occurrence of any one of the following: the Province changes the Fair

Hydro Act or any other legislation or regulation; Ontario's electricity market significantly changes due to actions undertaken by the Province; or the Act is declared invalid or unconstitutional.

From:	John Kim
To:	Ronald Kwan
Cc:	Usman Zahid; Francisco Chinchon; Gavin He; Darren Scanlan
Subject:	RE: OPG Q4 2017 Submission to Province
Date:	Saturday, February 24, 2018 11:31:34 AM
Attachments:	Q4 2017 OPG FS PROVINCE MAILING Feb 16_EFB_v3 [Version to Be Reviewed].docx Q4 2017 MD&A - DRAFT - Feb 16 - PROVINCE MAILING_EFB_v3 [Version to Be Reviewed].docx 2017 AIF - DRAFT - Feb 16 - PROVINCE MAILING_EFB_v3 [Version to Be Reviewed].docx

Hi Ron,

Pls. see attached. No issue on the NR.

Thanks,

John

Z:\Users\CEF\Hydro 2018\OPG\Financials\Q4 2017

From: HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
Sent: February-16-18 5:11 PM
To: Shruti.Talwar@ontario.ca; Manu.Sud@ontario.ca; John Kim <John.Kim@ofina.on.ca>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: GORE Michael -FIN & C CTRL <michael.gore@opg.com>; PAN Rebecca -FIN & C CTRL <rebecca.pan@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>
Subject: OPG Q4 2017 Submission to Province

Hi All,

Please find attached OPG's draft Q4 2017 Financial Results Press Release, Management's Discussion and Analysis (MD&A), Annual Information Form (AIF) and Financial Statements for the Province's review.

We would greatly appreciate comments on the above **no later than Thursday, Feb 22nd**.

These documents will be filed with the Ontario Securities Commission on **Thursday, March 8th** following OPG's Board of Directors meeting.

Kindly forward all comments directly to Philip Ho – philip.ho@opg.com.

To assist the review process, the following are the key items in the Q4 2017 MD&A:

Highlights	
Recent Developments	MD&A p.13-19
OEB's Decision on OPG's Application for New Regulated Prices	MD&A p.13-15
Darlington Refurbishment	MD&A p.16-17; 28-30
Ontario's Fair Hydro Plan	MD&A p.17-18

Philip Ho, CPA, CA | Senior Manager, External Reporting & Accounting Policy | Ontario Power Generation
700 University Avenue, Toronto ON M5G 1X6 | Phone: (416) 592-3320| E-mail: philip.ho@opg.com

ONTARIO POWER GENERATION INC.

CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2017

[DRAFT]

STATEMENT OF MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL INFORMATION

Ontario Power Generation Inc.'s (OPG) management is responsible for the presentation and preparation of the annual consolidated financial statements and Management's Discussion and Analysis (MD&A).

The consolidated financial statements have been prepared in accordance with United States generally accepted accounting principles (US GAAP). The MD&A has been prepared in accordance with the requirements of securities regulators, including National Instrument 51-102 of the Canadian Securities Administrators and its related published requirements.

The consolidated financial statements and information in the MD&A necessarily include amounts based on informed judgments and estimates of the expected effects of current events and transactions with appropriate consideration to materiality. Something is considered material if it is reasonably expected to have a significant impact on the Company's earnings, cash flow, value of an asset or liability, or reputation. In addition, in preparing the financial information, we must interpret the requirements described above, make determinations as to the relevancy of information to be included, and make estimates and assumptions that affect the reported information. The MD&A also includes information regarding the impact of current transactions and events, sources of liquidity and capital resources, operating trends, and risks and uncertainties. Actual results in the future may differ materially from our present assessment of this information because future events and circumstances may not occur as expected.

In meeting our responsibility for the reliability of the financial information, we maintain and rely on a comprehensive system of internal controls and internal audits, including organizational and procedural controls and internal controls over financial reporting. Our system of internal controls includes: written communication of our policies and procedures governing corporate conduct and risk management; comprehensive business planning; effective segregation of duties; delegation of authority and personal accountability; careful selection and training of personnel; and accounting policies, which we regularly update. This structure ensures appropriate internal controls over transactions, assets and records. We also regularly test internal controls. These controls and testing are designed to provide us with reasonable assurance that the financial records are reliable for preparing financial statements and other financial information, assets are safeguarded against unauthorized use or disposition, liabilities are recognized, and we are in compliance with all regulatory requirements.

Management, including the President and Chief Executive Officer (CEO) and the Chief Financial Officer (CFO), is responsible for maintaining disclosure controls and procedures (DC&P) and internal controls over financial reporting (ICOFR). DC&P is designed to provide reasonable assurance that all relevant information is gathered and reported to senior management, including the President and CEO and the CFO, on a timely basis so that appropriate decisions can be made regarding public disclosure. ICOFR is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements in accordance with US GAAP.

An evaluation of the effectiveness of the design and operation of OPG's DC&P and ICOFR was conducted as of December 31, 2017. Accordingly, we, as OPG's President and CEO and CFO, will certify OPG's annual disclosure documents filed with the Ontario Securities Commission, which includes attesting to the design and effectiveness of OPG's DC&P and ICOFR.

The Board of Directors, based on recommendations from its Audit and Risk Committee, reviews and approves the consolidated financial statements and the MD&A, and oversees management's responsibilities for the presentation and preparation of financial information, maintenance of appropriate internal controls, management and control of major areas of financial risk, and assessment of significant and related party transactions.

The consolidated financial statements have been audited by Ernst & Young LLP, independent external auditors appointed by the Board of Directors. The Independent Auditors' Report outlines the auditors' responsibilities and the scope of their examination and their opinion on OPG's consolidated financial statements. The independent external auditors, as confirmed by the Audit and Risk Committee, had direct and full access to the Audit and Risk Committee, with and without the presence of management, to discuss their audit and their findings therefrom, as to the integrity of OPG's financial reporting and the effectiveness of the system of internal controls.

Jeff Lyash
President and Chief Executive Officer

Ken Hartwick
Chief Financial Officer and Senior Vice President – Finance

March 8, 2018

INDEPENDENT
AUDITORS' REPORT

To the Shareholder of Ontario Power Generation Inc.

We have audited the accompanying consolidated financial statements of Ontario Power Generation Inc., which comprise the consolidated balance sheets as at December 31, 2017 and 2016, and the consolidated statements of income, comprehensive income, cash flows and changes in shareholder's equity for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with United States generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Ontario Power Generation Inc. as at December 31, 2017 and 2016, and the results of its operations and its cash flows for the years then ended in accordance with United States generally accepted accounting principles.

Toronto, Canada

March 8, 2018

Ernst & Young LLP

Chartered Professional Accountants,
Licensed Public Accountants

CONSOLIDATED STATEMENTS OF INCOME

Years Ended December 31 *(millions of dollars except where noted)*	**2017**	**2016**
Revenue *(Note 17)*	**5,158**	5,653
Fuel expense *(Note 17)*	**689**	727
Gross margin	**4,469**	4,926
Operations, maintenance and administration *(Note 17)*	**2,824**	2,747
Depreciation and amortization *(Note 4)*	**679**	1,257
Accretion on fixed asset removal and nuclear waste management liabilities *(Note 8)*	**960**	929
Earnings on nuclear fixed asset removal and nuclear waste management funds *(Note 8)*	**(801)**	(746)
Earnings from Fair Hydro Trust *(Note 17)*	**(1)**	-
Income from investments subject to significant influence	**(38)**	(37)
Property taxes	**40**	46
Restructuring	**-**	6
	3,663	4,202
Income before other gains, interest and income taxes	**806**	724
Other gains *(Note 17)*	**379**	17
Income before interest and income taxes	**1,185**	741
Net interest expense *(Note 6)*	**95**	120
Income before income taxes	**1,090**	621
Income tax expense *(Note 9)*	**209**	168
Net income	**881**	453
Net income attributable to the Shareholder	**860**	436
Net income attributable to non-controlling interest	**21**	17
Basic and diluted net income per common share *(dollars) (Note 15)*	**3.35**	1.70

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Years Ended December 31 *(millions of dollars)*	2017	2016
Net income	**881**	453
Other comprehensive income, net of income taxes *(Note 10)*		
Actuarial loss on re-measurement of liabilities for pension and other post-employment benefits [1]	**(23)**	(6)
Reclassification to income of amounts related to pension and other post-employment benefits [2]	**10**	12
Reclassification to income of losses on derivatives designated as cash flow hedges [3]	**18**	19
Unrealized loss on available-for-sale securities [4]	**(8)**	(1)
Other comprehensive (loss) income for the year	**(3)**	24
Comprehensive income	**878**	477
Comprehensive income attributable to the Shareholder	**857**	460
Comprehensive income attributable to non-controlling interest	**21**	17

[1] Net of income tax recovery of $7 million and $2 million for 2017 and 2016, respectively.
[2] Net of income tax expenses of $3 million and $4 million for 2017 and 2016, respectively.
[3] Net of income tax expenses of $2 million for each of 2017 and 2016.
[4] Net of income tax recovery of $2 million and nil for 2017 and 2016, respectively.

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31 *(millions of dollars)*	2017	2016
Operating activities		
Net income	**881**	453
Adjust for non-cash items:		
Depreciation and amortization *(Note 4)*	**679**	1,257
Accretion on fixed asset removal and nuclear waste management liabilities	**960**	929
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(801)**	(746)
Pension and other post-employment benefit costs *(Note 11)*	**412**	464
Deferred income taxes	**19**	(36)
Mark-to-market on derivative instruments	**(3)**	3
Provision for used nuclear fuel and low and intermediate level nuclear waste	**116**	118
Regulatory assets and liabilities	**(558)**	(170)
Provision for materials and supplies	**33**	42
Other gains	**(371)**	-
Other	**1**	(25)
	1,368	2,289
Contributions to nuclear fixed asset removal and nuclear waste management funds	**-**	(150)
Expenditures on fixed asset removal and nuclear waste management	**(313)**	(275)
Reimbursement of eligible expenditures on nuclear fixed asset removal and nuclear waste management	**79**	70
Contributions to pension funds and expenditures on other post-employment benefits and supplementary pension plans	**(322)**	(363)
Expenditures on restructuring	**(4)**	(6)
Distributions received from investments subject to significant influence	**50**	52
Net changes to other long-term assets and liabilities	**32**	20
Net changes to non-cash working capital balances *(Note 18)*	**54**	180
Cash flow provided by operating activities	**944**	1,817
Investing activities		
Acquisition of Fair Hydro Trust financing receivables *(Notes 3 and 19)*	**(1,179)**	-
Purchase of available-for-sale securities	**-**	(213)
Proceeds from deposit note	**70**	110
Net proceeds from sale of property, plant and equipment	**484**	-
Investment in property, plant and equipment and intangible assets	**(1,853)**	(1,816)
Cash flow used in investing activities	**(2,478)**	(1,919)
Financing activities		
Issuance of Class A shares *(Note 14)*	**519**	-
Issuance of long-term debt *(Note 6)*	**1,301**	334
Repayment of long-term debt	**(1,103)**	(273)
Issuance of long-term debt by Fair Hydro Trust *(Note 6)*	**601**	-
Distribution to non-controlling interest	**(15)**	(14)
Capital contribution from non-controlling interest	**19**	-
Issuance of short-term notes	**1,960**	3,108
Repayment of short-term debt	**(1,700)**	(3,331)
Cash flow provided by (used in) financing activities	**1,582**	(176)
Net increase (decrease) in cash and cash equivalents	**48**	(278)
Cash and cash equivalents, beginning of year	**186**	464
Cash and cash equivalents, end of year	**234**	186

See accompanying notes to the consolidated financial statements

CONSOLIDATED BALANCE SHEETS

As at December 31 *(millions of dollars)*	2017	2016
Assets		
Current assets		
Cash and cash equivalents [1]	**234**	186
Available-for-sale securities	**188**	212
Receivables from related parties *(Note 19)*	**369**	429
Nuclear fixed asset removal and nuclear waste management funds *(Notes 8 and 17)*	**23**	24
Fuel inventory *(Note 17)*	**309**	310
Materials and supplies *(Note 17)*	**103**	100
Prepaid expenses	**192**	198
Other current assets	**146**	298
	1,564	1,757
Property, plant and equipment *(Notes 4 and 17)*	**29,950**	29,315
Less: accumulated depreciation	**8,628**	9,317
	21,322	19,998
Intangible assets *(Notes 4 and 17)*	**565**	503
Less: accumulated amortization	**432**	404
	133	99
Other assets		
Nuclear fixed asset removal and nuclear waste management funds *(Notes 8 and 17)*	**16,701**	15,960
Financing receivables *(Note 19)*	**1,179**	-
Long-term materials and supplies *(Note 17)*	**355**	345
Regulatory assets *(Note 5)*	**7,231**	5,855
Investments subject to significant influence *(Note 20)*	**309**	321
Other long-term assets	**28**	37
	25,803	22,518
	48,822	44,372

[1] Includes $4 million restricted for Fair Hydro Trust purposes.

See accompanying notes to the consolidated financial statements

CONSOLIDATED BALANCE SHEETS

As at December 31 *(millions of dollars)*	2017	2016
Liabilities		
Current liabilities		
Accounts payable and accrued charges *(Note 19)*	**1,228**	1,164
Short-term debt *(Note 7)*	**260**	2
Deferred revenue due within one year	**12**	12
Long-term debt due within one year *(Note 6)*	**398**	1,103
Income taxes payable	**80**	123
	1,978	2,404
Long-term debt *(Notes 6 and 17)*	**5,921**	4,417
Other liabilities		
Fixed asset removal and nuclear waste management liabilities *(Notes 8 and 17)*	**20,421**	19,484
Pension liabilities *(Note 11)*	**3,423**	3,012
Other post-employment benefit liabilities *(Note 11)*	**3,092**	2,897
Long-term accounts payable and accrued charges	**252**	213
Deferred revenue	**351**	298
Deferred income taxes *(Note 9)*	**879**	829
Regulatory liabilities *(Note 5)*	**594**	310
	29,012	27,043
Equity		
Common shares [1] *(Note 14)*	**5,126**	5,126
Class A shares [2] *(Note 14)*	**519**	-
Retained earnings	**6,396**	5,534
Accumulated other comprehensive loss *(Note 10)*	**(295)**	(295)
Equity attributable to the Shareholder	**11,746**	10,365
Equity attributable to non-controlling interest *(Note 22)*	**165**	143
Total equity	**11,911**	10,508
	48,822	44,372

[1] 256,300,010 common shares outstanding at a stated value of $5,126 million as at December 31, 2017 and December 31, 2016.

[2] 12,217,616 Class A shares outstanding at a stated value of $519 million as at December 31, 2017.

Commitments and Contingencies *(Notes 6, 9, 11 and 16)*

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY

Years Ended December 31 *(millions of dollars)*	**2017**	**2016**
Common shares	**5,126**	5,126
Class A shares *(Note 14)*	**519**	-
Retained earnings		
Balance at beginning of year	**5,534**	5,098
Net income attributable to the Shareholder	**860**	436
Reclassification of non-controlling interest on change in ownership interest *(Note 22)*	**2**	-
Balance at end of year	**6,396**	5,534
Accumulated other comprehensive loss, net of income taxes		
Balance at beginning of year	**(295)**	(319)
Other comprehensive (loss) income	**(3)**	24
Reclassification of non-controlling interest on change in ownership interest *(Note 22)*	**3**	-
Balance at end of year	**(295)**	(295)
Equity attributable to the Shareholder	**11,746**	10,365
Equity attributable to non-controlling interest		
Balance at beginning of year	**143**	140
Equity contribution from non-controlling interest *(Note 22)*	**21**	-
Reclassification of non-controlling interest on change in ownership interest *(Note 22)*	**(5)**	-
Distribution to non-controlling interest	**(15)**	(14)
Income attributable to non-controlling interest	**21**	17
Balance at end of year	**165**	143
Total equity	**11,911**	10,508

See accompanying notes to the consolidated financial statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the years ended December 31, 2017 and 2016

1. DESCRIPTION OF BUSINESS

Ontario Power Generation Inc. (OPG or the Company) was incorporated on December 1, 1998 pursuant to the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the Province or the Shareholder). OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario.

2. BASIS OF PRESENTATION

These consolidated financial statements have been prepared and presented in accordance with United States generally accepted accounting principles (US GAAP).

As required by *Ontario Regulation 395/11,* as amended, under the *Financial Administration Act* (Ontario), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. Since January 1, 2012, OPG also has received exemptive relief from the Ontario Securities Commission (OSC) from the requirements of section 3.2 of National Instrument 52-107, *Acceptable Accounting Policies and Auditing Standards*. The exemption allows OPG to file consolidated financial statements based on US GAAP, rather than International Financial Reporting Standards (IFRS), without becoming a US Securities and Exchange Commission registrant, or issuing public debt.

The current OSC exemption, received in 2014, will terminate on the earliest of the following:

- January 1, 2019
- The financial year that commences after OPG ceases to have activities subject to rate regulation
- The effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within IFRS specific to entities with rate-regulated activities.

All dollar amounts are presented in Canadian dollars, except in tabular format where noted. Certain of the 2016 comparative amounts have been reclassified from financial statements previously presented to conform to the 2017 consolidated financial statement presentation.

3. SIGNIFICANT ACCOUNTING POLICIES AND ESTIMATES

Consolidation

The consolidated financial statements of the Company include the accounts of OPG and its majority-owned subsidiaries, and variable interest entities (VIEs) where OPG is the primary beneficiary. All significant intercompany balances and intercompany transactions have been eliminated on consolidation.

Where OPG does not control an investment, but has significant influence over operating and financing policies of the investee, the investment is accounted for under the equity method. OPG co-owns the Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS) with TransCanada Energy Ltd. and co-owns the Brighton Beach gas-fired combined cycle GS (Brighton Beach) with ATCO Power Canada Ltd. OPG accounts for its 50 percent ownership interest in each of these jointly controlled entities using the equity method.

Variable Interest Entities

OPG performs ongoing analysis to assess whether it holds any VIEs. VIEs of which OPG is deemed to be the primary beneficiary are consolidated. The primary beneficiary of a VIE has both the power to direct the activities of the entity that most significantly impact its economic performance and the obligation to absorb losses of the entity that could potentially be significant to the Company. In circumstances where OPG is not deemed to be the primary beneficiary, the VIE is not recorded in OPG's consolidated financial statements.

Nuclear Waste Management Organization (NWMO)

In 2002, OPG and other Canadian nuclear waste producers established a separately incorporated NWMO in accordance with the *Nuclear Fuel Waste Act* (Canada) (NFWA). The primary long-term mandate of the NWMO is to implement an approach to address the long-term management of used nuclear fuel in Canada. In addition to the above mandate, the NWMO currently provides project management services for OPG's proposed Deep Geologic Repository (DGR) for the long-term management of low and intermediate level waste (L&ILW) and certain other nuclear life cycle liability management services. OPG has the majority of voting rights at the NWMO Board of Directors' and members' level. The NFWA requires the nuclear fuel waste owners to establish and make payments into trust funds for the purpose of funding the implementation of the long-term nuclear used fuel management plan in accordance with the NFWA. OPG provides over 90 percent of NWMO's funding, primarily towards the design and implementation of Canada's Adaptive Phased Management plan for the long-term management of nuclear used fuel. As a result, OPG is expected to absorb a majority of the NWMO's expected losses through future funding in the event of any shortfall. Therefore, OPG holds a variable interest in the NWMO, of which it is the primary beneficiary. Accordingly, the applicable amounts in the accounts of the NWMO, after elimination of all significant intercompany transactions, are consolidated.

Fair Hydro Trust

On March 2, 2017, the Province announced Ontario's Fair Hydro Plan (the Fair Hydro Plan) aimed at reducing electricity bills for eligible~~all~~ residential customers, and as many as half a million farm and~~,~~ small businesses ~~and other eligible consumers~~ (Specified Consumers) in the province on average by 25 percent. The rate reduction is inclusive of an eight percent rebate equivalent to the provincial portion of the harmonized sales tax granted by the Ontario government in January 2017. As part of the Fair Hydro Plan, a portion of the Global Adjustment costs ~~resulting from the Fair Hydro Plan shortfall~~ will be refinanced over a longer time period. The Global Adjustment includes the difference between Ontario's electricity market clearing price used to dispatch generation and the prices paid to contracted and regulated generators in the province, and the cost of conservation and demand management programs. On June 1, 2017, the *Ontario Fair Hydro Plan Act, 2017* (the Fair Hydro Act or the Act) received Royal Assent and the associated general regulation came into force in June 2017. Effective May 1, 2017, the Independent Electricity System Operator (IESO) began to defer a portion of the Global Adjustment costs. The Act allows for the IESO to transfer a portion of the balance in the variance account to a financing entity that will fund the deferral in exchange for the right to recover the balance and associated financing and other costs from Specified Consumers in the future (Investment Interest).

In December 2017, the Fair Hydro Trust (the Trust) was established as the financing entity contemplated by the Fair Hydro Act. Immediately after the establishment, OPG entered into a management agreement with the Trust which conveys to OPG all of the powers and duties of managing the Trust, including determining whether to acquire Investment Interests from the IESO related to the shortfall from the rate reduction mandated by the Fair Hydro Act, negotiating and executing all agreements, fulfilling all reporting requirements, and administering all of its day-to-day activities. In addition to the powers and duties delegated to OPG as manager under the management agreement, OPG is also required to comply with its duties as Financial Services Manager under the Fair Hydro Act and the regulations.

The Trust is essentially all debt funded and has minimal equity at risk to finance its activities. As part of the funding structure of the Trust, concurrent with every issuance of senior debt, it is expected that OPG will purchase subordinated debt of the Trust in an aggregate amount equal to, but no more than 49 percent of all of the required funding. The subordination level may vary over time, but must at least equal to, or be greater than 35 percent of all outstanding debt. Approximately 90 percent of such amount is expected to be funded through equity investments in OPG by the Province, with the remainder being funded from OPG's available funds, including all or a portion of the proceeds from OPG's medium term notes program. Based on management's assessment, it is concluded that OPG holds a variable interest in the Trust through its ownership of the most subordinated debt, of which it is the primary beneficiary. Accordingly, the applicable amounts in the accounts of the Trust, after elimination of all significant intercompany transactions, have been consolidated by OPG.

PSS Generating Station Limited Partnership (PSS or the Partnership)

As at December 31, 2017, PSS has recognized sufficient level of income and has eliminated deficits within the partnership. Hence, the Partnership has met the criteria of having sufficient equity at risk to finance its activities, and ceased being classified as a variable interest entity. Since OPG is the primary beneficiary of PSS, it continues to consolidate the Partnership.

Use of Management Estimates

The preparation of consolidated financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the consolidated financial statements, and the reported amounts of revenues and expenses for the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in the period incurred. Significant estimates are included in the determination of pension and other post-employment benefit (OPEB) balances, asset retirement obligations (AROs) and associated asset retirement costs capitalized as part of property, plant and equipment (PP&E), income taxes (including deferred income taxes), contingencies, regulatory assets and liabilities, valuation of investments in segregated funds, depreciation and amortization expenses. Actual results may differ significantly from these estimates.

Cash and Cash Equivalents and Short-Term Investments

Cash and cash equivalents include cash on deposit and money market securities with a maturity of less than 90 days on the date of purchase. All other money market securities with a maturity on the date of purchase that is greater than 90 days, but less than one year, are recorded as short-term investments and classified as current assets. These securities are valued at the lower of cost and market.

Inventories

Inventories, consisting of fuel and materials and supplies, are measured at the lower of cost and net realizable value. Cost is determined as weighted average cost for fuel inventory and average cost for materials and supplies.

Property, Plant and Equipment, Intangible Assets and Depreciation and Amortization

PP&E and intangible assets are recorded at cost. Interest costs incurred during construction and development are capitalized as part of the cost of the asset based on the interest rates on OPG's long-term debt. Expenditures for replacements of major components are capitalized.

Depreciation and amortization rates for the various classes of assets are based on their estimated service lives. Asset removal costs that have not been specifically provided for in current or previous periods are charged to operations, maintenance and administration (OM&A) expenses when incurred. Repairs and maintenance costs also are expensed when incurred.

PP&E are depreciated on a straight-line basis, except for computers, which are depreciated on a declining balance basis. Intangible assets, which consist of major application software, are amortized on a straight-line basis.

As at December 31, 2017, the amortization periods of PP&E and intangible assets are as follows:

Nuclear generating stations and major components	15 to 74 years [1]
Thermal generating stations and major components	5 to 50 years
Hydroelectric generating stations and major components	10 to 100 years
Administration and service facilities	10 to 50 years
Computers – declining balance	12% to 40% per year
Major application software	5 years
Service equipment	5 to 10 years

[1] As at December 31, 2017, the end of station life for depreciation purposes for the Darlington, Pickering, Bruce A and Bruce B nuclear generating stations ranged between 2022 and 2061. Major components are depreciated over the lesser of the station life and the life of the components.

Asset Impairment

Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. The review is based on the presence of impairment indicators such as the future economic benefit of the assets and external market conditions. The net carrying amount of assets is considered impaired if it exceeds the sum of the estimated undiscounted cash flows expected to result from the asset's use and eventual disposition. In cases where the sum of the undiscounted expected future cash flows is less than the carrying amount, an impairment loss is recognized. This loss equals the amount by which the carrying amount exceeds the fair value. Fair value is determined using expected discounted cash flows when quoted market prices are not available. The impairment is recognized in income in the period in which it is identified.

The carrying values of investments accounted for under the equity method are reviewed annually for the presence of any indicators of impairment. If an impairment exists and is determined to be other-than-temporary, an impairment charge is recognized. This charge equals the amount by which the carrying value exceeds the investment's fair value.

Rate Regulated Accounting

The *Ontario Energy Board Act, 1998* and *Ontario Regulation 53/05* provide that OPG receives regulated prices for electricity generated from the Sir Adam Beck 1, 2 and Pump hydroelectric generating stations, the DeCew Falls 1 and 2 hydroelectric generating stations, the R.H. Saunders Hydroelectric GS, the 48 hydroelectric generating stations prescribed for rate regulation effective in 2014, and the Pickering and Darlington nuclear generating stations (collectively, prescribed facilities or regulated facilities). OPG's regulated prices for these facilities are determined by the Ontario Energy Board (OEB).

The OEB is a self-funding Crown corporation. Its mandate and authority come from the *Ontario Energy Board Act, 1998,* the *Electricity Act, 1998*, and a number of other provincial statutes. The OEB is an independent, quasi-judicial tribunal that reports to the Legislature of the Province through the Ontario Ministry of Energy. It regulates market participants in Ontario's natural gas and electricity industries. The OEB carries out its regulatory functions through public hearings and other more informal processes such as consultations.

US GAAP recognizes that rate regulation can create economic benefits and obligations that are required by the regulator to be obtained from, or settled with, the customers. When the Company assesses that there is sufficient assurance that incurred costs in respect of the regulated facilities will be recovered in the future, those costs are deferred and reported as a regulatory asset. When the Company is required to refund amounts to customers in the future in respect of the regulated facilities, including amounts related to costs that have not been incurred but for which the OEB has provided recovery through regulated prices, the Company records a regulatory liability.

Certain of the regulatory assets and liabilities recognized by the Company relate to variance and deferral accounts authorized by the OEB, including those authorized pursuant to *Ontario Regulation 53/05*. Variance and deferral accounts typically capture differences between actual costs and revenues and the corresponding forecast amounts

approved by the OEB in setting regulated prices, or record the impact of items not reflected in the approved regulated prices. The measurement of these regulatory assets and liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of *Ontario Regulation 53/05* and the OEB's decisions. The estimates and assumptions made in the interpretation of the regulation and the OEB's decisions are reviewed as part of the OEB's regulatory process.

Regulatory assets and liabilities for variance and deferral account balances approved by the OEB for inclusion in regulated prices are amortized based on approved recovery or repayment periods. Disallowed balances are charged to operations in the period that the corresponding OEB decision is issued.

Regulatory assets and liabilities for variance and deferral account balances approved by the OEB are classified as current if they are expected to be recovered from, or refunded to, customers within 12 months of the end of the reporting period, based on recovery or repayment periods authorized by the OEB. All other regulatory asset and liability balances are classified as non-current on the consolidated balance sheets.

In addition to regulatory assets and liabilities for variance and deferral accounts, OPG recognizes regulatory assets and liabilities for unamortized amounts recorded in accumulated other comprehensive income (AOCI) in respect of pension and OPEB obligations, and deferred income taxes, in order to reflect the expected recovery or repayment of these amounts through future regulated prices charged to customers. There are measurement uncertainties related to these balances due to the assumptions made in the determination of pension and OPEB obligations and deferred income taxes that are attributed to rate regulated business segments.

The regulatory asset for unamortized pension and OPEB amounts recorded in AOCI has reflected the OEB's use, since April 1, 2008, of the accrual basis of accounting for including pension and OPEB amounts in approved regulated prices for OPG. This is also the manner in which these costs are recognized in OPG's consolidated financial statements. Therefore, unamortized amounts in respect of OPG's pension and OPEB plans recognized in AOCI generally would not be reflected in regulated prices until they have been reclassified from AOCI and recognized as amortization components of the benefit costs for these plans. The regulatory asset is reversed as underlying unamortized balances are amortized as components of the benefit cost.

In setting OPG's regulated prices effective November 1, 2014, the OEB limited amounts for pension and OPEB costs allowed in the approved revenue requirements to the regulated business portion of the Company's cash expenditures on its pension and OPEB plans. It is the Company's position that this decision by the OEB does not constitute a change in the basis of rate recovery for OPG's pension and OPEB costs. This position is based on the OEB's establishment of the Pension & OPEB Cash Versus Accrual Differential Deferral Account pursuant to its November 2014 decision, and the expectation expressed by the OEB in that decision that a transition from the accrual basis of recovery for OPG, if required, would be addressed in a future OPG rate proceeding, informed by the outcome of an OEB generic proceeding related to the regulatory treatment and recovery of pension and OPEB costs. Effective November 1, 2014, the Pension & OPEB Cash Versus Accrual Differential Deferral Account records the difference between OPG's actual pension and OPEB costs for the regulated business determined using the accrual method applied in OPG's audited consolidated financial statements and OPG's corresponding actual cash expenditures for these plans. The OEB's November 2014 decision indicated that the future recovery, if any, of amounts recorded in the deferral account would be subject to the outcome of an OEB generic proceeding on the regulatory treatment and recovery of pension and OPEB costs. In May 2015, the OEB began a consultation process to develop standard principles to guide its future review of pension and OPEB costs of rate regulated utilities in the electricity and natural gas sectors, including establishing appropriate regulatory mechanisms for cost recovery. The consultation is continuing. On September 14, 2017, the OEB issued its final report on the guiding principles and the policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the Ontario electricity and natural gas sectors. The report establishes the accrual basis of accounting as the method of determining pension and OPEB amounts for rate-setting purposes, unless the OEB finds that this method does not result in just and reasonable rates in the circumstances of a particular utility.

In consideration of the above factors, the Company continues to believe that there is sufficient likelihood that unamortized pension and OPEB amounts that have not yet been reclassified from AOCI will be included in future regulated prices or in an OEB-authorized deferral or variance account for future recovery, as they are recognized in benefit costs. Therefore, the Company continues to recognize a regulatory asset for these unamortized amounts and also has recognized a regulatory asset for the balance of the Pension & OPEB Cash Versus Accrual Differential Deferral Account discussed in Note 5.

See Notes 5, 8, 9, and 11 for additional disclosures related to the OEB's decisions, regulatory assets and liabilities, and rate regulated accounting.

Revenue Recognition

All of OPG's electricity generation is offered into the real-time energy spot market administered by the IESO. Revenue is recognized as electricity is generated and metered to the IESO.

Revenue Recognition – Regulated Generation

Energy revenue generated from OPG's regulated facilities is based on regulated prices determined by the OEB that include a base regulated price and, as applicable, rate riders for the recovery or repayment of approved variance and deferral account balances.

The base regulated prices in effect during 2016 were established by the OEB's November 2014 decision and December 2014 order, using a forecast cost-of-service rate-setting methodology based on the OEB-approved revenue requirements, taking into account the OEB-approved forecasts of production and operating costs for the regulated facilities for 2014 and 2015 and a return on rate base. Rate base is a regulatory construct that, for OPG, represents the average net level of investment in regulated fixed and intangible assets in-service and an allowance for working capital. The revenues from the regulated hydroelectric facilities are also subject to the OEB-approved hydroelectric incentive mechanism. This mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers.

The rate riders in effect during 2016 were established by the OEB in its October 2015 order on OPG's application to recover balances in most of the Company's authorized variance and deferral accounts as at December 31, 2014. The OEB-authorized variance and deferral accounts are discussed in Note 5.

The OEB's decision and order on OPG's May 2016 five-year application for new regulated prices for its nuclear and regulated hydroelectric generation was issued on December 28, 2017, following a public hearing process. The OEB set an effective date for OPG's new regulated prices of June 1, 2017. OPG had requested an effective date of January 1, 2017 and has filed a motion with the OEB in January 2018 to review and vary this aspect of the OEB's December 2017 decision. [**MONITOR**] See Note 5 for further information on OPG's May 2016 application.

Revenue Recognition – Non-regulated Generation and Other Revenue

The electricity generation from OPG's non-regulated assets receives the Ontario electricity spot market price, except where an energy supply agreement (ESA) with the IESO or another contractual agreement is in place. As at December 31, 2017, most of OPG's operating non-regulated assets are subject to an ESA. Revenue from the generating stations subject to an ESA is recognized in accordance with the terms of the agreement.

OPG also sells into, and purchases from, interconnected markets of other provinces and the northeast and midwest regions of the US. All contracts that are not designated as hedges are recorded on the consolidated balance sheets at market value, with gains or losses recorded in the consolidated statements of income. Gains and losses on energy trading contracts (including those to be physically settled) are recorded on a net basis in the consolidated statements of income. Accordingly, power purchases of $15 million were netted against revenue in 2017 (2016 – $19 million).

OPG derives non-energy revenue under the terms of a lease arrangement and associated agreements with Bruce Power L.P. (Bruce Power) related to the Bruce nuclear generating stations. This includes lease revenue and revenue from heavy water sales, detritiation services and waste management services. OPG's net revenues from the lease of these stations and related agreements, including a portion of heavy water sales, are credited to customers and therefore have reduced regulated prices for the generation from the nuclear facilities owned and operated by OPG. The minimum lease payments are recognized in revenue on a straight-line basis over the term of the lease.

In addition, non-energy revenue includes isotope sales, real estate rentals and other service revenues. Revenues from these activities are recognized as services are provided, or as products are delivered, in accordance with the terms stipulated in the respective contracts.

Fixed Asset Removal and Nuclear Waste Management Liabilities

OPG recognizes AROs for fixed asset removal and nuclear waste management, discounted for the time value of money. OPG estimates both the amount and timing of future cash expenditures based on the plans for fixed asset removal and nuclear waste management. The liabilities are initially recorded at their estimated fair value, which is based on a discounted value of the expected costs to be paid.

On an ongoing basis, the liabilities for nuclear fixed asset removal and nuclear waste management (Nuclear Liabilities) are increased by the present value of the incremental (variable) cost portion for the nuclear waste generated each year, with the corresponding amounts charged to OM&A expenses. Variable expenses relating to L&ILW are charged to OM&A expenses. Variable expenses relating to the management and storage of nuclear used fuel are charged to fuel expense. The liabilities may also be adjusted due to changes in the estimated amount or timing of the underlying future cash flows, with resulting changes in the related asset retirement costs capitalized as part of the carrying amount of the related fixed assets in service. A comprehensive reassessment of all underlying assumptions and baseline cost estimates for the Nuclear Liabilities is performed periodically. Changes in the Nuclear Liabilities resulting from changes in assumptions or estimates that impact the amount or timing of the originally estimated undiscounted future cash flows are recorded as an adjustment to the liabilities. Upward revisions in the Nuclear Liabilities represent the present value of increases in future undiscounted cash flows determined using a current credit-adjusted risk-free rate. Downward revisions in the Nuclear Liabilities represent the present value of decreases in future undiscounted cash flows determined using the weighted average discount rate reflected in the existing liability. Upon settlement of the liabilities, a gain or loss would be recorded.

Accretion arises because the fixed asset removal and nuclear waste management liabilities are reported on a net present value basis. Accretion expense is the increase in the carrying amount of the liabilities due to the passage of time.

The asset retirement cost is capitalized by increasing the carrying value of the related fixed assets in service. The capitalized cost is depreciated over the remaining service life of the related fixed assets and is included in depreciation and amortization expenses.

OPG has no legal obligation associated with the decommissioning of its hydroelectric generating facilities and the costs cannot be reasonably estimated because of the long service life of these assets. With either maintenance efforts or rebuilding, the water control structures are assumed to be used for the foreseeable future. Accordingly, OPG has not recognized a liability for the decommissioning of its hydroelectric generating facilities.

Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

Pursuant to the Ontario Nuclear Funds Agreement (ONFA) between OPG and the Province, OPG has established and sets aside funds in a Used Fuel Segregated Fund and a Decommissioning Segregated Fund (together the Nuclear Segregated Funds). The Used Fuel Segregated Fund is intended to fund expenditures associated with the long-term management of radioactive used nuclear fuel bundles and certain costs of used fuel storage incurred after the nuclear stations are shut down, while the Decommissioning Segregated Fund was established to fund the costs

of nuclear fixed asset removal and long-term L&ILW management, and certain costs of used fuel storage incurred after the nuclear stations are shut down. OPG's funding obligations and resulting contributions to the Nuclear Segregated Funds are determined based on periodically updated reference plans approved by the Province under the ONFA. OPG maintains the Nuclear Segregated Funds in third-party custodial and trust accounts that are segregated from the rest of OPG's assets.

OPG's investments in the Nuclear Segregated Funds and the corresponding amounts payable to/receivable from the Province are classified as held-for-trading. The Nuclear Segregated Funds are measured at fair value based on the bid prices of the underlying equity and fixed income securities, and, in the case of the alternative investment portfolio, using appropriate valuation techniques as outlined in Note 13, with realized and unrealized gains and losses recognized in OPG's consolidated statements of income.

Financing Receivables

Financing receivables consist of the current and irrevocable right of the Fair Hydro Trust to collect payments from Specified Consumers in the future in accordance with the Fair Hydro Act and associated general regulation. These amounts are measured at the transaction price entered into with the IESO on market terms upon acquisition and subsequently measured on an amortized cost basis. The basis of amortization follows the effective interest method.

Derivatives

All derivatives, including embedded derivatives that must be separately accounted for, generally are classified as held-for-trading and recorded at fair value in the consolidated balance sheets. Transaction costs are expensed as incurred for financial instruments classified or designated as held-for-trading.

Derivatives qualify for hedge accounting if they meet stringent documentation requirements, and if the derivative instrument that is designated as a hedge is expected to effectively hedge the identified risk throughout the life of the hedged item. At the inception of a hedging relationship, OPG documents the relationship between the hedging instrument and the hedged item, its risk management objective, and its strategy for undertaking the hedge. A documented assessment is made, both at the inception of a hedge and on an ongoing basis, of whether or not the derivatives that are used in hedging transactions are highly effective in offsetting the changes attributable to the hedged risks in the fair values or cash flows of the hedged items.

All derivative contracts not designated as hedges are recorded on the consolidated balance sheets as derivative assets or liabilities at fair value, with changes in the fair value recorded in the revenue of the Services, Trading, and Other Non-Generation segment. Refer to Note 12 for a discussion of OPG's risk exposures and the derivative instruments used to manage these risks.

Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly arm's-length transaction between market participants at the measurement date. Fair value measurements are required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model. OPG uses a fair value hierarchy, grouping assets and liabilities into three levels based on the relative objectivity of the inputs used to measure fair value, with Level 1 representing the most objective. Refer to Note 13 for a discussion of fair value measurements and the fair value hierarchy.

Available-for-Sale Securities

Available-for-sale (AFS) securities are measured at fair value, with unrealized gains and losses due to changes in fair value recognized in other comprehensive income (OCI). Gains and losses are realized and included in net income when the securities are sold or awarded. Related transaction costs are expensed as incurred, and dividend income

is included in net income in the period dividends are declared. Equity securities are initially measured at the transaction price.

Research and Development

Research and development costs are expensed as incurred. Research and development costs incurred to discharge long-term obligations for which specific provisions have already been made, such as the Nuclear Liabilities, are charged to the related liability.

Leases

Leases are evaluated and classified as either operating or capital leases for financial reporting purposes. Capital leases, which transfer substantially all of the risks and benefits incidental to ownership of the leased item, are capitalized at the inception of the lease at the fair value of the leased property or, if lower, at the present value of the minimum lease payments. Capital leases are depreciated over the shorter of the estimated useful life of the asset and the lease term.

Leases where the lessor retains substantially all the risks and benefits incidental to ownership of the asset are classified as operating leases. Operating lease payments, other than contingent rentals, are recognized as an expense in the consolidated statements of income on a straight-line basis over the lease term. Where the amount of rent expense recognized is different from the actual operating lease payment, other than contingent rentals, the difference is deferred and included as assets or liabilities on the consolidated balance sheets.

Pension and Other Post-Employment Benefits

OPG's post-employment benefit programs consist of a contributory defined benefit registered pension plan, a defined benefit supplementary pension plan, and other post-retirement benefits (OPRB) including group life insurance and health care benefits, and long-term disability (LTD) benefits. Post-employment benefit programs are also provided by the NWMO, which is consolidated into OPG's financial results. Unless otherwise noted, information on the Company's post-employment benefit programs is presented on a consolidated basis.

OPG accrues its obligations under pension and OPEB plans in accordance with US GAAP. The obligations for pension and OPRB are determined using the projected benefit method pro-rated on service. The obligation for LTD benefits is determined using the projected benefit method on a terminal basis. Pension and OPEB obligations are impacted by factors including interest rates, adjustments arising from plan amendments, demographic assumptions, experience gains or losses, salary levels, inflation, and health care cost escalation assumptions. Pension and OPEB costs and obligations are determined annually by independent actuaries using management's best estimate assumptions.

Assumptions are significant inputs to actuarial models that measure pension and OPEB obligations and related effects on operations. Discount rate, inflation rate, and changes in salary levels are three critical assumptions in the determination of benefit costs and obligations. In addition, the expected long-term rate of return on plan assets is a critical assumption in the determination of registered pension plan cost and the health care cost trend rate is a critical assumption in the determination of OPEB cost and obligations. These assumptions, as well as other assumptions involving demographic factors such as retirement age, mortality, and employee turnover, are evaluated periodically by management in consultation with independent actuaries. During the evaluation process, the assumptions are updated to reflect past experience and expectations for the future. Actual results in any given year will often differ from actuarial assumptions because of economic and other factors giving rise to actuarial gains and losses. In accordance with US GAAP, for pension and OPRB, the impact of these updates and differences on the respective benefit obligations is accumulated and amortized over future periods. For LTD benefits, the impact of these updates and differences is immediately recognized as OPEB costs in the period incurred.

The discount rates, which are representative of AA corporate bond yields, are used to calculate the present value of the expected future cash flows on the measurement date in order to determine the projected benefit obligations for the Company's employee benefit plans. A lower discount rate increases the benefit obligations and increases benefit costs. The expected rate of return on plan assets is based on the pension fund's asset allocation and the expected return considering long-term risks and returns associated with each asset class within the plan portfolio. A lower expected rate of return on plan assets increases pension cost.

Pension fund assets include equity securities, corporate and government debt securities, pooled funds, real estate, infrastructure, and other investments. These assets are managed by professional investment managers. The pension fund does not invest in equity or debt securities issued by OPG. Pension fund assets are valued using market-related values for purposes of determining the amortization of actuarial gains or losses and the expected return on plan assets. The market-related value recognizes gains and losses on equity assets relative to a six percent assumed real return over a five-year period.

Pension and OPEB costs include current service costs, interest costs on the obligations, the expected return on pension plan assets, adjustments for plan amendments, and adjustments for actuarial gains or losses, which result from changes in assumptions and experience gains and losses. Past service costs or credits arising from pension and OPRB plan amendments are amortized on a straight-line basis over the expected average remaining service life to full eligibility of the employees covered by the corresponding plan. Past service costs or credits arising from amendments to LTD benefits are immediately recognized as OPEB costs in the period incurred. Due to the long-term nature of pension and OPRB liabilities, the excess of the net cumulative unamortized gain or loss, over 10 percent of the greater of the benefit obligation and the market-related value of the plan assets (the corridor), is amortized over the expected average remaining service life of the employees, which represents the period during which the associated economic benefits are expected to be realized by the Company. Actuarial gains or losses for LTD benefits are immediately recognized as OPEB costs in the period incurred.

OPG recognizes the funded status of its defined benefit plans on the consolidated balance sheets. The funded status is measured as the difference between the fair value of plan assets and the benefit obligation, on a plan-by-plan basis.

Actuarial gains or losses and past service costs or credits arising during the year that are not recognized immediately as components of benefit costs are recognized as increases or decreases in OCI, net of income taxes. These unamortized amounts in AOCI are subsequently reclassified and recognized as components of pension and OPRB costs as described above.

OPG records an offsetting regulatory asset or liability for the portion of the adjustments to AOCI that is attributable to the regulated operations in order to reflect the expected recovery or refund of these amounts through future regulated prices charged to customers. For the recoverable or refundable portion attributable to regulated operations, OPG records a corresponding change in this regulatory asset or liability for the amount of the increases or decreases in OCI and for the amounts reclassified from AOCI into benefit costs during the period.

When the recognition of the transfer of employees and employee-related benefits gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement. A curtailment is the loss by employees of the right to earn future benefits under the plan. A settlement is the discharge of a plan's liability.

Income Taxes and Investment Tax Credits

OPG is exempt from income taxes under the *Income Tax Act* (Canada). However, under the *Electricity Act, 1998*, OPG is required to make payments in lieu of corporate income taxes to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by the *Electricity Act, 1998* and related regulations. This results in OPG paying taxes similar to those imposed under the federal and Ontario tax acts.

OPG's operations are complex and the computation of the provision for income taxes involves interpretation of the various tax statutes and regulations. OPG has taken certain filing positions in calculating the amount of its income tax provision. These filing positions may be challenged on audit by the Ontario Ministry of Finance and some of them possibly disallowed, resulting in a potential significant change in OPG's tax provision upon reassessment. A change in the tax provision upon reassessment impacting regulated operations may be recoverable from or refundable to customers through the Income and Other Taxes Variance Account authorized by the OEB.

OPG follows the liability method of accounting for income taxes. Under the liability method, deferred income tax assets and liabilities are determined based on differences between the accounting and tax bases of assets and liabilities. Deferred amounts are measured using the enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect of a change in tax rates on deferred income tax assets and liabilities is included in income in the period the change is enacted.

If management determines that it is more likely than not that some, or all, of a deferred income tax asset will not be realized, a valuation allowance is recorded to report the balance at the amount expected to be realized.

OPG recognizes deferred income taxes associated with its regulated operations and records an offsetting regulatory asset or liability for the deferred income taxes that are expected to be recovered or refunded through future regulated prices charged to customers.

Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return and investment tax credits are recorded only when the more likely than not recognition threshold is satisfied. Tax benefits and investment tax credits recognized are measured at the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement.

Investment tax credits are recorded as a reduction to income tax expense. OPG classifies interest and penalties associated with unrecognized income tax benefits as income tax expense.

Change in Accounting Estimates

Change in Nuclear Liabilities Estimate

In the fourth quarter of 2017, OPG achieved sufficient confidence in the Company's plans to pursue the continued safe and reliable operation of two units at the Pickering GS to 2022 and the four remaining units to 2024. This resulted in a change to the useful lives for the Pickering GS, for the purposes of calculating depreciation. Effective December 31, 2017, the change to the estimated service live of the Pickering GS has been reflected in an increase to the estimate of the Nuclear Liabilities of $188 million, and a corresponding changes in the carrying value of the nuclear generating stations to which the liabilities relate. The increase in the liabilities is primarily due to higher fixed costs associated with the Used Fuel Disposal and L&ILW Storage programs, discounted using the current credit-adjusted risk-free rate of 2.94 percent.

OPG filed an application with the OEB (EB-2018-0002) on December 29, 2017 to seek approval to establish a deferral account to record, from January 1, 2018 until the effective date of the OEB's next payment amounts order, the revenue requirement impact of changes to nuclear liabilities and depreciation and amortization expense resulting from changes to station end-of-life dates for OPG's Pickering prescribed nuclear facilities that were effective December 31, 2017. On January 31, 2018 the OEB issued an interim order (EB-2018-0002) for the establishment of the Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account, pending the outcome of the proceeding.

Pension and Other Post-Employment Benefits

Effective January 1, 2017, OPG changed the method used to estimate the service and interest cost components of pension and OPEB costs. OPG adopted a full yield curve approach to the estimation of these cost components, by applying the specific spot rates along the yield curve used in the determination of the projected benefit obligations to the relevant projected cash flows. Under the previous method, these components of pension and OPEB costs were calculated using the same single weighted-average discount rates as reflected in the calculation of the benefit obligations. This change in the method was accounted for prospectively, as a change in estimate. The resulting reduction in pension and OPEB costs is estimated at approximately $135 million in 2017. Approximately 90 percent of this reduction in pension and OPEB costs was attributed to the Company's regulated business segments and therefore was offset by the impact of regulatory variance and deferral accounts authorized by the OEB. This change does not affect the measurement of the total benefit obligation as the change in the current service and interest cost components from the previous method will be offset by a corresponding change in the actuarial gain and loss recorded in AOCI.

Pension Plan Actuarial Valuation

A new actuarial valuation of the OPG registered pension plan was filed with the Financial Services Commission of Ontario in September 2017 with an effective date of January 1, 2017. The annual funding requirements in accordance with the new actuarial valuation are $212 million for 2017, $215 million for 2018, and $219 million for 2019.

Recent Accounting Pronouncements Not Yet Adopted

Revenue from Contracts with Customers

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09, *Revenue from Contracts with Customers* (Topic 606), which supersedes nearly all existing revenue recognition guidance, including industry-specific guidance, under US GAAP. The core principle of Topic 606 is to recognize revenues when promised goods or services are transferred to customers in an amount that reflects the consideration to which an entity expects to be entitled for those goods or services. Either a full retrospective application or a modified retrospective application is required for annual periods beginning on or after January 1, 2018, including interim periods within that year. Early adoption is permitted.

OPG has assessed the impact of the standard on accounting for the Company's revenue streams and consolidated financial statements. OPG's major revenue streams include regulated generation revenue from base regulated prices and rate riders established by the OEB, as well as revenue from generation assets under long-term contractual arrangements with the IESO. OPG has completed its analyses of the impact of Topic 606 on all of its revenue streams, and has not identified any material differences in the timing or amount of revenue recognition for these streams.

The Company will apply the new revenue standard in its 2018 first quarter interim financial statements and is in the process of evaluating the additional disclosures required under the new standard.

Lease Accounting

In February 2016, the FASB issued ASU No. 2016-02, *Leases* (Topic 842). The update includes comprehensive changes to existing guidance for lease accounting, particularly for lessees, and aims to increase transparency and comparability among organizations by requiring the recognition of lease assets and lease liabilities on the balance sheet. The standard is effective for annual periods beginning after December 15, 2018, including interim periods within that year.

Under the current guidance, entities are required to use a modified retrospective approach for leases that exist, or are entered into, after the beginning of the earliest comparative period presented in the financial statements of the period of adoption. Under this method, Topic 842 would effectively be implemented by recognizing any adjustments stemming from the transition, as of beginning of the earliest comparative period presented in the entities' financial statements. Full retrospective application is prohibited. In January 2018, the FASB issued a proposed ASU wherein entities would be able to utilize an additional optional transition method of recording the cumulative impact of adopting the new lease standard to the opening balance in the initial period of adoption; with comparative periods continuing to be presented in accordance with the existing leasing standard, Topic 840 - *Leases*, including disclosures. [**MONITOR**] The Company will continue to monitor the status of this proposed ASU.

The FASB also issued ASU No. 2018-01, *Land Easement Practical Expedient for Transition to Topic 842* in January 2018. The amendments therein allows an entity to choose not to evaluate under Topic 842 land easements that exist or expired before the entity's adoption of the new leasing standard and that were not previously accounted for as leases under Topic 840.

The Company continues to implement and execute a comprehensive project governance framework, which comprises a Steering Committee, Implementation & Stakeholder Committee, Project Management Office, and various working groups in order to evaluate the implement the new standard. The working groups are represented by cross functional finance and non-finance stakeholders who will support the financial and operational implementation of the standard. The Company continues to evaluate the impact of the new leasing standard on its consolidated financial statements.

Recognition and Measurement of Financial Assets and Financial Liabilities

In January 2016, the FASB issued ASU No. 2016-01, *Financial Instruments – Overall: Recognition and Measurement of Financial Assets and Financial Liabilities*. Under the updated guidance, entities will have to measure equity investments at fair value and recognize any changes in fair value in net income. The update will be effective for OPG's 2018 fiscal year, including interim periods. As a result of this update, effective January 1, 2018, the AFS classification for securities will no longer be available, with any unrealized gains and losses related to such securities recognized in net income instead of OCI. Any unrealized gains and losses for AFS securities reported by OPG in AOCI as of the end of 2017 will be reclassified to retained earnings as of January 1, 2018. OPG's Hydro One share holdings are currently the Company's only AFS securities. As at December 31, 2017, these shares are valued on the consolidated balance sheet at $188 million (December 31, 2016 − $212 million), for which a loss of $8 million (2016 − $1 million) has been recorded in AOCI. OPG continues to evaluate whether the new standard will have any further impact on its consolidated financial statements.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost

In March 2017, the FASB issued ASU No. 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. Under the new guidance, employers that sponsor defined benefit plans for pensions and/or other postretirement benefits are required to present the service cost component of net periodic benefit cost in the same statement of income line item as other employee compensation costs arising from services rendered during the period. The other components of the net periodic benefit cost are to be presented separately from the line item that includes the service cost and outside of any subtotal of income from operations, if such a subtotal is presented. In addition, the new guidance requires that only the service cost component of net benefit cost be eligible for capitalization.

This guidance is effective for fiscal years beginning after December 15, 2017, including interim periods of those years. The guidance is not expected to have a material impact on OPG's consolidated financial statements, as OPG currently capitalizes only the service cost component of post-retirement benefits costs. Additionally, OPG already includes the service cost component of post-retirement benefit costs with other compensation costs, within the OM&A expenses line item in the consolidated statements of income, and does not show a subtotal of income from operations. As such, the new guidance is not expected to affect the presentation of OPG's consolidated financial statements.

4. PROPERTY, PLANT AND EQUIPMENT, INTANGIBLE ASSETS AND DEPRECIATION AND AMORTIZATION

PP&E as at December 31 consist of the following:

(millions of dollars)	**2017**	**2016**
Nuclear generating stations	**11,985**	11,057
Regulated hydroelectric generating stations	**9,566**	9,430
Contracted generation portfolio generating stations	**3,935**	3,751
Other property, plant and equipment	**372**	1,595
Construction in progress	**4,092**	3,482
	29,950	29,315
Less: accumulated depreciation		
Generating stations	**8,480**	7,948
Other property, plant and equipment	**148**	1,369
	8,628	9,317
	21,322	19,998

Construction in progress as at December 31 consists of the following:

(millions of dollars)	**2017**	**2016**
Darlington Refurbishment	**3,507**	2,563
Peter Sutherland Sr. GS	**17**	236
Other	**568**	683
	4,092	3,482

Intangible assets as at December 31 consist of the following:

(millions of dollars)	**2017**	**2016**
Nuclear generating stations	**122**	122
Regulated hydroelectric generating stations	**6**	7
Contracted generation portfolio generating stations	**5**	4
Computer software and other intangible assets	**393**	350
Development in progress	**39**	20
	565	503
Less: accumulated amortization		
Generating stations	**123**	120
Computer software and other intangible assets	**309**	284
	432	404
	133	99

Depreciation and amortization expenses, including amounts recognized in regulatory variance and deferral accounts authorized by the OEB, for the years ended December 31 consist of the following:

(millions of dollars)	**2017**	**2016**
Depreciation	**649**	602
Amortization of intangible assets	**30**	27
Amounts recognized in regulatory variance and deferral accounts	**-**	26
Amortization of regulatory assets and liabilities *(Note 5)*	**-**	602
	679	1,257

Interest capitalized to construction in progress during 2017 was $162 million (2016 – $141 million), at an average rate of five percent (2016 – five percent).

5. REGULATORY ASSETS AND LIABILITIES

OPG's May 2016 application with the OEB for new regulated prices included a request for new rate riders to recover or repay the December 31, 2015 balances in all of the Company's OEB-authorized variance and deferral accounts, with the exception of the Pension & OPEB Cash Versus Accrual Differential Deferral Account, less amounts previously approved for recovery or repayment for these accounts in 2016. The application also requested the continuation of all applicable existing variance and deferral accounts. In March 2017, the OEB approved a settlement agreement reached by OPG and intervenors on a limited set of issues in the application (Settlement Agreement). Among the settled issues, the agreement provided for the continuation of all applicable existing variance and deferral accounts and accepted a number of variance and deferral account balances for recovery, as requested in OPG's application. The periods of recovery or repayment for the accepted variance and deferral account balances were excluded from the scope of the Settlement Agreement.

In the OEB's December 2017 Decision and Order, the OEB accepted all applicable variance and deferral account balances for recovery that were not already accepted as part of the partial Settlement Agreement that was reached by OPG and intervenors. That OEB-approved Settlement Agreement also provided for the continuation of all applicable existing variance and deferral accounts effective June 1, 2017. The December 2017 decision and order allows for recovery of $305 million recorded in certain variance and deferral accounts as at December 31, 2015, without adjustments. OPG's draft Payment Amounts Order proposed the recovery period to be January 1, 2019 to December 31, 2021.

Consistent with the effective date of the OEB's December 2017 decision and order, for the period from January 1, 2017 to May 31, 2017, OPG continued to record additions to the existing variance and deferral accounts for the nuclear and regulated hydroelectric facilities pursuant to the OEB's previous decisions and orders. These additions reflected differences between actual and forecast amounts embedded in the regulated prices in effect prior to June 1, 2017.

In its December 2017 decision and order on OPG's rate application, the OEB granted OPG approval to request disposal of applicable audited deferral and variance account balances, including the Pension & OPEB Cash Versus Accrual Differential Account, in calendar year 2018. Under the requirements of US GAAP, the period of deferring amounts recorded in the Pension & OPEB Cash Versus Accrual Differential Deferral Account must not exceed five years from the time that they were incurred. Accordingly, such amounts recorded during November 2014 must begin to be recovered no later than November 2019 and must be fully recovered within 20 years of November 2014 or OPG will be required to write off the regulatory asset for these amounts.

The regulatory assets and liabilities recorded as at December 31 are as follows:

(millions of dollars)	**2017**	**2016**
Regulatory assets		
Variance and deferral accounts authorized by the OEB		
Pension and OPEB Cost Variance Account	**716**	716
Pension & OPEB Cash Versus Accrual Differential Deferral Account *(Note 11)*	**614**	497
Hydroelectric Surplus Baseload Generation Variance Account	**360**	210
Bruce Lease Net Revenues Variance Account	**121**	95
Other variance and deferral accounts	**124**	107
	1,935	1,625
Interim Period Revenue Shortfall Account	**544**	-
Pension and OPEB Regulatory Asset *(Note 11)*	**3,855**	3,392
Deferred Income Taxes	**897**	838
Total regulatory assets	**7,231**	5,855
Regulatory liabilities		
Variance and deferral accounts authorized by the OEB		
Hydroelectric Water Conditions Variance Account	**150**	51
Pension & OPEB Cash Variance Account	**140**	58
Impacts Resulting from Changes in Station End-of-Life Dates Deferral Account	**103**	71
Rate Smoothing Deferral Account	**63**	-
Other variance and deferral accounts	**138**	130
Total regulatory liabilities	**594**	310

The changes in the regulatory assets and liabilities during 2017 and 2016 are as follows:

(millions of dollars)	Pension and OPEB Cost Vari-ance	Pension & OPEB Cash vs Accrual Differen-tial Deferral	Hydro-electric Surplus Baseload Genera-tion Variance	Bruce Lease Net Reve-nues Variance	Water Condit-ions variance	Pension & OPEB Cash	Impact Resulting from Changes in Station End-of-Life Dates Deferral Account	Rate Smooth-ing Deferral Account	Other Vari-ance and Deferral (net)	Interim Period Revenue Shortfall Account	Pension and OPEB Regula-tory Asset	Deferred Income Taxes
Net regulatory assets (liabilities) January 1, 2016	865	315	114	95	(23)	28	-	-	260	-	3,362	792
Increase (decrease)	-	182	126	143	(33)	(86)	(71)	-	-	-	30	46
Interest	-	-	2	-	(1)	-	0	-	1	-	-	-
Amortization	(149)	-	(32)	(143)	6	-	0	-	(284)	-	-	-
Net regulatory assets (liabilities) December 31, 2016	716	497	210	95	(51)	(58)	(71)	-	(23)	-	3,392	838
Increase (decrease)	**-**	**117**	**146**	**25**	**(98)**	**(81)**	**(32)**	**(62)**	**10**	**544**	**463**	**59**
Interest	**-**	**-**	**4**	**1**	**(1)**	**(1)**	**0**	**(1)**	**(1)**	**-**	**-**	**-**
Net regulatory assets (liabilities) December 31, 2017	**716**	**614**	**360**	**121**	**(150)**	**(140)**	**(103)**	**(63)**	**(14)**	**544**	**3,855**	**897**

Pension and OPEB Cost Variance Account

As authorized by the OEB, for the period from March 1, 2011 to October 30, 2014, the Pension and OPEB Cost Variance Account recorded the differences between OPG's actual pension and OPEB costs for the regulated business determined on an accrual basis and related tax impacts, and corresponding forecast amounts reflected in the regulated prices then in effect. In its November 2014 decision, the OEB determined that the pension and OPEB amounts reflected in OPG's regulated prices established by that decision effective November 1, 2014 would be limited to the Company's estimated minimum contributions to its registered pension plan and a forecast of OPG's expenditures on the OPEB and supplementary pension plans. As such, the OEB ordered the Pension and OPEB Cost Variance Account to record only amortization beginning on November 1, 2014.

In its October 2015 order, the OEB approved the continuation of the previously authorized recovery of 10/12 of the account balance as at December 31, 2012 over a 144-month period to December 31, 2024. Amounts recorded in the account in 2013 and 2014 were approved for recovery over a 72-month period to June 30, 2021 by the OEB's October 2015 order. In OPG's draft payment amounts order, the recovery period was adjusted to extend beyond June 30, 2021 and December 31, 2024 to account for the break in recovery of the account in the 2017 and 2018 periods as proposed by OPG.

Pension & OPEB Cash Versus Accrual Differential Deferral Account

In its November 2014 decision and December 2014 order, the OEB established the Pension & OPEB Cash Versus Accrual Differential Deferral Account. Effective November 1, 2014, this deferral account records the difference between OPG's actual pension and OPEB costs for the regulated business determined on an accrual basis under US GAAP and OPG's corresponding actual cash expenditures for these plans. The balance in the account as at

December 31, 2017 represents the excess of costs calculated using the accrual basis over the cash basis for the period from November 1, 2014 to December 31, 2017. The Company has recognized the amount set aside in the deferral account as a regulatory asset.

The OEB's November 2014 decision indicated that the future recovery, if any, of amounts recorded in the deferral account would be subject to the outcome of the OEB generic proceeding on the regulatory treatment and recovery of pension and OPEB costs. On September 14, 2017, the OEB issued its final report on the guiding principles and the policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the Ontario electricity and natural gas sectors. The report establishes the accrual basis of accounting as the method of determining pension and OPEB amounts for rate-setting purposes, unless the OEB finds that this method does not result in just and reasonable rates in the circumstances of a particular utility. The OEB's September 2017 report and the OEB's December 2017 decision on OPG's application for new regulated prices require OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the Pension & OPEB Cash to Accrual Differential Deferral Account in effect since November 1, 2014, until such time as the OEB approves resumption of the accrual basis of recovery.

Consistent with the expectations set out in the OEB's December 2017 decision, in 2018, OPG plans to file an application with the OEB requesting disposition of the Pension & OPEB Cash Versus Accrual Differential Deferral Account balance.

Hydroelectric Surplus Baseload Generation Variance Account

The Hydroelectric Surplus Baseload Generation Variance Account records the impact of forgone production at OPG's regulated hydroelectric facilities due to surplus baseload generation conditions.

In its December 2017 Decision and Order, the OEB approved the disposition of the Hydroelectric Surplus Baseload Generation Variance Account balance as at December 31, 2015, as proposed. OPG has proposed a recovery period of January 1, 2019 to December 31, 2021.

Bruce Lease Net Revenues Variance Account

In accordance with *Ontario Regulation 53/05*, the OEB is required to include the difference between OPG's revenues and costs associated with the two nuclear generating stations on lease to Bruce Power in the determination of the regulated prices for production from OPG's regulated nuclear facilities. Based on *Ontario Regulation 53/05* requirements, the OEB has established a variance account that captures differences between OPG's actual revenues and costs related to these stations and the corresponding forecasts included in approved nuclear regulated prices, including the costs associated with OPG's Nuclear Liabilities and the earnings from the portion of the Nuclear Segregated Funds related to the Bruce stations.

In 2013, the OEB ordered the portion of the balance in the Bruce Lease Net Revenues Variance Account related to the impact of the derivative liability embedded in the terms of the lease agreement between OPG and Bruce Power related to the Bruce nuclear generating stations (Bruce Lease) in effect prior to December 2015 to be recovered on the basis of OPG's expected rent rebate payments to Bruce Power and associated income tax impacts. The OEB's October 2015 order reaffirmed this approach and included, in amounts authorized for recovery over the period to the end of 2016, amounts for the derivative liability. In December 2015, as a result of amendments to the Bruce Lease, OPG reversed the derivative liability, with a corresponding reduction to the regulatory asset for the Bruce Lease Net Revenue Variance Account. Amounts collected from customers for the derivative liability for periods after its reversal are subject to refund in the future and have been recognized as a regulatory liability as part of the variance account balance.

The regulatory asset balance for the Bruce Lease Net Revenues Variance Account as at December 31, 2017 reflects a net amount of $190 million recoverable from customers for non-derivative variances recorded in 2015 through 2017, which is partially offset by a liability of $69 million to customers for amounts recovered for the derivative liability

since its reversal in December 2015. Non-derivative amounts recorded during 2017 included those arising from the adjustment to the Nuclear Liabilities and related changes to the estimated service lives of OPG's nuclear stations, for accounting purposes, effective December 31, 2015 and the updated 2017 ONFA reference plan approved by the province.

In its December 2017 Decision and Order, the OEB approved the disposition of the Bruce Lease Net Revenues Account balance as at December 31, 2015, as proposed. OPG has proposed a recovery period of January 1, 2019 to December 31, 2021.

Interim Period Revenue Shortfall Account

The Interim Period Revenue Shortfall regulatory asset records the revenue shortfall between proposed Nuclear and Regulated Hydroelectric rates and existing Nuclear and Regulated Hydroelectric rates from June 1, 2017 through December 31 2017 based on actual production. The recovery of this account is expected to begin January 1, 2019 through to December 31, 2021. [**UPDATE**]

Pension and OPEB Regulatory Asset

The Pension and OPEB Regulatory Asset represents unamortized amounts in respect of OPG's pension and OPEB plans that have been recognized in OCI and not yet reclassified into the amortization component of the benefit costs in respect of these plans. These amounts are expected to be recovered from customers through future regulated prices. The regulatory asset is reversed as underlying unamortized balances are amortized as components of benefit costs. For further details, refer to Note 3 under the heading, *Rate Regulated Accounting*. The AOCI amounts related to pension and OPEB plans are presented in Note 11.

Deferred Income Taxes

OPG is required to record a regulatory asset or liability for the deferred income taxes that are expected to be recovered or refunded through future regulated prices charged to customers for generation from OPG's regulated facilities. In addition, OPG is required to recognize a deferred income tax liability or asset for the regulatory asset or liability for the amount of deferred income taxes expected to be included in future regulated prices and paid to, or recovered, from customers. Income taxes are discussed in Note 9.

Hydroelectric Water Conditions Variance Account

The Hydroelectric Water Conditions Variance Account captures the impact of differences in regulated hydroelectric electricity production due to differences between forecast water conditions underlying the production forecast approved by the OEB in setting regulated hydroelectric prices, and the actual water conditions.

In its December 2017 Decision and Order, the OEB approved the disposition of the Hydroelectric Water Conditions Variance Account balance as at December 31, 2015, as proposed. OPG has proposed a recovery period of January 1, 2019 to December 31, 2021.

Pension & OPEB Cash Payment Variance Account

The Pension & OPEB Cash Payment Variance Account was approved in EB-2013-0321 and continued in EB-2014-0370. The account records the difference between OPG's actual registered pension plan contributions and OPEB plan payments (including the long-term disability benefit plan) attributed to the prescribed generating facilities, and such forecast amounts reflected in the revenue requirement approved by the OEB.

In its December 2017 Decision and Order, the OEB approved the disposition of the Pension & OPEB Cash Payment Variance Account balance as at December 31, 2015, as proposed. OPG has proposed a recovery period of January 1, 2019 to December 31, 2021.

Impact Resulting from Changes in Station End-of-Life Dates Deferral Account

In December 2015, as required by the OEB's previous decisions and orders, OPG applied to the OEB for an accounting order to establish a new deferral account to record the revenue requirement impact on the Pickering and Darlington nuclear generating stations of changes to the Nuclear Liabilities and depreciation expense arising from extensions in the estimated useful lives of OPG's nuclear stations, for accounting purposes, effective December 31, 2015. These impacts were not reflected in the existing regulated prices. In March 2016, the OEB issued its final decision and order establishing the requested account, the Impact Resulting from Changes in Station End-of-Life Dates Deferral Account, effective January 1, 2016. The deferral account recorded these impacts until new regulated prices reflecting the above changes came into effect on June 1, 2017.

The extensions to the estimated useful lives of OPG's nuclear generating stations effective December 31, 2015, for accounting purposes, included those of the Bruce A GS and the Bruce B GS to reflect the estimated end-of-life dates per the updated refurbishment agreement between the IESO and Bruce Power announced in December 2015, a one-year extension for the Darlington GS to reflect the approval of the refurbishment schedule in 2015, and an extension of less than one year for the Pickering GS. To reflect these changes, OPG recognized a total increase of $2,330 million in the Nuclear Liabilities and a corresponding increase in the related asset retirement costs capitalized to PP&E, effective December 31, 2015.

Rate Smoothing Deferral Account

In accordance with section 5.5 of *Ontario Regulation 53/05*, OPG shall establish a Rate Smoothing Deferral Account. This account shall record, for each respective year, the difference between: (i) the total annual revenue requirement for the prescribed nuclear facilities approved by the OEB; and, (ii) the portion of that revenue requirement in (i) that is used in connection with setting the approved nuclear payment amounts in each year.

Consistent with the requirements of *Ontario Regulation 53/05*, OPG's overall production weighted payment amounts will be smoothed, with a resulting portion of the approved annual nuclear revenue requirements for the 2017-2021 period deferred in the Rate Smoothing Deferral Account for future collection. The non-deferred portion of each year's nuclear revenue requirement will be divided by the OEB-approved forecast of OPG's nuclear electricity generation for the corresponding year to determine the base nuclear regulated price. Per the regulation, the deferral account records interest at a long-term debt rate reflecting OPG's cost of long-term borrowing approved by the OEB, compounded annually. The regulation also requires the OEB to authorize recovery of the balance in the account on a straight line basis over a period not to exceed ten years following the end of the Darlington Refurbishment project. OPG recognizes positive amounts deferred under rate smoothing as an increase in net regulatory assets and an increase in revenue in the period to which the underlying approved revenue requirement relates. Negative amounts determined under rate smoothing are correspondingly recorded as a decrease in net regulatory assets and a decrease to revenue.

On January 17, 2018, OPG submitted a draft payment amounts order to the OEB that proposed nuclear base regulated prices for each year of the 2017-2021 period. The proposed regulated prices reflected the December 2017 decision's findings in calculating the 2017-2021 nuclear revenue requirements and reflected a rate smoothing proposal developed by OPG in accordance with *Ontario Regulation 53/05* and OEB's direction. As at December 31, 2017 OPG recorded a liability of $63 million and is expected to have a regulatory asset balance of approximately $750 million by 2021.

Other Variance and Deferral Accounts

Regulatory assets

As at December 31, 2017 and 2016, regulatory assets for Other variance and deferral accounts included amounts for the Nuclear Liability Deferral Account, the Nuclear and Hydroelectric Deferral and Variance Over/Under Recovery Variance Account, the Nuclear Development Account, and the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account and the Fitness for Duty Deferral Account.

Pursuant to *Ontario Regulation 53/05*, the Nuclear Liability Deferral Account has been authorized by the OEB in connection with changes to OPG's liabilities for nuclear used fuel management and nuclear decommissioning and L&ILW management associated with the nuclear facilities owned and operated by OPG, which are comprised of the Pickering and Darlington nuclear generating stations. The deferral account records the revenue requirement impact associated with the changes in these liabilities arising from an approved reference plan, in accordance with the terms of the ONFA.

The Nuclear and Hydroelectric Deferral and Variance Over/Under Recovery Variance Accounts records any shortfall or over-recovery of the approved variance and deferral account balances due to differences between actual and forecast nuclear and hydroelectric production respectively.

The Nuclear Development Variance Account records variances between the actual non-capital costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities and the corresponding forecasts reflected in the regulated prices approved by the OEB.

The Fitness for Duty Deferral Account was approved by the OEB in the EB-2016-0152 Decision and order, effective June 1, 2017. The account shall record the costs related to implementing the Canadian Nuclear Safety Commission (CNSC) Fitness for Duty program. The Fitness for Duty program is a drug, alcohol, psychological and physical testing program for employees in nuclear facilities, which is anticipated to be a license requirement of the CNSC.

Regulatory liabilities

As at December 31, 2017 and 2016, regulatory liabilities for Other variance and deferral accounts included amounts for the Ancillary Services Net Revenue Variance Account, the Income and Other Taxes Variance Account, the Hydroelectric Incentive Mechanism Variance Account, the SR&ED ITC Variance Account and the Capacity Refurbishment Variance Account.

The Ancillary Services Net Revenue Variance Account has been authorized by the OEB to capture differences between actual nuclear and regulated hydroelectric ancillary services net revenue and the forecast amounts of such revenue approved by the OEB in setting regulated prices.

The Income and Other Taxes Variance Account includes deviations in income taxes for the regulated business, from those approved by the OEB in setting regulated prices, caused by changes in tax rates and rules, as well as reassessments.

The Hydroelectric Incentive Mechanism Variance Account records a credit to customers equal to 50 percent of OPG's hydroelectric incentive mechanism revenues above a specified threshold for the regulated hydroelectric facilities.

As at December 31, 2017, regulatory liabilities for Other variance and deferral accounts also included the SR&ED ITC Variance Account and the Capacity Refurbishment Variance Account. The SR&ED ITC Variance Account was approved by the OEB in its EB-2016-0152 Decision, effective June 1, 2017. This account will record the tax expense impact for the nuclear facilities as a result of the difference between actual SR&ED ITCs (attributed to the nuclear facilities) as determined after any tax audits and the forecast SR&ED ITCs included in the nuclear revenue requirement approved by the OEB. Pursuant to *Ontario Regulation 53/05*, the OEB has authorized the Capacity Refurbishment Variance Account. The account captures variances from the forecasts reflected in the regulated prices for capital and non-capital costs incurred to increase the output of, refurbish, or add operating capacity to one or more of the regulated facilities. The balance in the account as at December 31, 2017 includes variances related to

the refurbishment of the Darlington nuclear generating station, life extension initiatives at the Pickering nuclear generation station, and other projects.

6. LONG-TERM DEBT AND NET INTEREST EXPENSE

Long-term debt consists of the following as at December 31: [1]

(millions of dollars)	**2017**	**2016**
Notes payable to the OEFC [2]		
Senior Notes		
bear interest at rates ranging from 3.12% to 5.44%; maturity dates ranging from 2018 to 2047	**3,195**	3,295
Medium Term Note Program [3]		
Senior Notes		
3.32% due 2027	**500**	-
UMH Energy Partnership [4]		
Senior Notes		
7.86% due 2041	**181**	184
PSS Generating Station Limited Partnership [5]		
Senior Notes		
4.90% due 2067	**245**	245
Lower Mattagami Energy Limited Partnership [6]		
Senior Notes		
bear interest at rates ranging from 2.4% to 5.26%; maturity dates ranging from 2021 to 2052	**1,595**	1,795
Fair Hydro Trust [7]		
Senior notes		
2.32% due 2019	**601**	-
Other	**19**	15
	6,336	5,534
Less: bond issuance fees	**(17)**	(14)
Less: due within one year	**(398)**	(1,103)
Long-term debt	**5,921**	4,417

[1] The interest rates disclosed reflect the effective interest rate of the debt, except for the Fair Hydro Trust notes which reflect the weighted average interest rate during the period the notes were outstanding from December 21 to December 31, 2017.

[2] OEFC is entitled to receive in full amounts owing in respect of the senior debt.

[3] These notes are direct unsecured obligations of OPG and rank *pari passu* with all other OPG's unsubordinated and unsecured obligations.

[4] These notes are secured by the assets of the Upper Mattagami and Hound Chute project. Principal repayments of $3 million per year are made on a semi-annual basis until maturity in 2041, at which time the remaining principal balance of $116 million becomes due.

[5] These notes are secured by the assets of the Peter Sutherland Sr. GS project. The notes have an interest-only feature until 2025 and will be amortized with blended semi-annual principal and interest payments thereafter until maturity in 2067, at which time the remaining principal balance of $49 million becomes due.

[6] These notes are secured by the assets of the Lower Mattagami River project, including existing and new operating facilities.

[7] The notes were issued under an $800 million two-year revolving warehouse facility discussed below and are secured by the assets of the Fair Hydro Trust.

In June 2016, OPG entered into a $700 million general corporate credit facility agreement with the OEFC, which expired on December 31, 2017. In September 2017, the agreement was amended, with the credit facility increased to $2,350 million and the expiry date extended to December 31, 2018. As of December 31, 2017, $800 million were outstanding from the credit facility.

In February 2017, OPG issued senior notes payable to the OEFC totalling $200 million and maturing in February 2047. The effective interest rate and coupon interest rate of these notes was 4.12 percent. In June 2017,

OPG issued senior notes payable to the OEFC totalling $100 million and maturing in June 2047. The effective interest rate and coupon interest rate of these notes was 3.65 percent. In August 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in August 2047. The effective interest rate and coupon interest rate of these notes was 3.86 percent. In September 2017, OPG issued senior notes payable to the OEFC totalling
$400 million and maturing in September 2047. The effective interest rate and coupon interest rate of these notes was 4.07 percent.

In October 2017, OPG issued $500 million of senior notes payable under a Medium Term Note Program. The notes bear a coupon interest rate of 3.32 percent and an effective rate of 3.43 percent, payable semi-annually until maturity in October 2027. The offering was made under OPG's $2 billion short form base shelf prospectus filed in September 2017.

In 2015, PSS, a subsidiary of OPG, issued long-term debt totalling $245 million in support of the Peter Sutherland Sr. Generating Station (GS) project. The majority of the debt proceeds, totalling $180 million, were invested in a structured deposit note with staggered maturity dates ranging from January 2016 to April 2017. As at December 31, 2017, the deposit note had matured.

In October 2016, Lower Mattagami Energy Limited Partnership (LME) issued senior notes totalling $220 million maturing in October 2026. The effective interest rate and coupon interest rate of these notes were 2.40 percent and 2.31 percent, respectively.

In December 2017, the Trust entered into an $800 million revolving warehouse facility agreement with an expiry date of December 21, 2019. As at December 31, 2017, there were outstanding senior notes of $601 million under this credit facility, which were used to finance 51 percent of the Trust's funding requirement for the acquisition of the first tranche of Investment Interest from the IESO in December 2017. The outstanding balance has been classified as long-term debt to reflect the terms and substance of the facility agreement. The interest incurred on this debt is recorded within Earnings from Fair Hydro Trust on the consolidated statements of income. Please refer to Note 17 for additional information on Fair Hydro Trust's financial information.

In February 2018, the Trust issued $500 million of senior notes payable with a coupon interest rate of 3.36 percent and an effective interest rate of 3.42 percent, payable semi-annually until maturity on May 15, 2033. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility issued by the Trust in December 2017. By the end of the first quarter of 2018, the Trust is expected to acquire another tranche of Investment Interest from the IESO, which it expects to fund using its revolving warehouse facility. **[MONITOR]**

The following table summarizes the net interest expense:

(millions of dollars)	December 31 **2017**	**2016**
Interest on long-term debt	**289**	290
Interest on short-term debt	**7**	8
Interest income	**(9)**	(7)
Interest capitalized to property, plant and equipment and intangible assets	**(162)**	(141)
Interest related to regulatory assets and liabilities [1]	**(30)**	(30)
Net interest expense	**95**	120

[1] Includes interest to recognize the cost of financing related to regulatory variance and deferral accounts, as authorized by the OEB, and interest deferred in the Bruce Lease Net Revenues Variance Account, the Capacity Refurbishment Variance Account, and the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account.

Interest paid in 2017 was $258 million (2016 – $269 million), of which $ 251 million (2016 – $261 million) relates to interest paid on long-term debt.

The net book value of the pledged assets of PSS, UMH, LME, and Lower Mattagami Limited Partnership against their debt as at December 31, 2017 was $3,645 million (2016 – $3,510 million).

7. SHORT-TERM DEBT

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. During 2017, OPG renewed and extended the expiry date of both tranches to May 2022. There were no amounts outstanding under the bank credit facility. There was $100 million of commercial paper outstanding under OPG's commercial paper program as at December 31, 2017. The Commercial paper program is used to provide short-term funding requirement for the Company, at rates of approximately one percent and are less than one year in duration.

As at December 31, 2017, the LME maintained a $400 million bank credit facility to support the funding requirements for the Lower Mattagami River project including support for LME's commercial paper program. The facility consists of a $300 million tranche maturing in August 2022 and a $100 million tranche maturing in August 2018. As at December 31, 2017, there was $160 million commercial paper outstanding under LME's commercial paper program (December 31, 2016 – nil). A letter of credit of $55 million was issued in July 2017 and remains outstanding as at December 31, 2017 under the first tranche of LME's credit facility.

As at December 31, 2017, OPG maintained $25 million of short-term, uncommitted overdraft facilities and $468 million of short-term, uncommitted credit facilities, which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other general corporate purposes. As at December 31, 2017, a total of $390 million of Letters of Credit had been issued under these facilities. This included $353 million for the supplementary pension plans, $36 million for general corporate purposes, and $1 million related to the operation of the PEC.

The Company has an agreement to sell an undivided co-ownership interest in its current and future accounts receivable to an independent trust. The maximum amount of co-ownership interest that can be sold under this agreement is $150 million, expiring on November 30, 2018. As at December 31, 2017, there were Letters of Credit outstanding under this agreement of $150 million (December 31, 2016 – $150 million), which were issued in support of OPG's supplementary pension plans.

UMH Energy Partnership has entered into an $8 million short-term, uncommitted overdraft facility and $16 million of irrevocable, standby Letters of Credit facilities in support of its operations. As at December 31, 2017, total Letters of Credit of $15 million had been issued under these facilities.

8. NUCLEAR FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT FUND AND FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT LIABILITIES

The liabilities for fixed asset removal and nuclear waste management on a present value basis as December 31, consist of the following:

(millions of dollars)	**2017**	**2016**
Liability for nuclear used fuel management	**11,970**	11,292
Liability for nuclear decommissioning and nuclear low and intermediate level waste management	**8,107**	7,811
Liability for non-nuclear fixed asset removal	**344**	381
Fixed asset removal and nuclear waste management liabilities	**20,421**	19,484

The changes in the fixed asset removal and nuclear waste management liabilities for the years ended December 31 are as follows:

(millions of dollars)	**2017**	**2016**
Liabilities, beginning of year	**19,484**	20,169
Increase in liabilities due to accretion [1]	**974**	1,024
Decrease in liabilities resulting from the ONFA reference plan update process	**-**	(1,567)
Net change in liabilities reflecting changes to the estimated useful lives *(Note 3)*	**158**	-
Increase in liabilities due to changes in estimates of nuclear used fuel and nuclear waste management expenses and other expenses [1]	**118**	133
Liabilities settled by expenditures on fixed asset removal and nuclear waste management	**(313)**	(275)
Liabilities, end of year	**20,421**	19,484

[1] Amounts shown exclude the impact of regulatory variance and deferral accounts.

OPG's fixed asset removal and nuclear waste management liabilities are comprised of expected costs to be incurred up to and beyond termination of operations and the closure of nuclear and thermal generating facilities, and other facilities. Costs will be incurred for activities such as preparation for safe storage and safe storage of the nuclear stations, dismantlement, demolition and disposal of facilities and equipment, remediation and restoration of sites, and the ongoing and long-term management of nuclear used fuel and L&ILW material.

The determination of the accrual for fixed asset removal and nuclear waste management costs requires significant assumptions since these programs are long-term in nature. The most recent comprehensive update of the cost estimates for the Nuclear Liabilities is contained in the 2017−2021 ONFA reference plan, which was finalized and approved by the Province in the fourth quarter of 2016 (2017 ONFA Reference Plan).

For the purposes of calculating OPG's Nuclear Liabilities, as at December 31, 2017, consistent with the current accounting end-of-life assumptions, nuclear station decommissioning activities are projected to occur over approximately the next 80 years. The estimates for the Nuclear Liabilities include cash flow estimates for decommissioning the nuclear stations for approximately 40 years after stations are shut down and to 2088 for placement of used fuel into the assumed long-term disposal repository, followed by extended monitoring.

The significant assumptions underlying operational, technical, and economic factors used in the calculation of the accrued Nuclear Liabilities are subject to periodic review. Changes to these assumptions, including changes to assumptions on the timing of the nuclear waste programs including construction of waste disposal facilities, station end-of-life dates, waste disposal methods, financial indicators, or the technology employed, may result in significant changes to the value of the accrued liabilities. With programs of this long-term duration and the evolving technology to handle the nuclear waste, there is a significant degree of inherent uncertainty surrounding the measurement of the costs for these programs. These costs may increase or decrease over time.

Liability for Nuclear Used Fuel Management Costs

The liability for nuclear used fuel management represents the cost of managing the highly radioactive used nuclear fuel bundles. The federal NFWA, proclaimed into force in 2002, required that Canada's nuclear fuel waste owners form a nuclear waste management organization, and that each waste owner establish a trust fund for used fuel management costs as specified in the NFWA. This organization, the NWMO, is responsible for the design and implementation of Canada's plan for the long-term management of nuclear used fuel waste. To estimate its liability for nuclear used fuel management costs, OPG has adopted an approach consistent with the Adaptive Phased Management concept approved by the Government of Canada, which assumes a deep geologic repository as part of the long-term management of nuclear used fuel, with an in-service date of 2043 at the earliest.

Liability for Nuclear Decommissioning and L&ILW Management Costs

The liability for nuclear decommissioning and L&ILW management represents the estimated costs of decommissioning the nuclear generating stations after the end of their service lives, as well as the cost of managing L&ILW generated by the stations. The significant assumptions used in estimating future nuclear fixed asset removal costs include a deferred dismantlement basis for decommissioning of the stations, whereby the reactors will be de-watered and de-fueled immediately after the station has ceased operations and thereafter will remain in a safe state condition for a 30-year period, prior to an approximate 10-year dismantlement period.

The life cycle costs of L&ILW management include the costs of processing and storage of such radioactive wastes during and following the operation of the nuclear stations, as well as the costs of the ultimate long-term management of these wastes. The current assumptions used to establish the accrued costs for the management of L&ILW include an L&ILW DGR to be owned and operated by OPG. Agreement was previously reached with local municipalities for OPG to develop a deep geologic repository for the long-term management of L&ILW adjacent to OPG's Western Waste Management Facility in Kincardine, Ontario.

Liability for Non-Nuclear Fixed Asset Removal Costs

The liability for non-nuclear fixed asset removal primarily represents the estimated costs of decommissioning OPG's thermal generating stations at the end of their services lives. The liability is based on third-party cost estimates following an in-depth review of plant sites and an assessment of required clean-up and restoration activities completed in 2017.

OPG performed a revaluation of the liability for non-nuclear fixed asset removal as at December 31, 2017. OPG recognized a decrease in the non-nuclear fixed asset removal liabilities of approximately $30 million, resulting in an decrease in asset retirement costs of $18 million capitalized as part of the carrying value of PP&E, and a gain of $12 million recorded to net income in 2017.

Ontario Nuclear Funds Agreement

In accordance with the ONFA, OPG sets aside and invests funds that are held in segregated custodian and trustee accounts specifically for discharging its life cycle obligation for nuclear decommissioning and long-term nuclear waste management. The Used Fuel Segregated Fund and the Decommissioning Segregated Fund were established under the ONFA for this purpose. OPG makes contributions to the Nuclear Segregated Funds based on the approved ONFA reference plan in effect. ONFA reference plans are subject to approval by the Province.

Since inception, OPG has been making quarterly payments to the Used Fuel Segregated Fund over the assumed lives of its nuclear generating stations, as specified in the ONFA, including contributions to the NFWA Trust established by OPG pursuant to the NFWA. The NFWA Trust forms part of the Used Fuel Segregated Fund, with any OPG contributions to the Used Fuel Segregated Fund, as well as any portion of the fund currently not in the trust, being able to be applied towards the NFWA Trust's annual contribution requirements pursuant to the NFWA. As a result, required funding of the Used Fuel Segregated Fund for 2017 was nil (2016 – $150 million). ONFA

requirements have resulted in the majority of the underlying used fuel management obligation being funded through OPG contributions over the initial estimated useful lives of the nuclear generating stations assumed in the ONFA, which did not reflect subsequent extensions to the nuclear station lives to reflect refurbishment and life extension decisions.

OPG has not been required to make contributions to the Decommissioning Segregated Fund, which was fully funded at its inception through an initial contribution made by the Province and, taking into account asset performance and changes in underlying funding obligation over time, at the time of every subsequent approved ONFA reference plan.

The 2017 ONFA Reference Plan was approved by the Province in December 2016, with an effective date of January 1, 2017. Based on the funded status of the Used Fuel Segregated Fund and the Decommissioning Segregated Fund reflecting the life cycle liability estimates per the 2017 ONFA Reference Plan, no overall contributions to either fund are currently required starting in 2017. Contributions may be required in the future should either or both of the funds be in an underfunded position when a new reference plan is prepared.

The *Nuclear Safety and Control Act* (Canada) requires OPG to have sufficient funds available to discharge its existing nuclear waste management and nuclear facilities decommissioning obligations. As required by the terms of the ONFA, the Province has provided a Provincial Guarantee to the CNSC since 2003, on behalf of OPG. The Provincial Guarantee provides for any shortfall between the CNSC consolidated financial guarantee requirement and the value of the Nuclear Segregated Funds. OPG pays the Province an annual guarantee fee of 0.5 percent of the amount of the Provincial Guarantee. The value of the Provincial Guarantee amount in effect through to the end of 2017 was $1,551 million. Based on this guarantee amount, OPG paid a guarantee fee of $8 million to the Province for each of 2017 and 2016.

Commented [DS1]: Realize that these financial statements are only through Dec. 31, 2017, but to be safe, wanted to flag the CNSC decision in November 2017 such that the Province no longer provides a Provincial Guarantee as of Jan. 1, 2018.

The investments in the Nuclear Segregated Funds include a diversified portfolio of equities and fixed income securities that are invested across geographic markets, as well as investments in infrastructure, real estate, and agriculture. The Nuclear Segregated Funds are invested to fund long-term liability requirements and, as such, the portfolio asset mix is structured to achieve the required return over a long-term horizon. While short-term fluctuations in market value will occur, managing the long-term return of the Nuclear Segregated Funds remains the primary goal. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

Decommissioning Segregated Fund

Under the ONFA, OPG is wholly responsible for cost estimate changes and investment returns in the Decommissioning Segregated Fund. As at December 31, 2017 and 2016, the Decommissioning Segregated Fund was in an overfunded position.

Upon termination of the ONFA, the Province has the sole right to any excess funds in the Decommissioning Segregated Fund, which is the excess of the fair market value of the fund's assets over the underlying estimated future costs, as per the most recently approved ONFA reference plan. Accordingly, when the Decommissioning Segregated Fund is overfunded, OPG limits the fund earnings recognized in the consolidated financial statements by recording an amount due to the Province, such that the asset recognized for the fund on the consolidated balance sheet is equal to the cost estimate of the liability based on the most recently approved ONFA reference plan. Additionally, OPG recognizes the portion of the surplus that it may direct to the Used Fuel Segregated Fund, which is possible when the surplus in the Decommissioning Segregated Fund is such that the underlying liabilities, as defined by the most recently approved ONFA reference plan, are at least 120 percent funded. In those circumstances, OPG may direct, at the time a new reference plan is approved, up to 50 percent of the surplus over 120 percent to the Used Fuel Segregated Fund, with the OEFC entitled to a distribution of an equal amount. Therefore, when the Decommissioning Segregated Fund is at least 120 percent funded, OPG recognizes 50 percent of the excess greater than 120 percent in income, up to the amount by which the Used Fuel Segregated Fund is underfunded. Based on the 2017 ONFA Reference Plan, the Used Fuel Segregated Fund was in a marginally overfunded position as at December 31, 2016, for the first time since inception. As a result, OPG recognized a due to the Province amount

such that the Decommissioning Segregated Fund asset on the consolidated balance sheet as at December 31, 2017 and 2016 was limited to the value of the underlying liability per the 2017 ONFA Reference Plan. The payable to the Province may be reduced in subsequent periods in the event that the Decommissioning Segregated Fund earns less than its target rate of return, a new ONFA reference plan is approved with a higher underlying funding liability, or the Used Fuel Segregated Fund changes to an underfunded status. When the Decommissioning Segregated Fund is underfunded, the earnings on the fund reflect actual fund returns based on the market value of the assets.

When the Decommissioning Segregated Fund is in an overfunded status at less than 120 percent, OPG recognized its annual earnings on the fund at 3.25 percent plus the long-term Ontario Consumer Price Index (CPI) specified in the most recently approved ONFA reference plan, which is the rate of growth in the underlying funding liability. The same treatment is applied to the Decommissioning Segregated Fund when it is in an overfunded status at greater than 120 percent, if the Used Fuel Segregated Fund is fully funded.

Used Fuel Segregated Fund

OPG is responsible for cost increases in the funding liability for used fuel waste management under the ONFA, subject to specified graduated liability thresholds, pursuant to which the Province limits OPG's total financial exposure for the first 2.23 million nuclear used fuel bundles at approximately $15.7 billion in present value dollars as at December 31, 2017. The graduated liability thresholds do not apply to used fuel bundles beyond the 2.23 million threshold.

Under the ONFA, the Province guarantees OPG's annual return in the Used Fuel Segregated Fund at 3.25 percent plus the change in the Ontario CPI, as defined by ONFA, for funding related to the first 2.23 million used fuel bundles, (committed return). OPG recognizes the committed return on the Used Fuel Segregated Fund as Earnings on the Nuclear Segregated Funds. The difference between the committed return and the actual market return determined based on the fair value of the fund assets related to the first 2.23 million used fuel bundles is recorded as due to or due from the Province. This amount due to or due from the Province represents the amount that would be paid to or received from the Province if the committed return were to be settled as at the consolidated balance sheets date. The 2.23 million threshold represents the estimated total life cycle fuel bundles based on the initial estimated useful lives of the nuclear stations assumed in the ONFA.

As prescribed under the ONFA, OPG's contributions for fuel bundles in excess of 2.23 million are not subject to the rate of return guaranteed by the Province, and earn a return based on changes in the market value of the assets of the Used Fuel Segregated Fund.

If there is a surplus in the Used Fuel Segregated Fund such that the liabilities, as defined by the most recently approved ONFA reference plan, are at least 110 percent funded, the Province, has the right, at any time, to access the excess amount greater than 110 percent. Upon termination of the ONFA, the Province is entitled to any surplus in the fund, which is the excess of the fair market value of the Used Fuel Segregated Fund assets over the estimated future costs, as per the most recently approved ONFA reference plan. Neither OPG nor the Province has a right to direct any amounts from the Used Fuel Segregated Fund to the Decommissioning Segregated Fund. Therefore, when the Used Fuel Fund is overfunded, OPG limits the earnings it recognizes by recording an amount due to the Province, such that the asset recognized for the fund on the consolidated balance sheets is equal to the cost estimate of the liability per the most recently approved ONFA reference plan. This results in OPG recognizing annual earnings on the fund at 3.25 percent plus the long-term Ontario CPI specified in the most recently approved ONFA reference plan, which is the rate of growth in the underlying funding liability, when the fund is overfunded.

As at December 31, 2017, the Used Fuel Segregated Fund was marginally overfunded in accordance with the 2017 ONFA Reference Plan, and OPG recognized a due to the Province amount of $55 million such that the asset recognized for the fund was limited to the value of the underlying funding liability. This payable to the Province may be reduced in subsequent periods in the event that the Used Fuel Segregated Fund earns less than its target rate of return or in the event that a new ONFA reference plan is approved with a higher underlying funding liability.

Nuclear Segregated Funds

The nuclear fixed asset removal and nuclear waste management funds as at December 31 consist of the following:

(millions of dollars)	Fair Value 2017	2016
Decommissioning Segregated Fund	**9,099**	8,317
Due to Province – Decommissioning Segregated Fund	**(1,933)**	(1,477)
	7,166	6,840
Used Fuel Segregated Fund [1]	**12,087**	11,082
Due to Province – Used Fuel Segregated Fund	**(2,529)**	(1,938)
	9,558	9,144
Total Nuclear Segregated Funds	**16,724**	15,984
Less: current portion	**23**	24
Non-current Nuclear Segregated Funds	**16,701**	15,960

[1] The Ontario NFWA Trust represents $3,882 million as at December 31, 2017 (2016 – $3,688 million) of the Used Fuel Segregated Fund on a fair value basis.

The fair value of the securities invested in the Nuclear Segregated Funds as at December 31 is as follows:

(millions of dollars)	Fair Value 2017	2016
Cash and cash equivalents and short-term investments	**227**	354
Alternative investments	**2,357**	1,989
Pooled funds	**1,713**	1,329
Marketable equity securities	**10,457**	9,503
Fixed income securities	**6,405**	6,181
Net receivables/payables	**27**	43
	21,186	19,399
Due to Province	**(4,462)**	(3,415)
	16,724	15,984

The historical cost, gross unrealized aggregate appreciation and depreciation of investment, gross unrealized foreign exchange gains, and fair value of the Nuclear Segregated Funds as at December 31, 2017 and 2016 are summarized as follows:

	2017		
(millions of dollars)	**Decommissioning Segregated Fund**	**Used Fuel Segregated Fund**	**Total**
Historical cost	**7,327**	**9,902**	**17,229**
Gross unrealized gains (losses)			
Aggregate appreciation	**1,789**	**2,188**	**3,977**
Aggregate depreciation	**(134)**	**(180)**	**(314)**
Foreign exchange	**117**	**177**	**294**
	9,099	**12,087**	**21,186**
Due to Province	**(1,933)**	**(2,529)**	**(4,462)**
Total fair value	**7,166**	**9,558**	**16,724**
Less: current portion	**5**	**18**	**23**
Non-current fair value	**7,161**	**9,540**	**16,701**

	2016		
(millions of dollars)	**Decommissioning Segregated Fund**	**Used Fuel Segregated Fund**	**Total**
Historical cost	6,896	9,385	16,281
Gross unrealized gains (losses)			
Aggregate appreciation	1,326	1,564	2,890
Aggregate depreciation	(165)	(222)	(387)
Foreign exchange	260	355	615
	8,317	11,082	19,399
Due to Province	(1,477)	(1,938)	(3,415)
Total fair value	6,840	9,144	15,984
Less: current portion	8	16	24
Non-current fair value	6,832	9,128	15,960

Net realized and unrealized gains or losses from investments for the years ended December 31, 2017 and 2016 are summarized as follows:

(millions of dollars)	2017 Decommissioning Segregated Fund	2017 Used Fuel Segregated Fund	2017 Total
Net realized gains			
Realized gains excluding foreign exchange	**198**	**245**	**443**
Realized foreign exchange gains	**54**	**65**	**119**
Net realized gains	**252**	**310**	**562**
Net unrealized gains			
Unrealized gains excluding foreign exchange	**494**	**666**	**1,160**
Unrealized foreign exchange losses	**(143)**	**(178)**	**(321)**
Net unrealized gains	**351**	**488**	**839**

(millions of dollars)	2016 Decommissioning Segregated Fund	2016 Used Fuel Segregated Fund	2016 Total
Net realized gains			
Realized gains excluding foreign exchange	84	180	264
Realized foreign exchange gains	30	41	71
Net realized gains	114	221	335
Net unrealized gains			
Unrealized gains excluding foreign exchange	360	442	802
Unrealized foreign exchange losses	(165)	(216)	(381)
Net unrealized gains	195	226	421

The change in the Nuclear Segregated Funds for the years ended December 31 is as follows:

(millions of dollars)	Fair Value 2017	Fair Value 2016
Decommissioning Segregated Fund, beginning of year	**6,840**	6,549
Increase in fund due to return on investments	**807**	505
Decrease in fund due to reimbursement of eligible expenditures	**(25)**	(22)
Increase in due to Province	**(456)**	(192)
Decommissioning Segregated Fund, end of year	**7,166**	6,840
Used Fuel Segregated Fund, beginning of year	**9,144**	8,587
Increase in fund due to contributions made	**-**	150
Increase in fund due to return on investments	**1,059**	690
Decrease in fund due to reimbursement of eligible expenditures	**(54)**	(48)
Increase in due to Province	**(591)**	(235)
Used Fuel Segregated Fund, end of year	**9,558**	9,144

The earnings from the Nuclear Segregated Funds during 2017 and 2016 were impacted by the Bruce Lease Net Revenues Variance Account authorized by the OEB. The earnings on the Nuclear Segregated Funds for the years ended December 31 are as follows:

(millions of dollars)	**2017**	**2016**
Decommissioning Segregated Fund	**351**	313
Used Fuel Segregated Fund	**468**	455
Bruce Lease Net Revenues Variance Account	**(18)**	(22)
Total earnings	**801**	746

9. INCOME TAXES

OPG follows the liability method of accounting for income taxes. The Company records an offsetting regulatory asset or liability for the deferred income taxes that are expected to be recovered or refunded through future regulated prices charged to customers for generation from OPG's regulated facilities.

A reconciliation between the statutory and the effective rate of income taxes is as follows:

(millions of dollars)	**2017**	**2016**
Income before income taxes	**1,090**	621
Combined Canadian federal and provincial statutory enacted income tax rates	**26.5%**	26.5%
Statutory income tax rates applied to accounting income	**289**	165
(Decrease) increase in income taxes resulting from:		
Income tax (recovery) expense deferred in regulatory assets and liabilities	**(20)**	65
Scientific Research and Experimental Development investment tax credits	**(47)**	(48)
Manufacturing and processing credit	**(16)**	(9)
Other	**3**	(5)
	(80)	3
Income tax expense	**209**	168
Effective rate of income taxes	**19.1%**	27.0%

Significant components of the income tax expense are presented in the table below:

(millions of dollars)	**2017**	**2016**
Current income tax expense	**190**	204
Deferred income tax expense (recovery)	**19**	(36)
Income tax expense	**209**	168

The income tax effects of temporary differences that give rise to deferred income tax assets and liabilities as at December 31 are as follows:

(millions of dollars)	**2017**	**2016**
Deferred income tax assets:		
Fixed asset removal and nuclear waste management liabilities	**5,096**	4,861
Other assets and liabilities	**2,057**	1,813
	7,153	6,674
Deferred income tax liabilities:		
Property, plant and equipment and intangible assets	**(1,923)**	(1,807)
Nuclear fixed asset removal and nuclear waste management funds	**(4,181)**	(3,996)
Other assets and liabilities	**(1,928)**	(1,700)
	(8,032)	(7,503)
Net deferred income tax liabilities	**(879)**	(829)

During 2017, OPG recorded an increase in the deferred income tax liability for the income taxes that are expected to be recovered or refunded through regulated prices charged to customers of $59 million (2016 – $46 million). Since these deferred income taxes are expected to be refunded through future regulated prices, OPG recorded a corresponding increase to the regulatory asset for deferred income taxes. As a result, the deferred income tax expense for 2017 and 2016 was not impacted.

The following table summarizes the deferred income tax liabilities recorded for the rate regulated operations that are expected to be recovered through future regulated prices:

(millions of dollars)	**2017**	**2016**
January 1:		
Deferred income tax liabilities on temporary differences related to regulated operations	**627**	592
Deferred income tax liabilities on temporary differences related to the regulatory asset for the deferred income tax liabilities	**211**	200
	838	792
Changes during the year:		
Increase in deferred income tax liabilities on temporary differences related to regulated operations	**44**	35
Increase in deferred income tax liabilities on temporary differences related to the regulatory asset for the deferred income tax liabilities	**15**	11
Balance as at December 31	**897**	838

The tax benefit associated with an income tax position is recognized only when it is more likely than not that such a position will be sustained upon examination by the taxing authorities based on the technical merits of the position. The current and deferred income tax benefit is equal to the largest amount, considering possible settlement outcomes, that is greater than 50 percent likely of being realized upon settlement with the taxing authorities.

A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

(millions of dollars)	**2017**	**2016**
Unrecognized tax benefits, beginning of year	**77**	72
Additions based on tax positions related to the current year	**21**	19
Additions for tax positions of prior years	**-**	2
Reductions for tax positions of prior years	**(20)**	(16)
Unrecognized tax benefits, end of year	**78**	77

As at December 31, 2017, OPG's unrecognized tax benefits were $78 million (2016 – $77 million), excluding interest and penalties, all of which, if recognized, would affect OPG's effective tax rate. Changes in unrecognized tax benefits over the next 12 months cannot be predicted with certainty.

OPG recognizes interest and penalties related to unrecognized tax benefits as income tax expense. As at December 31, 2017, OPG had recorded interest on unrecognized tax benefits of $8 million (2016 – $8 million). OPG considers its significant tax jurisdiction to be Canada. OPG remains subject to income tax examination for years after 2013.

OPG paid $195 million in income taxes (net of tax refunds) during 2017 (2016 – $98 million).

10. ACCUMULATED OTHER COMPREHENSIVE LOSS

The changes in the balance of each component of accumulated other comprehensive loss (AOCL), net of income taxes, are as follows:

	2017			
(millions of dollars)	**Unrealized Gains and Losses on Cash Flow Hedges [1]**	**Pension and OPEB [1]**	**Available-for-sale Securities [1]**	**Total [1]**
AOCL, beginning of year	**(87)**	**(207)**	**(1)**	**(295)**
Actuarial loss on re-measurement of liabilities for pension and OPEB	**-**	**(23)**	**-**	**(23)**
Unrealized loss on available-for-sale securities	**-**	**-**	**(8)**	**(8)**
Amounts reclassified from AOCL	**18**	**10**	**-**	**28**
Other comprehensive income (loss) for the year	**18**	**(13)**	**(8)**	**(3)**
Reclassification of non-controlling interest on change in ownership interest *(Note 22)*	**3**	**-**	**-**	**3**
AOCL, end of year	**(66)**	**(220)**	**(9)**	**(295)**

[1] All amounts are net of income taxes.

	2016			
(millions of dollars)	**Unrealized Gains and Losses on Cash Flow Hedges [1]**	**Pension and OPEB [1]**	**Available-for-sale Securities [1]**	**Total [1]**
AOCL, beginning of year	(106)	(213)	-	(319)
Actuarial loss on re-measurement of liabilities for pension and OPEB	-	(6)	-	(6)
Unrealized loss on available-for-sale securities	-	-	(1)	(1)
Amounts reclassified from AOCL	19	12	-	31
Other comprehensive income (loss) for the year	19	6	(1)	24
AOCL, end of year	(87)	(207)	(1)	(295)

[1] All amounts are net of income taxes.

The significant amounts reclassified out of each component of AOCL, net of income taxes, during December 31, 2017 and 2016 are as follows:

	Amount Reclassified from AOCL		
(millions of dollars)	**2017**	**2016**	**Statement of Income Line Item**
Amortization of losses from cash flow hedges			
Losses	**20**	21	Net interest expense
Income tax recovery	**(2)**	(2)	Income tax expense
	18	19	
Amortization of amounts related to pension and OPEB			
Actuarial losses and past service costs	**13**	16	See (1) below
Income tax recovery	**(3)**	(4)	Income tax expense
	10	12	
Total reclassifications for the year	**28**	31	

[1] These AOCL components are included in the computation of pension and OPEB costs (see Note 11 for additional details).

11. PENSION AND OTHER POST-EMPLOYMENT BENEFITS

Fund Assets

The OPG registered pension fund investment guidelines are stated in an approved Statement of Investment Policies and Procedures (SIPP). The SIPP is reviewed and approved by the Audit and Risk Committee of OPG's Board of Directors at least annually and includes a discussion of investment objectives and expectations, asset mix and rebalancing, and the basis for measuring the performance of the pension fund assets.

In accordance with the SIPP, investment allocation decisions are made with a view to achieve OPG's objective of meeting obligations of the plan as they come due. The pension fund assets are invested in four categories of asset classes. The first category is liability hedging assets, which are intended to hedge the inflation and interest rate sensitivity of the plan liabilities. The second category is return enhancing assets, which are intended to obtain higher investment returns compared to the returns expected for liability hedging assets. The third category is real assets, which offer exposure to the combined characteristics of liability hedging and return enhancing assets. The fourth category is return diversifying strategies, which are intended to improve the overall return of the pension fund while mitigating the downside market risk.

To achieve the above objective, OPG has adopted the following target strategic asset allocation:

	Target
Asset Class	
Liability Hedging Assets	34%
Return Enhancing Assets	31%
Real Assets	20%
Return Diversifying Assets	15%

The plan may use derivatives for risk management or strategic purposes, where such activity is consistent with the plan's investment objectives.

Significant Concentrations of Risk in Fund Assets

The assets of the pension fund are diversified to limit the impact of any individual investment. The pension fund is diversified across multiple asset classes. Fixed income securities are diversified among Canadian government bonds, government agency bonds, real return bonds, and corporate bonds. Equity securities are diversified across

Canadian, US, and Global stocks. There are also real estate, infrastructure, and agriculture portfolios that represent approximately 12 percent of the total pension fund assets as at December 31, 2017. Investments in the above asset classes are further diversified across funds, investment managers, strategies, vintages, sectors and geographies, depending on the specific characteristics of each asset class.

Credit risk with respect to the pension fund's fixed income securities is managed by risk tolerance guidelines, which requires that fixed income securities comply with various investment constraints that ensure prudent diversification and prescribed minimum required credit rating quality. Credit risk, as it relates to the pension fund's derivatives, is managed through the use of International Swap and Derivatives Association documentation and counterparty management performed by the fund's investment managers.

Risk Management

Risk management oversight with respect to the pension fund includes, but is not limited to, the following activities:

- Periodic asset/liability management and strategic asset allocation studies
- Monitoring of funding levels and funding ratios
- Monitoring compliance with asset allocation guidelines and investment management agreements
- Monitoring asset class performance against asset class benchmarks
- Monitoring investment manager performance against benchmarks
- Monitoring of risk tolerance guidelines

Expected Rate of Return on Plan Assets

The expected rate of return on plan assets is based on the fund's asset allocation, as well as the return expectations considering long-term risks and returns associated with each asset class within the plan portfolio. The asset management decisions consider the economic liabilities of the plan.

Fair Value Measurements

OPG is required to classify fair value measurements using a fair value hierarchy. This hierarchy groups financial instruments into three levels, based on the significance of inputs used in measuring the fair value of the assets and liabilities. Refer to Note 13 for a detailed discussion of fair value measurements and the fair value hierarchy.

The following tables present pension plan assets measured at fair value in accordance with the fair value hierarchy:

	December 31, 2017			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Cash and cash equivalents	**377**	**-**	**-**	**377**
Short-term investments	**-**	**9**	**-**	**9**
Fixed income				
Corporate debt securities	**-**	**521**	**-**	**521**
Government bonds	**-**	**3,476**	**-**	**3,476**
Equities				
Canadian	**1,441**	**329**	**-**	**1,770**
US	**1,551**	**-**	**-**	**1,551**
Global	**1,681**	**-**	**-**	**1,681**
Pooled funds	**459**	**105**	**-**	**564**
Other	**15**	**-**	**-**	**15**
	5,524	**4,440**	**-**	**9,964**
Investments measured at NAV [1]				**4,221**
				14,185 [2]

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to the total fair value of plan assets presented in tables following.

[2] The table above excludes pension fund receivables and payables.

	December 31, 2016			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Cash and cash equivalents	690	-	-	690
Fixed income				
Corporate debt securities	-	407	-	407
Government bonds	-	3,483	-	3,483
Equities				
Canadian	1,449	291	-	1,740
US	1,495	-	-	1,495
Global	1,643	-	-	1,643
Pooled funds	118	413	-	531
	5,395	4,594	-	9,989
Investments measured at NAV [1]				3,504
				13,493 [2]

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to the total fair value of plan assets presented in tables following.

[2] The table above excludes pension fund receivables and payables.

Plan Costs and Liabilities

Details of OPG's pension and OPEB obligations, pension fund assets and costs are presented in the following tables:

	Registered and Supplementary Pension Plans		Other Post-Employment Benefits	
	2017	**2016**	**2017**	**2016**
Weighted Average Assumptions – Benefit Obligations at Year-End				
Discount rate for projected benefit obligation	**3.57 %**	3.90 %	**3.60 %**	3.94 %
Salary schedule escalation rate - initial rate [1]	**1.90 %**	1.80 %	**1.90 %**	1.80 %
- thereafter	**2.50 %**	2.50 %	**2.50 %**	2.50 %
Rate of cost of living increase to pensions	**2.00 %**	2.00 %	**n/a**	n/a
Initial health care trend rate	**n/a**	n/a	**5.80 %**	5.90 %
Ultimate health care trend rate	**n/a**	n/a	**4.32 %**	4.32 %
Year ultimate health care trend rate reached	**n/a**	n/a	**2030**	2030
Rate of increase in disability benefits	**n/a**	n/a	**2.00 %**	2.00 %

[1] Per year to December 31, 2021.

	Registered and Supplementary Pension Plans		Other Post-Employment Benefits	
	2017	**2016**	**2017**	**2016**
Weighted Average Assumptions – Costs for the Year				
Expected return on plan assets, net of expenses	**6.00 %**	6.00 %	**n/a**	n/a
Discount rate for projected benefit obligation	**3.90 %**	4.10 %	**3.94 %**	4.13 %
Discount rate for current service cost	**4.15 %**	4.10 %	**4.03 %**	4.13 %
Discount rate for interest on projected benefit obligation	**3.37 %**	4.10 %	**3.53 %**	4.13 %
Discount rate for interest on current service cost	**3.95 %**	4.10 %	**3.85 %**	4.13 %
Salary schedule escalation rate - initial rate [1]	**1.80 %**	1.60 %	**1.80 %**	1.60 %
- thereafter	**2.50 %**	2.50 %	**2.50 %**	2.50 %
Rate of cost of living increase to pensions	**2.00 %**	2.00 %	**n/a**	n/a
Initial health care trend rate	**n/a**	n/a	**5.90 %**	6.00 %
Ultimate health care trend rate	**n/a**	n/a	**4.32 %**	4.33 %
Year ultimate health care trend rate reached	**n/a**	n/a	**2030**	2030
Rate of increase in disability benefits	**n/a**	n/a	**2.00 %**	2.00 %
Expected average remaining service life for employees (years)	**12**	12	**13**	13

[1] Per year to December 31, 2021.

(millions of dollars)	Registered Pension Plans 2017	2016	Supplementary Pension Plans 2017	2016	Other Post-Employment Benefits 2017	2016
Components of Cost Recognized for the year						
Current service costs	**274**	277	**7**	7	**67**	67
Interest on projected benefit obligation	**548**	634	**11**	12	**106**	133
Expected return on plan assets, net of expenses	**(766)**	(734)	**-**	-	**-**	-
Amortization of past service costs [1]	**-**	-	**-**	-	**1**	1
Amortization of net actuarial loss [1]	**183**	192	**6**	4	**-**	19
Recognition of LTD net actuarial loss (gain)	**-**	**-**	**-**	**-**	**11**	(52)
Costs recognized [2]	**239**	369	**24**	23	**185**	168

[1] The amortization of past service costs and net actuarial loss was recognized as an increase to OCI. This increase was partially offset by the impact of the Pension and OPEB Regulatory Asset discussed in Note 5.

[2] Excludes the impact of regulatory variance and deferral accounts discussed in Note 5.

Total benefit costs, including the impact of the Pension & OPEB Cash Payment Variance Account and the Pension & OPEB Cash Versus Accrual Differential Deferral Account, for the years ended December 31 are as follows:

(millions of dollars)	2017	2016
Registered pension plans	**239**	369
Supplementary pension plans	**24**	23
Other post-employment benefits	**185**	168
Pension & OPEB Cash Payment Variance Account *(Note 5)*	**81**	86
Pension & OPEB Cash Versus Accrual Differential Deferral Account *(Note 5)*	**(117)**	(182)
Pension and other post-employment benefit costs	**412**	464

The pension and OPEB obligations and the pension fund assets measured as at December 31 are as follows:

(millions of dollars)	Registered Pension Plans 2017	2016	Supplementary Pension Plans 2017	2016	Other Post-Employment Benefits 2017	2016
Change in Plan Assets						
Fair value of plan assets at beginning of year	**13,506**	13,160	**-**	-	**-**	-
Contributions by employer	**214**	255	**14**	15	**94**	93
Contributions by employees	**97**	85	**-**	-	**-**	-
Actual return on plan assets, net of expenses	**1,207**	714	**-**	-	**-**	-
Benefit payments	**(761)**	(708)	**(14)**	(15)	**(94)**	(93)
Fair value of plan assets at end of year	**14,263**	13,506	**-**	-	**-**	-
Change in Projected Benefit Obligations						
Projected benefit obligations at beginning of year	**16,199**	15,475	**336**	299	**2,992**	3,188
Employer current service costs	**274**	277	**7**	7	**67**	67
Contributions by employees	**97**	85	**-**	-	**-**	-
Interest on projected benefit obligation	**548**	634	**11**	12	**106**	133
Benefit payments	**(761)**	(708)	**(14)**	(15)	**(94)**	(93)
Net actuarial loss (gain)	**987**	436	**16**	33	**119**	(303)
Projected benefit obligations at end of year	**17,344**	16,199	**356**	336	**3,190**	2,992
Funded status – deficit at end of year	**(3,081)**	(2,693)	**(356)**	(336)	**(3,190)**	(2,992)

The following table provides the pension and OPEB liabilities and their classification on the consolidated balance sheets as at December 31:

(millions of dollars)	Registered Pension Plans 2017	2016	Supplementary Pension Plans 2017	2016	Other Post-Employment Benefits 2017	2016
Current liabilities	**-**	-	**(14)**	(17)	**(98)**	(95)
Non-current liabilities	**(3,081)**	(2,693)	**(342)**	(319)	**(3,092)**	(2,897)
Total liabilities	**(3,081)**	(2,693)	**(356)**	(336)	**(3,190)**	(2,992)

The accumulated benefit obligations for the registered pension plans and supplementary pension plans as at December 31, 2017 are $16,005 million and $333 million, respectively (2016 – $14,909 million and $293 million, respectively). The accumulated benefit obligation differs from the projected benefit obligation in that the accumulated benefit obligation includes no assumption about future compensation levels.

The following table provides the components of OPG's OCI related to pension and OPEB plans and the offsetting Pension and OPEB Regulatory Asset, discussed in Note 5, for the years ended December 31, on a pre-tax basis:

(millions of dollars)	Registered Pension Plans 2017	Registered Pension Plans 2016	Supplementary Pension Plans 2017	Supplementary Pension Plans 2016	Other Post-Employment Benefits 2017	Other Post-Employment Benefits 2016
Changes in plan assets and benefit obligations recognized in OCI						
Current year net actuarial loss (gain)	**546**	456	**16**	33	**108**	(251)
Amortization of net actuarial loss	**(183)**	(192)	**(6)**	(4)	**-**	(19)
Amortization of past service costs	**-**	-	**-**	-	**(1)**	(1)
Total decrease (increase) in OCI	**363**	264	**10**	29	**107**	(271)
Less: increase (decrease) in Pension and OPEB Regulatory Asset *(Note 5)*	**352**	253	**9**	27	**102**	(250)
Net decrease (increase) in OCI (pre-tax)	**11**	11	**1**	2	**5**	(21)

The following table provides the components of OPG's AOCL and the offsetting Pension and OPEB Regulatory Asset that have not yet been recognized as components of benefit costs as at December 31, on a pre-tax basis:

(millions of dollars)	Registered Pension Plans 2017	Registered Pension Plans 2016	Supplementary Pension Plans 2017	Supplementary Pension Plans 2016	Other Post-Employment Benefits 2017	Other Post-Employment Benefits 2016
Unamortized amounts recognized in AOCL						
Past service costs	**-**	-	**-**	-	**4**	5
Net actuarial loss	**3,650**	3,287	**116**	106	**378**	270
Total recognized in AOCL	**3,650**	3,287	**116**	106	**382**	275
Less: Pension and OPEB Regulatory Asset *(Note 5)*	**3,391**	3,039	**109**	100	**355**	253
Net recognized in AOCL (pre-tax)	**259**	248	**7**	6	**27**	22

The following table provides the components of OPG's AOCL and the offsetting Pension and OPEB Regulatory Asset as at December 31 (included in the table above) that are expected to be amortized as components of benefit costs and recognized as increases to OCI and reductions in the Pension and OPEB Regulatory Asset in 2018, on a pre-tax basis:

(millions of dollars)	Registered Pension Plans	Supplementary Pension Plans	Other Post-Employment Benefits
Past service costs	**-**	**-**	**1**
Net actuarial loss	**198**	**7**	**6**
Total increase in OCI	**198**	**7**	**7**
Less: estimated decrease in Pension and OPEB Regulatory Asset	**184**	**6**	**6**
Net increase in OCI (pre-tax)	**14**	**1**	**1**

The most recently filed actuarial valuation, for funding purposes, of the OPG registered pension plan, as at January 1, 2017, was filed with the FSCO in September 2017. The next filed funding valuation must have an effective date no later than January 1, 2020. For 2018, OPG's required contribution to its registered pension plan is expected to be $215 million. The amount of OPG's additional, voluntary contribution, if any, is revisited from time to time. OPG will continue to assess the requirements for contributions to the pension plan.

The supplementary pension plans are not funded, but are secured by Letters of Credit totalling $353 million as at December 31, 2017 (2016 – $349 million).

Estimated future benefit payments to participants in the pension and OPEB plans based on the assumptions used to measure the benefit obligations as at December 31, 2017 are as follows:

(millions of dollars)	Registered Pension Plans	Supplementary Pension Plans	Other Post-Employment Benefits
2018	676	15	98
2019	696	15	101
2020	722	15	105
2021	747	16	108
2022	764	16	111
2023 through 2027	4,397	86	633

A one percent increase or decrease in the health care trend rate would result in an increase in the current service and interest components of the 2017 OPEB costs of $40 million (2016 – $45 million) or a decrease in the service and interest components of the 2017 OPEB costs of $29 million (2016 – $33 million). A one percent increase or decrease in the health care trend rate would result in an increase in the projected OPEB obligation as at December 31, 2017 of $592 million (2016 – $560 million) or a decrease in the projected OPEB obligation as at December 31, 2017 of $451 million (2016 – $426 million).

12. RISK MANAGEMENT AND DERIVATIVES

OPG is exposed to risks related to changes in market interest rates on debt expected to be issued in the future and movements in foreign currency that affect the Company's assets, liabilities, and forecasted transactions. Select derivative instruments are used to manage such risks. Derivatives are used as hedging instruments, as well as for trading purposes.

Interest rate risk is the risk that the value of assets and liabilities can change due to movements in related interest rates. Interest rate risk for OPG arises with the need to refinance existing debt and/or undertake new financing. The management of these risks includes using derivatives to hedge the exposure in accordance with corporate risk management policies. OPG periodically uses interest rate swap agreements to mitigate elements of interest rate risk exposure associated with anticipated financing.

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are denominated in, or tied to, US dollars. OPG enters into foreign exchange derivatives and agreements with major financial institutions, when appropriate, in order to manage the Company's exposure to foreign currency movements.

The majority of OPG's revenues are derived from sales through the IESO administered spot market. Market participants in the IESO spot market provide collateral in accordance with the IESO prudential support requirements to cover funds that they might owe to the market. Although the credit exposure to the IESO represents a significant portion of OPG's accounts receivable, the Company's management accepts this risk due to the IESO's primary role in the Ontario electricity market. The remaining receivables exposure is to a diverse group of generally high quality counterparties. OPG's allowance for doubtful accounts as at December 31, 2017 was less than $1 million. OPG's fair value derivatives totalled a net liability of $20 million as at December 31, 2017 (December 31, 2016 − $24 million).

The following table shows the pre-tax amounts related to derivatives recorded in AOCL and net income for the years ended December 31:

(millions of dollars)	**2017**	**2016**
Cash flow hedges (recorded in AOCL)		
Reclassification of losses to net interest expense	**19**	21
Commodity derivatives (recorded in net income)		
Realized losses in revenue	**(9)**	(12)
Unrealized gains (losses) in revenue	**3**	(3)

Existing pre-tax net losses of $19 million deferred in AOCL as at December 31, 2017 are expected to be reclassified to net income within the next 12 months.

13. FAIR VALUE MEASUREMENTS

OPG is required to classify fair value measurements using a fair value hierarchy. This hierarchy groups financial assets and liabilities into three levels, based on the inputs used in measuring the fair value of the financial assets and liabilities. The fair value hierarchy has the following levels:

- Level 1: Valuation of inputs is based on unadjusted quoted market prices observed in active markets for identical assets or liabilities.
- Level 2: Valuation is based on inputs other than quoted prices under Level 1 that are observable for the asset or liability, either directly or indirectly.
- Level 3: Valuation is based on inputs for the asset or liability that are not based on observable market data.

The fair value of financial instruments traded in active markets is based on quoted market prices as at the consolidated balance sheet dates. A market is regarded as active if quoted prices are readily and regularly available from an exchange, dealer, broker, industry group, pricing service, or regulatory agency, and those prices represent actual and regularly occurring market transactions on an arm's length basis. The quoted market price used for financial assets held by OPG is the current bid price. These instruments are included in Level 1 and are comprised primarily of equity investments and fund investments.

For financial instruments for which quoted market prices are not directly available, fair values are estimated using forward price curves developed from observable market prices or rates. The estimation of fair value may include the use of valuation techniques or models, based wherever possible on assumptions supported by observable market prices or rates prevailing as at the consolidated balance sheet dates. This is the case for over-the-counter derivatives and securities, which include energy commodity derivatives, foreign exchange derivatives, interest rate swap derivatives, and fund investments. Pooled fund investments are valued at the unit values supplied by the pooled fund administrators. The unit values represent the underlying net assets at fair values, determined using closing market prices. Valuation models use general assumptions and market data and therefore do not reflect the specific risks and other factors that would affect a particular instrument's fair value. The methodologies used for calculating the fair value adjustments are reviewed on an ongoing basis to ensure that they remain appropriate. If all significant inputs required to fair value an instrument are observable, the instrument is included in Level 2.

The following is a summary of OPG's financial instruments and their fair value as at December 31, 2017 and December 31, 2016:

	Fair Value		Carrying Value [1]		
(millions of dollars)	**2017**	**2016**	**2017**	**2016**	**Balance Sheet Line Item**
Nuclear Segregated Funds (includes current portion) [2]	**16,724**	15,984	**16,724**	15,984	Nuclear fixed asset removal and nuclear waste management funds
Financing receivables	**1,179**	-	**1,179**	-	Financing receivables
Investment in Hydro One shares	**188**	212	**188**	212	Available-for-sale securities
Payable related to cash flow hedges	**(40)**	(48)	**(40)**	(48)	Long-term accounts payable and accrued charges
Long-term debt (includes current portion and medium) term notes)	**(6,835)**	(6,033)	**(5,735)**	(5,520)	Long-term debt
Long-term debt – Fair Hydro Trust	**(601)**	-	**(601)**	-	Long-term debt
Other financial instruments	**(16)**	(18)	**(16)**	(18)	Various

[1] The carrying values of other financial instruments included in cash and cash equivalents, receivables from related parties, other current assets, short-term debt, and accounts payable and accrued charges approximate their fair values due to the immediate or short-term maturity of these financial instruments.

[2] The Nuclear Segregated Funds are comprised of the Decommissioning Segregated Fund and the Used Fuel Segregated Fund.

The fair value of long-term debt instruments is determined based on a conventional pricing model, which is a function of future cash flows, the current market yield curve and term to maturity. These inputs are considered Level 2 inputs.

The fair value of the Trust debt and Medium Term Note Program debt (included in the Long-term debt line above) are based on unadjusted quoted active market prices, which are considered Level 1 inputs. All other long-term debt instruments is determined based on a conventional pricing model, which is a function of future cash flows, the current market yield curve and term to maturity. These inputs are considered Level 2 inputs. For the financing receivables related to the Investment Interest acquired from the IESO, fair value is estimated to equal the fair value of the underlying debt due to the direct relationship of the asset, and the debt instruments that financed the acquisition. The financing receivables are funded by both the senior and subordinated debt issued by the Trust. The long-term debt ranks as senior notes and has inputs that are based on unadjusted quoted active market prices, which are considered Level 1 inputs, while the portion funded by the subordinated debt has inputs that are based on indicative pricing from the market, which are considered Level 2 inputs.

If one or more of the significant inputs is not based on observable market data, the instrument is included in Level 3. Specific valuation techniques are used to value these instruments. Significant Level 3 inputs include: recent comparable transactions, comparable benchmark information, bid/ask spread of similar transactions, and other relevant factors.

Transfers into, out of, or between levels are deemed to have occurred on the date of the event or change in circumstances that caused the transfer to occur.

The following tables present financial assets and financial liabilities measured at fair value in accordance with the fair value hierarchy as at December 31, 2017 and December 31, 2016:

	December 31, 2017			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Used Fuel Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	**6,090**	**4,705**	**-**	**10,795**
Investments measured at NAV [1]				**1,292**
				12,087
Due to Province				**(2,529)**
Used Fuel Segregated Fund, net				**9,558**
Decommissioning Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	**4,547**	**3,487**	**-**	**8,034**
Investments measured at NAV [1]				**1,065**
				9,099
Due to Province				**(1,933)**
Decommissioning Segregated Fund, net				**7,166**
Investment in available-for-sale securities	**188**	**-**	**-**	**188**
Other financial assets	**5**	**3**	**6**	**14**
Liabilities				
Other financial liabilities	**(28)**	**(2)**	**-**	**(30)**

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to amounts presented on the consolidated balance sheets.

(millions of dollars)	December 31, 2016 Level 1	Level 2	Level 3	Total
Assets				
Used Fuel Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	5,602	4,394	-	9,996
Investments measured at NAV [1]				1,086
				11,082
Due to Province				(1,938)
Used Fuel Segregated Fund, net				9,144
Decommissioning Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	4,171	3,243	-	7,414
Investments measured at NAV [1]				903
				8,317
Due to Province				(1,477)
Decommissioning Segregated Fund, net				6,840
Investments in available-for-sale securities	212	-	-	212
Other financial assets	6	2	9	17
Liabilities				
Other financial liabilities	(29)	(6)	-	(35)

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to amounts presented on the consolidated balance sheets.

During the year ended December 31, 2017, there were no transfers between Level 1 and Level 2. In addition, there were no transfers into or out of Level 3.

The following table presents the changes in OPG's net assets measured at fair value that are classified as Level 3 financial instruments.

(millions of dollars)	Other financial instruments
Opening balance, January 1 2017	**9**
Unrealized losses included in revenue	**(3)**
Realized losses included in revenue	**(9)**
Purchases	**9**
Closing balance, December 31, 2017	**6**

Nuclear Segregated Funds

The fair value of the investments within the Nuclear Segregated Funds' alternative investment portfolio is determined using appropriate valuation techniques, such as recent arm's length market transactions, references to current fair values of other instruments that are substantially the same, discounted cash flow analyses, third-party independent appraisals, valuation multiples, or other valuation methods. Any control, size, liquidity or other discount premiums on the investments are considered in the determination of fair value. Alternative investments are measured at fair value using NAV as a practical expedient.

The process of valuing investments for which no published market price exists is based on inherent uncertainties and the resulting values may differ from values that would have been used had a ready market existed for these investments. The values may also differ from the prices at which the investments may be sold.

The following are the classes of investments within the Nuclear Segregated Funds that are reported on the basis of NAV as at December 31, 2017:

(millions of dollars except where noted)	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice
Alternative Investments				
Infrastructure	**1,330**	**798**	**n/a**	**n/a**
Real Estate	**936**	**440**	**n/a**	**n/a**
Agriculture	**90**	**97**	**n/a**	**n/a**
Pooled Funds				
Short-term Investments	**32**	**n/a**	**Daily**	**1 - 5 Days**
Fixed Income	**729**	**n/a**	**Daily**	**1 - 5 Days**
Equity	**952**	**n/a**	**Daily**	**1 - 5 Days**
Total	**4,069**	**1,335**		

The fair value of the pooled funds is classified as Level 2. Infrastructure, real estate and agriculture investments are measured using NAV as a practical expedient for determining their fair value.

Infrastructure

This asset class includes investments in funds and assets with an objective to generate a combination of long-term capital appreciation and current income, generally through private investments in sectors such as energy, transportation, communication and utilities. The fair values of investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in these investments. The investments in its respective funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests/shares to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Distributions from each infrastructure fund will be received based on the operations of the underlying investments and/or as the underlying investments of the infrastructure funds are liquidated. It is not possible to estimate when the underlying assets in this asset class will be liquidated.

Real Estate

This asset class includes investments in funds and assets with an objective is to generate a combination of long-term capital appreciation and current income, generally through investments in institutional-grade real estate property. The fair values of the investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in these investments. The investments in its respective funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Distributions from each real estate fund will be received based on the operations of the underlying investments and/or as the underlying investments of the real estate funds are liquidated. For investments in private real estate corporations, shares may be redeemed through a pre-established redemption process. It is not possible to estimate when the underlying assets in this asset class will be liquidated.

Agriculture

This asset class includes investments in funds and assets with an objective to provide a differentiated return source, income yield, and inflation protection, generally through private investments inglobal farmland and timberland. The fair values of the investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in these investments. The investments in its respective funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests/shares to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Distributions from each fund will be received based on the operations of the underlying investments and/or as the underlying investments of the funds are liquidated. It is not possible to estimate when the underlying assets in this asset class will be liquidated.

Pooled Funds

This asset class represents investments in pooled funds, which primarily include a diversified portfolio of fixed income securities, issued mainly by Canadian corporations, and diversified portfolios of Emerging Market listed equity. The investment objective of the pooled funds is to achieve capital appreciation and income through professionally managed portfolios. The fair value of the investments in this class has been estimated using NAV per share of the investments. There are no significant restrictions on the ability to sell the investments in this class.

14. SHARE CAPITAL

Common Shares

As at December 31, 2017 and 2016, OPG had 256,300,010 common shares issued and outstanding at a stated value of $5,126 million. OPG is authorized to issue an unlimited number of common shares without nominal or par value. Any issue of new shares is subject to the consent of OPG's shareholder.

Class A Shares

The Company's Articles of Amalgamation were amended effective December 1, 2017 to allow for the creation and issuance of non-voting Class A shares to the Province in exchange for its equity injections in OPG to be used solely for its investment in the Trust. All of the outstanding shares are owned directly by the Province and OPG is authorized to issue an unlimited number of Class A shares without nominal or par value. The Class A and common shares rank equally as to dividends on a share for share basis, and all dividends declared by OPG shall be declared in equal amounts per share on all outstanding shares without preference or distinction. Upon the liquidation, dissolution or wind-up of OPG, whether voluntary or involuntary, the holders of Class A shares and common shares are entitled to share equally, on a share for share basis, in all distributions of property and assets without preference or distinction. Any issue of new shares is subject to the consent of the Province. OPG is entitled to redeem outstanding shares in connection with the repayment of the Trust's debt or other purposes as may be approved by OPG's Board of Directors.

In December 2017, OPG issued 12,217,616 Class A shares at a price of $42.46 per share to the Province for its equity injection in OPG, generating proceeds of $519 million, which was used to fund 44 percent of the total funding requirement of the Trust's acquisition of Investment Interest from the IESO.

15. EARNINGS PER COMMON SHARE

Basic and diluted earnings per common share is calculated by dividing net income attributable to the Shareholder of OPG by the weighted average number of common shares outstanding.

Class A shares are included in the weighted average number of common shares outstanding. The weighted average number of shares outstanding as at December 31, 2017 was 256.7 million (2016 – 256.3 million). There were no dilutive securities during the years ended December 31, 2017 and 2016.

16. COMMITMENTS AND CONTINGENCIES

Litigation

On August 9, 2006, a Notice of Action and Statement of Claim filed with the Ontario Superior Court of Justice in the amount of $500 million was served against OPG and Bruce Power by British Energy Limited and British Energy International Holdings Limited (together British Energy). The action is for contribution and indemnity of any amounts British Energy was liable for in an arbitration against it by some of the owners of Bruce Power regarding an alleged breach of British Energy's representations and warranties to the claimants when they purchased British Energy's interest in Bruce Power (the Arbitration). Both the action and the Arbitration relate to corrosion to a steam generator unit discovered after OPG leased the Bruce nuclear generating stations to Bruce Power.

In 2012, the arbitrator found that British Energy was liable to the claimants for some of the damages they claimed. The final settlement amount was valued by British Energy at $71 million. In September 2014, British Energy amended its Statement of Claim (Amended Claim) to reduce the claim amount to $100 million to reflect that the purchasers of British Energy's interest in Bruce Power did not receive the full damages they originally claimed in the Arbitration. British Energy also added an allegation to its Amended Claim that OPG breached a covenant to maintain the steam generator between the time of the initial agreement to lease and the effective date of the lease in accordance with "Good Utility Practices".

In November 2016, British Energy obtained consent from Ontario Superior Court of Justice to a timetable for the remaining steps in the litigation, pursuant to which the matter must be set down for trial by December 31, 2018. OPG has delivered a statement of defence in accordance with an extension of the original June 30, 2017 delivery deadline set up in the timetable. [**MONITOR**]

Various other legal proceedings are pending against OPG or its subsidiaries covering a wide range of matters that arise in the ordinary course of business activities.

Each of these matters is subject to various uncertainties. Some of these matters may be resolved unfavourably. While it is not possible to determine the ultimate outcome of the various pending actions, it is the Company's belief that their resolution is not likely to have a material adverse impact on its financial position.

Guarantees

The Company and its joint venture partners have jointly guaranteed the financial performance of jointly owned entities related primarily to the payment of liabilities. As at December 31, 2017, the total amount of guarantees OPG provided to these entities was $82 million (December 31, 2016 − $83 million). OPG may terminate some of these guarantees within a short time frame by providing written notice to the counterparties at any time. Other guarantees have terms ending between 2019 and 2029. As at December 31, 2017, the potential impact of the fair value of these guarantees to income has been estimated to be negligible and OPG does not expect to make any payments associated with these guarantees.

Contractual Obligations

OPG's contractual obligations as at December 31, 2017, are as follows:

(millions of dollars)	2018	2019	2020	2021	2022	Thereafter	Total
Fuel supply agreements	158	125	115	88	67	67	620
Contributions to the OPG registered pension plan [1]	215	219	-	-	-	-	434
OPG long-term debt repayment	398	368	663	413	172	3,721	5,735
Interest on OPG long-term debt	244	226	204	175	161	3,006	4,016
Fair Hydro Trust senior debt repayment [2]	-	601	-	-	-	-	601
Interest on Fair Hydro Trust senior debt	15	15	-	-	-	-	30
Commitments related to Darlington Refurbishment project [3]	473	-	-	-	-	-	473
Commitments related to Ranney Falls GS project	29	5	-	-	-	-	34
Operating licences	40	41	24	28	28	87	248
Operating lease obligations	28	24	24	22	22	79	199
Unconditional purchase obligations	59	58	56	5	-	-	178
Accounts payable and accrued charges	957	8	-	-	-	16	981
Other	57	30	2	1	1	64	155
Total	2,673	1,720	1,088	732	451	7,040	13,704

[1] The pension contributions include ongoing funding requirements and additional funding requirements towards the deficit, in accordance with the actuarial valuation of the OPG registered pension plan as at January 1, 2017. The next actuarial valuation of the OPG registered pension plan must have an effective date no later than January 1, 2020. The pension contributions are affected by various factors including market performance, changes in actuarial assumptions, plan experience, changes in the pension regulatory environment, and the timing of funding valuations. Funding requirements after 2019 are excluded due to significant variability in the assumptions required to project the timing of future cash flows. The amount of OPG's additional, voluntary contribution, if any, is revisited from time to time.

[2] The notes were issued by the Fair Hydro Trust under an $800 million two-year revolving warehouse facility in December 2017. In February 2018, the Trust issued $500 million of senior notes payable to repay the majority of the outstanding balance of the revolving warehouse facility.

[3] Represents estimated currently committed costs to close the project, including accruals for completed work, demobilization of project staff and cancellation of existing contracts and material orders.

Other Commitments

Collective Agreements

As of December 31, 2017, OPG had approximately 9,212 regular employees. Most of OPG's regular employees are represented by two unions:

- **The PWU** – This union represents approximately 4,849 OPG employees or approximately 53 percent of OPG's regular workforce as at December 31, 2017. Union membership includes operators, technicians, skilled trades, clerical, and security personnel. The current collective agreement between OPG and the PWU has a three-year term, expiring on March 31, 2018.
- **The Society** – This union represents approximately 3,259 OPG employees or approximately 35 percent of OPG's regular workforce as at December 31, 2017. Union membership includes supervisors, professional engineers, scientists, and other professionals. The current collective agreement between OPG and The Society has a three-year term, expiring on December 31, 2018.

In addition to the regular workforce, construction work is performed through 19 craft unions with established bargaining rights at OPG facilities. These bargaining rights are established either through the Electrical Power Systems Construction Association or directly with OPG. Collective agreements between the Company and its construction unions are negotiated either directly or through EPSCA. All of these collective agreements currently have multi-year terms, expiring on April 30, 2020.

17. BUSINESS SEGMENTS

Effective in the fourth quarter of 2017, OPG has the following six reportable business segments:

- Regulated – Nuclear Generation
- Regulated – Nuclear Waste Management
- Regulated – Hydroelectric
- Contracted Generation Portfolio
- Services, Trading, and Other Non-Generation
- Fair Hydro Trust

Regulated – Nuclear Generation Segment

The Regulated – Nuclear Generation business segment operates in Ontario, generating and selling electricity from the Pickering GS and the Darlington GS, both owned and operated by OPG. The business segment also includes revenue under the terms of a long-term lease arrangement and related agreements with Bruce Power related to the Bruce nuclear generating stations. This revenue includes lease revenue, fees for nuclear waste management, and revenue from heavy water sales and detritiation services. The segment also earns revenue from isotope sales and ancillary services supplied by OPG-operated nuclear stations. Ancillary revenues are earned through voltage control and reactive support. Revenues under the agreements with Bruce Power, including a portion of heavy water sales, and from isotope sales and ancillary services are included by the OEB as a credit to customers in the determination of the regulated prices for production from OPG's nuclear facilities, which has had the effect of reducing these prices.

Regulated – Nuclear Waste Management Segment

OPG's Regulated – Nuclear Waste Management segment reports the results of the Company's operations associated with the management of nuclear used fuel and L&ILW, the decommissioning of OPG's nuclear generating stations including the stations on lease to Bruce Power and other waste management facilities, the management of the Nuclear Segregated Funds, and related activities including the inspection and maintenance of the waste storage facilities. Accordingly, accretion expense, which is the increase in the Nuclear Liabilities carried on the consolidated balance sheets in present value terms due to passage of time, and earnings from the Nuclear Segregated Funds are reported under this segment.

As the nuclear generating stations operate over time, OPG incurs incremental costs related to used nuclear fuel and low and intermediate level wastes, which increase the Nuclear Liabilities. OPG charges these incremental costs to current operations in the Regulated – Nuclear Generation segment to reflect the cost of producing energy from the Pickering and Darlington nuclear generating stations and earning revenue under the Bruce Lease and related agreements. Since the incremental costs increase the Nuclear Liabilities in the Regulated – Nuclear Waste Management segment, OPG records an inter-segment charge between the Regulated – Nuclear Generation and the Regulated – Nuclear Waste Management segments. The impact of the inter-segment charge is eliminated in the consolidated statements of income and balance sheets.

The Regulated – Nuclear Waste Management segment is considered rate regulated because OPG's costs associated with the Nuclear Liabilities have been included in the determination of regulated prices for production from the Pickering and Darlington nuclear generating stations, in accordance with the methodology applied by the OEB since its 2008 decision on OPG's first application for regulated prices.

Regulated – Hydroelectric Segment

OPG's Regulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from most of the Company's hydroelectric generating stations. The business segment includes the results of the Sir Adam Beck 1, 2 and Pump generating stations, the DeCew Falls 1 and 2 generating stations, and the R.H. Saunders GS

that were prescribed for rate regulation prior to 2014, and the 48 hydroelectric stations prescribed for rate regulation effective in 2014.

In addition, the business segment includes ancillary and other revenues from OPG's regulated hydroelectric stations. Ancillary revenues are earned through offering available generating capacity as operating reserve and through the supply of other ancillary services including voltage control and reactive support, certified black start facilities, regulation service, and other services. These ancillary revenues and other revenues are included by the OEB as a credit to ratepayers in the determination of the regulated prices for production from OPG's prescribed hydroelectric facilities, which has had the effect of reducing these prices.

Contracted Generation Portfolio Segment

The Contracted Generation Portfolio business segment operates in Ontario, generating and selling electricity from the Company's generating stations that are not prescribed for rate regulation. The segment primarily includes generating facilities that are under an ESA with the IESO or other long-term contracts.

The Contracted Generation Portfolio segment also includes OPG's share of equity income from its 50 percent ownership interests in the PEC and Brighton Beach stations.

The business segment also includes ancillary revenues and other revenues from the stations included in the segment, which are earned through offering available generating capacity as operating reserve, and the supply of other ancillary services including voltage control and reactive support, certified black start facilities, regulation service, and other services.

Services, Trading, and Other Non-Generation Segment

The Services, Trading, and Other Non-Generation segment is a non-generation segment that is not subject to rate regulation. It includes the revenue and expenses related to OPG's trading and other non-hedging activities. As part of these activities, OPG transacts with counterparties in Ontario and neighbouring energy markets in predominantly short-term trading activities of typically one year or less in duration. These activities relate to electricity that is purchased and sold at the Ontario border, financial energy trades, financial risk management energy product revenues, and sales of energy-related products. In addition, OPG has a wholly owned trading subsidiary that transacts solely in the US market. The results of this subsidiary are reported in this segment. All contracts that are not designated as hedges are recorded as assets or liabilities at fair value on the consolidated balance sheets with changes in fair value recorded in the revenue of this segment. In addition, the segment includes revenue from real estate rentals and non-regulated services, non-regulated business development activities, and, prior to OPG's decision to decommission the stations, preservation costs related to the former coal-fired Lambton GS and the Nanticoke GS sites.

OM&A expenses of the generation business segments include an inter-segment service fee for the use of certain PP&E and intangible assets held within Service, Trading, and Other Non-Generation segment. The total service fee is recorded as a reduction to the segment's OM&A expenses.

The service fee included in OM&A expenses by segment in 2017 and 2016 was as follows:

(millions of dollars)	**2017**	**2016**
Regulated – Nuclear Generation	**36**	34
Regulated – Hydroelectric	**7**	7
Contracted Generation Portfolio	**4**	4
Reduction to Services, Trading, and Other Non-Generation	**47**	45

Fair Hydro Trust Segment

The Trust was established on December 20, 2017 and was established as a non-generation segment that is not subject to rate regulation. It includes OPG's earnings from the Trust, which includes the financial results of the Trust, as well as revenues and expenses related to OPG's role as Financial Services Manager of the Fair Hydro Trust and holder of subordinated debt issued by the Trust. Revenues include recovery of related to third-party costs and fees for financial management and ongoing administration services. OM&A expenses include incurred third-party and other recoverable incurred costs related to the management and administration of the Trust. Net interest expense (income) include interest income from OPG's investment in subordinated debt of the Trust of up to 49 percent of the Trust's total outstanding debt, partially offset by interest costs on debt issued by OPG to fund five percent of the subordinated investment in the Trust.

The earnings from the Trust is comprised of the following:

For the year ended December 31 *(millions of dollars)*	**2017**
Revenues	**(8)**
OM&A expenses	**8**
Net interest expense (income)	**(1)**
Earnings from Fair Hydro Trust	**(1)**

Segment Income (Loss) for the Year Ended December 31, 2017 *(millions of dollars)*	Nuclear Generation	Regulated Nuclear Waste Management	Hydro-Electric	Unregulated Contracted Generation Portfolio	Unregulated Services, Trading, and Other Non-Generation	Fair Hydro Trust	Elimination	Total
Revenue	**3,095**	**121**	**1,436**	**579**	**43**	**-**	**(116)**	**5,158**
Fuel expense	**284**	**-**	**351**	**53**	**1**	**-**	**-**	**689**
Gross margin	**2,811**	**121**	**1,085**	**526**	**42**	**-**	**(116)**	**4,469**
Operations, maintenance and administration	**2,293**	**129**	**330**	**169**	**18**	**1**	**(116)**	**2,824**
Depreciation and amortization	**431**	**-**	**139**	**79**	**30**	**-**	**-**	**679**
Accretion on fixed asset removal and nuclear waste management liabilities	**-**	**943**	**-**	**9**	**8**	**-**	**-**	**960**
Earnings on nuclear fixed asset removal and nuclear waste management funds	**-**	**(801)**	**-**	**-**	**-**	**-**	**-**	**(801)**
Earnings from Fair Hydro Trust						**(1)**		**(1)**
Income from investments subject to significant influence	**-**	**-**	**-**	**(38)**	**-**	**-**	**-**	**(38)**
Property taxes	**26**	**-**	**1**	**7**	**6**	**-**	**-**	**40**
Other (gains) losses	**4**	**-**	**1**	**-**	**(384)**	**-**	**-**	**(379)**
Income (loss) before interest and income taxes	**57**	**(150)**	**614**	**300**	**364**	**-**	**-**	**1,185**
Net interest expense								**95**
Income before income taxes								**1,090**
Income tax expense								**209**
Net income								**881**

Segment Income (Loss) for the Year Ended December 31, 2016 *(millions of dollars)*	Nuclear Generation	Regulated Nuclear Waste Management	Hydroelectric	Unregulated Contracted Generation Portfolio	Unregulated Services, Trading, and Other Non-Generation	Elimination	Total
Revenue	3,481	138	1,527	573	68	(134)	5,653
Fuel expense	315	-	353	58	1	-	727
Gross margin	3,166	138	1,174	515	67	(134)	4,926
Operations, maintenance and administration	2,210	146	325	178	22	(134)	2,747
Depreciation and amortization	925	-	225	75	32	-	1,257
Accretion on fixed asset removal and nuclear waste management liabilities	-	912	-	9	8	-	929
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(746)	-	-	-	-	(746)
Income from investments to significant influence	-	-	-	(37)	-	-	(37)
Property taxes	26	-	1	7	12	-	46
Restructuring	-	-	-	-	6	-	6
Other (gains) losses	1	-	(19)	1	-	-	(17)
Income (loss) before interest and taxes	4	(174)	642	282	(13)	-	741
Net interest expense							120
Income before income taxes							621
Income tax expense							168
Net income							453

Selected Consolidated Balance Sheet information as at December 31, 2017 *(millions of dollars)*	Nuclear Gener-ation	Regulated Nuclear Waste Manage-ment	Hydro-electric	Unregulated Contracted Generation Portfolio	Unregulated Services, Trading, and Other Non-Generation	Fair Hydro Trust	Total
Segment property, plant and equipment in-service, net	**6,167**	**-**	**7,359**	**3,480**	**224**	**-**	**17,230**
Segment construction in progress	**3,839**	**-**	**157**	**78**	**18**	**-**	**4,092**
Segment property, plant and equipment, net	**10,006**	**-**	**7,516**	**3,558**	**242**	**-**	**21,322**
Segment intangible assets in-service, net	**4**	**-**	**1**	**5**	**84**	**-**	**94**
Segment development in progress	**16**	**-**	**-**	**-**	**23**	**-**	**39**
Segment intangible assets, net	**20**	**-**	**1**	**5**	**107**	**-**	**133**
Segment fuel inventory	**265**	**-**	**-**	**44**	**-**	**-**	**309**
Segment materials and supplies inventory, net:							
Current	**102**	**-**	**-**	**1**	**-**	**-**	**103**
Long-term	**351**	**-**	**-**	**4**	**-**	**-**	**355**
Nuclear fixed asset removal and nuclear waste management funds (current and non-current portions)	**-**	**16,724**	**-**	**-**	**-**	**-**	**16,724**
Financing receivables Fair Hydro Trust	**-**	**-**	**-**	**-**	**-**	**1,179**	**1,179**
Fixed asset removal and nuclear waste liabilities	**-**	**(20,077)**	**-**	**(151)**	**(193)**	**-**	**(20,421)**

Selected Consolidated Balance Sheet Information as at December 31, 2016 *(millions of dollars)*	Nuclear Generation	Regulated Nuclear Waste Management	Hydro-electric	Unregulated Contracted Generation Portfolio	Unregulated Services, Trading, and Other Non-Generation	Total
Segment property, plant and equipment in-service, net	5,653	-	7,355	3,282	226	16,516
Segment construction in progress	2,988	-	166	301	27	3,482
Segment property, plant and equipment, net	8,641	-	7,521	3,583	253	19,998
Segment intangible assets in-service, net	7	-	2	4	66	79
Segment development in progress	3	-	-	1	16	20
Segment intangible assets, net	10	-	2	5	82	99
Segment fuel inventory	276	-	-	34	-	310
Segment materials and supplies inventory, net:						
Current	99	-	-	1	-	100
Long-term	340	-	1	4	-	345
Nuclear fixed asset removal and nuclear waste management funds (current and non-current portions)	-	15,984	-	-	-	15,984
Fixed asset removal and nuclear waste management liabilities	-	(19,103)	-	(160)	(221)	(19,484)

Selected Capital Expenditure Information	Regulated		Unregulated				
(millions of dollars)	**Nuclear Generation**	**Nuclear Waste Manage-ment**	**Hydro-electric**	**Contracted Generation Portfolio**	**Services, Trading, and Other Non-Generation**	**Fair Hydro Trust**	**Total**
Year ended December 31, 2017							
Investment in property, plant and equipment, and intangible assets	**1,631**	**-**	**148**	**73**	**74**	**-**	**1,926**
Year ended December 31, 2016							
Investment in property, plant and equipment, and intangible assets	1,338	-	132	198	36	-	1,704

Shareholder Declarations and Shareholder Resolutions to Sell Certain Non-Core Real Estate Properties

In December 2015, OPG received a Shareholder Declaration and a Shareholder Resolution requiring the Company to sell its head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street in Toronto, Ontario. The sale was completed in April 2017 with a gain on sale of $283 million, which is net of tax effects of $95 million, recognized in net income during the year ended December 31, 2017. The pre-tax gain on sale was recorded as an item of Other gains in the consolidated statement of income in the Services, Trading and Other Non-Generation segment. Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. The amount of designated proceeds transferred into the Consolidated Revenue Fund ~~will~~ are expected to approximate ~~be equal to~~ the after-tax gain on sale. [**MONITOR**] The transfer is expected to take place ~~as early as~~ in the first quarter of 2018, through a special dividend authorized by OPG's Board of Directors in March 2018. **[MONITOR]**

Commented [DS2]: The amount of designated proceeds will be determined by regulation and therefore uncertain until the regulation is filed and made public.

In June 2016, OPG received a Shareholder Declaration and a Shareholder Resolution that requires the Company to sell its former Lakeview GS site located in Mississauga, Ontario. The Lakeview GS site assets were fully depreciated prior to June 2017. OPG entered into a purchase and sale agreement with a purchaser with the sale scheduled to close in March 2018. An estimated after-tax gain on sale of approximately $200 million will be recognized in net income upon completion of the transaction in the first quarter of 2018. **[MONITOR]** Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. In accordance with the Shareholder Resolution, approximately one-third of the site is to be transferred to the City of Mississauga, by the purchaser, for parkland, institutional, and cultural uses. **[MONITOR]**

18. NET CHANGES IN NON-CASH WORKING CAPITAL BALANCES

(millions of dollars)	December 31 2017	2016
Receivables from related parties	**60**	116
Prepaid expenses	**(14)**	(6)
Other current assets [1]	**(28)**	(32)
Fuel inventory	**1**	34
Materials and supplies	**(3)**	(4)
Income taxes payable	**2**	57
Accounts payable and accrued charges	**36**	15
	54	180

[1] Represents other accounts receivable.

19. RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One, the IESO and the OEFC. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly-owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions for the years ended December 31 are summarized below:

(millions of dollars)	2017 Revenue	2017 Expense	2016 Revenue	2016 Expense
Hydro One				
Electricity sales	**8**	**-**	6	-
Services	**1**	**10**	1	5
Dividends	**7**	**-**	6	-
Province of Ontario				
Change in Decommissioning Segregated Fund amount due to Province [1]	**-**	**456**	-	192
Change in Used Fuel Segregated Fund amount due to Province [1]	**-**	**591**	-	235
Hydroelectric gross revenue charge	**-**	**110**	-	120
ONFA guarantee fee	**-**	**8**	-	8
Other	**-**	**2**	-	-
OEFC				
Hydroelectric gross revenue charge	**-**	**216**	-	203
Interest expense on long-term notes	**-**	**158**	-	169
Income taxes, net of investment tax credits	**-**	**246**	-	104
IESO				
Electricity related revenue	**4,802**	**-**	5,082	-
Fair Hydro Trust	**4**	**3**	-	-
	4,822	**1,800**	5,095	1,036

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at December 31, 2017 and December 31, 2016, the Nuclear Segregated Funds were reported net of amounts due to the Province of $4,462 million and $3,415 million, respectively.

The receivable, AFS securities, payable and long-term debt balances between OPG and its related parties are summarized below:

(millions of dollars)	**December 31 2017**	**December 31 2016**
Receivables from related parties		
Hydro One	**1**	1
IESO − Electricity related receivables	**354**	421
IESO − Fair Hydro Trust [1]	**7**	-
OEFC	**-**	1
PEC	**4**	4
Province of Ontario	**3**	2
Financing receivables		
IESO − Fair Hydro Trust	**1,179**	-
Available-for-sale securities		
Hydro One shares	**188**	212
Accounts payable and accrued charges		
Hydro One	**1**	-
OEFC	**52**	61
Province of Ontario	**9**	2
IESO − Electricity-related payables	**5**	2
IESO − Fair Hydro Trust	**3**	-
Long-term debt (including current portion)		
Notes payable to OEFC	**3,195**	3,295

[1] Balance consists of unbilled revenue.

OPG holds interest-bearing Province of Ontario bonds in the Nuclear Segregated Funds and the OPG registered pension fund. As at December 31, 2017, the Nuclear Segregated Funds held $1,503 million of interest-bearing Province of Ontario bonds. As at December 31, 2016, the Nuclear Segregated Funds and the registered pension fund held $1,652 million and $284 million of interest-bearing Province of Ontario bonds, respectively. These bonds are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

In December 2017, the Trust purchased its first tranche of Investment Interest from the IESO for an exchange amount of $1.18 billion, which has been classified as a financing receivable on OPG's consolidated balance sheet. The transaction was settled in cash using proceeds from the Trust's issuance of senior and subordinated debt. Pursuant to the general regulation of the Act, the IESO is required to pay and remit carrying costs of the Trust, excluding repayment of principal on any debt obligations, up to July 31, 2021. Commencing May 1, 2021, Specified Consumers will be invoiced by their local distribution company for the Clean Energy Adjustment to pay financing and other costs of the Trust. These funds will be remitted to the Trust through the IESO and will be used to settle all funding and other related expenses of the Trust that underlie the financing receivable.

As at December 31, 2017, OPG's consolidated balance sheet included approximately $7 million of unbilled revenue from the IESO primarily for OPG's general fee for 2017 as Financial Services Manager relating to incurred third-party and certain direct labour costs. In February 2018, OPG submitted to the OEB its proposed general fee for 2017 in the amount of approximately $6 million for review pursuant to the requirements of the general regulation of the Fair Hydro Act. Once approved, the fees will be remitted to the Trust by the IESO and the Trust will pay OPG's fees as Financial Services Manager.

20. INVESTMENTS SUBJECT TO SIGNIFICANT INFLUENCE

Investments subject to significant influence consist of OPG's 50 percent ownership interest in the jointly controlled entities of the PEC gas-fired combined cycle generating station and the Brighton Beach, which are accounted for using the equity method. Details of the balances as at December 31, 2017 and December 31, 2016 are as follows:

(millions of dollars)	**2017**	**2016**
PEC		
Current assets	**20**	18
Long-term assets	**240**	256
Current liabilities	**(10)**	(8)
Long-term liabilities	**(6)**	(5)
Brighton Beach		
Current assets	**5**	5
Long-term assets	**160**	168
Current liabilities	**(17)**	(16)
Long-term liabilities	**(9)**	(7)
Long-term debt	**(74)**	(90)
Investments subject to significant influence	**309**	321

21. RESEARCH AND DEVELOPMENT

For the year ended December 31, 2017, research and development expenses of $106 million (2016 – $95 million) were charged to operations.

22. NON-CONTROLLING INTEREST

PSS Generating Station LP

PSS is a limited partnership between OPG, Coral Rapids Power Corporation (CRP) and PSS Generating Station Inc. (PSS GS Inc.). The principal business of the partnership is the development, construction, ownership, operation and maintenance of the 28 Megawatt (MW) Peter Sutherland Sr. hydroelectric GS on the New Post Creek. OPG and PSS GS Inc. are general partners and CRP is a limited partner in the partnership. CRP is a wholly owned subsidiary of the Taykwa Tagamou Nation.

The Peter Sutherland Sr. GS was placed in-service in March 2017 and, in April 2017, CRP increased its interest in PSS to 33 percent under the partnership agreement, by making contributions of $21 million, reducing OPG's interest to 67 percent. CRP's 33 percent interest in PSS is reported as non-controlling interest. As a result of CRP increasing its interest in the partnership, PSS's AOCL and partner's deficit were proportionately allocated to CRP as a reduction to its non-controlling interest.

Nanticoke Solar LP

In March 2016, Nanticoke Solar LP (NSLP), a partnership between OPG, SunEdison Canadian Construction LP (SECCLP) and a subsidiary of the Six Nations of the Grand River Development Corporation, was selected through IESO's Large Renewal Procurement program to construct a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands. In the first quarter of 2017, OPG acquired all of SECCLP's interests in NSLP, which represented 25 percent of the equity interest in NSLP. Subsequent to the acquisition, OPG owns 90 percent of the equity interest in NSLP, with an approximate value of $2 million. OPG consolidates the results of the NSLP in its consolidated financial statements and reports the equity interest of the other partner as non-controlling interest.

ONTARIO POWER GENERATION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

DECEMBER 31, 2017

[DRAFT]

2017 YEAR-END REPORT

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ONTARIO POWER GENERATION INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) should be read in conjunction with the audited consolidated financial statements and accompanying notes of Ontario Power Generation Inc. (OPG or Company) as at and for the year ended December 31, 2017. OPG's consolidated financial statements are prepared in accordance with United States generally accepted accounting principles (US GAAP) and are presented in Canadian dollars.

As required by *Ontario Regulation 395/11*, as amended, a regulation under the *Financial Administration Act* (Ontario) (FAA), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. In 2014, the Ontario Securities Commission (OSC) approved an exemption which allows OPG to apply US GAAP up to January 1, 2019. The term of the exemption is subject to certain conditions, which may result in the expiry of the exemption prior to January 1, 2019. For details, refer to the section, *Critical Accounting Policies and Estimates* under the heading, *Exemptive Relief for Reporting under US GAAP*. This MD&A is dated March 8, 2018.

FORWARD-LOOKING STATEMENTS

The MD&A contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could", and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

All forward-looking statements involve inherent assumptions, risks, and uncertainties, including those set out in the section, *Risk Management,* and forecasts discussed in the section, *Core Business, Strategy, and Outlook.* All forward-looking statements could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's generating station performance and availability, fuel costs, surplus baseload generation (SBG), cost of fixed asset removal and nuclear waste management, performance and earnings of investment funds, refurbishment of existing facilities, development and construction of new facilities, pension and other post-employment benefit (OPEB) obligations and funds, income taxes, proposed new legislation, the ongoing evolution of Ontario's electricity industry, environmental and other regulatory requirements, health, safety and environmental developments, business continuity events, the weather, financing and liquidity, applications to the Ontario Energy Board (OEB) for regulatory prices, the impact of regulatory decisions by the OEB, Ontario's Fair Hydro Plan (Fair Hydro Plan or the Plan) and forecasts of earnings, cash flows, Funds from Operations (FFO) Adjusted Interest Coverage, Return on Common Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI), Total Generating Cost (TGC) and capital expenditures. Accordingly, undue reliance should not be placed on any forward-looking statement. The forward-looking statements included in this MD&A are made only as of the date of this MD&A. Except as required by applicable securities laws, OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events, or otherwise.

THE COMPANY

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG was established under the *Business Corporations Act* (Ontario) (OBCA) and is wholly owned by the Province of Ontario (Province or Shareholder).

As at December 31, 2017, OPG's electricity generation portfolio had an in-service capacity of 16,210 megawatts (MW). OPG operates two nuclear generating stations, 66 hydroelectric generating stations, three thermal generating stations, and one wind power turbine. In addition, OPG and TransCanada Energy Ltd. co-own the 550 MW Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS). OPG and ATCO Power Canada Ltd. co-own the 560 MW Brighton Beach gas-fired combined cycle GS (Brighton Beach). OPG's 50 percent share of the in-service capacity and generation volume of these co-owned facilities is included in the generation portfolio statistics set out in this report. The income from the co-owned facilities is accounted for using the equity method of accounting, and OPG's share of income is presented as income from investments subject to significant influence in the Contracted Generation Portfolio segment.

OPG also owns two other nuclear generating stations, the Bruce A GS and the Bruce B GS, which are leased on a long-term basis to Bruce Power LP (Bruce Power). Income from these leased stations is included in revenue under the Regulated – Nuclear Generation segment. The leased stations are not included in the generation portfolio statistics set out in this report.

All of OPG's owned and co-owned generating facilities are located in Ontario. OPG does not operate PEC, Brighton Beach, the Bruce A GS and the Bruce B GS.

OPG's Reporting Structure

Effective in the fourth quarter of 2017, following the establishment of the Fair Hydro Trust (the Trust) as the financing entity to implement the Fair Hydro Plan under the *Ontario Fair Hydro Plan Act, 2017* (the Fair Hydro Act or the Act), OPG has modified its reportable business segments to include the Fair Hydro Trust segment. Through its control over the key activities of the Trust and its obligation to absorb losses through ownership of the Trust's subordinated debt, the Company consolidates the financial results of the Trust in accordance with US GAAP. The Fair Hydro Trust segment reports the income related to OPG's role as Financial Services Manager under the Act and holder of subordinated debt issued by the Trust, including the financial results of the Trust. The Fair Hydro Plan and the Fair Hydro Trust are discussed in the section, *Recent Developments* and in the section, *Core Business, Strategy, and Outlook* under the heading, *Business Segments*.

The composition of OPG's reportable business segments is as follows:

- Regulated – Nuclear Generation
- Regulated – Nuclear Waste Management
- Regulated – Hydroelectric
- Contracted Generation Portfolio
- Services, Trading, and Other Non-Generation
- Fair Hydro Trust.

OPG receives regulated prices for electricity generated from most of its hydroelectric facilities and all of the nuclear facilities that it operates (collectively, prescribed facilities or regulated facilities). The regulated facilities comprise 54 hydroelectric generating stations across a number of major river systems in the province, the Pickering Nuclear GS (Pickering GS) and Darlington Nuclear GS (Darlington GS).

The operating results related to these regulated facilities are described under the Regulated – Nuclear Generation, Regulated – Nuclear Waste Management, and Regulated – Hydroelectric segments. For the remainder of OPG's operating generating facilities, the operating results are described under the Contracted Generation Portfolio segment. A description of all OPG's segments is provided under the section, *Business Segments*.

In-Service Generating Capacity

OPG's in-service generating capacity by business segment as of December 31 was as follows:

(MW)	**2017**	**2016**
Regulated – Nuclear Generation [1]	**5,728**	5,728
Regulated – Hydroelectric	**6,426**	6,421
Contracted Generation Portfolio [2]	**4,056**	4,028
Total	**16,210**	16,177

[1] The in-service generating capacity as of December 31, 2017 and December 31, 2016 excludes Unit 2 of the Darlington GS. The unit, which has a generating capacity of 878 MW, was taken offline in mid-October 2016 and is currently undergoing refurbishment.

[2] Includes OPG's share of in-service generating capacity of 275 MW for PEC and 280 MW for Brighton Beach.

The total in-service capacity as at December 31, 2017 increased by 33 MW compared to 2016. The increase was primarily due to the completion of the 28 MW Peter Sutherland Sr. hydroelectric GS, which was placed in-service in the first quarter of 2017, and the upgrade of Unit 10 of the Sir Adam Beck 1 hydroelectric GS, which was completed in June 2017. Further details on the Peter Sutherland Sr. GS project are found in the section, *Core Business, Strategy, and Outlook* under the heading, *Project Excellence*.

REVENUE MECHANISMS FOR REGULATED AND NON-REGULATED GENERATION

Regulated Generation

The OEB sets the prices for electricity generated from OPG's regulated nuclear and regulated hydroelectric facilities. The following table presents the OEB-authorized regulated prices for electricity generated from these facilities during the periods from January 1, 2016 to May 30, 2017, as well as new regulated prices retrospectively effective June 1, 2017 that OPG has calculated and submitted to the OEB, based on the OEB's decision on OPG's 2017-2021 application for new regulated prices issued on December 28, 2017:

($/MWh)	2017		2016
	January 1 to May 31	**June 1 to December 31** [1]	
Regulated – Nuclear Generation			
Base regulated price	**59.29**	**80.65**	59.29
Variance and deferral account rate rider	**-**	**-**	10.84 [2]
	59.29	**80.65**	70.13
Regulated – Hydroelectric			
Base regulated price	**40.72**	**41.67**	40.72
Variance and deferral account rate rider	**-**	**-**	3.19 [2]
	40.72	**41.67**	43.91

[1] Regulated prices for the June 1, 2017 to December 31, 2017 period were calculated and submitted to the OEB by OPG in January 2018 based on the OEB's December 28, 2017 decision on OPG's 2017-2021 application for new regulated prices. The final regulated prices will be determined by the OEB as part of the final payment amounts order process, which is expected to be completed in the first half of 2018. As part of the process, the OEB is expected to authorize separate rate riders to allow for the recovery of the shortfall between the new regulated prices and the previous regulated prices that OPG continues to receive during the period between June 1, 2017 and the implementation date of the new regulated prices pending the issuance of the final payment amounts order. The incremental revenue for the period between June 1, 2017 and December 31, 2017 arising from this retrospective application of new regulated prices was accrued in 2017. **[MONITOR]**

[2] The OEB authorized interim period rate riders for the period from October 1, 2015 to December 31, 2016 to allow for the recovery of the riders effective July 1, 2015 for the period from July 1, 2015 to September 30, 2015. The nuclear interim period rate rider was $2.17 per megawatt hour (MWh) and the regulated hydroelectric interim period rate rider was $0.64/MWh. These interim period rate riders have not been included in the above table. All rate riders in effect during 2016 expired on December 31, 2016.

Based on the OEB's December 2017 decision, the new base regulated prices are determined on an incentive ratemaking methodology for the hydroelectric operations and under a custom incentive regulation framework for the nuclear operations. For the hydroelectric facilities, the new base regulated price is determined using a formula that annually escalates the previous regulated prices, subject to some adjustments, based on inflation less a stretch factor to incent additional innovation and efficiency. For the nuclear facilities, the new regulated price is determined under a rate smoothing approach that defers a portion of the approved nuclear revenue requirement for future collection, with the aim of making more stable changes in OPG's production-weighted regulated prices year over year. The nuclear revenue requirement is based on the OEB-approved forecasts of operating costs as reduced by a stretch factor and a return on rate base. Rate base for OPG represents the average net level of investment in regulated fixed and intangible assets in service and an allowance for working capital. The OEB's December 2017 decision and OPG's new regulated prices are discussed further in the section, *Recent Developments*.

The base regulated prices in effect during 2016 were established by the OEB's November 2014 decision and December 2014 order, effective November 1, 2014, using a forecast cost-of-service methodology based on the OEB-approved revenue requirements for the 2014 to 2015 period, taking into account the OEB-approved forecasts of production and operating costs for the regulated facilities and a return on rate base.

The increase in base regulated prices for the Regulated – Nuclear Generation segment from those last approved in 2014 is impacted by lower production for Darlington GS for the duration of Unit 2's refurbishment. The increase also

reflects OPG's ability to earn a return on higher in-service capital and recover costs to enable Pickering to operate beyond 2020 in line with the Long-Term Energy Plan (LTEP).

Rate riders for OPG are typically established to recover or repay approved balances in OEB-authorized regulatory variance and deferral accounts (regulatory accounts). Variance and deferral accounts typically capture, for subsequent review and approval, differences between actual costs and revenues and the corresponding forecast amounts approved by the OEB in setting regulated prices, or record the impact of items not reflected in the approved regulated prices. The rate riders in effect to the end of 2016 were established by the OEB's October 2015 order on OPG's 2014 application to recover the December 31, 2014 variance and deferral account balances. Revenue received from the recovery of variance and deferral account balances is largely offset by amortization expense related to these balances.

Non-Regulated Generation

Electricity generated from most of OPG's non-regulated assets is subject to Energy Supply Agreements (ESAs) with the Independent Electricity System Operator (IESO).

During 2017, ESAs were in effect for the following thermal generating facilities:

- Lennox GS: Capacity and production provided by the station are subject to an ESA for the period from January 1, 2013 to September 30, 2022
- Atikokan GS: Capacity and production provided by the station are subject to a ten-year ESA expiring in July 2024
- Thunder Bay GS: Capacity and production provided by the station are subject to a five-year ESA expiring in January 2020.

In addition, long-term hydroelectric ESAs are in place for the following facilities, with expiry dates ranging from 2059 to 2067:

- Lac Seul and Ear Falls generating stations
- Healey Falls GS
- Sandy Falls, Wawaitin, Lower Sturgeon, and Hound Chute generating stations
- Little Long, Harmon, Smoky Falls, and Kipling generating stations (collectively the Lower Mattagami River generating stations)
- Peter Sutherland Sr. GS, which was placed in-service in March 2017.

HIGHLIGHTS

Overview of Results

This section provides an overview of OPG's operating results for the years ended December 31, 2017 and December 31, 2016.

(millions of dollars – except where noted)	**2017**	**2016**
Revenue	**5,158**	5,653
Fuel expense	**689**	727
Gross margin	**4,469**	4,926
Operations, maintenance and administration	**2,824**	2,747
Depreciation and amortization	**679**	1,257
Accretion on fixed asset removal and nuclear waste management liabilities	**960**	929
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(801)**	(746)
Earnings from Fair Hydro Trust	**(1)**	-
Income from investments subject to significant influence	**(38)**	(37)
Property taxes	**40**	46
Restructuring	**-**	6
	3,663	4,202
Income before other gains, interest, and income taxes	**806**	724
Other gains	**379**	17
Income before interest and income taxes	**1,185**	741
Net interest expense	**95**	120
Income before income taxes	**1,090**	621
Income tax expense	**209**	168
Net income	**881**	453
Net income attributable to the Shareholder	**860**	436
Net income attributable to non-controlling interest [1]	**21**	17
Electricity production (TWh) [2]	**74.1**	78.2
Cash flow		
Cash flow provided by operating activities	**944**	1,817

[1] Relates to the 25 percent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in the Lower Mattagami Limited Partnership, the 33 percent interest of Coral Rapids Power Corporation (CRP), a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership (PSS), and the 10 percent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP. CRP increased its partnership interest to 33 percent in April 2017.

[2] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach and excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS was excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

Net income attributable to the Shareholder was $860 million for 2017, representing an increase of $424 million compared to 2016. Income before interest and income taxes was $1,185 million for 2017, representing an increase of $444 million compared to 2016. The following summarizes the significant factors which contributed to the variance:

Significant factors that increased income before interest and income taxes:

- Higher revenue from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments of approximately $480 million recorded in the fourth quarter of 2017 to reflect the OEB's decision on OPG's application for new regulated rates issued in December 2017 with a retrospective effective date of June 1,

2017. This revenue increase for the June 1, 2017 to December 31, 2017 period was recorded as an increase in regulatory assets, based on new regulated prices for that period proposed in OPG's January 2018 submission to the OEB based on the findings in the December 2017 decision, net of a regulatory liability recognized in relation to OPG's nuclear rate smoothing proposal included in that submission. The new regulated prices, the future collection period for the retrospective revenue increase, and the rate smoothing proposal are pending the OEB's approval through the payment amounts order process, which typically follows the OEB's issuance of a decision on a major rates application. The OEB's approval of the final payment amounts order, including determinations on the new regulated prices and rate smoothing, are not expected to have a material impact on the total revenue recorded for the June 1, 2017 to December 31, 2017 period. The OEB is expected to issue the final payment amounts order in the first half of 2018. **[MONITOR]**

- Higher earnings of $377 million from the Services, Trading, and Other Non-Generation segment, primarily as a result of the gain on sale of OPG's head office premises and associated parking facility, a non-core asset of the business. A gain on sale of $283 million, which is net of tax effects of $95 million, was recognized in net income upon completion of the transaction in the second quarter of 2017. The sale was undertaken pursuant to a Shareholder Declaration and a Shareholder Resolution. Further details can be found under the heading, *Recent Developments – Shareholder Declarations and Shareholder Resolutions to Sell Certain Non-Core Real Estate Properties*.
- Higher earnings of $24 million from the Regulated – Nuclear Waste Management segment, primarily due to higher earnings from the nuclear fixed asset removal and nuclear waste management funds (Nuclear Segregated Funds), partially offset by an increase in accretion expense on the nuclear fixed asset removal and nuclear waste management liabilities (Nuclear Liabilities).

Significant factors that reduced income before interest and income taxes:

- Lower revenue of approximately $285 million, partially offset by a decrease in fuel expense of $31 million, reflecting lower electricity generation of 4.9 terawatt hours (TWh) from the Regulated – Nuclear Generation segment. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS since October 2016, partially offset by an increase in generation from the Pickering GS. The increase in generation from the Pickering GS was primarily due to outage cycle optimization, favourable unit conditions and execution of planned outage work resulting in fewer unplanned and planned outage days at the station.
- Higher operations, maintenance and administration (OM&A) expenses of $77 million, mainly in the Regulated – Nuclear Generation segment, reflecting planned expenditures related to the major maintenance activities occurring at the nuclear stations.
- Higher depreciation and amortization expense of $22 million in the Regulated – Nuclear Generation segment, excluding amortization expense related to balances in regulatory accounts, primarily due to new assets in service.
- A gain of $22 million recorded in the first quarter of 2016 to reflect the OEB's decision on OPG's motion asking the OEB to review and vary parts of its November 2014 decision on OPG's regulated prices.

The expiry of rate riders for the recovery of OEB-approved balances in regulatory accounts on December 31, 2016 contributed to the decrease in revenue in 2017, compared to 2016, but was largely offset by a decrease in the amortization expense related to regulatory account balances.

Net interest expense decreased by $25 million in 2017, compared to 2016, primarily due to a higher amount of interest costs capitalized for the Darlington Refurbishment project.

Income tax expense increased by $41 million in 2017, compared to 2016, primarily due to higher income before income taxes, partially offset by a higher amount of income tax expense deferred in regulatory assets in 2017.

Segment Results

The following table summarizes OPG's income before interest and income taxes by business segment. Significant factors which contributed to the higher income during 2017, compared to 2016, are discussed above. A detailed discussion of OPG's performance by reportable segment is included in the section, *Discussion of Operating Results by Business Segment*.

(millions of dollars)	**2017**	**2016**
Income (loss) before interest and income taxes		
Regulated – Nuclear Generation	**57**	4
Regulated – Hydroelectric	**614**	642
Contracted Generation Portfolio	**300**	282
Total electricity generation business segments	**971**	928
Regulated – Nuclear Waste Management	**(150)**	(174)
Services, Trading, and Other Non-Generation	**364**	(13)
Fair Hydro Trust	**-**	-
	1,185	741

Electricity Generation

Electricity generation for 2017 and 2016 was as follows:

(TWh)	**2017**	**2016**
Regulated – Nuclear Generation	**40.7**	45.6
Regulated – Hydroelectric	**30.7**	29.5
Contracted Generation Portfolio [1]	**2.7**	3.1
Total OPG electricity generation	**74.1**	78.2
Total electricity generation by other generators in Ontario [2]	**70.5**	72.7

[1] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

[2] Non-OPG generation is calculated as the Ontario electricity demand plus net exports, as published by the IESO, minus OPG electricity generation.

Total OPG electricity generation decreased by 4.1 TWh in 2017, mainly due to lower electricity generation of 4.9 TWh from the Regulated – Nuclear Generation segment. As expected, this was primarily the result of the removal from service of Unit 2 at the Darlington GS for the duration of the unit's refurbishment, which began in October 2016. This decrease in electricity generation was partially offset by an increase in generation from the Pickering GS, primarily due to outage cycle optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of outage days at the station, as well as higher electricity generation from the Regulated – Hydroelectric segment.

The higher electricity generation from the Regulated – Hydroelectric segment in 2017 was due to higher water flows primarily on the eastern Ontario river systems, net of forgone electricity generation as a result of SBG conditions, discussed below.

The lower electricity generation from the Contracted Generation Portfolio segment was primarily due to higher SBG conditions.

OPG's operating results are affected by changes in grid-supplied electricity demand resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. Ontario's electricity demand as reported

by the IESO was 132.1 TWh in 2017 and 137.0 TWh and 2016, respectively, which excludes electricity exports out of the province.

Power that is surplus to the Ontario market is managed by the IESO, mainly through generation reductions at hydroelectric and nuclear stations and other grid-connected renewable resources. Reducing hydroelectric production is a measure used by the IESO to manage SBG conditions. Baseload generation supply surplus in Ontario was more prevalent in 2017 than in 2016, mainly due to higher water flows and reduced electricity demand in the province during 2017. During 2017 and 2016, OPG lost 5.9 TWh and 4.7 TWh of hydroelectric generation due to SBG conditions, respectively. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions in 2017 and 2016 was offset by the impact of a regulatory variance account authorized by the OEB. OPG did not forgo any electricity production at its nuclear stations due to SBG conditions.

Average Sales Prices

The majority of OPG's generation is from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments. The regulated prices authorized by the OEB for electricity generated from OPG's nuclear and regulated hydroelectric generating stations are discussed in the section, *Revenue Mechanisms for Regulated and Non-Regulated Generation*.

The average sales price for the Regulated – Nuclear Generation segment during 2017 was 7.1 cents per kilowatt hour (¢/kWh), compared to 6.9 ¢/kWh during 2016. The increase in this average sales price was primarily due to an increase in revenue for the period June 1, 2017 to December 31, 2017 recorded in the fourth quarter of 2017 to reflect the OEB's December 2017 decision on OPG's application for new regulated prices, with an effective date of June 1, 2017. The increase was partially offset by the expiry of an OEB-authorized nuclear rate rider of $10.84 per MWh, on December 31, 2016, for the recovery of variance and deferral account balances. The average sales price for the Regulated – Hydroelectric segment during 2017 was 4.2 ¢/kWh, compared to 4.4 ¢/kWh during 2016. The decrease in this average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized regulated hydroelectric rate rider of $3.19/MWh for the recovery of variance and deferral account balances, partially offset by the impact of an increase in revenue for the period June 1, 2017 to December 31, 2017 recorded in the fourth quarter of 2017 to reflect the OEB's December 2017 decision. The rate riders that expired on December 31, 2016 were established to recover approved balances recorded in the variance and deferral accounts in prior years. As such, the year-over-year changes in revenue from the rate riders were largely offset by changes in amortization expense related to these balances.

Cash Flow from Operations

Cash flow provided by operating activities for 2017 was $944 million, compared to $1,817 million for 2016. The decrease in cash flow provided by operating activities was expected and primarily due to lower generation revenue receipts reflecting lower generation from the Regulated – Nuclear Generation segment as a result of the ongoing refurbishment of Unit 2 at the Darlington GS and the expiry, on December 31, 2016, of the OEB-authorized rate riders for nuclear and regulated hydroelectric generation. The decrease in cash flow was also due to higher income tax instalments during 2017, compared to 2016.

The decrease in cash flow provided by operating activities was partly offset by lower contributions to the Used Fuel Segregated Fund in 2017. Both the Used Fuel Segregated Fund and the Decommissioning Segregated Fund were determined to be fully funded based on an updated estimate of OPG's nuclear waste management and nuclear facilities decommissioning obligations pursuant to an Ontario Nuclear Funds Agreement (ONFA) reference plan approved by the Province, effective January 1, 2017. Pursuant to the ONFA, the reference plan is required to be updated at least once every five years. Contributions to either or both of the Nuclear Segregated Funds may be required in the future should the funds be in an underfunded position at the time of the next ONFA reference plan update. The decrease in cash flow compared to the prior year also was partially offset by the payment of a supplemental rent rebate to Bruce Power in the first quarter of 2016 in relation to a period in 2015. The lease

agreement for the Bruce nuclear generating stations was amended in late 2015 to eliminate this rebate provision going forward.

Funds from Operations Adjusted Interest Coverage

FFO Adjusted Interest Coverage is an indicator of OPG's ability to meet interest obligations from operating cash flow. The indicator is measured over a 12-month period. The FFO Adjusted Interest Coverage was 3.3 times for 2017 compared to 5.1 times for 2016. FFO Adjusted Interest Coverage in 2017 reflected a year-over-year decrease in FFO before interest due to lower cash flow provided by operating activities and changes to non-cash working capital balances, offset by the impact of a lower adjusted interest expense due to a decrease in the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets.

The decrease in the excess of interest on pension and OPEB benefit obligations over expected return on pension plan assets in 2017 was primarily due to the change in the method used to estimate the interest cost and service cost component of pension and OPEB costs prospectively adopted as of January 1, 2017. The change in the method is discussed in the section, *Critical Accounting Policies and Estimates* under the heading, *Pension and Other Post-Employment Benefits*.

Return on Common Equity Excluding Accumulated Other Comprehensive Income

ROE Excluding AOCI is an indicator of OPG's performance consistent with the Company's strategy to provide value to the Shareholder. ROE Excluding AOCI is measured over a 12-month period. ROE Excluding AOCI for 2017 was 7.5 percent, compared to 4.2 percent for 2016. ROE Excluding AOCI increased for 2017, compared to 2016, primarily due to higher net income attributable to the Shareholder as a result of the gain on the sale of OPG's head office premises and associated parking facility recorded during the second quarter of 2017 and an increase in revenue for the period June 1, 2017 to December 31, 2017 recorded in the fourth quarter of 2017 to reflect the OEB's December 2017 decision on OPG's application for new regulated prices, with an effective date of June 1, 2017. The increase in net income attributable to the Shareholder was partially offset by the impact of lower nuclear electricity generation reflecting the Unit 2 refurbishment outage at the Darlington GS.

Enterprise Total Generating Cost per Megawatt-Hour

The Enterprise TGC per megawatt-hour (MWh) was $50.66 for the year ended December 31, 2017, compared to $48.45 for the same period in 2016. The increase in Enterprise TGC per MWh was expected and primarily due to lower nuclear electricity generation as a result of the Unit 2 refurbishment outage at the Darlington GS and higher sustaining capital expenditures, partially offset by higher SBG-adjusted hydroelectric electricity generation reflecting higher water flows.

If Unit 2 at the Darlington GS was not currently undergoing refurbishment and had continued to operate in a manner consistent with the performance of the remaining units at the station, adjusting for generation constraints on these units related to the transition of the station toward refurbishment, the Enterprise TGC would have been approximately $4 to $5 per MWh lower for the year ended December 31, 2017. This sensitivity was calculated using the estimated incremental electricity generation and associated fuel cost that are expected to have had resulted in the absence of the refurbishment.

Nuclear Total Generating Cost per Megawatt-Hour

The Nuclear TGC per MWh was $70.95 for the year ended December 31, 2017, compared to $62.30 for the same period in 2016. The increase in Nuclear TGC per MWh was expected and primarily due to the decrease in nuclear electricity generation primarily as a result of the Unit 2 refurbishment outage at the Darlington GS and higher sustaining capital expenditures.

Hydroelectric Total Generating Cost per Megawatt-Hour

The Hydroelectric TGC per MWh was $23.91 for the year ended December 31, 2017, compared to $25.49 for the same period in 2016. The improvement in the Hydroelectric TGC per MWh was primarily due to higher SBG-adjusted hydroelectricity generation reflecting higher water flows.

ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are not measurements in accordance with US GAAP and should not be considered alternative measures to net income, cash flow provided by operating activities, or any other performance measure under US GAAP. OPG believes that these non-GAAP financial measures are effective indicators of its performance and are consistent with the Company's strategic imperatives and related objectives. The definition and calculation of ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are found in the section, *Supplementary Non-GAAP Financial Measures*.

Recent Developments

OEB's Decision on OPG's Application for New Regulated Prices

The OEB's decision on OPG's May 2016 five-year application for new regulated prices for its nuclear and regulated hydroelectric generation was issued on December 28, 2017, following a public hearing process. The OEB set an effective date for OPG's new regulated prices of June 1, 2017. OPG had requested an effective date of January 1, 2017. The decision reflected the terms of an OEB-approved partial settlement agreement reached by OPG and intervenors on a limited set of issues in the first quarter of 2017 (Settlement Agreement). For the first time since OPG's prescribed facilities became subject to rate regulation, the new prices have been determined on an incentive ratemaking methodology for the hydroelectric operations and a custom incentive regulation framework for the nuclear operations.

For the hydroelectric facilities, effective June 1, 2017, the base regulated prices in effect prior to June 1, 2017, with some adjustments, will be escalated for each of years 2017 to 2021 using a formula equal to an industry-specific weighted inflation factor based on indices published annually by the OEB for use in incentive regulation formulas, less a stretch factor adjustment. The OEB accepted OPG's proposal to set the annual stretch factor adjustment at 0.3 percent. Based on the approved formula, the 2017 increase in the base regulated price for the regulated hydroelectric facilities is 1.4 percent as of June 1, 2017 and the 2018 increase is 0.9 percent as of January 1, 2018. For the 2019-2021 period, the base regulated price for the regulated hydroelectric facilities will be determined annually before the beginning of each year using the approved formula and inflation indices published by the OEB.

For the nuclear operations, a revenue requirement is determined for each of the years 2017 to 2021 based on the OEB-allowed level of OPG's forecast operating costs, reduced by a stretch factor amount, as well as a return on rate base determined using OEB's generic prescribed rate of return and an OPG-specific deemed capital structure. OPG has calculated that the findings of the OEB's December 2017 decision with respect to the forecast operating costs, rate base and deemed capital structure for the nuclear generating facilities will result in nuclear revenue requirements totalling $15.9 billion over the five years.

The OEB's findings with respect to the nuclear revenue requirement include approval for inclusion in rate base of in-service amounts related to the Darlington Refurbishment of $5.5 billion by 2021, including $4.8 billion forecast in the first quarter of 2020 upon return to service of Unit 2, $0.4 billion forecast for pre-requisite projects excluding the Heavy Water Storage and Drum Handling Facility (HWSF) over the 2016-2021 period and $0.3 billion for pre-requisite projects placed in service prior to 2016. The OEB is expected to review the HWSF project as part of a future application. In the decision, the OEB concluded that it is appropriate to evaluate OPG's performance on the Darlington Refurbishment project at an overall level rather by individual cost component, with recovery of any increases over the approved in-service amounts subject to a future prudence review. The revenue requirement impact of differences between the approved in-service additions and the actual in-service additions will be recorded in

the Capacity Refurbishment Variance Account authorized by the OEB pursuant to *Ontario Regulation 53/05*. The $4.8 billion forecast in-service amount upon return to service of Unit 2 includes expenditures incurred during the definition and planning phase of the project.

The OEB also approved OPG's requested forecast costs of approximately $292 million for activities to enable Pickering operations beyond 2020 and agreed to inclusion of operating cost and generation impacts associated with continued operation of Pickering in 2021 in nuclear regulated prices. The differences between approved forecast enabling costs for continued Pickering operations and the actual amounts will be recorded in the Capacity Refurbishment Variance Account for future review and disposition by the OEB.

Excluding amounts that otherwise would have been recorded in OEB-authorized regulatory accounts for repayment to, or recovery from, customers in the future, the OEB's decision reduced OPG's proposed five-year nuclear revenue requirement by $0.6 billion. The main adjustments made by the OEB included a reduction of $100 million per year to requested OM&A costs, a reduction of 10 percent per year to forecast non-Darlington refurbishment capital in-service additions entering rate base over the 2017-2021 period, an increase and expansion of the scope of the stretch factor for nuclear costs that further reduced the revenue requirement, and a rejection of OPG's request to increase the equity component of the existing deemed capital structure of 45 percent equity and 55 percent debt. The OEB increased and expanded the annual stretch factor to 0.6 percent to most of OPG's OM&A expenses incurred directly for, or allocated to, the nuclear facilities, as well as to non-Darlington refurbishment capital in-service additions. The stretch factor is applied starting in 2018 and compounds in each year to 2021.

In accordance with *Ontario Regulation 53/05*, the nuclear revenue requirement continues to be adjusted by the amount of OPG's revenues, net of costs, from leasing the Bruce nuclear generating stations to Bruce Power. As directed by the OEB, OPG's revenues and costs related to the Bruce nuclear generating stations continue to be determined in accordance with US GAAP for the purposes of establishing the nuclear revenue requirement and are subject to the Bruce Lease Net Revenues Variance Account in accordance with *Ontario Regulation 53/05*. This includes costs related to the portion of the Nuclear Liabilities associated with the Bruce nuclear generating stations. The OEB's decision maintained the previously approved cost recovery methodology for the costs of the Nuclear Liabilities for the prescribed facilities and for the Bruce facilities, directing OPG to file a future study examining such methodologies jurisdictionally and for OPG's assets specifically. The decision fully incorporated the impacts of the updated estimate of OPG's obligations for nuclear waste management and nuclear facilities decommissioning as at December 31, 2016, including through a new ONFA reference plan effective January 1, 2017 and the change in the Nuclear Liabilities recorded on December 31, 2016.

As proposed by OPG, the OEB set recovery of pension and OPEB costs in the nuclear revenue requirement on the basis of OPG's cash payments for pension and OPEB plans, with differences between pension and OPEB accrual costs and cash payments continuing to be recorded in the Pension & OPEB Cash to Accrual Differential Deferral Account. The regulatory treatment of pension and OPEB costs is discussed further under the heading, *OEB's Report on Regulatory Treatment of Pension and OPEB Costs*.

The OEB accepted all variance and deferral account balances proposed for recovery that were not already accepted as part of the Settlement Agreement, resulting in approval of recovery of $305 million recorded in variance and deferral variance accounts as at December 31, 2015, without adjustments. The Settlement Agreement provided for the continuation of all applicable existing variance and deferral accounts. In addition to the Rate Smoothing Deferral Account discussed below, the OEB established, as of the effective date of the new regulated prices, new variance and deferral accounts to record costs related to implementing the Canadian Nuclear Safety Commission's (CNSC) Fitness for Duty program and to record differences between forecast and actual amount of Scientific Research & Experimental Development investment tax credits attributable to the nuclear facilities.

Consistent with the requirements of *Ontario Regulation 53/05*, OPG's overall production-weighted regulated prices will be smoothed, with a resulting portion of the approved annual nuclear revenue requirements for the 2017-2021 period deferred in the Rate Smoothing Deferral Account for future collection. The non-deferred portion of each year's

nuclear revenue requirement is divided by the OEB-approved forecast of OPG's nuclear electricity generation for the corresponding year to determine the base nuclear regulated price. The OEB approved the nuclear electricity generation forecast as requested by OPG.

As amended in March 2017, *Ontario Regulation 53/05* requires rate smoothing to be applied in a manner that makes changes in OPG's weighted-average nuclear and hydroelectric regulated prices more stable year over year. Previously, the regulation required that rate smoothing be applied with a view of making more stable year-over-year changes in OPG's nuclear regulated prices only. Per the regulation, the deferral account records interest at a long-term debt rate reflecting OPG's cost of long-term borrowing approved by the OEB, compounded annually. The regulation requires the OEB to authorize recovery of the balance in the account on a straight line basis over a period not to exceed ten years following the end of the Darlington Refurbishment project. OPG recognizes positive amounts deferred under rate smoothing as an increase in net regulatory assets and an increase in revenue in the period to which the underlying approved revenue requirement relates. Negative amounts determined under rate smoothing are correspondingly recorded as a decrease in net regulatory assets and a decrease to revenue.

On January 17, 2018, OPG submitted a draft payment amounts order to the OEB that proposed nuclear base regulated prices for each year of the 2017-2021 period, including a rate smoothing proposal, based on the December 2017 decision's findings. The rate smoothing proposal takes into account the near-term and future impacts on customers, while seeking to ensure that resulting nuclear regulated prices allow for sufficient cash flow to maintain the Company's investment grade credit rating and support availability of cost effective funding, while taking into account both near-term and future impacts on customers. Based on the OEB's direction, the draft payment amounts order also included proposed periods for recovery, through interim period shortfall rate riders, of the retrospective revenue shortfall for the period between June 1, 2017 and the implementation date of the new regulated prices based on proposed new regulated prices that would have been in effect during that period. The draft payment amounts also included proposed recovery periods, through variance and deferral account rate riders, for regulatory account balances approved for recovery in this application. **[MONITOR]**

To reflect the OEB's decision, in the fourth quarter of 2017, OPG recorded incremental revenue of approximately $480 million for the period June 1, 2017 to December 31, 2017 based on the draft payment amounts order. The revenue was recorded as an increase in regulatory assets for the June 1, 2017 to December 31, 2017 revenue shortfall based on proposed new regulated prices for nuclear facilities and regulated hydroelectric facilities, net of a regulatory liability recognized in relation to OPG's rate smoothing proposal. The OEB's approval of the final payment amounts order, including the allocation of the approved revenue requirement between nuclear regulated prices and rate smoothing deferrals, is not expected to have a material impact on the net revenue increase recorded in the fourth quarter of 2017. The OEB is expected to issue the final payment amounts order and implement new regulated prices in the first half of 2018. **[MONITOR]**

Consistent with the effective date of the OEB's December 2017 decision, for the period from January 1, 2017 to May 31, 2017, OPG continued to record additions to the existing variance and deferral accounts for the nuclear and regulated hydroelectric facilities pursuant to the OEB's previous decisions and orders. These additions reflected differences between actual and forecast amounts embedded in the regulated prices in effect prior to the June 1, 2017 effective date.

In January 2018, OPG filed a motion asking the OEB to review and vary the effective date of the new regulated prices to January 1, 2017. The motion did not impact OPG's financial results for the year ended December 31, 2017.

Ontario's 2017 Long-Term Energy Plan

On October 26, 2017, Ontario's Ministry of Energy issued the 2017 LTEP that outlines the Province's plans for the future development of Ontario's electricity system. The 2017 LTEP focuses on the affordability, reliability and flexibility of a clean energy supply in the province. The 2017 LTEP replaces the previous LTEP issued in 2013.

As it relates to the supply of electricity, the 2017 LTEP recognizes the refurbishment of Ontario's nuclear generating stations as the most cost-effective option for producing emission-free baseload generation to meet Ontario's needs and reaffirms the Province's support for the refurbishment of the four units at the Darlington GS and the six units at the Bruce generating stations, subject to the principles established in the 2013 LTEP. The 2017 LTEP also recognizes the value to customers of continuing to operate the Pickering GS until 2024, as planned. With respect to hydroelectric electricity generation, the 2017 LTEP highlights the opportunity to continue to invest in optimizing existing hydroelectric facilities, noting that pumped hydroelectric storage could play an important role in the reliability of the electricity system.

Additionally, the 2017 LTEP discusses the potential impact of a number of innovative technologies on the future of the electricity system. Among others, these include the increased electrification of the transportation sector, the emergence of energy storage, and the opportunity for Ontario to foster nuclear innovation technologies. OPG continues to assess how best to capitalize on potential business opportunities in these and other areas. The 2017 LTEP also recognizes the importance of Indigenous peoples' continuing role in shaping Ontario's energy planning, projects and policies.

Darlington Refurbishment

In October 2016, OPG commenced the refurbishment of the first Darlington GS unit, Unit 2, as part of the Darlington Refurbishment project. The de-fuelling of the reactor and islanding of Unit 2, the physical separation of the unit under refurbishment from the three operating units, were completed in the first half of 2017.

The disassembly of reactor components commenced in the third quarter of 2017, with the removal of feeder tubes completed in September 2017. The removal of fuel channel assemblies commenced in October 2017. As part of the fuel channel assemblies, the removal of pressure tubes is in progress and will be followed by the removal of calandria tubes. The second major segment and the removal of all reactor components is expected to be completed by mid-2018.

All of the pre-requisite projects, including construction of facilities, infrastructure upgrades and installation of safety enhancements, with the exception of the HWSF, have been completed and placed in service. The completion of the HWSF has been delayed due to challenges with construction, with construction activities suspended for a portion of 2017. Construction to complete the facility recommenced in the fourth quarter of 2017, including work to preserve and protect the facility during winter. The HWSF is expected to be completed by the second quarter of 2019 and is not on the critical path for the Darlington Refurbishment project, which continues to track on schedule. The increase in the cost estimate for the HWSF will be accommodated within the overall Darlington Refurbishment budget of $12.8 billion. Taking into account the execution performance of the Unit 2 refurbishment, the overall Darlington Refurbishment project continues to track on budget.

On November 21, 2017, the Financial Accountability Office of Ontario issued a report, "*An Assessment of the Financial Risks of the Nuclear Refurbishment Plan*". The report assesses the impact of OPG and Bruce Power's nuclear refurbishments on customers and the Province based on mechanisms in place for the recovery of the costs to refurbish and subsequently operate the nuclear stations. The report concludes that refurbishment of the four units at the Darlington GS and the six units at the Bruce nuclear generating stations provides the most cost effective, low emission generation source available to meet Ontario's baseload electricity requirements.

The Darlington Refurbishment project is discussed further in the section, *Core Business, Strategy, and Outlook* under the heading, *Project Excellence*.

Canadian Nuclear Safety Commission Safety Rating for the Darlington GS and the Pickering GS

The CNSC publishes an annual report on the safety performance of Canada's nuclear power plants. The report assesses how well plant operators are meeting regulatory requirements and program expectations in the areas of operational performance, safety analysis, radiation protection, waste management and conventional health and

safety. On September 8, 2017, the CNSC issued an executive summary of its 2016 annual report, giving both the Darlington GS and the Pickering GS the highest possible safety rating of "Fully Satisfactory". The Darlington GS achieved this rating for the eighth consecutive year, while the Pickering GS achieved this rating for the second consecutive year.

Ontario's Fair Hydro Plan

On March 2, 2017, the Province announced the Fair Hydro Plan aimed at reducing electricity bills for eligible residential, farm, small businesses ~~and other eligible~~ consumers (Specified Consumers) in the province by refinancing a portion of the Global Adjustment costs over a longer period of time. The Global Adjustment includes the difference between Ontario's electricity market clearing price used to dispatch generation and the prices paid to contracted and regulated generators in the province, and the cost of conservation and demand management programs. On June 1, 2017, the Fair Hydro Act received Royal Assent and the associated general regulation came into force in June 2017. The Act established a framework under which the costs and benefits associated with the Government of Ontario's clean energy initiatives are to be allocated between present and future consumers of electricity under the Fair Hydro Plan. The general regulation provides details on the structural, operational and financial elements required to implement the Fair Hydro Plan.

Pursuant to the Act, effective May 1, 2017, the IESO began to defer a portion of the Global Adjustment costs. The Act allows the IESO to transfer a portion of the deferred balance to a financing entity that would fund the deferral in exchange for an irrevocable right to recover the balance and associated financing and other costs from Specified Consumers in the future (Investment Interest). The legislation appointed OPG as the Financial Services Manager under the Act and conveyed upon the Financial Services Manager statutory obligations, including the creation of one or more financing entities that may acquire Investment Interests from the IESO.

In November 2017, OPG's Board of Directors provided its final approval regarding OPG's involvement with the Trust on commercial terms following the fulfilment of all conditions it established in May 2017. Accordingly, the Fair Hydro Trust was established as the financing entity contemplated by the Act in December 2017. The majority unitholder and beneficiary of the Trust is a wholly-owned subsidiary of OPG. The Trust is structured to be bankruptcy remote and ring fenced from OPG in order to protect the Company's assets and operations.

In order for the Trust to finance the Investment Interest acquired from the IESO, it will incur senior debt from capital markets and subordinated debt from OPG. The Trust's investment will attract financing amounts and other related fees, which, under the general regulation, will be payable by the IESO as carrying costs until July 2021 and by Specified Consumers through the Clean Energy Adjustment to be invoiced by local distribution companies commencing in May 2021, with the three-month lag in 2021 intended to cover the billing and collection lag from the introduction of the Clean Energy Adjustment. The carrying costs include all financing and third-party costs other than payment of principal on debt.

Concurrent with every issuance of the Trust's senior notes, it is expected that OPG will purchase subordinated debt of the Trust in an aggregate amount not to exceed 49 percent of the Trust's total outstanding debt, with 44 percent of the funding to be provided by the Province through equity injections and five percent to be provided by OPG. The subordination level may vary over time, but must at least equal to, or be greater than 35 percent of all outstanding debt. Through OPG's control over the key activities of the Trust and its obligation to absorb losses through ownership of the Trust's subordinated debt, the Company consolidates the financial results of the Trust in accordance with US GAAP.

On December 21, 2017, the Trust purchased its first tranche of Investment Interest from the IESO in the amount of approximately $1.18 billion. Fifty-one percent of the funding requirement or $601 million was financed by the Trust through a revolving warehouse facility ranked as senior notes, and the remaining 49 percent was funded through the issuance of short-term subordinated debt to OPG. The Investment Interest has been classified as a financing receivable on OPG's consolidated balance sheet.

OPG's subordinated debt investment in the Trust was funded through the following sources:

- The Province provided 44 percent of the total funding requirement or $519 million, through an equity injection in OPG in exchange for approximately 12.2 million non-voting Class A common shares at a price of $42.46 per share. The Company's Articles of Amalgamation were amended effective December 1, 2017 to allow for the creation and issuance of Class A shares. Refer to Note 14 of OPG's 2017 audited consolidated financial statements for further details; and
- OPG provided five percent of the total funding requirement or approximately $60 million.

In February 2018, the Trust issued $500 million of senior notes payable with a coupon interest rate of 3.36 percent and an effective interest rate of 3.42 percent, payable semi-annually until maturity on May 15, 2033. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility issued in December 2017. By the end of the first quarter of 2018, the Trust is expected to acquire another tranche of Investment Interest from the IESO, which it expects to fund using its revolving warehouse facility.

Refer to the section, *Liquidity and Capital Resources* under the heading, *Financing Activities* for further details on the Trust's financing arrangements and OPG's public debt offering.

OEB's Report on Regulatory Treatment of Pension and OPEB Costs

On September 14, 2017, the OEB issued its final report on the guiding principles and policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the Ontario electricity and natural gas sectors. The report establishes the accrual basis of accounting as the method of determining pension and OPEB amounts for rate-setting purposes, unless the OEB finds that this method does not result in just and reasonable rates in the circumstances of a particular utility. The report also provides for the establishment of a generic variance account to record asymmetric carrying charges in favour of ratepayers on the differences between the accrual costs recovered and cash payments made by a utility in respect of pension and OPEB plans. Carrying charges on this differential are to be assessed at the OEB's prescribed interest rate, on a prospective basis from the effective date of the new variance account. For OPG, this differential will include amounts going back to November 1, 2014, with the charges calculated on the portion of the differential that has been recovered through regulated prices. None of this differential has been recovered to date. The prescribed interest rate is set quarterly by the OEB based on the quarterly return of a mid-term corporate bond index yield.

The OEB's September 2017 report and the OEB's December 2017 decision on OPG's application for new regulated prices require OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the Pension & OPEB Cash to Accrual Differential Deferral Account in effect since November 1, 2014, until such time as the OEB approves resumption of the accrual basis of recovery for OPG. The future recovery of amounts recorded in the account will be subject to this approval. The OEB's report did not impact OPG's financial results for the year ended December 31, 2017.

The Company recognizes the amount set aside in the Pension & OPEB Cash Versus Accrual Differential Deferral Account as a regulatory asset. As at December 31, 2017, the regulatory asset had a balance of $614 million. Consistent with the expectations set out in the OEB's December 2017 decision, in 2018, OPG plans to file an application with the OEB requesting disposition of the Pension & OPEB Cash Versus Accrual Differential Deferral Account balance as well as balances accumulated since December 31, 2015 in other regulatory accounts.

Shareholder Declarations and Shareholder Resolutions to Sell Certain Non-Core Real Estate Properties

In December 2015, OPG received a Shareholder Declaration and a Shareholder Resolution requiring the Company to sell its head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street in Toronto, Ontario. The sale was completed in April 2017, with a gain on sale of $283 million, which is net of tax effects of $95 million, recognized in net income in the second quarter of 2017. The pre-tax gain on sale was recorded

as an item of Other gains in the consolidated statement of income in the Services, Trading and Other Non-Generation segment. Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. The amount of designated proceeds transferred into the Consolidated Revenue Fund are expected to approximate ~~will be equal to~~ the after-tax gain on sale. **[MONITOR]** The transfer is expected to take place ~~as early as~~ in the first quarter of 2018, through a special dividend authorized by OPG's Board of Directors in March 2018. **[MONITOR]**

Commented [DS1]: The amount of designated proceeds will be determined by regulation and therefore uncertain until the regulation is filed and made public.

In June 2016, OPG received a Shareholder Declaration and a Shareholder Resolution that requires the Company to sell its former Lakeview GS site located in Mississauga, Ontario. OPG has entered into a purchase and sale agreement with a purchaser with the sale scheduled to close in March 2018. An estimated after-tax gain on sale of approximately $200 million is expected to be recognized in net income upon completion of the transaction in the first quarter of 2018. **[MONITOR]** Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. OPG anticipates the amount of designated proceeds transferred into the Consolidated Revenue Fund to approximate the after-tax gain on the sale. In accordance with the Shareholder Resolution, approximately one-third of the site is to be transferred to the City of Mississauga, by the purchaser, for parkland, institutional, and cultural uses.

CORE BUSINESS, STRATEGY, AND OUTLOOK

OPG's mission is to provide low cost power in a safe, clean, reliable and sustainable manner for the benefit of its customers and its Shareholder. OPG also seeks to pursue, on a commercial basis, generation development projects and other business expansion opportunities to the benefit of the Shareholder.

OPG's four key strategic imperatives are as follows:

- Operational Excellence
- Project Excellence
- Financial Strength
- Social Licence.

Operational Excellence

Operational excellence at OPG is accomplished by the safe and environmentally responsible generation of reliable and cost-effective electricity from the Company's generating assets through a highly trained and engaged workforce.

Workplace Safety and Public Safety

Workplace safety and public safety are fundamental core values at OPG. OPG is committed to operating all of its facilities in a safe, secure, and reliable manner that minimizes risks to a reasonably achievable level. Safety is an overriding priority in all activities performed at OPG's generating and other facilities, and all employees and contractors are expected to conduct themselves in manner that ensures workplace safety and public safety in line with the Company's safety culture.

In the area of workplace safety, OPG is committed to achieving excellent performance through continuous improvement and a strong safety culture, with the ultimate goal of zero injuries. OPG utilizes an integrated health and safety management system and a set of operational risk control procedures to ensure continued monitoring of health and safety performance and to support continuous learning and improvement in this area. Over the past five years, OPG has repeatedly stood in the top quartile of its comparator Canadian electrical utilities in various safety performance metrics.

Workplace safety performance is measured using two primary indicators at OPG, All Injury Rate (AIR) and Accident Severity Rate (ASR). OPG's AIR and ASR results for employee workplace safety were as follows for the year ended December 31:

	2017	2016
AIR *(injuries per 200,000 hours worked)*	**0.48**	0.56
ASR *(days lost per 200,000 hours)*	**3.57**	2.59

In 2017, OPG's AIR improved from 2016 and was the third-best performance year in the Company's history. For those employee injuries that caused lost time from work, the total time lost from work in 2017 was greater than the previous year. OPG's analysis of the underlying safety events indicated that major contributors to the injuries and near misses included inadequate situational awareness and attention to detail, and suboptimal risk-based decisions, rather than missing or inadequate standards or programs. OPG continues to implement a number of initiatives to target the injury trends based on the analysis of the safety events, with a focus on the use of human performance tools including increased field supervisory oversight, situational awareness, communication, and procedural use and adherence.

In order to strengthen its safety performance, OPG continues to progress an organization-wide "iCare Enough to Act" initiative launched in 2016 and aimed at renewing employees' commitment to their own and each other's safety and well-being. Approaches to supervisory oversight, communication and safe work planning are being modified and updated to further strengthen safety as a foundational element of the Company's values-based culture.

Contractors are required to conduct work safely at OPG sites. In support of this requirement, OPG utilizes an independent contractor pre-qualification process, provides on-site safety support for many of its major projects, and works with contract partners to improve their health and safety programs to meet OPG's requirements. In the past nine years, OPG has consistently shown a Construction Contractor AIR that is markedly better than the Infrastructure Health and Safety Association Contractor AIR, a metric of construction contractor safety performance across Ontario. OPG has maintained this performance while engaging in the refurbishment of the Darlington GS, one of the largest infrastructure projects in Canada. The hours worked by contractors in 2017 were the largest in OPG's history, largely attributable to this project.

OPG continues to maintain a strong focus on the nuclear safety program and to invest in nuclear safety systems. To ensure continued public safety, radiation exposure to members of the public resulting from the operation of OPG's nuclear generating stations is estimated on an annual basis for individuals living or working near the stations. The annual dose to the public resulting from operations of each nuclear facility is expressed in microsieverts (µSv), which is an international unit of radiation dose measurement. For 2016, the annual public doses resulting from the Darlington GS operations and the Pickering GS operations were 0.6 µSv and 1.5 µSv, respectively, which is less than 0.1 and 0.2 percent of the annual legal limit of 1,000 µSv, respectively. While the public doses from OPG's nuclear operations for the 2017 operating year will not be finalized until the second quarter of 2018, they are not expected to differ significantly from the 2016 levels.

In June 2016 and August 2016, the CNSC released sampling results from its independent environmental monitoring program, which confirmed that the public and the environment around OPG's nuclear generating stations continued to be safe. In September 2017, the CNSC issued an executive summary of its 2016 annual report on the safety performance of Canada's nuclear power plants, which gave both the Pickering GS and the Darlington GS the highest possible safety rating of "Fully Satisfactory". For further details, refer to the CNSC safety rating discussion in the section, *Highlights* under the heading, *Recent Developments*.

OPG remains committed to high standards of public safety on waterways around hydroelectric generating stations and dams, and continues to make investments in waterway and dam safety upgrades. The Company's practices in this area are routinely reviewed by an independent panel comprised of internationally recognized experts, who have

concluded that OPG's Dam Safety Program is industry leading in a number of areas. During 2017, OPG continued its water safety campaign with a series of public service announcements illustrating the danger of water near hydroelectric dams and hydroelectric generating stations.

Electricity Generation Production and Reliability

Key strategic initiatives in support of operational excellence, specific to each of OPG's core generating operations, are discussed below. Generation and reliability performance for 2017 is discussed by operating segment in the section, *Discussion of Operating Results by Business Segment*.

Nuclear Operations

OPG is pursuing a number of strategic initiatives aimed at the continued safe and reliable operation of the Pickering GS and targeting top performance at the Darlington GS.

OPG's objective is to maximize the safe and reliable operating life of the Pickering units. As announced in 2016 and approved by the Province, OPG is continuing to execute on a plan to extend safe and reliable operation of the Pickering GS to 2024. In addition to providing Ontario with a clean, reliable source of baseload electricity during nuclear unit refurbishments at the Darlington GS and the Bruce nuclear generating stations, extending operations at the Pickering GS will provide continued employment for up to 4,000 full-time employees at OPG and help to reduce approximately 17 million tonnes of carbon dioxide emissions, which is equivalent to removing approximately 3.4 million cars from Ontario's roads.

As part of the plan to extend Pickering operations, OPG has been continuing to undertake the required technical work to confirm that the station's pressure tubes, a key life-limiting component of the station, will remain fit for service for operation to 2024. In the fourth quarter of 2017, OPG has confirmed that technical assessments completed to date provide sufficient confidence in the programs and provisions in place to assure fitness-for-service of fuel channel components in line with the planned extended operations period. This evaluation is consistent with the safety case reflected in OPG's operating licence renewal application for the Pickering GS submitted to the CNSC in 2017, discussed below. Taking these factors into account, OPG revised the accounting end-of-life assumptions for the Pickering GS from December 31, 2020 for all units to December 31, 2022 for Units 1 and 4 and December 31, 2024 for Units 5 to 8, effective December 31, 2017.

The change in the Pickering GS accounting end-of-life assumptions did not impact OPG's net income in 2017. The change is expected to decrease depreciation expense by $77 million in 2018, including the associated impact on the nuclear asset retirement obligation (ARO) recorded as of December 31, 2017 but before the impact of regulatory accounts. Regulatory accounts, including a new deferral account proposed by OPG in a December 2017 application to the OEB, are expected to largely offset the decrease in depreciation expense. The change in the nuclear ARO recorded in the fourth quarter of 2017 is discussed in the section, *Critical Accounting Policies and Estimates* under the heading, *Asset Retirement Obligation*. On December 29, 2017, OPG applied for an accounting order to establish a variance account to record, from January 1, 2018 until the effective date of the OEB's next payment amounts order, the revenue requirement impact of changes to nuclear liabilities and depreciation and amortization expense resulting from changes to station end-of-life dates for OPG's Pickering prescribed nuclear facilities that will be effective December 31, 2017. Pending the OEB's review of the application, an interim order was issued January 31, 2018 establishing the proposed variance account effective January 1, 2018. The OEB's final decision for the account is expected later in 2018.

OPG's current five-year operating licence for the Pickering GS was approved by the CNSC in 2013 and expires on August 31, 2018. This current licence was issued assuming that the station would shut down in 2020. On June 28, 2017, OPG confirmed to the CNSC that it intends to cease commercial operation of all Pickering units on December 31, 2024. On August 28, 2017, OPG submitted a ten-year licence renewal application to the CNSC. The requested licence term spans the planned extended commercial operations period, through to the planned period of de-fuelling,

de-watering and beginning to place the station in a safe storage state in 2028. In support of the licence renewal, OPG undertook a Periodic Safety Review (PSR), a comprehensive assessment of the station's design and operation to confirm that there is a high level of safety throughout the operating life and to determine what reasonable and practical enhancements can be made to further improve safety. The PSR also includes a component condition assessment of the station to identify the work required to support the station's continued operation. The PSR has confirmed that extending operations of the Pickering units will continue to pose minimal risk to the health, safety and security of workers, the public and the environment. The final major component of the PSR was submitted to the CNSC in November 2017. The CNSC's review of the PSR submission and licence application is in progress. Based on the evidence and documentation submitted to the CNSC, OPG is confident in obtaining a licence renewal that would support its extended operations plan for Pickering GS.

OPG's nuclear operations are regularly benchmarked against top performing nuclear facilities around the world. This allows OPG to identify, develop and implement initiatives to further improve performance. In September 2016, OPG hosted a team of experts from the International Atomic Energy Agency (IAEA) at the Pickering GS to conduct a standard Operational Safety Review Team mission. The team conducted an in-depth review of performance and adherence to international safety standards. In the second quarter of 2017, the IAEA's Operational Safety Review Team released the final report and confirmed that the Pickering GS demonstrates strong commitment to safety. In December 2017, OPG hosted a World Association of Nuclear Operators (WANO) peer evaluation for the Pickering GS, which focused on the safe and reliable operation of the station while evaluating the plant material condition, functional and cross-functional areas of the organization. Pickering showed significant improvement since its last review and has sustained its strong rating in 2018, resulting in its best ever WANO peer review.

OPG remains focused on improving reliability and increasing electricity generation output from its nuclear fleet. This includes improving equipment reliability, optimizing outages, implementing integrated asset management planning and enhancing maintenance programs. Improved equipment reliability generally results in fewer generation interruptions. Nuclear inspection and testing programs are largely driven by maintenance and regulatory requirements, and are designed to ensure that equipment is performing safely and reliably. Execution of this and other outage work continues to be a high priority. As part of its commitment to operational excellence, OPG continues to focus on improving the planning, execution, monitoring, and reporting of outage work.

OPG continues to make investments in the performance of the Pickering GS, with a focus on improving plant reliability and maximizing the value of the asset over its remaining life through implementing equipment modifications and fuel handling reliability improvements, reducing equipment maintenance backlogs, and completing critical and high priority work. OPG also continues to make investments in the Darlington GS necessary to sustain safe and reliable operations for the next three decades and aimed at positioning the station for industry-leading operating and cost performance in the longer term. This includes investments in life cycle and aging management projects, facility upgrades as well as work in support of regulatory commitments.

Delivering solutions that provide the best combination of safety, cost and effectiveness, as well as establishing challenging financial targets based on comprehensive benchmarking and taking into account the operating environment of the nuclear stations, continues to be a vital part of OPG's strategy to improve performance of the nuclear business unit. Financial and staffing targets continue to be reviewed and adjusted where necessary to reduce operating costs, while ensuring safety and reliability are not compromised.

In 2016, OPG submitted applications with the CNSC seeking a ten-year licence renewal for the Western Waste Management Facility (WWMF), located at the Bruce generating stations' site, to May 31, 2027, and a ten-year licence renewal for the Pickering Waste Management Facility (PWMF) to August 31, 2028. The licence renewal applications were presented to the CNSC at public hearings in April 2017. On May 30, 2017, the CNSC announced that the WWMF licence was renewed for a ten-year period and will be valid until May 31, 2027. On February 7, 2018, the CNSC announced that the PWMF licence was renewed for a ten-year period and will be valid until August 31, 2028.

In 2017, the CNSC approved regulatory document *REGDOC 2.2.4 – Fitness for Duty – Managing Alcohol and Drug Use* for use at Canadian nuclear power plants. This document sets out requirements for managing fitness for duty of workers in relation to alcohol and drug use at high-security sites, including for-cause alcohol and drug testing for workers in positions identified as safety-sensitive or safety-critical and random alcohol and drug testing for workers holding safety-critical positions. OPG intends to enhance its existing Fitness for Duty program to comply with these new requirements. OPG is working with its partners in the Canadian nuclear industry to develop a program suitable for Canada and its workers.

Hydroelectric Operations

The objectives of OPG's hydroelectric operations include operating and maintaining the generating facilities in a safe, efficient and cost-effective manner, while increasing the output from the facilities and pursuing opportunities to increase capacity. OPG aims to increase the facilities' output by improving operational flexibility, enhancing reliability, optimizing outage planning and, subject to water conditions, increasing availability to meet electricity system demand. OPG continues to evaluate and implement plans to increase capacity, maintain and improve operational performance, and extend the operating life of its hydroelectric generating assets.

OPG's hydroelectric operations are regularly benchmarked against peer utilities in North America. Based on 2016 data, 19 of the OPG's 25 large regulated hydroelectric facilities benchmarked in the top two quartiles for unit energy costs. This group of 19 facilities represents 94 percent of the energy delivered from the regulated hydroelectric fleet. Similarly, 18 of 25 large regulated hydroelectric facilities benchmarked in the top two quartiles for availability based on 2016 data. OPG continues to pursue innovation and technology-based improvements in its asset management and equipment maintenance strategies in order to increase reliability and further reduce costs of the hydroelectric fleet.

As part of OPG's ongoing strategy to reduce costs and increase operational efficiency, the operations of the Company's hydroelectric and thermal assets were previously combined into one organization, with five regional operations groups. In 2017, OPG reduced the number of regional operations groups to four, by integrating the Central Operations work centres into three of the other existing regional operations groups. In addition, during the third quarter of 2017, OPG opened an amalgamated control room located at the Saunders hydroelectric GS, combining the Chenaux and Saunders control rooms. The amalgamated control room will control all operational activities at the ten hydroelectric stations along the Madawaska, Ottawa and St. Lawrence rivers.

OPG's plans for its existing hydroelectric generating stations are accomplished through multi-year capital investment and other programs, including replacements and upgrades of turbine runners, and refurbishment or replacement of existing generators, transformers, and controls. The aim of OPG's runner replacement and upgrade program is to increase hydroelectric station capacity by leveraging efficiency enhancements in runner design. Where economical and practical, OPG also pursues opportunities to refurbish, expand or redevelop its existing hydroelectric stations. Over the next four years, OPG plans to increase the total capacity of its hydroelectric generating fleet by approximately 150 MW, which, in addition to the runner replacement and upgrade program, includes the Ranney Falls GS and Sir Adam Beck frequency conversion projects. OPG is also planning to repair, rehabilitate, or replace a number of aging civil hydroelectric structures.

As part of its commitment to operational excellence, OPG continues to make investments in its existing hydroelectric generating fleet. During 2017, OPG continued to execute a number of projects, including:

- Completion of the overhaul and upgrade of Unit 10 of the Sir Adam Beck 1 GS, which increased the station's capacity by 6 MW
- Continued work on the overhaul and rehabilitation of Unit 1 of the Sir Adam Beck Pump GS to ensure reliable unit operation for approximately the next 20 years
- Completion of the replacement of the Shebandowan Lake Control Dam at the Kakabeka Falls GS, which will maintain structural integrity and enhance dam safety for another 100 years

- Continued work on the overhaul and upgrade of Unit 1 of the Harmon GS with completion of the turbine upgrade, generator rehabilitation and upgrade of protection and control systems
- Continued work on the overhaul and upgrade of Unit 2 of the DeCew Falls GS, with turbine and generator rehabilitation and upgrade of protection and control systems completed during the year, and, in the fourth quarter of 2017, commencement of the overhaul and upgrade of Unit 2 of the Little Long GS
- Continued work on the overhaul and rehabilitation of Unit 2 of the Lower Notch GS, with generator rehabilitation completed during the year, and in the fourth quarter of 2017, commencement of the overhaul and rehabilitation of Unit 6 of the Sir Adam Beck Pump GS
- Commencement of definition phase work for the Water Conveyance System project to rehabilitate the Sir Adam Beck 1 GS canal and associated structures, ensuring their continued safe and reliable operations for approximately the next 50 years.

In 2018, OPG plans to commence execution of several major sustaining projects across the hydroelectric fleet, including the overhaul and upgrade of Unit 5 of the Sir Adam Beck 1 GS, the rehabilitation of Caribou Falls Block Dam No.2, and automatic sluicegates system replacement at the Whitedog Falls GS. Definition phase activities on several other major projects are also expected to commence in 2018, including frequency conversion of Units 1 and 2 of the Sir Adam Beck 1 GS and the overhaul and upgrade of the R.H. Saunders GS units.

Thermal Operations

OPG's thermal operations consist of biomass-fuelled generating units at each of Atikokan GS and Thunder Bay GS, and the oil/gas dual-fuelled Lennox GS.

These stations, which operate as peaking facilities under their respective energy supply requirements, provide Ontario's electricity system with the flexibility to meet changing daily system demand and capacity requirements and enable the system to accommodate the expansion of Ontario's renewable generation portfolio. The continued operation of these stations will continue to provide Ontario with over 2,000 MW of peaking generation capacity. The stations operate under their respective ESAs.

OPG's biomass-fuelled generating units are among the world's leading in their innovation. The Atikokan GS is the largest generating station in North America fuelled by 100 percent biomass, while the Thunder Bay GS unit uses advanced biomass that is thermally treated to allow it to be stored outdoors and withstand exposure to the weather.

Former thermal stations that are no longer available to generate electricity are included in the Services, Trading, and Other Non-Generation segment once they are removed from service. This includes the Lambton GS and Nanticoke GS sites, which ceased operations in 2013. Over 2015 and 2016, OPG announced that these stations would be decommissioned safely, securely and in an environmentally responsible manner. The costs of the decommissioning are charged to a previously established decommissioning provision.

During 2017, OPG substantially completed the demolition of the Nanticoke coal yard equipment and structures and issued a contract for the demolition of the Nanticoke powerhouse and associated structures. In the fourth quarter of 2017, the demolition contractor had been mobilized to prepare for the removal of the powerhouse and associated structures and initiated the preparatory work for the demolition of the stacks. The demolition of the stacks took place in February 2018. **[MONITOR]** A competitive bidding process for the demolition of the Lambton GS is in progress, with a contract for the removal of the powerhouse and associated structures expected to be issued during 2018. The decommissioning plan for the Nanticoke GS accommodates the construction and operation of the Nanticoke solar facility.

An update of the asset retirement obligations related to the Nanticoke and Lambton sites has been completed. For a discussion of the revaluation of this liability for non-nuclear fixed asset removal as at December 31, 2017, refer to the section, *Critical Accounting Policies and Estimates* under the heading, *Asset Retirement Obligations*.

Environmental Performance

OPG's Environmental Policy states that "OPG shall meet compliance obligations, including any environmental commitments that it makes, with the objective of exceeding these compliance obligations where it makes business sense". This policy commits OPG to:

- maintain an ISO 14001-registered environmental management system (EMS)
- work to prevent or mitigate adverse impacts on the environment with a long-term objective of continual improvement
- strive to be a leader in climate change mitigation
- manage sites in a manner that strives to maintain, or enhance where it makes business sense, significant natural areas and associated species of concern.

In 2017, OPG maintained the ISO 14001 registration of its company-wide EMS. Within the EMS, OPG has planning, operational control, and monitoring programs to manage the Company's positive and negative impacts on the environment. Significant environmental aspects of OPG's operations include: spills, chemical and thermal emissions to water, water flow and level changes, radiological emissions, low and intermediate level radioactive waste (L&ILW), enhancement and disruption of wildlife habitat, displacement of fossil fuels, and fish impingement and entrainment. Further details regarding OPG's environmental risks can be found in the section, *Risk Management* under the heading, *Environmental Risk*.

Environmental performance targets are set as part of the annual business planning process. These targets are based on past performance and external benchmarking to promote continual improvement. OPG met or outperformed its 2017 targets for spills, environmental infractions, carbon-14 emissions to air, and L&ILW. Targets for tritium emissions to air and water were not achieved due to equipment performance issues; however, emissions remained less than one percent of the regulatory limit. There were no significant environmental events during 2017.

In 2016, the Government of Ontario passed the *Climate Change Mitigation and Low-Carbon Economy Act, 2016* and the associated *Cap and Trade Program Regulation*. The legislation provides the foundation for regulating greenhouse gas (GHG) emissions in Ontario and establishes a cap and trade program, with the first compliance period being from January 1, 2017 to December 31, 2020.

The cap and trade program is a market mechanism intended to give Ontarians an incentive to reduce GHG emissions by putting a price on carbon. OPG has an internal program to meet its GHG emissions compliance obligations. With OPG's low GHG emitting fleet, these obligations are not expected to have a material financial impact on the Company.

OPG monitors actions being taken by the Government of Ontario and the Government of Canada to reduce GHG emission levels and transition to a low-carbon economy. In support of efforts to mitigate climate change, the Company continues to evaluate and implement plans to increase the generation capacity of its hydroelectric generating fleet, where economical, invest in other low-carbon technologies, and take a leadership role in the electrification of Ontario's transportation sector.

OPG has developed biodiversity management plans that identify priority natural areas, conservation goals, threats, and proposed actions to sustain biodiversity at its properties. To maximize benefits and manage impacts, initiatives include biodiversity monitoring, site naturalization, habitat creation, and control of invasive species.

OPG works with community partners to support regional ecosystems and biodiversity across Ontario. In 2017, OPG continued efforts to protect and restore habitat, promote biodiversity education and awareness, and help the recovery of species at risk. In November 2017, OPG's biodiversity program was recognized by the Canadian Electricity Association with the 2017 Sustainable Electricity award for Commitment to Continuous Performance Improvement.

OPG communicates its environmental performance internally to employees and to external stakeholders, including the Ontario Ministry of the Environment and Climate Change (MOECC), Environment and Climate Change Canada, the CNSC, and local communities. Details of OPG's environmental performance and initiatives to fulfill the Company's Environmental Policy can be found in OPG's 2016 Sustainability Report, available on the Company's website at www.opg.com.

Improving Efficiency and Reducing Costs

As part of its commitment to operational excellence, OPG remains strongly focused on reducing costs by pursuing sustainable efficiency and productivity improvements across operating business units and support functions, while ensuring that there is no adverse impact on the safety, reliability and environmental sustainability of the Company's operations. Building on significant efficiency achieved since 2011 under a more scalable, centre-led organizational model, this includes streamlining of processes, simplifying governance, upgrading technology, optimizing service delivery models, and continuing to leverage attrition to achieve human resource targets aligned with business requirements. Strategies to improve cost performance and organizational capability are being implemented at the enterprise and business unit level. These strategies are supported by continuing to embed an outcomes-driven culture that reinforces cost effectiveness, efficiency and organizational agility as part of business decision-making.

OPG is proceeding with an enterprise-wide process to evaluate the impact of the eventual shutdown of the Pickering GS on the Company's operating cost structure. This multi-year initiative, known as OPG25, involves identifying and implementing a coordinated set of plans and targets to ensure the optimization of the Company's longer-term operating model, business strategies and organizational design between now and the planned end of Pickering commercial operations. The overall aim of the initiative is to ensure ongoing cost effectiveness of the Company's operations after the eventual shutdown of the Pickering GS and to mitigate the cost impacts associated with the shutdown. Through this work and a continued focus on productivity enhancements, OPG expects to deliver increased value to customers and achieve improvement in outcomes of future applications for regulated prices under the OEB's incentive regulation framework.

In 2017, OPG also launched a strategy to accelerate the pace of digital transformation across the enterprise. The strategy is focused on making investments to modernize information technology infrastructure, enhance mobility, connectivity and field and office productivity, and improve equipment reliability and station performance through data management and data analysis. The strategy will increase operational efficiency, reduce operating costs and help to enable optimization initiatives in support of OPG25.

People and Culture

A well trained and engaged workforce is fundamental to the achievement of OPG's strategic imperatives. To succeed in a demanding business environment, OPG is focused on building a diverse, healthy, engaged workforce and fostering a culture of collaboration, accountability and innovation. OPG also continues to communicate and implement the values and behaviours expected from its employees in order to maintain a strong focus on safety, performance excellence, continuous improvement, and corporate citizenship.

The Company continues to focus on improving the capability of its workforce through leadership development, knowledge management, diversity and inclusion programs, and hiring in critical areas. Ability to secure the right talent mix in order to effectively meet the Company's immediate and longer term business needs on a timely basis is supported through workforce planning, resourcing and on-boarding strategies, both to acquire external talent into the organization and to develop existing employees. The goal of workforce planning and resourcing strategies is to ensure that the Company has a diverse workforce with the right skill set and capability for the safe and effective operation of the generating facilities and successful delivery of major projects, including the Darlington Refurbishment. These strategies take into account changes in anticipated staffing requirements leading up and subsequent to the end of planned commercial operations of the Pickering GS and the period to de-fuel, de-water and

place the station in a safe state condition after shutdown. The end of commercial operations at the Pickering GS is expected to lead to a significant reduction in OPG's workforce.

As part of the strategy to develop and engage employees and to build leadership talent in support of the Company's long-term success, OPG has an active succession planning program with a focus on accelerating development. This includes a company-wide high-potential leadership development program for qualified internal candidates. This 14-month cross-functional, competitive-entry program is designed to identify and develop candidates for future leadership positions while they are relatively early in their careers. OPG also has a talent management monitoring process to proactively assess staffing risks, challenges and opportunities.

Electricity generation involves complex technologies that require highly skilled and trained workers. Many positions at OPG have significant educational prerequisites and rigorous requirements for continuous training and periodic requalification. In addition to maintaining its internal training infrastructure, OPG relies on partnerships with government agencies, other electrical industry partners and educational institutions to meet the required level of qualification. Training delivery models are evaluated for effectiveness and efficiency.

Effective January 1, 2017, OPG implemented an Executive Compensation Program that is compliant with *Ontario Regulation 304/16: Executive Compensation Framework*, introduced in September 2016. While the Province released two subsequent amendments, *Ontario Regulation 187/17* and *Ontario Regulation 400/17* in June 2017 and November 2017, respectively, OPG's Executive Compensation Program continues to be subject to the original regulation's requirements. The regulation sets out how all employers designated under the *Broader Public Sector Executive Compensation Act, 2014*, including OPG, must establish and post compensation programs for executives. The program must include the compensation philosophy, salary and performance-related pay caps, comparative analysis details, and a description of other elements of compensation. OPG's Executive Compensation Program, which applies to employees at the Vice President level and higher, is designed to provide compensation that is at the 50th percentile of the market and focused on at-risk, performance based pay. The program will better enable OPG to attract, align and retain the executive talent critical to delivering Shareholder and customer value, while ensuring continued safe and reliable operations.

Project Excellence

OPG is pursuing a number of generation development and other major projects in support of Ontario's electricity planning initiatives. OPG also continues to plan and execute maintenance and capital improvement projects related to its existing assets. OPG strives for excellence in the planning and delivery of all projects across the Company.

OPG's vision for project excellence is to be an industry leader in project management capability and performance. As part of its commitment to project excellence, OPG continues to enhance and streamline its approach to project planning and execution, with the goal of delivering all projects safely, on time, on budget, and with high quality. Achieving project excellence at OPG involves, among other things, implementing a common, scalable project delivery model across all business units, establishing qualified project management teams, optimizing contracting strategies, engaging qualified and experienced vendors, and effectively monitoring and controlling performance.

The status updates for OPG's major projects as of December 31, 2017 are outlined below.

Project	Capital expenditures		Approved budget	Expected in-service date	Current status
(millions of dollars)	Year-to-date	Life-to-date			
Darlington Refurbishment	1,249	4,434	12,800 [1]	First unit - 2020 Last unit - 2026	All Unit 2 feeder tubes were removed safety in the fourth quarter of 2017 and the removal of fuel channel assemblies is in progress. Construction activities on the HWSF have recommenced in the fourth quarter. Planning and procurement activities for the refurbishment of Unit 3 are continuing. The overall project is tracking on schedule and on budget.
Peter Sutherland Sr. Hydroelectric GS	41	277	300	2017	The station was placed in-service on March 31, 2017, ahead of the originally planned schedule, and is expected to close below the approved budget. Project close-out activities are in progress.
Sir Adam Beck Pump GS Reservoir Refurbishment	3	49	58	2017	The refurbishment was completed and the reservoir was returned to service in February 2017, ahead of the originally planned in-service date and below the approved budget.
Ranney Falls Hydroelectric GS	25	28	77	2019	Excavation has been completed and construction is continuing in the expanded forebay, powerhouse and spillway area. Concrete placement of the new powerhouse and the spillway integrated structure is in progress. The project is tracking on schedule and on budget.
Nanticoke Solar Facility	2	3	107	2019	Significant contracts for equipment and engineering construction services have been executed, with construction planned to commence in the first quarter of 2018. **[MONITOR]**
Deep Geologic Repository (DGR) for L&ILW	9 [2]	204 [2]			On August 21, 2017, the federal Minister of Environment and Climate Change requested further information related to the project's environmental assessment (EA). OPG is working on a response to this information request.

[1] The total project budget of $12.8 billion is for the refurbishment of all four units at the Darlington GS.
[2] Expenditures are charged against the Nuclear Liabilities.

Darlington Refurbishment

The Darlington generating units are approaching their originally designed end-of-life. Refurbishment of the four generating units is expected to extend the operating life of the station by approximately 30 years. The approved budget for the four-unit refurbishment is $12.8 billion, which includes the costs of the pre-requisite projects in support of the execution phase of the refurbishment. The first refurbished unit is scheduled to be returned to service in the first quarter of 2020 and the last unit is scheduled to be completed by 2026. The project continues to track on schedule.

The Darlington Refurbishment project is a multi-phase program comprising the following five major sub-projects:

- **Retube and Feeder Replacement**, which includes the removal and replacement of fuel channel assemblies and feeder tubes in each reactor
- **Turbines and Generators**, which consists of inspections and repairs of turbine generator sets and the replacement of analog control systems with digital control systems
- **De-fuelling and Fuel Handling**, which involves the de-fuelling of the reactors and the refurbishment of the fuel handling equipment
- **Steam Generators**, which includes mechanical cleaning, water lancing, and inspection and maintenance work on the generators
- **Balance of Plant**, which consists of work on smaller projects to replace or repair certain other station components.

In 2016, the Darlington Refurbishment project transitioned from the planning phase to the execution phase, as OPG commenced the refurbishment of the first unit, Unit 2, in October 2016 as planned. The unit was taken offline on October 15, 2016. De-fuelling of the reactor was completed in January 2017, with a total of 480 fuel channels de-fuelled. Islanding of Unit 2, the physical separation of the unit under refurbishment from the three operating units, was completed in April 2017, signifying the completion of the first major segment of the project.

The second major segment includes preparatory work to support the removal of feeder tubes and fuel channel assemblies, followed by the removal of reactor components. The preparatory work was completed in the second quarter of 2017. The Re-tube Tooling Platform for hosting the tooling for the removal, inspection and installation activities, and the setup of specialized tooling and equipment needed for the removal and replacement of the reactor components were completed in the third quarter of 2017. The disassembly of reactor components commenced in August 2017, with the removal of all 960 feeder tubes completed safely in September 2017. The removal of fuel channel assemblies commenced in October 2017. As part of the fuel channel assemblies, the removal of pressure tubes is in progress and will be followed by the removal of calandria tubes. The second major segment and the removal of all reactor components is expected to be completed by mid-2018. Key projects in the second major segment finished in 2018 include the completion of the primary side steam generator layup and installation of steam generator access ports to support future inspections. Other key project activities being executed during the second segment include the continuation of the major turbine generator overhaul, which will be completed in the second quarter of 2018, and continued execution of the major electrical scope. OPG is also continuing to execute work to support the requirements set out in the CNSC-approved Integrated Implementation Plan for the station.

Most of the pre-requisite projects, including construction of facilities, infrastructure upgrades and installation of safety enhancements, have been completed and placed in-service. The Re-tube Waste Processing Building was completed in November 2017. Completion of the HWSF has been delayed due to challenges with construction. OPG suspended the project in the second quarter of 2017 to evaluate the best approach to optimize cost and schedule and complete the project. Construction to complete the facility recommenced in the fourth quarter of 2017. The HWSF is expected to be completed by the second quarter of 2019 and is not on the critical path for the Darlington Refurbishment project, which continues to track on schedule. The increase in the cost estimate for the HWSF will be accommodated within the overall Darlington Refurbishment budget of $12.8 billion. Taking into account the execution performance of the Unit 2 refurbishment, the overall Darlington Refurbishment project continues to track on budget.

In addition to the execution of refurbishment activities on Unit 2, OPG is continuing planning activities for the refurbishment of the second unit, Unit 3, and is entering into associated commitments to procure major components that require long lead times. As of December 31, 2017, $93 million has been invested in planning activities related to the refurbishment of the second unit, Unit 3. These planning activities are being undertaken in accordance with the refurbishment project schedule. In February 2018, the Province confirmed its commitment to proceed with Darlington's Unit 3 refurbishment in 2020. **[MONITOR]**

Peter Sutherland Sr. Hydroelectric GS

In March 2017, the project to construct the 28 MW two-unit Peter Sutherland Sr. hydroelectric GS successfully completed final testing and commissioning of the turbine and generator units, and both units were declared substantially complete. On March 31, 2017, the project received a permit from the MOECC to take water for operations to allow the station to operate commercially. This in-service date was well ahead of the originally planned schedule of the first half of 2018. The project's schedule was accelerated to take advantage of favourable weather conditions. The project is expected to close below the approved budget of $300 million. Project close-out activities are in progress. OPG began to receive contracted revenue for the project following the IESO's confirmation of the station's commercial operations as of March 31, 2017, under a hydroelectric ESA.

Under the partnership agreement, as the unit is placed in-service, the CRP, a corporation wholly owned by the Taykwa Tagamou Nation, may acquire up to a 33 percent partnership interest through its investment in PSS. In April 2017, the CRP acquired a 33 percent interest in PSS.

Sir Adam Beck Pump GS Reservoir Refurbishment

The Sir Adam Beck Pump GS refurbishment construction began in April 2016 and the 300-hectare reservoir was returned to service in February 2017 upon completion of the reservoir commissioning program. The Sir Adam Beck Pump GS facility allows OPG to pump and store water diverted from the Sir Adam Beck generating complex during periods of low electricity demand, to be used to generate up to 600 MW of electricity during subsequent periods of high electricity demand. The work on the project included installation of a new partial liner and construction of a grout curtain in the bedrock foundation of the reservoir dyke. The refurbishment is expected to add approximately 50 more years to the reservoir's life. The project was completed ahead of the originally planned in-service date of April 2017 and below the approved budget of $58 million. The Sir Adam Beck Pump GS is reported in the Regulated – Hydroelectric segment.

Ranney Falls Hydroelectric GS

In 2017, OPG began construction work on a 10 MW single-unit powerhouse on the existing Ranney Falls GS site, as part of the Regulated – Hydroelectric segment. The new unit will replace an existing unit that reached its end of life in 2014. The existing forebay structure has been demolished and the new concrete structure has been completed. Excavation has been completed and construction continues in the expanded forebay, powerhouse and spillway area. The new forebay concrete wall has been completed, and concrete placement of the new powerhouse and the spillway integrated structure is in progress. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget.

Nanticoke Solar Facility

The construction of a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands under a Large Renewable Procurement contract with the IESO, through Nanticoke Solar LP, a partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation, is planned to commence in the first quarter of 2018. During 2017, the partnership continued work to obtain approvals and permits required to enable the commencement of construction. Significant contracts for equipment and engineering construction services were executed in the first quarter of 2018. The facility is expected to be completed in the first quarter of 2019, with a budget of $107 million. **[MONITOR]**

Deep Geologic Repository for Low and Intermediate Level Waste

OPG has proposed a deep geologic repository as the preferred solution for the safe long-term management of the L&ILW produced from the continued operation of OPG-owned nuclear generating stations. Agreement has been reached with local municipalities for OPG to develop the L&ILW DGR on lands adjacent to the WWMF in Kincardine, Ontario. The environmental effects of the proposed L&ILW DGR were examined by the CNSC and Canadian Environmental Assessment Agency (CEAA)-appointed Joint Review Panel (JRP) to meet the requirements of the *Canadian Environmental Assessment Act*. The JRP submitted its report on the EA to the federal Minister of Environment in May 2015, concluding that, given mitigation, there is unlikely to be significant environmental impact from the project and recommending that the Minister approve the EA. In December 2016, at the request of the federal Minister of Environment and Climate Change, OPG submitted additional information on certain aspects of the EA, including information related to alternate locations for the project. Following its review of OPG's submission and a period of public comment, the CEAA requested further information that OPG subsequently provided in May 2017. In June 2017, the CEAA notified OPG that it had sufficient and adequate information to proceed with the next step of the environmental assessment process and advised that a draft report and updated terms and conditions would be prepared for public review.

On August 21, 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of potential cumulative effects of the project on the Saugeen Ojibway Nation's (SON) physical and cultural heritage, including a description of the potential effects of the project on the Nation's spiritual and cultural connection to the land, taking into account the results of the SON Community Process. OPG is working closely with the SON to formulate a response to the information request.

The L&ILW DGR at the WWMF site remains OPG's preferred solution for the safe long-term management of the L&ILW. The in-service date of the L&ILW DGR is expected to be approximately six to seven years from the start of construction.

Financial Strength

As a commercial enterprise, OPG's financial priority is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future expansion. Inherent in this priority are four objectives:

- Increasing revenue, reducing costs and achieving appropriate return
- Ensuring availability of cost effective funding for operational needs, generation development projects and other business opportunities, and long-term obligations
- Pursuing opportunities to expand the existing core business and capitalize on new growth paths
- Managing risks, which is discussed in the section, *Risk Management*.

Increasing Revenue, Reducing Costs and Achieving Appropriate Return

In line with its commercial mandate, OPG is focused on increasing revenue and net income and achieving an appropriate rate of return on the Shareholder's investment, while taking into account the impact on Ontario electricity customers by seeking further efficiencies in the Company's cost structure.

For the regulated operations, achievement of the above objectives is largely dependent on outcomes of rate applications to the OEB and growth of the asset base earning a return as part of the regulated prices.

With respect to rate application outcomes, OPG has been focused on demonstrating in its rate applications that the costs required to operate and invest in the assets are reasonable and being prudently incurred, and should be fully recovered, and that the Shareholder's investment in these assets should earn an appropriate rate of return. While the OEB's decision on OPG's 2017-2021 application for new regulated prices reduced OPG's forecasted costs used to set new regulated prices, the decision will result in a substantial increase in revenue and net income compared to

existing regulated prices. The existing base regulated prices were set in 2014 to allow the Company to recover its approved nuclear costs over a higher nuclear production volume, based on the 2014 and 2015 outage profile that did not include a Darlington refurbishment outage.

The OEB's decision to reduce recovery of OPG's forecasted cost levels, including through the use of stretch factors under an incentive rate-making model, will negatively impact OPG's ability to earn an appropriate return on the Shareholder's investment in the regulated assets. To improve the financial strength of the regulated operations, OPG will continue to focus on optimizing operational performance and outage plans across the generating fleet and on pursuing further efficiency improvements in the Company's cost structure and operating model. OPG's cost and productivity improvement strategies are discussed further in the section, *Core Business, Strategy and Outlook* under the heading, *Operational Excellence – Improving Efficiency and Reducing Costs*.

OPG continues to invest in the regulated asset base, with the Darlington Refurbishment project being the single largest such capital investment. In its decision on OPG's 2017-2021 application for new regulated prices, the OEB has allowed inclusion of a total of $5.5 billion in Darlington Refurbishment in-service capital additions by 2021, including pre-requisite projects other than HWSF and including in-service amounts upon planned return to service of Unit 2 in the first quarter of 2020. Once in-service, these assets will attract a return on equity of approximately 8.8 percent during the 2017-2021 period set by the OEB, based on a deemed capital structure of 45 percent equity and 51 percent debt. The average OEB-approved cost of deemed debt for the 2017-2021 period is approximately 4.6 percent. OPG also continues to pursue an extensive capital program across its regulated hydroelectric operations that includes expansion, redevelopment and life extension of the generating facilities, where economic. These renewable assets have long service lives and, with either maintenance efforts or rebuilding, will continue to supply electricity for the foreseeable future. The OEB's decision on OPG's application for new regulated prices is discussed further in the section, *Highlights* under the heading, *Recent Developments*.

For generation assets that do not form part of the assets regulated by the OEB, OPG's strategy has been to secure appropriate long-term revenue arrangements. In line with this strategy, virtually all of OPG's non-regulated operating facilities and assets under construction are subject to long-term ESAs or other long-term contracts with the IESO. This includes the Peter Sutherland Sr. GS, which was placed in service and began receiving contracted revenue under a hydroelectric ESA as of March 31, 2017. The Peter Sutherland Sr. GS ESA expires in 2067.

OPG's capital structure currently reflects lower levels of debt than the deemed capital structure reflected in the Company's existing regulated prices and maintained by the OEB's December 2017 decision on new regulated prices. OPG continues to evaluate strategies to enhance Shareholder returns by optimizing the Company's capital structure through better alignment with the deemed capital structure, taking into account the overall financial strength of the Company and the potential impact on the Company's investment grade credit rating.

Ensuring Availability of Cost Effective Funding

OPG actively monitors its funding requirements and forecasts availability of funds to ensure that it can meet the Company's operational needs, project commitments and long-term obligations. OPG utilizes multiple sources of funds, including funds generated from operations, commercial paper, securitization of assets, letters of credit, credit facilities, long-term corporate debt (sourced from both the OEFC and public debt offerings), credit facilities with the OEFC, private placement project financing, and equity issuance. The Company's financing strategy leverages the strength of its balance sheet to obtain cost effective long-term corporate debt. OPG also accesses the capital markets for private placement project financing, secured by the assets of the project, where the characteristics of the project support such financing. Maintaining an investment grade credit rating is critical to OPG's ability to access cost effective financing.

In April 2017, DBRS Limited (DBRS) re-affirmed the long-term credit rating on OPG's debt at 'A (low)' and OPG's commercial paper rating at 'R-1 (low)'. All ratings from DBRS have a stable outlook. In July 2017, S&P Global

Ratings (S&P) re-affirmed OPG's long-term credit rating at 'BBB+' with a stable outlook. S&P's commercial paper rating for OPG is 'A-1 (low)'.

OPG intends to continue to access the capital markets, where appropriate, to obtain cost effective financing for future generation development projects. The Company continues to evaluate arrangements that would appropriately support its financing needs, its capital expenditure programs, its financing of OPG's subordinated debt investment in the Trust, and the Trust's acquisition of Investment Interest from the IESO. OPG's liquidity and capital resources are discussed in the section, Liquidity and Capital Resources.

Building Our Business

Through pursuit of commercial-based opportunities to expand its business, OPG strives to be a leader in the North American transition toward a low carbon future while maintaining and expanding the Company's scale and energy industry leadership. This strategy considers the Company's financial position and anticipated future changes in the generating fleet, including the eventual end of Pickering commercial operations. The strategy is also informed by industry, technological, environmental, social, and economic external factors. Opportunities are evaluated using financial and risk-based analyses as well as strategic considerations.

Currently, OPG's strategy primarily focuses on the renewal and expansion of the Company's portfolio of generating assets in Ontario, including the redevelopment and expansion of existing sites and potential new developments. The strategy leverages OPG's operating and project development expertise as well as the Company's existing diverse physical asset base. Acquisition opportunities are considered as they arise, taking into account operating synergies, strategic benefits, financial returns and risk profile. OPG's current major generation development projects and asset life extension initiatives are discussed in the section, *Core Business, Strategy, and Outlook* under the headings, *Operational Excellence* and *Project Excellence*.

OPG also actively seeks to expand beyond its core generation business through investments in innovation and emergent low-carbon technologies, including selective solar generation, nuclear innovation, energy storage, distributed generation, electric vehicle infrastructure and other development. Additionally, OPG continues to consider potential paths to extend its business through broader electricity sector opportunities, within and outside Ontario. Business expansions opportunities may be pursued in partnership with other commercial entities where appropriate synergies exist and are aligned with OPG's business objectives.

Social Licence

As the largest electricity generator in Ontario with diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust. OPG is committed to maintaining high standards of public safety and corporate citizenship, including environmental stewardship, transparency, community engagement, and Indigenous relations. OPG works to maintain public trust with stakeholders by engaging site communities, sharing information, and being transparent about performance. In addition, OPG's operations are subject to extensive regulatory oversight, with public participation, by the CNSC, the OEB, and other bodies. OPG's commitment to safety is discussed in the section, *Core Business, Strategy, and Outlook* under the heading, *Workplace and Public Safety*.

OPG is focused on building long-term, mutually beneficial working relationships with Indigenous communities, businesses and organizations across Ontario, and continues to support procurement, employment and educational opportunities with its Indigenous community partners. The Company seeks to establish these relationships based on a foundation of respect for the languages, customs, and political, social and cultural organizations of the Indigenous communities.

OPG's commitment in this area includes pursuing generation-related development partnerships on the basis of long-term commercial arrangements, such as the construction of the Peter Sutherland Sr. GS in partnership with Taykwa Tagamou Nation and the development of the Nanticoke solar facility in partnership with the Six Nations of the Grand

River. During 2017, OPG also continued to engage with Indigenous communities regarding the Company's nuclear waste management operations, through regularly scheduled meetings and ongoing dialogue in connection with OPG's proposed L&ILW DGR, the re-licensing of the PWMF and the WWMF, and the Pickering GS re-licensing. Engagement was also conducted with First Nations in southwestern Ontario regarding the demolition of the Lambton and Nanticoke generating stations and with the Mississaugas of New Credit regarding the Shareholder-directed sale of the former Lakeview GS site.

OPG is also committed to improving Indigenous access to procurement and employment opportunities, including increasing the profile of the nuclear generation industry in Indigenous communities. In 2017, OPG launched an Indigenous Business Engagement (IBE) Initiative. The purpose of this initiative is to increase access to procurement opportunities for Indigenous businesses interested in supplying materials and services to OPG. The IBE Initiative is based on a strategy that will identify opportunities in contracts, scopes of work and business plans for potential Indigenous business engagement; include criteria related to suppliers' ability to engage or partner with Indigenous people or businesses in assessing procurement proposals; and invest in relationships with Indigenous communities by increasing outreach efforts to enhance understanding of how to do business with OPG. OPG has been engaging with Indigenous businesses and communities as well as its suppliers to promote the IBE Initiative, including the Mohawk Council of Akwesasne as well as the Williams Treaties First Nations, located proximate to the Pickering and Darlington nuclear generating stations.

OPG has been actively developing recruitment plans targeting Indigenous peoples. As part of this initiative, during the fourth quarter of 2017, OPG participated in several Indigenous-specific career fairs, hosted a Day in the Trades event for Indigenous students and job seekers as part of an open house at the Darlington Energy Centre, and approved plans aimed at increasing the number of Indigenous apprentices as part of the nuclear operations' recruitment program.

OPG also contributes to the well-being of its host communities through the Company's Corporate Citizenship Program (CCP), which supports charitable and non-profit grassroots initiatives in the areas of environment, education, and community involvement, including support for Indigenous initiatives. In 2017, OPG's CCP provided support to over 800 initiatives, of which 84 were Indigenous.

OPG has a strategy to help position the Company as a leader in transportation electrification in the province. The strategy aims to leverage the Company's clean, reliable and cost-effective electricity to power transportation, capitalize on future commercial growth opportunities, and enhance the Company's social licence. OPG is pursuing initiatives to increase the use of electric vehicles within its operations, and is assessing vehicle grid integration and hydrogen applications for the transportation sector. Ontario's climate change plan aims for electric and hydrogen passenger vehicles to represent five percent of new vehicle sales in the province by 2020.

As part of its commitment to help de-carbonize Ontario's transportation sector, OPG is a founding sponsor of Plug'n Drive, a non-profit organization working to accelerate the adoption of electric vehicles and to maximize their environmental and economic benefits. In May 2017, Plug'n Drive announced the opening of the world's first experiential learning facility dedicated to electric vehicle education and awareness, with OPG sponsoring the Centre's training facility.

Further details regarding OPG's commitment to sustainable development, including information regarding the Company's environmental and social performance and initiatives, are provided in OPG's 2016 Sustainability Report available on the Company's website at www.opg.com.

Outlook

The financial performance of OPG's regulated operations is driven, in large part, by the outcome of applications for regulated prices to the OEB. Subject to the OEB's issuance of the final payment amounts order expected in the first half of 2018, the OEB's December 2017 decision on OPG's application for new regulated prices provides substantial

price certainty for the regulated business for the 2017 to 2021 period. During this period, OPG will continue to focus on optimizing operational performance and outage plans across the generating fleet and on pursuing further efficiency improvements in the Company's cost structure and operating model.

The OEB's decision established June 1, 2017 as the effective date of the new regulated prices, which negatively affected OPG's net income and ROE Excluding AOCI in 2017 relative to OPG's requested effective date of January 1, 2017. The full-year effect of new regulated prices in 2018 is expected to contribute to an improvement in net income and ROE Excluding AOCI over the 2017 results.

Subject to the OEB's final determination on nuclear rate smoothing as part of the payment amounts order process, OPG expects an improvement in cash flow from operating activities in 2018, compared to 2017. This will reflect OPG beginning to receive revenue from the IESO based on new regulated prices following the OEB's implementation of these prices, expected in the first half of 2018. Additionally, the Fair Hydro Trust segment will begin to contribute positive cash flow from operating activities in 2018. OPG expects to continue to have the necessary financial capacity and sufficient access to cost effective financing sources to continue to fund its capital requirements and other disbursements, including the financing of the Fair Hydro Trust.

Several OEB-authorized regulatory variance and deferral accounts currently in place contribute to reducing the relative variability of the Company's net income and ROE Excluding AOCI. Among others, the regulatory accounts include those related to the revenue impact of variability in water flows and forgone production due to SBG conditions at the regulated hydroelectric stations. As there are no variance or deferral accounts in place related to the impact of generation performance of the nuclear stations on revenue from base regulated prices, the Regulated – Hydroelectric segment generally is expected to produce overall more predictable earnings. OPG continues to operate and maintain its nuclear facilities with a view to optimize their performance and availability, while focusing on improving the overall reliability and predictability of the fleet.

Electricity generated from most of OPG's non-regulated assets is subject to ESAs or other long-term contracts with the IESO. Based on these agreements, OPG expects the Contracted Generation Portfolio segment to continue to contribute a generally stable level of earnings and cash flow from operating activities going forward.

Lower nuclear generation due to the Darlington Refurbishment outages will continue, as planned, to negatively impact the Enterprise TGC and Nuclear TGC metrics for the duration of the refurbishment project. Lower hydroelectric generation due to outages related to various refurbishment and operational projects may negatively impact Enterprise TGC and Hydroelectric TGC for the duration of these projects. Variability in sustaining capital investment expenditures and nuclear outage profile may also impact TGC metrics in future periods.

OPG's total forecast capital expenditures for the 2018 year are approximately $2.1 billion. **[CONFIRM]** This includes amounts for the Darlington Refurbishment project, hydroelectric and other development projects including the Ranney Falls GS redevelopment and construction of the Nanticoke solar facility, and sustaining capital investments across the generating fleet. OPG's major projects are discussed in the section, *Project Excellence*.

In addition to the operating and financial performance of the electricity generation business, OPG's results are affected by the earnings on the Nuclear Segregated Funds, which are reported in the Regulated – Nuclear Waste Management segment. While the Nuclear Segregated Funds are managed to achieve, in the long term, the target rate of return based on the discount rate specified in the ONFA, the rates of return earned in a given period can be subject to various external factors including financial market conditions and, for the portion of the Used Fuel Segregated Fund guaranteed by the Province under the ONFA, changes in the Ontario consumer price index (CPI). In the near term, these factors can be volatile and cause fluctuations in the Company's income. This volatility is partially mitigated by the impact of the OEB-authorized Bruce Lease Net Revenues Variance Account and the funded status of the two segregated funds, discussed below.

As OPG does not have the right to withdraw surplus amounts from the Nuclear Segregated Funds, OPG limits the amount of Nuclear Segregated Funds assets reported on the balance sheet to the present value of the underlying life cycle funding liabilities per the most recently approved ONFA Reference Plan. This reduces the volatility of earnings on the Nuclear Segregated Funds reflected in net income when the funds are in a fully funded or overfunded position. As at December 31, 2017, the Decommissioning Segregated Fund was overfunded by approximately 27 percent, and the Used Fuel Segregated Fund was marginally overfunded, by less than one percent, based on the 2017 ONFA Reference Plan. Variability in asset performance due to volatility inherent in financial markets and changes in Ontario CPI, or changes in funding liability estimates, may result in either or both funds becoming underfunded in the future.

OPG's results are also affected by the earnings from the Fair Hydro Trust segment. Management expects an increase in 2018 earnings from the segment, primarily related to interest income from OPG's investment in subordinated debt of the Trust. OPG's involvement with the Fair Hydro Plan over time is expected to put downward pressure on ROE Excluding AOCI as a result of increases in shareholder's equity through future issuances of Class A common shares to partially fund OPG's subordinated debt investment in the Trust.

KEY OPERATING AND FINANCIAL PERFORMANCE INDICATORS

OPG evaluates the performance of its generating stations using a number of key indicators. Key operating performance indicators aligned with corporate strategic imperatives are measures of production reliability, cost effectiveness, environmental performance, and safety performance. Certain of the measures used vary depending on the generating technology.

Enterprise TGC, Nuclear TGC, Hydroelectric TGC, ROE Excluding AOCI, and FFO Adjusted Interest Coverage ratio discussed below are not measurements in accordance with US GAAP. They should not be considered as alternative measures to net income or any other measure of performance under US GAAP. However, OPG believes that these non-GAAP financial measures are effective indicators of its performance and are consistent with the Company's strategic imperatives and related objectives. The definition and calculation of Enterprise TGC per MWh, Nuclear TGC per MWh, Hydroelectric TGC per MWh, ROE Excluding AOCI, and FFO Adjusted Interest Coverage are found in the section, *Supplementary Non-GAAP Financial Measures*.

Enterprise Total Generating Cost per Megawatt-Hour

Enterprise TGC per MWh is used to measure OPG's overall organizational cost performance. Enterprise TGC per MWh is defined as OM&A expenses (excluding the Darlington Refurbishment project and other generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to OPG's electricity generation business), fuel expense for OPG-operated stations including hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures (excluding the Darlington Refurbishment project and other generation development projects) incurred during the period, divided by total electricity generation from OPG-operated generating stations plus electricity generation forgone due to SBG conditions during the period.

Nuclear Total Generating Cost per Megawatt-Hour

Nuclear TGC per MWh is used to measure the cost performance of OPG's nuclear generating assets. Nuclear TGC per MWh is defined as OM&A expenses of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to OPG's nuclear electricity generation business), nuclear fuel expense for OPG-operated stations (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs) incurred during the period, divided by nuclear electricity generation for the period.

Hydroelectric Total Generating Cost per Megawatt-Hour

Hydroelectric TGC per MWh is used to measure the cost performance of OPG's hydroelectric generating assets. Hydroelectric TGC per MWh is defined as OM&A expenses of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segments (excluding generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the hydroelectric electricity generation business), hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding expenditures related to the Peter Sutherland Sr. GS, Ranney Falls GS, and other hydroelectric generation development projects) incurred during the period, divided by total hydroelectric electricity generation plus hydroelectric electricity generation forgone due to SBG conditions during the period. OPG reports hydroelectric gross revenue charge and water rental payments as fuel expense.

Nuclear Unit Capability Factor

OPG's nuclear stations are baseload facilities that are not designed for fluctuating production levels to meet peaking demand. The nuclear Unit Capability Factor is a key measure of nuclear station performance. It measures the amount of energy that the unit(s) generated over a period of time, adjusted for externally imposed constraints such as transmission or demand limitations, as a percentage of the amount of energy that would have been produced over the same period had the unit(s) produced maximum generation. Capability factors are primarily affected by planned and unplanned outages. By industry definition, capability factors exclude production losses beyond plant management's control, such as grid-related unavailability. The nuclear Unit Capability Factor also excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS is excluded from the measure effective October 15, 2016, when the unit was taken offline as part of the Darlington Refurbishment project.

Hydroelectric Availability

OPG's hydroelectric stations operate as baseload, intermediate, or peaking stations. Hydroelectric Availability represents the percentage of time the generating unit is capable of providing service, whether or not it is actually generating electricity, compared to the total time for the respective period.

Thermal Equivalent Forced Outage Rate

Equivalent Forced Outage Rate (EFOR) is an index of the reliability of a generating unit at OPG's thermal stations. It is measured by the ratio of time a generating unit is forced out of service by unplanned events, including any forced deratings, compared to the amount of time the generating unit was available to operate.

Return on Common Equity Excluding Accumulated Other Comprehensive Income

ROE Excluding AOCI is an indicator of OPG's performance consistent with its objective to deliver value to the Shareholder. ROE Excluding AOCI is defined as net income attributable to the Shareholder for the period divided by average equity attributable to the Shareholder excluding AOCI for that period, and is measured over a period of 12 months.

Funds from Operations Adjusted Interest Coverage

The FFO Adjusted Interest Coverage ratio is an indicator of OPG's ability to meet interest obligations from operating cash flow and is consistent with the Company's objective of ensuring availability of cost effective funding. The FFO Adjusted Interest Coverage ratio is defined as FFO before interest divided by adjusted interest expense, and is measured over a period of 12 months.

Other Key Indicators

In addition to production reliability, cost effectiveness, and financial performance indicators, OPG has identified certain environmental and safety performance measures. These measures are discussed in the section, *Core Business, Strategy, and Outlook*.

BUSINESS SEGMENTS

Effective in the fourth quarter of 2017, OPG has the following six reportable business segments:

- Regulated – Nuclear Generation
- Regulated – Nuclear Waste Management
- Regulated – Hydroelectric
- Contracted Generation Portfolio
- Services, Trading, and Other Non-Generation
- Fair Hydro Trust.

Regulated – Nuclear Generation Segment

The Regulated – Nuclear Generation business segment operates in Ontario, generating and selling electricity from the Pickering GS and the Darlington GS, both owned and operated by OPG. The business segment also includes revenue under the terms of a long-term lease arrangement and related agreements with Bruce Power related to the Bruce nuclear generating stations. This revenue includes lease revenue, fees for nuclear waste management, and revenue from heavy water sales and detritiation services. The segment also earns revenue from isotope sales and ancillary services supplied by OPG from the nuclear stations it operates. Ancillary revenues are earned through voltage control and reactive support. Revenues under the agreements with Bruce Power, including a portion of heavy water sales, and from existing isotope sales contracts and ancillary services are included by the OEB in the determination of the regulated prices for production from OPG's nuclear facilities, which has the effect of reducing these prices.

Regulated – Nuclear Waste Management Segment

OPG's Regulated – Nuclear Waste Management segment reports the results of the Company's operations associated with the management of nuclear used fuel and L&ILW, the decommissioning of OPG's nuclear generating stations including the stations on lease to Bruce Power and other facilities, the management of the Nuclear Segregated Funds, and related activities including the inspection and maintenance of the waste storage facilities. Accordingly, accretion expense, which is the increase in the Nuclear Liabilities carried on the consolidated balance sheets in present value terms due to the passage of time, and earnings from the Nuclear Segregated Funds are reported under this segment.

As the nuclear generating stations operate over time, OPG incurs incremental costs related to used nuclear fuel and L&ILW, which increase the Nuclear Liabilities. OPG charges these incremental costs to current operations in the Regulated – Nuclear Generation segment to reflect the cost of producing energy from the Pickering and Darlington nuclear generating stations and earning revenue under the Bruce Power lease arrangement and related agreements. Since the incremental costs increase the Nuclear Liabilities reported in the Regulated – Nuclear Waste Management segment, OPG records an inter-segment charge between the Regulated – Nuclear Generation and the Regulated – Nuclear Waste Management segments. The impact of the inter-segment charge is eliminated in the consolidated statements of income and balance sheets.

The Regulated – Nuclear Waste Management segment is considered rate regulated because OPG's costs associated with the Nuclear Liabilities are included in the OEB's determination of regulated prices for production from the Pickering and Darlington nuclear generating stations.

Regulated – Hydroelectric Segment

OPG's Regulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from most of the Company's hydroelectric generating stations. The business segment comprises the results of 54 hydroelectric generation stations across a number of major river systems in the province.

In addition, the business segment includes ancillary and other revenues from OPG's regulated hydroelectric stations. Ancillary revenues are earned through offering available generating capacity as operating reserve and through the supply of other ancillary services including voltage control and reactive support, certified black start facilities, regulation service, and other services. These ancillary revenues and other revenues are included by the OEB in the determination of the regulated prices for production from OPG's prescribed hydroelectric facilities, which has the effect of reducing these prices.

Contracted Generation Portfolio Segment

The Contracted Generation Portfolio business segment operates in Ontario, generating and selling electricity from the Company's generating stations that are not prescribed for rate regulation. The segment primarily includes generating facilities that are under an ESA with the IESO or other long-term contracts.

The Contracted Generation Portfolio segment also includes OPG's share of equity income from its 50 percent ownership interests in the PEC and Brighton Beach stations. Brighton Beach operates under an energy conversion agreement between Brighton Beach and Shell Energy North America (Canada) Inc., and the PEC station is operated under the terms of an Accelerated Clean Energy Supply contract with the IESO. OPG's share of the in-service generating capacity and generation volume from its interests in the PEC and Brighton Beach stations are reported in this segment.

The business segment also includes ancillary revenues and other revenues from the stations included in the segment, which are earned through offering available generating capacity as operating reserve, and the supply of other ancillary services including voltage control and reactive support, certified black start facilities, regulation service, and other services.

Services, Trading, and Other Non-Generation Segment

The Services, Trading, and Other Non-Generation segment is a non-generation segment that is not subject to rate regulation. It includes the revenue and expenses related to OPG's trading and other non-hedging activities. As part of trading activities, OPG transacts with counterparties in Ontario and neighbouring energy markets in predominantly short-term trading activities of typically one year or less in duration. These activities relate to electricity that is purchased and sold at the Ontario border, financial energy trades, financial risk management energy product revenues, and sales of energy-related products. In addition, OPG has a wholly owned trading subsidiary that transacts solely in the United States (US) market. The results of this subsidiary are reported in this segment. All contracts that are not designated as hedges are recorded as assets or liabilities at fair value on the consolidated balance sheets, with changes in fair value recorded in the revenue of this segment.

In addition, the segment includes revenue from real estate rentals and non-regulated services, gains or losses on disposition of non-regulated real estate assets, costs associated with non-regulated business development activities, and costs related to the Lambton GS and Nanticoke GS sites.

Fair Hydro Trust Segment

The Fair Hydro Trust segment is a non-generation segment that is not subject to rate regulation. It includes OPG's earnings from the Fair Hydro Trust, which includes the financial results of the Trust, as well as income related to OPG's role as Financial Services Manager of the Fair Hydro Trust and holder of subordinated debt issued by the Trust. Earnings include interest income from OPG's investment in subordinated debt of the Trust of up to 49 percent of the Trust's total outstanding debt, recovery of third-party costs and fees for financial management and ongoing administration services, partially offset by interest costs on debt issued by OPG to fund five percent of the subordinated investment in the Trust, incurred third-party costs, and other incurred costs related to the management and administration of the Trust.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

Regulated – Nuclear Generation Segment

(millions of dollars)	**2017**	**2016**
Revenue	**3,095**	3,481
Fuel expense	**284**	315
Gross margin	**2,811**	3,166
Operations, maintenance and administration	**2,293**	2,210
Depreciation and amortization	**431**	925
Property taxes	**26**	26
Income before other losses, interest, and income taxes	**61**	5
Other gains	**4**	1
Income before interest and income taxes	**57**	4

Income before interest and income taxes from the segment increased by $53 million in 2017, compared to 2016. Segment earnings were favourably affected by the OEB's decision on OPG's application for new regulated prices issued in December 2017 with a retrospective effective date of June 1, 2017. The revenue increase of approximately $465 million in relation to the June 1, 2017 to December 31, 2017 period resulting from the OEB's decision was recorded as an increase in net regulatory assets in the fourth quarter of 2017. This revenue increase was based on new regulated prices for that period proposed in OPG's January 2018 submission to the OEB based on the findings in the decision and is net of a regulatory liability recognized in relation to OPG's nuclear rate smoothing proposal in that submission.

Segment earnings were unfavourably affected by a reduction in electricity generation of 4.9 TWh in 2017, compared to 2016. This reduced revenue by approximately $285 million, partially offset by a decrease in fuel expense. The lower electricity generation was primarily due to the ongoing Unit 2 refurbishment outage at the Darlington GS that began in October 2016, partially offset by the higher electricity generation from the Pickering GS. The income impact of OEB-approved regulatory accounts also contributed to the decrease in income for the year.

The increase in OM&A expenses of $83 million in 2017, compared to 2016, reflected planned expenditures related to the major maintenance activities and higher project expenditures occurring at the nuclear stations. Depreciation and amortization expenses, excluding amortization expense related to regulatory account balances, increased by $22 million primarily due to new assets in service in 2017.

The expiry of a nuclear rate rider for the recovery of OEB-approved balances in regulatory accounts on December 31, 2016 contributed to the decrease in segment revenue in 2017, compared to 2016, but was largely offset by a decrease in amortization expense related to these balances.

The Unit Capability Factors for the Darlington GS and Pickering GS for 2017 and 2016 were as follows:

	2017	2016
Unit Capability Factor *(%)* [1]		
Darlington GS	**85.2**	89.5
Pickering GS	**80.0**	75.2

[1] The nuclear Unit Capability Factor excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS was excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

The lower Unit Capability Factor at the Darlington GS in 2017, compared to 2016, reflected the higher number of planned outage days in 2017, largely driven by constraints related to the transition of the station's operating units toward refurbishment.

The increase in the Unit Capability Factor at the Pickering GS in 2017, compared to 2016, was primarily due to outage cycle optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station compared to 2016.

The definition of the nuclear Unit Capability Factor is found in the section, *Key Operating and Financial Performance Indicators.*

Regulated – Nuclear Waste Management Segment

(millions of dollars)	2017	2016
Revenue	**121**	138
Operations, maintenance and administration	**129**	146
Accretion on nuclear fixed asset removal and nuclear waste management liabilities	**943**	912
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(801)**	(746)
Loss before interest and income taxes	**(150)**	(174)

Earnings from the segment improved by $24 million in 2017 compared to 2016. The improvement was primarily due to higher earnings from the Nuclear Segregated Funds, partially offset by an increase in accretion expense on the Nuclear Liabilities. Accretion expense represents a financing cost due to the increase in the present value of the underlying liabilities with the passage of time.

The year-over-year increase in the earnings from the funds was primarily due to a reduction in the earnings recorded in the fourth quarter of 2016 to reflect an accounting adjustment to limit Nuclear Segregated Funds assets reported on the consolidated balance sheet to the underlying funding liabilities based on an updated ONFA reference plan approved by the Province. The updated ONFA reference plan resulted in a reduction in the funding liabilities. As both the Decommissioning Segregated Fund and the Used Fuel Fund have been in an overfunded position since the beginning of 2017, the earnings on the funds recognized in net income during the year reflected the growth rate in the present value of the funding liabilities and were not impacted by market returns and the rate of return guaranteed by the Province for the portion of the Used Fuel Segregated Fund. Further details on the accounting for the Nuclear Segregated Funds can be found in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

The year-over-year increase in accretion on nuclear fixed removal and nuclear waste management liabilities in 2017, compared to 2016, was primarily due to the impact on accretion expense related to the increase in asset retirement obligation associated with the life extension of the Bruce nuclear assets from the agreement executed between Bruce Power and the Province in late 2015. This increase was offset in 2016 due to the Bruce Lease Net Revenues Variance Account but is reflected in accretion with the resetting of base rates in 2017. This increase was partially

offset by the impact of the decrease in Nuclear Liabilities to reflect an updated estimate as part of the ONFA reference plan update process.

As of December 31, 2016, OPG recorded a decrease of approximately $1,570 million to the Nuclear Liabilities and associated asset retirement costs capitalized as part of the carrying value of the nuclear generating stations to reflect an updated estimate of OPG's obligations for nuclear waste management and nuclear facilities decommissioning determined as part of the ONFA reference plan update process. The resulting year-over-year decreases in accretion expense recorded in the Regulated – Nuclear Waste Management segment and depreciation and fuel expenses recorded in the Regulated – Nuclear Generation segment were offset by the impact of the OEB-authorized Bruce Lease Net Revenues Variance Account and Nuclear Liability Deferral Account recorded in the corresponding segments for the period up to May 31, 2017, and by the retrospective revenue impact of the OEB's decision for the period from June 1, 2017 to December 31, 2017 recorded in the Regulated – Nuclear Generation segment.

Regulated – Hydroelectric Segment

(millions of dollars)	**2017**	**2016**
Revenue [1]	**1,436**	1,527
Fuel expense	**351**	353
Gross margin	**1,085**	1,174
Operations, maintenance and administration	**330**	325
Depreciation and amortization	**139**	225
Property tax	**1**	1
Income before other gains, interest and income taxes	**615**	623
Other losses (gains)	**1**	(19)
Income before interest and income taxes	**614**	642

[1] During 2017 and 2016, the Regulated – Hydroelectric segment revenue included incentive payments of $12 million and $14 million, respectively, related to the OEB-approved hydroelectric incentive mechanism. The mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers.

The decrease in income before interest and income taxes of $28 million in 2017, compared to 2016, was primarily due to a gain of $22 million recognized during the first quarter of 2016 to reflect the OEB's January 2016 decision reversing a portion of an earlier capital cost disallowance related to the Niagara Tunnel project expenditures, in response to a motion by OPG. The income impact of OEB-approved regulatory accounts and higher OM&A expenses also contributed to the decrease in income for the year. The higher OM&A expenses were primarily related to overhaul work and civil repairs completed during the year.

These factors were partially offset by the recognition of a revenue increase of approximately $15 million in the fourth quarter of 2017 to reflect the OEB's decision on OPG's application for new regulated prices. This incremental revenue was in relation to the June 1, 2017 to December 31, 2017 period based on the June 1, 2017 retrospective effective date of the new regulated prices and was recorded as an increase to regulatory assets.

The decrease in revenue from the segment for the year ended December 31, 2017, compared to the same period in 2016, was largely due to the expiry of an OEB-authorized hydroelectric rate rider on December 31, 2016. As the rate rider allowed for the recovery of approved balances in OEB-authorized regulatory accounts, this decrease in revenue was largely offset by lower amortization expense related to these balances.

The Hydroelectric Availability for the stations included in the Regulated – Hydroelectric segment was as follows:

	2017	2016
Hydroelectric Availability *(%)*	**88.0**	89.0

The Hydroelectric Availability decreased during 2017, compared to 2016, primarily due to a higher number of unplanned outage days at the Northwestern Ontario, Niagara, and Eastern Ontario regions' hydroelectric stations, partially offset by higher availability from the Sir Adam Beck Pump GS due to a higher number of planned outages days in 2016 as a result of the refurbishment of the station's reservoir.

The definition of Hydroelectric Availability is found in the section, *Key Operating and Financial Performance Indicators*.

Contracted Generation Portfolio Segment

(millions of dollars)	2017	2016
Revenue	**579**	573
Fuel expense	**53**	58
Gross margin	**526**	515
Operations, maintenance and administration	**169**	178
Depreciation and amortization	**79**	75
Accretion on fixed asset removal liabilities	**9**	9
Property taxes	**7**	7
Income from investments subject to significant influence	**(38)**	(37)
Income before other losses, interest, and income taxes	**300**	283
Other losses	**-**	1
Income before interest and income taxes	**300**	282

Income before interest and income taxes increased by $18 million during 2017, compared to 2016. The increase in earnings primarily resulted from revenues from the Peter Sutherland Sr. GS that was placed in-service at the end of the first quarter of 2017 and lower OM&A expenses, partially offset by lower revenues from the Lower Mattagami River hydroelectric generating stations and Atikokan GS. The lower OM&A expenses were mainly due to the prospective adoption of the full yield curve approach to the estimation of the service and interest cost components of pension and OPEB costs starting in 2017.

The Hydroelectric Availability and the Thermal EFOR for the Contracted Generation Portfolio segment were as follows:

	2017	2016
Hydroelectric Availability *(%)*	**74.6**	77.3
Thermal EFOR *(%)*	**2.4**	1.6

Lower Hydroelectric Availability during 2017, compared to 2016, was primarily due to an increase in the number of planned outage days at the Lower Mattagami River hydroelectric generating stations.

The higher thermal EFOR in 2017, compared to 2016, was primarily due to a higher number of unplanned outage days at a Lennox GS unit as a result of a transmission outage and a generator-related outage in 2017.

The definitions of Hydroelectric Availability and Thermal EFOR are found in the section, *Key Operating and Financial Performance Indicators*.

Services, Trading, and Other Non-Generation Segment

(millions of dollars)	2017	2016
Revenue	**43**	68
Fuel expense	**1**	1
Gross margin	**42**	67
Operations, maintenance and administration	**18**	22
Depreciation and amortization	**30**	32
Accretion on fixed asset removal liabilities	**8**	8
Property taxes	**6**	12
Restructuring	**-**	6
Loss before other gain, interest, and income taxes	**(20)**	(13)
Other gains	**(384)**	-
Income before interest and income taxes	**364**	(13)

Segment earnings improved by $377 million in 2017 compared to 2016. The increase in earnings mainly reflected the gain on the sale of OPG's head office premises and associated parking facility recorded during the second quarter of 2017 of $283 million, which is net of tax effects of $95 million, partially offset by a decrease in rental revenue due to the sale of the head office premises.

The year-over-year decrease in OM&A expenses in 2017 reflected higher expenses incurred in 2016 prior to the decision taken in the fourth quarter of 2016 to proceed with the decommissioning of the Lambton GS, largely offset by a higher write-off of previously incurred project expenditures in 2017.

During the fourth quarter of 2017, OPG recorded $12 million in Other gains related to the revaluation of the asset retirement obligations for Lambton and Nanticoke generating stations in line with the current decommissioning plans and cost estimates. During each of 2017 and 2016, OPG recorded a charge against earnings to adjust the scrap value estimate for the Lambton GS, as a reduction to Other gains.

Fair Hydro Trust Segment

(millions of dollars)	2017
Operations, maintenance and administration	**1**
Earnings from Fair Hydro Trust	**(1)**
Income before interest and income taxes	**-**

The Fair Hydro Trust was established on December 20, 2017. The Fair Hydro Trust segment includes the revenue and expenses related to OPG's role as Financial Services Manager of the Fair Hydro Trust and holder of subordinated debt issued by the Trust, including the financial results of the Trust. Earnings from Fair Hydro Trust were $1 million in 2017, primarily due to net interest income earned on OPG's subordinated debt investment for the 11-day period following the acquisition of the first tranche of Investment Interest from the IESO on December 21, 2017. The earnings were offset by an allocation of OM&A expenses for labour costs relating to OPG's employees that are not exclusively dedicated to the segment but who provided services to set up the Trust during the year. Pursuant to the general regulation of the Fair Hydro Act, such labour costs are not recoverable as part of OPG's fees for 2017. Refer to the section, *Recent Developments* under the heading, *Ontario's Fair Hydro Plan* and the section, *Business Segments* under the heading, *Fair Hydro Trust Segment* for further details on the Fair Hydro Trust.

LIQUIDITY AND CAPITAL RESOURCES

OPG's primary sources of liquidity and capital are funds generated from operations, bank financing, credit facilities provided by the Ontario Electricity Financial Corporation (OEFC), long-term corporate debt, including public debt offerings and notes payable to the OEFC, private placement project financing, and equity issuance. These sources are used for multiple purposes including: to invest in plants and technologies, to undertake major projects, to fund long-term obligations such as contributions to the pension fund and the Nuclear Segregated Funds, to make payments under the OPEB plans, to fund expenditures on Nuclear Liabilities not eligible for reimbursement from the Nuclear Segregated Funds, and to service and repay long-term debt, to provide general working capital, and to fund a portion of OPG's subordinated debt investment in the Fair Hydro Trust and the Trust's acquisition of Investment Interest from the IESO.

Changes in cash and cash equivalents for 2017 and 2016 were as follows:

(millions of dollars)	**2017**	**2016**
Cash and cash equivalents, beginning of period	**186**	464
Cash flow provided by operating activities	**944**	1,817
Cash flow used in investing activities	**(2,478)**	(1,919)
Cash flow provided by (used in) financing activities	**1,582**	(176)
Net increase (decrease) in cash and cash equivalents	**48**	(278)
Cash and cash equivalents, end of period	**234**	186

For a discussion regarding cash flow provided by operating activities and the FFO Adjusted Interest Coverage ratio, refer to the details in the section, *Highlights* under the heading, *Overview of Results*.

Investing Activities

Electricity generation is a capital-intensive business. It requires continued investment in plants and technologies to maintain and improve operating performance including asset reliability, safety and environmental performance, to increase the generating capacity of existing stations, and to invest in the development of new generating stations, emerging technologies and other business growth opportunities.

Cash flow used in investing activities in 2017 increased by $834 million compared to 2016. The increase in net cash flow used in investing activities was primarily due to the Trust's acquisition of the first tranche of Investment Interest from the IESO in the amount of approximately $1.18 billion in December 2017 and higher expenditures on the Darlington Refurbishment project in 2017.

The increase in net cash flow used in investing activities was partially offset by the receipt of proceeds from the sale of OPG's head office premises and associated parking facility in 2017 and the acquisition of nine million common shares of Hydro One Limited (Hydro One) in 2016. OPG acquired the Hydro One shares for investment purposes, to mitigate the risk of future price volatility related to the Company's future share delivery obligations under the current collective agreements with the Power Workers' Union (PWU) and The Society of Energy Professionals (The Society).

Financing Activities

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. In the second quarter of 2017, OPG renewed and extended the expiry date of both tranches from May 2021 to May 2022. There were no amounts outstanding under the bank credit facility as at December 31, 2017.

There was $100 million of commercial paper outstanding under OPG's commercial paper program as at December 31, 2017.

As at December 31, 2017, OPG also maintained $25 million of short-term, uncommitted overdraft facilities, and a further $468 million of short-term, uncommitted credit facilities which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other general corporate purposes. As at December 31, 2017, a total of $390 million of Letters of Credit had been issued under these facilities. This included $353 million for the supplementary pension plans, $36 million for general corporate purposes, and $1 million related to the operation of the PEC.

The Company has an agreement to sell an undivided co-ownership interest in its current and future accounts receivable to an independent trust, expiring on November 30, 2018. The maximum amount of co-ownership interest that can be sold under this agreement is $150 million. As at December 31, 2017, no borrowings were issued under this agreement and there were Letters of Credit outstanding under this agreement of $150 million, which were issued in support of OPG's supplementary pension plans.

As at December 31, 2017, Lower Mattagami Energy Limited Partnership (LME) maintained a $400 million bank credit facility to support the funding requirements for the Lower Mattagami River project including support for LME's commercial paper program. The facility consists of a $300 million tranche maturing in August 2022 and a $100 million tranche maturing in August 2018. As at December 31, 2017, there was $160 million commercial paper outstanding under LME's commercial paper program. A letter of credit of $55 million was issued in July 2017 and remains outstanding as at December 31, 2017 under the $300 million tranche of LME's credit facility.

In June 2016, OPG entered into a $700 million general corporate credit facility agreement with the OEFC, with an expiry date of December 31, 2017. During 2017, the agreement was amended to increase the credit facility to $2,350 million and to extend its expiry date to December 31, 2018. As at December 31, 2017, there were outstanding long-term borrowings of $800 million under this credit facility.

In February 2017, OPG issued senior notes payable to the OEFC totalling $200 million and maturing in February 2047. The effective interest rate and coupon interest rate of these notes was 4.12 percent. In June 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in June 2047. The effective interest rate and coupon interest rate of these notes was 3.65 percent. In August 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in August 2047. The effective interest rate and coupon interest rate of these notes was 3.86 percent. In September 2017, OPG issued senior notes payable to the OEFC totalling $400 million and maturing in September 2047. The effective interest rate and coupon interest rate of these notes was 4.07 percent.

In October 2017, OPG issued $500 million of senior notes payable under a Medium Term Note Program. The notes bear a coupon interest rate of 3.32 percent and an effective rate of 3.43 percent, payable semi-annually until maturity on October 4, 2027. The offering was made under OPG's $2 billion short form base shelf prospectus dated September 12, 2017. The net proceeds will be used for general corporate purposes.

In December 2017, the Fair Hydro Trust entered into an $800 million revolving warehouse facility agreement with an expiry date of December 21, 2019. As at December 31, 2017, there were outstanding senior notes of $601 million under this credit facility, which were used to finance 51 percent of the Trust's funding requirement for the acquisition of the first tranche of Investment Interest from the IESO in December 2017.

In February 2018, the Trust issued $500 million of senior notes payable with a coupon interest rate of 3.36 percent and an effective interest rate of 3.42 percent, payable semi-annually until maturity on May 15, 2033. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility issued by the Trust in December 2017. By the end of the first quarter of 2018, the Trust is expected to acquire another tranche of Investment Interest from the IESO, which it expects to fund using its revolving warehouse facility.

As at December 31, 2017, OPG's long-term debt outstanding was $5,735 million, including $398 million due within one year and excluding Fair Hydro Trust's senior debt included in OPG's consolidated balance sheets. The Fair Hydro Trust's senior debt outstanding was $601 million as at December 31, 2017.

Contractual Obligations

OPG's contractual obligations as at December 31, 2017, are as follows:

(millions of dollars)	2018	2019	2020	2021	2022	Thereafter	Total
Fuel supply agreements	158	125	115	88	67	67	620
Contributions to the OPG registered pension plan [1]	215	219	-	-	-	-	434
OPG long-term debt repayment	398	368	663	413	172	3,721	5,735
Interest on OPG long-term debt	244	226	204	175	161	3,006	4,016
Fair Hydro Trust senior debt repayment [2]	-	601	-	-	-	-	601
Interest on Fair Hydro Trust senior debt	15	15	-	-	-	-	30
Commitments related to Darlington Refurbishment project [3]	473	-	-	-	-	-	473
Commitments related to Ranney Falls GS project	29	5	-	-	-	-	34
Operating licences	40	41	24	28	28	87	248
Operating lease obligations	28	24	24	22	22	79	199
Unconditional purchase obligations	59	58	56	5	-	-	178
Accounts payable and accrued charges	957	8	-	-	-	16	981
Other	57	30	2	1	1	64	155
Total	2,673	1,720	1,088	732	451	7,040	13,704

[1] The pension contributions include ongoing funding requirements and additional funding requirements towards the deficit, in accordance with the actuarial valuation of the OPG registered pension plan as at January 1, 2017. The next actuarial valuation of the OPG registered pension plan must have an effective date no later than January 1, 2020. The pension contributions are affected by various factors including market performance, changes in actuarial assumptions, plan experience, changes in the pension regulatory environment, and the timing of funding valuations. Funding requirements after 2019 are excluded due to significant variability in the assumptions required to project the timing of future cash flows. The amount of OPG's additional, voluntary contribution, if any, is revisited from time to time.

[2] The notes were issued by the Fair Hydro Trust under an $800 million two-year revolving warehouse facility in December 2017. In February 2018, the Trust issued $500 million of senior notes payable to repay the majority of the outstanding balance of the revolving warehouse facility.

[3] Represents estimated currently committed costs to close the project, including accruals for completed work, demobilization of project staff and cancellation of existing contracts and material orders.

Other Commitments

Collective Agreements

As of December 31, 2017, OPG had approximately 9,200 regular employees. Most of OPG's regular employees are represented by two unions:

- The PWU – This union represents approximately 4,850 OPG employees or approximately 53 percent of OPG's regular workforce as at December 31, 2017. Union membership includes operators, technicians, skilled trades, clerical, and security personnel. The current collective agreement between OPG and the PWU has a three-year term, expiring on March 31, 2018. Negotiations for a new labour agreement with the PWU are underway. **[MONITOR]**
- The Society – This union represents approximately 3,250 OPG employees or approximately 35 percent of OPG's regular workforce as at December 31, 2017. Union membership includes supervisors, professional engineers, scientists, and other professionals. The current collective agreement between OPG and The Society has a three-year term, expiring on December 31, 2018.

In addition to the regular workforce, construction work is performed through 19 craft unions with established bargaining rights at OPG facilities. These bargaining rights are established either through the Electrical Power Systems Construction Association (EPSCA) or directly with OPG. Collective agreements between the Company and its construction unions are negotiated either directly or through EPSCA. All of these collective agreements currently have multi-year terms, expiring on April 30, 2020.

BALANCE SHEET HIGHLIGHTS

The following section provides other highlights of OPG's audited consolidated financial position using selected balance sheet data as at December 31:

(millions of dollars)	**2017**	**2016**
Property, plant and equipment – net	**21,322**	19,998
The increase was primarily due to capital expenditures on the Darlington Refurbishment project, partially offset by depreciation expense.		
Nuclear fixed asset removal and nuclear waste management funds *(current and non-current portions)*	**16,724**	15,984
The increase was primarily due to earnings on the Nuclear Segregated Funds, partially offset by reimbursement of eligible expenditures on nuclear fixed asset removal and nuclear waste management activities.		
Regulatory assets and liabilities – net *(current and non-current portions)*	**6,637**	5,545
The increase was primarily due to the addition of the Interim period revenue shortfall account, increases in the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB AOCI regulatory asset. In addition, there was no amortization recorded in 2017 consistent with OPG's proposal in the Draft Payment Amounts Order filed with the OEB in January 2018.		
Long-term debt *(current and non-current portions)*	**6,319**	5,520
The increase was primarily due to the issuance of senior notes payable by the Trust to finance the acquisition of an Investment Interest in the shortfall from the rate reductions mandated by the Fair Hydro Act of $601 million, issuance of senior notes payable totaling $804 million during 2017 primarily with the OEFC, and issuance of senior notes totaling $500 million under the Medium Term Note Program. The balance is offset by the debt repayment of $1 billion in 2017.		
Fixed asset removal and nuclear waste management liabilities	**20,421**	19,484
The increase was primarily a result of accretion expense representing the increase in the present value liabilities due to the passage of time, and an increase in the estimate for the nuclear ARO of $188 million recorded in 2017, which is discussed in *Critical Accounting Policies and Estimates* under the heading, Asset Retirement *Obligation*. The increase was partially offset by expenditures on nuclear fixed asset removal and waste management activities.		
Pension liabilities	**3,423**	3,012
The increase was primarily due to the re-measurement of the liabilities at the end of 2017 reflecting lower discount rates, partially offset by the excess of actual returns on pension plan assets over interest costs on the liabilities during 2017, as discussed in the section, *Critical Accounting Policies and Estimates* under the *heading, Pension and Other Post-Employment Benefits.*		
Other post-employment benefit liabilities	**3,092**	2,897
The increase was primarily due to the remeasurement of the liabilities at the end of 2017 reflecting lower discount rates, partially offset by the updated lower per capital health care claims costs assumption as part of the 2017 actuarial valuation.		

Off-Balance Sheet Arrangements

In the normal course of operations, OPG engages in a variety of transactions that, under US GAAP, are either not recorded in the Company's interim consolidated financial statements or are recorded in the Company's interim consolidated financial statements using amounts that differ from the full contract amounts. Principal off-balance sheet activities for OPG include guarantees and long-term contracts.

Guarantees

As part of normal business, OPG and certain of its subsidiaries and joint ventures enter into various agreements to provide financial or performance assurance to third parties. Such agreements include guarantees, standby Letters of Credit and surety bonds. For more details on guarantees issued by the company, refer to Note 15 of OPG's audited consolidated financial statements.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

OPG's significant accounting policies, including the impact of major recent accounting pronouncements, are outlined in Note 3 of the audited consolidated financial statements. Certain of these policies are recognized as critical accounting policies by virtue of the subjective and complex judgments and estimates required around matters that are inherently uncertain and could result in materially different amounts being reported under different conditions or assumptions. The critical accounting policies and estimates that affect OPG's US GAAP consolidated financial statements are highlighted below.

Exemptive Relief for Reporting under US GAAP

As required by *Ontario Regulation 395/11,* as amended, under the FAA, OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. Since January 1, 2012, OPG also has received exemptive relief from the OSC from the requirements of section 3.2 of National Instrument 52-107 *Acceptable Accounting Policies and Auditing Standards* (NI 52-107). The exemption allows OPG to file consolidated financial statements with the OSC based on US GAAP, rather than International Financial Reporting Standards (IFRS), without becoming a U.S. Securities and Exchange Commission registrant.

The current OSC exemption, received in 2014, will terminate on the earliest of the following:

- January 1, 2019
- The financial year that commences after OPG ceases to have activities subject to rate regulation
- The effective date prescribed by the International Accounting Standards Board (IASB) for the mandatory application of a standard within IFRS specific to entities with rate-regulated activities.

As a result of OPG's 2011 decision to adopt US GAAP, as required by the FAA regulation, OPG's earlier plan to convert to IFRS, effective January 1, 2012, was discontinued. OPG had substantively completed its IFRS conversion project, which included separate diagnostic, development, and implementation phases, when it suspended the project. If a future transition to IFRS for the purposes of OPG's consolidated financial statements is required, conversion work can be effectively restarted with sufficient lead time to evaluate and conclude on changes that occurred subsequent to the decision to suspend the project. OPG continues to monitor the IASB's current standard-setting project related to entities with rate-regulated activities and is evaluating alternatives with respect to the Company's future financial reporting.

Rate Regulated Accounting

The *Ontario Energy Board Act, 1998* and *Ontario Regulation 53/05* provide that OPG receives regulated prices for electricity generated from 54 hydroelectric generating stations and the Pickering and Darlington nuclear generating stations. OPG's regulated prices for these facilities are determined by the OEB.

The OEB is a self-funding Crown corporation. Its mandate and authority come from the *Ontario Energy Board Act, 1998*, the *Electricity Act, 1998*, and a number of other provincial statutes. The OEB is an independent, quasi-judicial tribunal that reports to the Legislature of the Province through the Ontario Ministry of Energy. It regulates market participants in Ontario's natural gas and electricity industries. The OEB carries out its regulatory functions through public hearings and other more informal processes such as consultations.

US GAAP recognizes that rate regulation can create economic benefits and obligations that are required by the regulator to be obtained from, or settled with, the customers. When the Company assesses that there is sufficient assurance that incurred costs in respect of the regulated facilities will be recovered in the future, those costs are deferred and reported as a regulatory asset. When the Company is required to refund amounts to customers in the future in respect of the regulated facilities, including amounts related to costs that have not been incurred and for which the OEB has provided recovery through regulated prices, the Company records a regulatory liability.

Certain of the regulatory assets and liabilities recognized by the Company relate to variance and deferral accounts authorized by the OEB, including those authorized pursuant to *Ontario Regulation 53/05.* The measurement of these regulatory assets and liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of *Ontario Regulation 53/05* and the OEB's decisions. The estimates and assumptions made in the interpretation of the regulation and the OEB's decisions are reviewed as part of the OEB's regulatory process.

Regulatory assets and liabilities for variance and deferral account balances approved by the OEB for inclusion in regulated prices are amortized based on approved recovery or repayment periods.

In addition to regulatory assets and liabilities for variance and deferral accounts, OPG recognizes regulatory assets and liabilities for unamortized amounts recorded in AOCI in respect of pension and OPEB obligations, and deferred income taxes, in order to reflect the expected recovery or repayment of these amounts through future regulated prices charged to customers. There are measurement uncertainties related to these balances due to the assumptions made in the determination of pension and OPEB obligations and deferred income taxes that are attributed to rate regulated business segments.

The regulatory asset for unamortized pension and OPEB amounts recorded in AOCI has reflected the OEB's use, since April 1, 2008, of the accrual basis of accounting for including pension and OPEB amounts in approved regulated prices for OPG. This is also the manner in which these costs are recognized in OPG's consolidated financial statements. Therefore, unamortized amounts in respect of OPG's pension and OPEB plans recognized in AOCI generally would not be reflected in regulated prices until they have been reclassified from AOCI and recognized as amortization components of the benefit costs for these plans.

Since November 1, 2014, the OEB has limited amounts for pension and OPEB costs included in the approved revenue requirements and regulated prices to the regulated business portion of the Company's cash expenditures for its pension and OPEB plans. The difference between actual pension and OPEB costs determined using the accrual method applied in OPG's audited consolidated financial statements and OPG's corresponding actual cash expenditures for these plans is captured in OEB-authorized Pension & OPEB Cash Versus Accrual Differential Deferral Account for future consideration. In 2017, the OEB issued a report outlining the guiding principles and policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the Ontario electricity and natural gas sectors. The report establishes the accrual basis of accounting as the method of determining pension and OPEB amounts for rate-setting purposes, unless the OEB finds that this method does not result in just and reasonable rates in the circumstances of a particular utility. The OEB's report and the OEB's December 2017 decision on OPG's

application for new regulated prices require OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the existing deferral account, until such time as the OEB approves resumption of the accrual basis of recovery for OPG. The future recovery of amounts recorded in the account will be subject to this approval. Further details on the OEB's 2017 report can be found in the section, *Highlights* under the heading, *Recent Developments – OEB's Decision on OPG's Application for New Regulated Prices*.

It remains the Company's position that, taken collectively, OEB's decisions on OPG's applications for regulated prices and the OEB's 2017 report in this area do not constitute a change in the basis of OPG's rate recovery of pension and OPEB costs. The Company continues to believe that there is sufficient likelihood that unamortized pension and OPEB amounts that have not yet been reclassified from AOCI will be included in future regulated prices, or in an OEB-authorized regulatory account for future recovery, as they are recognized in benefit costs. Similarly, the Company continues to believe that there is sufficient likelihood that amounts recorded in the Pension & OPEB Cash Versus Accrual Differential Deferral Account will be recovered, and consistent with the expectations set out in the OEB's December 2017 decision, plans to file an application with the OEB in 2018 requesting recovery of the account balance. Therefore, the Company continues to recognize regulatory assets for the above amounts.

See Notes 3, 5, 8, 9, and 11 of OPG's 2017 audited consolidated financial statements for additional disclosures related to the OEB's decisions, regulatory assets and liabilities, and rate regulated accounting.

Useful Lives of Long-Lived Assets

OPG reviews estimated station useful lives for its generating assets on a regular basis.

Nuclear Generating Stations

For the nuclear stations, this process involves reviewing major life limiting components (such as pressure tubes, feeders and steam generators) to determine an appropriate end-of-life date for the station. Useful lives are set such that, with normal and customary maintenance activities, stations are expected to be operational until such time as their life-limiting component's threshold is expected to be reached.

Hydroelectric and Thermal Generating Stations

Although there is a link between the age of a facility and the capital investment required to maintain that facility, age does not establish an upper limit on the expected useful life of hydroelectric facilities and dams. Regular maintenance and the replacement of specific components typically allow hydroelectric stations to operate for very long periods. For hydroelectric generating stations, an upper age limit of 100 years have been set.

Thermal generating stations reported in the Contracted – Generation Portfolio business segment primarily have useful lives that are in line with the term of the Energy Supply Agreements with the IESO.

Financing Receivables

Financing receivables consist of the current and irrevocable right of the Fair Hydro Trust to collect payments from Specified Consumers in the future in accordance with the Fair Hydro Act and associated general regulation. These amounts are measured at the transaction price entered into with the IESO on market terms upon acquisition and subsequently measured on an amortized cost basis. The basis of amortization follows the effective interest method.

Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

In accordance with the ONFA, OPG sets aside and invests funds that are held in segregated custodian and trustee accounts specifically for discharging its obligation for nuclear facilities decommissioning and long-term nuclear waste management. The Decommissioning Segregated Fund was established to fund the future costs of nuclear fixed asset removal and long-term L&ILW management, and certain costs of used fuel storage incurred after the stations are shut down. The Used Fuel Segregated Fund was established to fund the future costs of long-term nuclear used

fuel management and certain costs of used fuel storage incurred after the stations are shut down. Costs for L&ILW management and used fuel storage incurred during station operation are not funded by the Nuclear Segregated Funds. They are funded through the Company's operating cash flow or other sources of liquidity.

Based on the current approved ONFA reference plan, starting in 2017, OPG is not currently required to make overall contributions to the Used Fuel Segregated Fund or the Decommissioning Segregated Fund. Prior to 2017, OPG made contributions to the Used Fuel Segregated Fund quarterly, including a one-time special payment in earlier years, as required by the ONFA. These contributions reflected ONFA requirements to fund the majority of the underlying used fuel liability by the end of the initial estimated useful lives of the nuclear stations assumed in the ONFA, resulting in significantly higher contributions to the Used Fuel Segregated Fund in the earlier years of OPG's existence. OPG has not been required to make contributions to the Decommissioning Segregated Fund, which was fully funded at its inception through the initial contribution made by the Province and, taking into account asset performance and changes in underlying funding obligations over time, at the time of every subsequent approved ONFA reference plan. Contributions to either or both funds may be required in the future should the funds be in an underfunded position when a new reference plan is prepared. Such may be the case as a result of variability in asset performance due to volatility inherent in financial markets and, for the portion of the Used Fuel Segregated Fund guaranteed by the Province, changes in the Ontario CPI. Future contribution levels also are dependent on changes in baseline cost estimates and underpinning assumptions used to establish the funding obligations in subsequent ONFA reference plans.

Decommissioning Segregated Fund

Upon termination of the ONFA, the Province has the sole right to any excess funds in the Decommissioning Segregated Fund. Accordingly, when the Decommissioning Segregated Fund is overfunded, OPG limits the fund earnings it recognizes in the consolidated financial statements by recording an amount due to the Province, such that the fund asset recognized on the consolidated balance sheet is equal to the cost estimate of the liability based on the most recently approved ONFA reference plan. Additionally, OPG recognizes the portion of the surplus that it may direct to the Used Fuel Segregated Fund, which is possible when the surplus is such that the underlying liabilities, as defined by the most recently approved ONFA reference plan, are at least 120 percent funded. In those circumstances, OPG may direct, at the time a new or amended reference plan is approved, up to 50 percent of the surplus over 120 percent to the Used Fuel Segregated Fund, with the OEFC entitled to a distribution of an equal amount. Therefore, when the Decommissioning Segregated Fund is at least 120 percent funded, OPG recognizes 50 percent of the excess greater than 120 percent in income, up to the amount by which the Used Fuel Segregated Fund is underfunded.

The amount due to the Province in respect of the Decommissioning Segregated Fund could be reduced in subsequent periods in the event that the fund earns less than is target rate of return, a new ONFA reference plan is approved with a higher underlying liability, or the amount of the underfunding in the Used Fuel Segregated Fund increases.

When the Decommissioning Segregated Fund is underfunded, the earnings on the fund reflect actual fund returns based on the market value of the assets.

Used Fuel Segregated Fund

Under the ONFA, the Province guarantees OPG's annual return in the Used Fuel Segregated Fund at 3.25 percent plus the change in the Ontario CPI, as defined in the ONFA, for funding related to the first 2.23 million used fuel bundles ("committed return"). OPG recognizes the committed return on the Used Fuel Segregated Fund as earnings on the Nuclear Segregated Funds. The difference between the committed return and the actual market return determined based on the fair value of the fund's assets related to the first 2.23 million used fuel bundles is recorded as due to or due from the Province. This amount represents the amount OPG would pay to, or receive from, the Province if the committed return were to be settled as of the consolidated balance sheet date. Upon approval of a

new or amended ONFA reference plan, the Province is obligated to make an additional contribution to the Used Fuel Segregated Fund in relation to the first 2.23 million used fuel bundles if the fund's assets earned a rate of return that is less than the guaranteed rate of return. If the return on the fund's assets exceeds the Province's guaranteed rate of return, the Province is entitled to withdraw any portion of the excess related to the 2.23 million used fuel bundles, upon approval of a new or amended ONFA reference plan. The 2.23 million threshold represents the estimated total life cycle fuel bundles based on the initial estimated useful lives of the nuclear stations assumed in the ONFA.

As prescribed under the ONFA, OPG's contributions attributed to the used fuel bundles in excess of 2.23 million are not subject to the rate of return guaranteed by the Province, and earn a return based on changes in the market value of the assets of the Used Fuel Segregated Fund.

If there is a surplus in the Used Fuel Segregated Fund such that the funding liabilities, as defined by the most recently approved ONFA Reference Plan, are at least 110 percent funded, the Province has the right, at any time, to access the excess amount greater than 110 percent. Upon termination of the ONFA, the Province is entitled to any surplus in the fund. Accordingly, when the Used Fuel Segregated Fund is overfunded, OPG limits the fund earnings it recognizes in the consolidated financial statements by recording an amount due to the Province, such that the balance of the fund is equal to the cost estimate of the liability based on the most recently approved ONFA reference plan. In accordance with the ONFA, neither OPG nor the Province have a right to direct any amounts from the Used Fuel Segregated Fund to the Decommissioning Segregated Fund.

Provincial Guarantee

In accordance with the *Nuclear Safety and Control Act* (Canada), the CNSC requires OPG to have sufficient funds available to discharge its existing nuclear waste management and nuclear decommissioning obligations. The CNSC process requires the CNSC financial guarantee requirement to be updated once every five years and for OPG to provide an annual report to the CNSC on the assumptions, asset values, and resulting financial guarantee requirements. The CNSC financial guarantee requirement calculation takes into account nuclear waste expected to be generated to the end of each year.

In November 2017, the CNSC accepted OPG's proposed 2018-2022 CNSC financial guarantee requirement to be satisfied by the forecast fair market value of the Nuclear Segregated Funds without the requirement of a Provincial Guarantee for the 2018-2022 period. As required by the terms of the ONFA, the Province is committed to provide a Provincial Guarantee to the CNSC, on behalf of OPG, should there be a shortfall between the CNSC financial guarantee requirement and the fair market value of the Nuclear Segregated Funds in the 2018-2022 period, as it has done in the past. OPG pays the Province an annual guarantee fee equal to 0.5 percent of the outstanding amount, if any, of the Provincial Guarantee.

The value of the Provincial Guarantee in effect through to the end of 2017 was $1,551 million. Based on this guarantee amount, OPG paid a guarantee fee of $8 million to the Province for each of 2016 and 2017.

Pension and Other Post-Employment Benefits

The determination of OPG's pension and OPEB costs and obligations is based on accounting policies and assumptions, as discussed below.

Accounting Policy

OPG's post-employment benefit programs consist of a contributory defined benefit registered pension plan, a defined benefit supplementary pension plan, and other post retirement benefits (OPRB) including group life insurance and health care benefits, and long-term disability (LTD) benefits. Post-employment benefit programs also are provided by the Nuclear Waste Management Organization (NWMO), which is consolidated into OPG's financial results. Unless otherwise noted, information on the Company's post-employment benefit programs is presented on a consolidated basis.

OPG accrues its obligations under pension and OPEB plans in accordance with US GAAP. The obligations for pension and OPRB are determined using the projected benefit method pro-rated on service. The obligation for LTD benefits is determined using the projected benefit method on a terminal basis. Pension and OPEB obligations are impacted by factors including interest rates, adjustments arising from plan amendments, demographic assumptions, experience gains or losses, salary levels, inflation, and health care cost escalation assumptions. Pension and OPEB costs and obligations are determined annually by independent actuaries using management's best estimate assumptions.

Pension fund assets include equity securities, corporate and government debt securities, pooled funds, real estate, infrastructure and other investments. These assets are managed by professional investment managers. The pension fund does not invest in equity or debt securities issued by OPG. Pension fund assets are valued using market-related values for purposes of determining the amortization of actuarial gains or losses and the expected return on plan assets. The market-related value recognizes gains and losses on equity assets relative to a six percent assumed real return over a five-year period.

Pension and OPEB costs include current service costs, interest costs on the obligations, the expected return on pension plan assets, adjustments for plan amendments and adjustments for actuarial gains or losses, which result from changes in assumptions and experience gains and losses. Past service costs or credits arising from pension and OPRB plan amendments are amortized on a straight-line basis over the expected average remaining service life to full eligibility of the employees covered by the corresponding plan. Past service costs or credits arising from amendments to LTD benefits are immediately recognized as OPEB costs in the period incurred. Due to the long-term nature of pension and OPRB liabilities, the excess of the net cumulative unamortized gain or loss, over 10 percent of the greater of the benefit obligation and the market-related value of the plan assets (the corridor) for each plan is amortized over the expected average remaining service life of the employees covered by the plan, which represents the period during which the associated economic benefits are expected to be realized by the Company. Actuarial gains or losses for LTD benefits are immediately recognized as OPEB costs in the period incurred.

OPG recognizes the funded status of its defined benefit plans on the consolidated balance sheets. The funded status is measured as the difference between the fair value of plan assets and the benefit obligation, on a plan-by-plan basis.

Actuarial gains or losses and past service costs or credits arising during the year that are not recognized immediately as components of benefit costs are recognized as increases or decreases in other comprehensive income (OCI), net of income taxes. These unamortized amounts in AOCI are subsequently reclassified and recognized as amortization components of pension and OPRB costs as described above.

As at December 31, 2017, the unamortized net actuarial loss and unamortized past service costs for the pension and OPEB plans totalled $4,148 million (2016 – $3,668 million). Details of the unamortized net actuarial loss and unamortized past service costs as at December 31, 2017 and 2016 are as follows:

(millions of dollars)	Registered Pension Plans 2017	2016	Supplementary Pension Plans 2017	2016	Other Post-Employment Benefits 2017	2016
Net actuarial gain not yet subject to amortization due to use of market-related values	**(418)**	(570)	**-**	-	**-**	-
Net actuarial loss not subject to amortization due to use of the corridor	**1,735**	1,619	**36**	34	**299**	267
Net actuarial loss subject to amortization	**2,333**	2,238	**80**	72	**79**	3
Unamortized net actuarial loss	**3,650**	3,287	**116**	106	**378**	270
Unamortized past service costs	**-**	-	**-**	-	**4**	5

OPG records an offsetting regulatory asset or liability for the portion of the adjustments to AOCI that is attributable to the regulated operations in order to reflect the expected recovery or refund of these amounts through future regulated prices charged to customers. For the recoverable or refundable portion attributable to regulated operations, OPG records a corresponding change in this regulatory asset or liability for the amount of the increases or decreases in OCI and for the reclassification of AOCI amounts into benefit costs during the period.

When the recognition of the transfer of employees and employee-related benefits gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement. A curtailment is the loss by employees of the right to earn future benefits under the plan. A settlement is the discharge of a plan's liability.

Accounting Assumptions

Assumptions are significant inputs to actuarial models that measure pension and OPEB obligations and related effects on operations. Discount rate, inflation rate and changes in salary levels are three critical assumptions in the determination of benefit costs and obligations. In addition, the expected long-term rate of return on plan assets is a critical assumption in the determination of registered pension plan cost, and the health care cost trend rate is a critical assumption in the determination of OPEB cost and obligations. These assumptions, as well as other assumptions involving demographic factors such as retirement age, mortality, and employee turnover, are evaluated periodically by management in consultation with independent actuaries. During the evaluation process, the assumptions are updated to reflect past experience and expectations for the future. Actual results in any given year will often differ from actuarial assumptions because of economic and other factors giving rise to actuarial gains and losses.

The discount rates, which are representative of the AA corporate bond yields, are used to calculate the present value of the expected future cash flows on the measurement date in order to determine the projected benefit obligations for the Company's employee benefit plans. A lower discount rate increases the benefit obligations. The weighted-average discount rate used to determine the projected pension and OPEB benefit obligations as at December 31, 2017 was 3.6 percent. This represents a decrease compared to the 3.9 percent discount rate that was used to determine the obligations as at December 31, 2016.

In 2016 and prior years, benefit costs were calculated using the same single weighted-average discount rates as reflected in the calculation of the benefit obligations. Effective January 1, 2017, OPG adopted a full yield curve approach to the estimation of the service and interest cost components of pension and OPEB costs, by applying the specific spot rates along the yield curve used in the determination of the projected benefit obligations to the relevant projected cash flows. The change improves the correlation between projected benefit cash flows and the corresponding yield curve spot rates, and provides a more precise measurement of service and interest costs. This change in the method was accounted for prospectively, as a change in estimate. The resulting reduction in pension and OPEB costs is estimated at approximately $135 million for the twelve months ended December 31, 2017. Approximately 90 percent of this reduction in pension and OPEB costs was attributed to the Company's regulated

business segments and therefore was offset by the impact of OEB-authorized regulatory accounts. The change does not affect the measurement of the total benefit obligation as the change in the current service and interest cost components from the previous method is offset by a corresponding change in the actuarial gain or loss recorded in AOCI.

The expected rate of return on plan assets is determined based on the pension fund's asset allocation and the expected return considering long-term risks and returns associated with each asset class within the plan portfolio. A lower expected rate of return on plan assets increases pension cost.

A new actuarial valuation of the OPG registered pension plan was filed with the Financial Services Commission of Ontario in September 2017 with an effective date of January 1, 2017. The annual funding requirements in accordance with the new actuarial valuation are outlined in the section, *Liquidity and Capital Resources* under the heading, *Contractual and Commercial Commitments*. OPG conducted a comprehensive actuarial valuation for accounting purposes of its pension and OPEB plans in 2017, using demographic data as at January 1, 2017 consistent with the new funding valuation and using assumptions as at December 31, 2017. As part of the valuation, the plans' demographic and other assumptions were reviewed and revised, as necessary, by independent actuaries.

The deficit for the registered pension plan, for accounting purposes, increased from $2,693 million as at December 31, 2016 to $3,081 million as at December 31, 2017. This increase was largely due to a re-measurement of the liabilities at the end of 2017 reflecting lower discount rates, partially offset by the excess of actual returns on the pension plan assets over interest costs on the liabilities during the year.

The projected benefit obligations for OPEB increased from $2,992 million as at December 31, 2016 to $3,190 million as at December 31, 2017. This increase was largely due to a re-measurement of the liabilities at the end of 2017 reflecting a decrease in the discount rates, partially offset by the updated, lower per capita health care claims costs assumption as part of the 2017 actuarial valuation.

A change in the following assumptions, holding all other assumptions constant, would increase (decrease) pension and OPEB costs for the year ended December 31, 2017 as follows:

(millions of dollars)	**Registered Pension Plans [1]**	**Supplementary Pension Plans [1]**	**Other Post-Employment Benefits [1]**
Expected long-term rate of return			
0.25% increase	(32)	n/a	n/a
0.25% decrease	32	n/a	n/a
Discount rate			
0.25% increase	(56)	(1)	(2)
0.25% decrease	59	1	13
Inflation			
0.25% increase	98	1	-
0.25% decrease	(91)	(1)	-
Salary increases			
0.25% increase	22	3	-
0.25% decrease	(20)	(2)	-
Health care cost trend rate			
1% increase	n/a	n/a	77
1% decrease	n/a	n/a	(29)

n/a – change in assumption not applicable.

[1] Excludes the impact of regulatory accounts.

Asset Retirement Obligation

OPG recognizes ARO for fixed asset removal and nuclear waste management liabilities, discounted for the time value of money. OPG estimates both the amount and timing of future cash expenditures based on the plans for fixed asset removal and nuclear waste management. The ARO is comprised of expected costs to be incurred up to and beyond termination of operations and the closure of nuclear and thermal generating plant facilities and other facilities. Costs are expected to be incurred for activities such as preparation for safe storage and safe storage of nuclear stations, dismantlement, demolition and disposal of facilities and equipment, remediation and restoration of sites, and the ongoing and long-term management of nuclear used fuel bundles and L&ILW material. The liabilities associated with the decommissioning of the nuclear generating stations and the long-term management of used nuclear fuel comprise the most significant amounts of the total obligation.

The nuclear decommissioning liability includes the estimated costs of closing the nuclear stations after the end of their service lives, which includes preparation and placement of the stations into a safe state condition followed by an assumed 30-year safe store period prior to station dismantlement and site restoration. Activities associated with the placement of stations into a safe state condition include de-fuelling and de-watering of the nuclear reactors. OPG is responsible for the nuclear waste management and nuclear decommissioning obligations associated with the Bruce nuclear generating stations and includes the associated costs in its ARO. Pursuant to the lease agreement, Bruce Power must return the two Bruce stations to OPG together, in a de-fuelled and de-watered state. As such, these de-watering and de-fuelling costs are not part of OPG's ARO.

The life cycle costs of L&ILW management include the costs of processing and storage of such radioactive wastes during and following the operation of the nuclear stations, as well as the costs of the ultimate long-term management of these wastes. The current assumptions used to establish the obligation for these costs include an L&ILW DGR facility to be constructed and operated by OPG, as discussed in the section, *Core Business, Strategy, and Outlook* under the heading, *Project Excellence*. To estimate the liability for nuclear used fuel management, OPG has adopted an approach consistent with the Adaptive Phased Management concept approved by the Government of Canada, which assumes a deep geologic repository for the long-term management of Canada's nuclear used fuel waste. The NWMO is responsible for the design and implementation of Canada's plan for the long-term management of used nuclear fuel.

The following costs are recognized as a liability on OPG's consolidated balance sheets:

- the present value of the costs of decommissioning the nuclear and thermal production facilities and other facilities after the end of their useful lives
- the present value of the fixed cost portion of nuclear waste management programs that are required based on the total volume of waste expected to be generated over the assumed lives of the stations
- the present value of the variable cost portion of nuclear waste management programs taking into account waste volumes generated to date.

The significant assumptions underlying operational and technical factors used in the calculation of the accrued liabilities are subject to periodic review. Changes to these assumptions, including changes to assumptions on the timing of the programs including construction of assumed waste disposal facilities, station end-of-life dates, waste disposal methods, financial indicators, decommissioning strategy, and the technology employed may result in significant changes to the value of the accrued liabilities. With programs of such long-term duration and the evolving technology to handle nuclear waste, there is a significant degree of inherent uncertainty surrounding the measurement of the costs for these programs. These costs may increase or decrease over time.

The estimates for the Nuclear Liabilities are reviewed on an ongoing basis as part of the overall nuclear waste management program. A comprehensive reassessment of all underlying assumptions and baseline cost estimates is performed periodically, at least once every five years, in line with the required ONFA reference plan update process. Changes in the Nuclear Liabilities resulting from changes in assumptions or estimates that impact the amount or

timing of the estimated undiscounted future cash flows are recorded as an adjustment to the liabilities. Upward revisions in the Nuclear Liabilities represent the present value of a net increase in future undiscounted cash flows determined using a current credit-adjusted risk-free rate. Downward revisions in the Nuclear Liabilities represent the present value of a net decrease in future undiscounted cash flows determined using the weighted average discount rate reflected in the existing liability. Resulting changes in the related asset retirement costs are capitalized as part of the carrying amount of nuclear fixed assets in service.

As of December 31, 2017, OPG recorded an increase of $188 million in the Nuclear Liabilities and associated asset retirement costs capitalized as part of carrying value of property, plant and equipment (PP&E) reflecting the change in the Pickering GS accounting end-of-life assumptions from December 31, 2020 for all operating units to December 31, 2022 for Units 1 and 4 and December 31, 2024 for Units 5 to 8. The increase in the liabilities is primarily due to higher fixed costs associated with the Used Fuel Disposal and L&ILW Storage programs, discounted using the current credit-adjusted risk-free rate of 2.94 percent. The adjustment did not impact net income for 2017. The adjustment is not expected to have a material impact on net income in 2018 as the associated impact on expenses is expected to be largely offset by OEB-authorized regulatory accounts. The change in accounting end-of-life assumptions for the Pickering GS are discussed in further detail in the section, *Core Business, Strategy, and Outlook* under the heading, *Operational Excellence – Electricity Generation Production and Reliability*.

For the purposes of calculating OPG's Nuclear Liabilities, as at December 31, 2017, consistent with the current accounting end-of-life assumptions, nuclear station decommissioning activities are projected to occur over approximately the next 80 years.

The liability for nuclear fixed asset removal and nuclear waste management on a present value basis as at December 31, 2017 was $20,077 million (2016 – $19,103 million). As at December 31, 2017, the undiscounted cash flows of expenditures for OPG's Nuclear Liabilities in 2017 dollars are as follows:

(millions of dollars)	**2018**	**2019**	**2020**	**2021**	**2022**	**Thereafter**	**Total**
Expenditures for nuclear fixed asset removal and nuclear waste management [1]	323	326	323	311	598	40,513	42,394

[1] The majority of the expenditures are expected to be reimbursed by the Nuclear Segregated Funds established by the ONFA. Any contributions required under the ONFA are not included in these undiscounted cash flows. Accounting for the Nuclear Segregated Funds is discussed in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

The liability for non-nuclear fixed asset removal was $344 million as at December 31, 2017 (2016 – $381 million). This liability primarily represents the present value of estimated costs of decommissioning OPG's thermal generating stations at the end of their service lives. OPG has updated the asset retirement obligations for the thermal generating stations as of December 31, 2017, based on a review of required decommissioning, clean-up and restoration activities, underlying economic assumptions and anticipated timing of these activities in line with current accounting end-of-life assumptions for the operating sites. For the shutdown Nanticoke and Lambton generating stations, the update reflects the estimated cost of executing current decommissioning plans. For the currently operating sites, OPG recognized a decrease of $18 million in the non-nuclear fixed asset removal liabilities and associated asset retirement costs capitalized as part of the carrying value of PP&E as at December 31, 2017. For the Nanticoke and Lambton sites, a reduction in the non-nuclear fixed asset removal liabilities and a gain of approximately $12 million was recorded in net income in the fourth quarter of 2017, in the, Services, Trading, and Other Non-Generation segment.

For the purpose of measuring the non-nuclear fixed asset removal liability, asset removal activities are assumed to take place approximately over the next one to 12 years. The amount of undiscounted estimated future cash flows associated with the thermal liabilities is approximately $400 million.

OPG has no legal obligation associated with the decommissioning of its hydroelectric generating facilities and the costs cannot be reasonably estimated because of the long service life of these assets. With either maintenance efforts or rebuilding, the water control structures are assumed to be used for the foreseeable future. Accordingly, OPG has not recognized a liability for the decommissioning of its hydroelectric generating facilities.

Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly arm's-length transaction between market participants at the measurement date. Fair value measurements are required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model.

The fair value of financial assets and liabilities for which quoted prices in an active market are available, including exchange traded derivatives and other financial instruments, are determined directly from those quoted market prices.

For financial instruments for which quoted market prices are not directly available, fair values are estimated using forward price curves developed from observable market prices or rates. The estimation of fair value may include the use of valuation techniques or models, based wherever possible on assumptions supported by observable market prices or rates prevailing at the consolidated balance sheet dates. This is the case for over-the-counter derivatives and securities, which include energy commodity derivatives, foreign exchange derivatives, interest rate swap derivatives, and fund investments. Pooled fund investments are valued at the unit values supplied by the pooled fund administrators. The unit values represent the underlying net assets at fair values, determined using closing market prices. Valuation models use general assumptions and market data and therefore do not reflect the specific risks and other factors that may affect a particular instrument's fair value. The methodologies used for calculating the fair value adjustments are reviewed on an ongoing basis to ensure that they remain appropriate. If the valuation technique or model is not based on observable market data, specific valuation techniques are used, primarily based on recent comparable transactions, comparable benchmark information, bid/ask spread of similar transactions, and other relevant factors.

For the financing receivables related to the Investment Interest acquired from the IESO, fair value is estimated to equal the fair value of the underlying debt due to the direct relationship of the asset, and the debt instruments that financed the acquisition.

OPG's use of financial instruments exposes the Company to certain risks, including credit risk, foreign currency risk and interest rate risk. A discussion of how OPG manages these and other risks is found under the section, *Risk Management*.

Recent Accounting Pronouncements Not Yet Adopted

The recent US GAAP accounting pronouncements related to revenue recognition, leases, and financial instruments are described below. Other recent accounting pronouncements applicable to OPG are outlined in Note 3 of the audited consolidated financial statements.

Revenue from Contracts with Customers

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09, *Revenue from Contracts with Customers* (Topic 606), which supersedes nearly all existing revenue recognition guidance, including industry-specific guidance, under US GAAP. The core principle of Topic 606 is to recognize revenues when promised goods or services are transferred to customers in an amount that reflects the consideration to which an entity expects to be entitled for those goods or services. Either a full retrospective

application or a modified retrospective application is required for annual periods beginning on or after January 1, 2018, including interim periods within that year. Early adoption is permitted.

OPG has assessed the impact of the standard on accounting for the Company's revenue streams and consolidated financial statements. OPG's major revenue streams include regulated generation revenue from base regulated prices and rate riders established by the OEB, as well as revenue from generation assets under long-term contractual arrangements with the IESO. OPG has completed its analyses of the impact of Topic 606 on all of its revenue streams, and has not identified any material differences in the timing or amount of revenue recognition for these streams.

The Company will apply the new revenue standard in its 2018 first quarter interim financial statements and is in the process of evaluating the additional disclosures required under the new standard.

Lease Accounting

In February 2016, the FASB issued ASU No. 2016-02, *Leases* (Topic 842). The update includes comprehensive changes to existing guidance for lease accounting, particularly for lessees, and aims to increase transparency and comparability among organizations by requiring the recognition of lease assets and lease liabilities on the balance sheet. The standard is effective for annual periods beginning after December 15, 2018, including interim periods within that year.

Under the current guidance, entities are required to use a modified retrospective approach for leases that exist, or are entered into, after the beginning of the earliest comparative period presented in the financial statements of the period of adoption. Under this method, Topic 842 would effectively be implemented by recognizing any adjustments stemming from the transition, as of beginning of the earliest comparative period presented in the entities' financial statements. Full retrospective application is prohibited. In January 2018, the FASB issued a proposed ASU wherein entities would be able to utilize an additional optional transition method of recording the cumulative impact of adopting the new lease standard to the opening balance in the initial period of adoption; with comparative periods continuing to be presented in accordance with the existing leasing standard, Topic 840 - *Leases*, including disclosures. [**MONITOR**] The Company will continue to monitor the status of this proposed ASU.

The FASB also issued ASU No. 2018-01, *Land Easement Practical Expedient for Transition to Topic 842* in January 2018. The amendments therein allows an entity to choose not to evaluate under Topic 842 land easements that exist or expired before the entity's adoption of the new leasing standard and that were not previously accounted for as leases under Topic 840.

The Company continues to implement and execute a comprehensive project governance framework, which comprises a Steering Committee, Implementation & Stakeholder Committee, Project Management Office, and various working groups in order to evaluate the implement the new standard. The working groups are represented by cross functional finance and non-finance stakeholders who will support the financial and operational implementation of the standard. The Company continues to evaluate the impact of the new leasing standard on its consolidated financial statements.

Recognition and Measurement of Financial Assets and Financial Liabilities

In January 2016, the FASB issued ASU No. 2016-01, *Financial Instruments – Overall: Recognition and Measurement of Financial Assets and Financial Liabilities*. Under the updated guidance, entities will have to measure equity investments at fair value and recognize any changes in fair value in net income. The update will be effective for OPG's 2018 fiscal year, including interim periods. As a result of this update, effective January 1, 2018, the available-for-sale (AFS) classification for equity securities will no longer be available, with any unrealized gains and losses related to such securities recognized in net income instead of OCI. Any unrealized gains and losses for AFS securities reported by OPG in AOCI as of the end of 2017 will be reclassified to retained earnings as of January 1, 2018. OPG's equity shareholdings in Hydro One are currently the Company's only AFS securities. As at December

31, 2017, these shares are valued on the consolidated balance sheet at $188 million, for which a loss of $8 million has been recorded in AOCI. OPG does not expect the new standard to have any other significant impact on its consolidated financial statements.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost

In March 2017, the FASB issued ASU No. 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. Under the new guidance, employers that sponsor defined benefit plans for pensions and/or other postretirement benefits are required to present the service cost component of net periodic benefit cost in the same statement of income line item as other employee compensation costs arising from services rendered during the period. The other components of the net periodic benefit cost are to be presented separately from the line item that includes the service cost and outside of any subtotal of income from operations, if such a subtotal is presented. In addition, the new guidance requires that only the service cost component of net benefit cost be eligible for capitalization.

This guidance is effective for fiscal years beginning after December 15, 2017, including interim periods of those years. The guidance is not expected to have a material impact on OPG's consolidated financial statements, as OPG currently capitalizes only the service cost component of post-retirement benefits costs. Additionally, OPG already includes the service cost component of post-retirement benefit costs with other compensation costs, within the operations, maintenance and administration expenses line item in the consolidated statements of income, and does not show a subtotal of income from operations. As such, the new guidance is not expected to affect the presentation of OPG's consolidated financial statements.

RISK MANAGEMENT

Overview

OPG faces various risks that could significantly impact the achievement of its strategic imperatives. The objective of risk management is to identify, assess and mitigate key risks, and to preserve and increase the value of the Shareholder's investment in the Company.

The Audit and Risk Committee is mandated to fulfill the oversight responsibilities of the Board of Directors for matters relating to the identification and management of the Company's key business risks. OPG's Enterprise Risk Management framework is designed to identify and evaluate risks on the basis of their potential impact on the Company's strategic imperatives and business plan objectives. Formal risk management policies, procedures and systems are in place to identify, assess and mitigate risks to the Company. Senior management also establishes set limits for the market risk, credit risk and energy trading activities of the Company.

The key risks to OPG's strategic imperatives are briefly described below. These are key risks that management believes could materially affect its business, revenues, net income, assets or capital resources. There may be further risks and uncertainties that are not presently known, or that are not currently believed to be material, that may in the future adversely affect the Company's performance or financial condition.

Risks to Achieving Operational Excellence

OPG is exposed to variable output from its existing generating stations that could adversely impact its financial performance. The operational risks of a station are generally a function of its age, human performance, and the technology used.

Asset Conditions and Generation Variability

The uncertainty associated with electricity production by OPG's generating units is primarily driven by the condition of station components and systems, which are subject to the effects of aging and the manner in which the units operate. To safely operate the units to meet electricity system requirements, a unit could be derated resulting in reduced generation. The primary implications of these risks may include additional safety requirements, lower than expected generation and revenues, and higher operating or capital costs. To respond to this risk, OPG continues to:

- monitor performance, implement extensive inspection and maintenance programs;
- identify future work required to sustain and, as appropriate, upgrade a station equipment; and
- undertake projects required to reliably operate within design and operating parameters.

Extension of Commercial Operations at Pickering to 2024

In January 2016, the Province of Ontario announced its approval of OPG's plan to pursue the continued safe and reliable operation of the Pickering GS to 2024. Under OPG's plan, the six operating units at the Pickering GS would operate until 2022, at which point two units would be shut down and the remaining four units would continue to operate until 2024. The current operating licence for the Pickering GS, which expires in August 2018, was issued in 2013 assuming that the station would shut down in 2020. Technical assessments have been completed to determine the ability of the Pickering units to continue to be fit for service to support extended operations. There is high technical confidence in the programs and provisions in place to operate the station to the end of 2024.

Inability to extend operations as planned would result in a reduction of OPG's future generation revenue and cash flows and lead to the advancement of station shutdown and decommissioning expenditures.

Risk factors for extended operations include the discovery of unexpected conditions, equipment failures, the state of critical plant components that are reaching end-of-life and a requirement for significant plant modifications. To mitigate these risks, OPG has implemented actions recommended from the technical assessments as part of the outage work program. OPG has also incorporated those actions into the comprehensive inspection and maintenance program under the Life Cycle Management Plan.

Supply Chain

OPG's ability to operate effectively is in part dependent upon timely access to equipment, materials, and service suppliers. Loss of key equipment, materials and service suppliers, particularly for the nuclear business, could affect OPG's operations and execution of major capital projects. OPG mitigates this risk, to the extent possible, through contract negotiations, contract terms, vendor monitoring, diversification of supplier base and business continuity plans.

Cyber Security

OPG's operations depend in part, on the efficient operation and management of the Company's complex information technology and operational systems in a secure, vigilant and resilient manner that minimizes cyber risks. Cyber security incidents may have an adverse impact on OPG's reputation, energy production, and public and employee safety.

Cyber security incidents have been on the rise for the past few years and this trend is only expected to intensify as global reliance on technology increases. OPG has strategies in place to prepare for, respond to, and recover from cyber security incidents. OPG continuously monitors, assesses, and improves the effectiveness of its strategies and program considering leading industry practices and remains proactive in information and intelligence sharing to learn and adapt to the changing cyber environment. In 2017, the media reported several worldwide cyber-attacks, such as WannaCry and Petya, which impacted multiple sectors including power and utilities. OPG's operational responses to those cyber-attacks were timely and effective resulting in no or low operational impact to OPG.

As a registered Ontario market participant, OPG must comply with reliability standards that apply to the Bulk Electric System elements specified under North American Electric Reliability Corporation and the relevant Bulk Power System facilities as determined by the Northeast Power Coordinating Council. In addition, OPG's nuclear cyber assets are subject to CNSC licensing conditions and regulatory requirements. For other cyber assets not subject to applicable regulatory requirements, OPG has adopted a risk-based approach based on the National Institute of Standards and Technology cyber security framework to manage its cyber security. Policies are in place to manage the Company's cyber risks and programs which are subject to oversight by management and the Board.

Regulatory Compliance

OPG is subject to extensive federal and provincial legislation and regulations by various entities such as the OEB, CNSC and the IESO.

The uncertainty associated with nuclear regulatory compliance is driven by plant aging, changes to technical codes, and challenges raised by the public at regulatory hearings, particularly in the areas of safety, environment and emergency preparedness. Addressing these requirements could add to the cost of operations, including replacement or modification of a station component or additional requirements for waste management. In some instances, these requirements may result in a reduction or elimination of the productive capacity of a station.

The Provincial agency, Office of the Fire Marshal and Emergency Management (OFMEM) is required to periodically update the Provincial Nuclear Emergency Response Plan (PNERP). In 2016, the CNSC advised the OFMEM to consider more severe accidents in the update to the PNERP, which may result in potential changes to the planning basis. Potentially, these changes may include new protective requirements and expansion of the emergency plan requirements for Pickering. In December 2017, the Province approved the updated PNERP Master Plan. The development of a detailed Implementing Plan for the Pickering GS is in progress. To date, there is no significant impact on OPG from the updated PNERP.

In December 2015, the CNSC granted the Darlington GS a ten-year operating licence, valid until November 30, 2025. The new licence spans most of the planned duration of the Darlington Refurbishment project, which provides greater regulatory stability and reduces regulatory risk. As discussed in the section, *Core Business, Strategy and Outlook*, under the heading, *Nuclear Operations*, the plan to extend Pickering operations to 2024 is subject to the CNSC's approval of the Pickering licence renewal application and other regulatory requirements as set out by the CNSC.

Nuclear Waste Management

The handling, storage and disposal of nuclear waste exposes OPG to various risks that it manages in accordance with the applicable regulatory requirements. Additionally, the interim storage of nuclear waste is subject to rigorous oversight and monitoring.

Currently, there are no licenced facilities in Canada for the permanent disposal of used nuclear fuel or L&ILW. The risks to OPG's proposed L&ILW DGR for the safe long-term management of L&ILW are discussed below under the heading, *Risks to Achieving Project Excellence – Deep Geologic Repository for Low and Intermediate Level Waste*.

Human Resources and Organizational Structure

The development of new leaders and retention of staff in critical roles is a key factor to OPG's success. The risk associated with the alignment and availability of skilled and experienced resources continues to exist for OPG in specific areas, including leadership and project management positions. To mitigate this risk, OPG continues to focus on succession planning, leadership development and knowledge management programs to improve the capability of its workforce. OPG expects to meet the human resource needs of the business by developing existing employees and hiring in specific areas, while continuing to leverage attrition through realignment of work and streamlining of processes, where appropriate.

Labour Relations

As of December 31, 2017, approximately 88 percent of OPG's regular labour force was represented by a union. The collective agreements with the PWU and The Society are due for renewal in 2018. There is a risk that OPG may not be able to negotiate terms that allow for compensation levels consistent with its rate orders.

OPG's current collective agreements with the PWU expires on March 31, 2018 and renewal negotiations began in early 2018. In the event of a labour disruption by the PWU, OPG could face financial or reputational implications. OPG has contingency plans in place to minimize the impact. **[MONITOR]**

The collective agreement between OPG and The Society expires on December 31, 2018 and renewal negotiations are expected to begin in mid-2018. The parties do not have the right to strike or lock-out. If the parties are unable to reach an agreement, the terms of the new collective agreement would be decided through interest mediation/arbitration.

Health and Safety

OPG's operations involve inherent occupational safety risks and hazards that could impact the achievement of the Company's health and safety goals. OPG is committed to continuous improvement and achievement of its ultimate goal of zero injuries through a formal enterprise-wide safety management system and by continuing to foster a strong health and safety culture among its employees and contractors. The safety management system serves to focus the Company on proactively managing safety risks and hazard exposures to employees and contractors. OPG also strategically engages with external parties for benchmarking and auditing. This ensures that OPG's management system achieves its intended results and maximizes the opportunity to incorporate program improvements.

Business Continuity and Emergency Management

OPG may be exposed to natural, technological or human-caused hazards including significant events against which it is not fully insured or indemnified; or to parties that fail to meet their indemnification obligations. These hazards have the potential to disrupt operations resulting in decreased generation revenue or additional costs to repair damages and restore operations.

OPG's business continuity program provides a framework to build resilience into critical business processes to ensure continued operation of critical business functions. OPG's emergency management program is designed to ensure that the Company can manage an emergency in a timely and effective manner. OPG's plans and implementation procedures identify immediate response actions to be taken to protect the health and safety of workers and the public, and to limit the impact of the incident on site security, production capability and the environment. The program elements are designed to meet legal and regulatory requirements.

Risks to Achieving Project Excellence

OPG is undertaking several capital intensive projects with significant investments. There may be an adverse effect on the Company if it is unable to: obtain necessary approvals; raise the necessary funds; effectively manage the projects on time and on budget; or fully recover capital costs and earn an appropriate return on investment. These projects may also have a significant impact on OPG's borrowing capacity and credit rating. Some projects may be ultimately reassessed as being uneconomic. The risks associated with OPG's current major projects are described below.

Darlington Refurbishment

There are financial and reputational risk exposures for OPG if actual costs exceed the budget or if OPG does not meet the project schedule. In addition, failure to achieve the objectives of the refurbishment project may result in future forced outages and more complex planned outages, potentially impacting the post-refurbishment performance or useful life of the units. Failure to carry out the refurbishment of the first unit as planned may result in the Province

exercising an off-ramp for the refurbishment of the remaining units. In January 2018, Refurbishment senior management met with the Minister of Energy, Cabinet and Treasury Board to provide an update on the status of the Darlington Refurbishment project and to request a decision to not exercise the Unit 3 off-ramp. The request was based on the performance to date on the Unit 2 project. Additionally, OPG continues to apply lessons learned that have been captured on the execution of Unit 2 into the planning of future units.

There are a number of specific risks that OPG is managing and mitigating in relation to the Darlington Refurbishment project, which include OPG and vendor performance risks, delay or productivity risks, financial risks related to escalation of costs, technical risks such as equipment conditions resulting in additional scope and execution risks. A large portion of the costs for the Darlington Refurbishment project is being paid to contractors and suppliers, including vendors that will engineer, procure and construct components of the project. There is a risk that, as the volume of work increases significantly, vendor capability, capacity and performance shortfalls may impact project objectives and deliverables.

OPG systematically manages the risks associated with the Darlington Refurbishment project through robust risk management practices to achieve project deliverables on time and budget with quality. OPG engaged in an extensive five-year project planning phase to determine the project scope and to rigorously estimate costs. During this phase, OPG also took into account major lessons learned from other nuclear refurbishments and large scale, complex projects. In order to fully define the scope and material requirements for the project, the planning phase included the completion of detailed designs before proceeding with the execution of the unit refurbishments. Further risk mitigation has been implemented through the construction of a full scale model training reactor, which allows for simulations and training for unit refurbishment execution tasks.

OPG's risk management strategy aims to ensure that contractors are held accountable and appropriate incentives and disincentives are in place. There is also an increased risk of contractor initiated safety events, which may impact OPG's reputation. Mitigating actions include:

- Collaborative training and planning with vendors on executing work safely;
- An enhanced human performance program;
- Increased field presence by supervisory staff; and
- Collaboration with Bruce Power to streamline processes and reduce burden on vendors.

OPG is also managing other ongoing risks that could potentially impact the project, including those related to continuity of skilled leaders within OPG and its vendor partners, as well as the availability of technical resources to support the project through execution.

Both management and Board of Directors have engaged Independent, third-party oversight for the execution phase of the project.

Deep Geologic Repository for Low and Intermediate Level Waste

OPG, with the support of Bruce County municipalities, is proposing to construct and operate a deep geologic repository for the safe long-term management of L&ILW. While broad local community support for the proposed L&ILW DGR is stable, OPG continues its engagement with the SON towards securing support for the project.

In August 2017, the federal Minister of Environment and Climate Change wrote to OPG and commended OPG for its collaborative work with the SON and for the practical demonstration of reconciliation practises. In light of that work, the Minster requested OPG to update its analysis of the potential cumulative effects of the DGR project on the physical and cultural heritage of the SON, taking into account the results of the SON Community Process. OPG continues to work with the SON, however the timing and outcome of the SON Community Process and the EA decision by the Minister are uncertain.

Risks to Maintaining Financial Strength

Risks related to rate regulation, financial markets and long-term obligations could significantly impact OPG's financial performance. The Company is also exposed to risks such as weak electricity demand, displacement of generation by competitors and financial risk associated with energy trading.

Rate Regulation

There is an inherent risk that regulated prices established by the OEB may not provide for the recovery of actual costs incurred by OPG's regulated operations or allow the regulated operations to earn an appropriate rate of return. This could occur if, in setting regulated prices, the OEB makes adjustments to forecasts submitted by OPG, if actual production and costs significantly differ from the forecasts approved by the OEB, or if OPG is unable to achieve OEB-approved stretch factors included in regulated prices under incentive ratemaking. Differences between OPG's actual and forecast production and costs could be due to factors such as outages or project execution risks. In providing evidence in support of its applications for regulated prices, OPG aims to clearly demonstrate to the OEB that the costs for the regulated operations are reasonable, prudently incurred and should be fully recovered from customers.

Certain differences between elements of OEB-approved revenue requirements and OPG's actual results are recorded in OEB-approved variance and deferral accounts for future review by the OEB. Additionally, these accounts may be subject to an OEB prudence review. There is uncertainty associated with the outcomes of future proceedings for the recovery or refund of these balances.

Nuclear Rate Smoothing Proposal

Consistent with the requirements of *Ontario Regulation 53/05*, OPG's nuclear rates will be smoothed as a result of OPG deferring a portion of the approved annual nuclear revenue requirements during the period from January 1, 2017 to the end of the Darlington Refurbishment project in a Rate Smoothing Deferral Account.

There is a risk that the magnitude of the deferral ordered by the OEB will result in regulated prices that do not provide sufficient cash flow to the Company for meeting its financial objectives in an optimal manner, including ensuring sufficient liquidity, cost effectively funding the Darlington Refurbishment project and other expenditures and maintaining the Company's investment grade credit rating. Maintaining adequate levels of credit metrics will support OPG's investment grade credit rating. As such, OPG requested the OEB to consider the impact on its credit rating when smoothing the nuclear base rates. **[MONITOR]**

Post-Employment Benefit Obligations Risk

OPG's post-employment benefit obligations include pension, group life insurance, health care benefits, and LTD benefits. OPG's post-employment benefit obligations and costs and pension plan contributions could be materially affected in the future by numerous factors including: changes in discount rates, inflation rates and other actuarial assumptions; future investment returns; experience gains and losses; the funded status of the pension plans; changes in benefits; changes in the regulatory environment including potential changes to the *Pension Benefits Act* (Ontario); changes in OPG's operations and the measurement uncertainty incorporated into the actuarial valuation process.

The OPG registered pension plan, which covers most of OPG's employees and retirees, is a contributory defined benefit plan that is indexed to inflation up to a certain maximum. Contributions to the OPG registered pension plan are determined by actuarial valuations, which are filed with the appropriate regulatory authorities at least every three years. Future actuarial valuations could increase OPG's funding requirements due to market and economic-related conditions. A significant decline in the financial markets could trigger an immediate requirement to update the actuarial valuation based on declines in the funded status. OPG continues to assess the requirements for contributions to the registered pension plan, including the timing of future actuarial valuations. OPG's OPEB

obligations are not funded and the associated employee benefits are paid from cash flows provided by operating activities or other sources of liquidity.

Nuclear Liabilities and Nuclear Segregated Funds

As required by the CNSC, OPG is responsible for the management of used nuclear fuel and L&ILW and the decommissioning of its nuclear stations and waste management facilities. The cost estimates for OPG's nuclear waste management and decommissioning obligations are based on multiple underlying assumptions and estimates that are inherently uncertain and may evolve over time. The assumptions include station end-of-life dates, waste volumes, waste disposal methods, the timing of construction of assumed waste disposal facilities, waste packaging systems, decommissioning strategy and financial indicators. To address the inherent uncertainty, OPG undertakes to perform a comprehensive review of the underlying assumptions and baseline cost estimates at least once every five years, in line with the required ONFA Reference Plan update process.

The most recent comprehensive update of the nuclear waste management and decommissioning obligations was approved by the Province in December 2016 as part the 2017 ONFA Reference Plan. An approved ONFA Reference Plan determines OPG's contributions to the Nuclear Segregated Funds. Based on the 2017 ONFA Reference Plan, no contributions are currently required to the Nuclear Segregated Funds. Additional contributions may be required should the Nuclear Segregated Funds be in an underfunded position in the future.

Nuclear Funds are segregated under ONFA in order to fund the long-term waste management, used fuel management and decommissioning expenditures. These funds are managed to achieve, in the long term, the target rate of return based on the discount rate specified in the ONFA. Investments in the Nuclear Segregated Funds are allocated to certain asset classes including fixed income securities, domestic and international equity securities, pooled funds, infrastructure, agriculture and real estate. The rates of return earned on these segregated funds may vary depending on current and future financial market conditions. The asset mix of the funds is determined jointly by OPG and the Province in accordance with the ONFA.

Under ONFA, OPG bears the market risk related to the portion of the Nuclear Segregated Funds set aside for:

- decommissioning of Pickering and Darlington nuclear generating stations; and
- long-term management of the irradiated used fuel bundles in excess of the first 2.23 million bundles and L&ILW after the respective Pickering GS and Darlington GS shut down.

A significant drawdown in the Nuclear Funds would first reduce the surplus in the respective funds before impacting OPG's net income. As such, the income statement impact of this risk is reduced when the Nuclear Segregated Funds are in a fully funded position.

Liquidity

OPG operates in a capital intensive business. Significant financial resources are required to fund major development and other capital improvement projects, including the Darlington Refurbishment project. In addition, the Company has other significant disbursement requirements including pension contributions, payments towards OPEB and other benefit plans, funding ongoing operations, debt maturities with the OEFC, OPG's investment in the Fair Hydro Plan and investments in new generating capacity and other business development opportunities. OPG must ensure that it has the financial capacity and sufficient access to cost effective financing sources to fund its capital requirements and other disbursements. In support of this objective, OPG utilizes multiple sources and forecasts availability of funds, actively monitors funding requirements and is focused on maintaining its investment grade credit rating. The Company's ability to arrange sufficient and cost-effective debt financing could be adversely affected by a number of factors, including, financial market and general economic conditions, the regulatory environment in Ontario, the Company's results of operations and financial conditions, the ratings assigned to the Company by credit rating agencies and the current timing of debt maturities.

A discussion of corporate liquidity is included in the section, *Liquidity and Capital Resources*.

Commodity Markets

Changes in the market price of fuels used to produce electricity can adversely impact OPG's earnings and cash flow from operations.

To manage the risk of unpredictable increases in the price of fuels, the Company has fuel hedging programs, which include using fixed price and indexed contracts.

The percentages hedged of OPG's fuel requirements are shown in the following table. These amounts are based on yearly forecasts of generation and supply mix and, as such, are subject to change as these forecasts are updated.

	2018	2019	2020
Estimated fuel requirements hedged [1]	72.9%	68.2%	65.3%

[1] Represents the approximate portion of megawatt-hours of expected generation production (and year-end inventory targets) from each type of OPG-operated facility (nuclear, hydroelectric and thermal) for which the Company has entered into contractual arrangements or obligations in order to secure the price of fuel, or which is subject to regulation. In the case of hydroelectric generation, this represents the gross revenue charge and water rental charges. Excess fuel inventories (nuclear and thermal) in a given year are attributed to the next year for the purpose of measuring hedge ratios.

Foreign Exchange

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are primarily denominated in, or tied to US dollars (USD). To manage this risk, OPG employs various financial instruments such as forwards and other derivative contracts, in accordance with approved risk management policies. As at December 31, 2017, OPG had total foreign exchange contracts outstanding with a notional value of USD $5 million.

Trading

OPG's financial performance can be affected by its trading activities. OPG's electricity trading operations are closely monitored, with total exposures measured and reported to senior management on a daily basis. The main metric used to measure the financial risk of trading activity is Value at Risk (VaR). VaR is defined as a probabilistic maximum potential future loss expressed in monetary terms for a portfolio based on normal market conditions over a set period of time. During 2017, the VaR utilization ranged between $0.1 million and $0.4 million, compared to between nil and $1.5 million in 2016.

Credit

The Company's credit risk exposure is a function of its electricity sales, trading and hedging activities, treasury activities including investing and commercial transactions with various suppliers of goods and services. OPG's credit risk exposure relating to electricity sales is considered low as the majority of sales are through the IESO-administered spot market. The IESO oversees the credit worthiness of all market participants. In accordance with the IESO's prudential support requirements, market participants are required to provide collateral to cover funds that they might owe to the market.

The following table summarizes OPG's credit exposure to all counterparties from electricity transactions and trading as at December 31, 2017:

	All Counterparties		Largest Counterparties	
Credit Rating [1]	**Number of Counterparties** [2]	**Potential Exposure** [3] *(millions of dollars)*	**Number of Counterparties**	**Potential Exposure** *(millions of dollars)*
Investment grade	15	18	5	14
IESO [4]	1	360	1	360
Total	16	378	6	374

[1] Credit ratings are based on OPG's own analysis, taking into consideration external rating agency analysis where available, as well as recognizing explicit credit support provided through parental guarantees, Letters of Credit or other forms of security.

[2] OPG's counterparties are defined on the basis of individual master agreements.

[3] Potential exposure is OPG's statistical assessment of maximum exposure over the life of each transaction at a 95 percent confidence interval.

[4] Credit exposure is an estimate of the short-term receivable amount arising from OPG's electricity sales into the IESO market. The credit exposure and associated receivable vary each month based on electricity sales. The monthly receivable from the IESO is typically paid to OPG in the subsequent month as per the IESO payment schedule.

Other major components of OPG's credit risk exposure include those associated with vendors that are contracted to provide services or products. OPG manages its exposure to various suppliers or counterparties by evaluating their financial condition and ensuring that the Company holds appropriate collateral or other forms of security.

Contracted Generation

The Company's generating stations that operate under ESAs with the IESO or other long-term contracts are subject to several obligations, including but not limited to:

- availability targets;
- monthly and annual reporting; and
- must offer obligations, as specified in their respective contracts.

OPG could incur penalties up to and including termination of the respective contract if these facilities fail to meet their contractual obligations. This risk is mitigated through:

- education of staff who work with these facilities;
- continuous communication between staff managing the contracts and staff managing the stations;
- processes that monitor and address contractual obligations and milestones; and
- the implementation of maintenance, capital investment (approved by the IESO when required by the contracts) and other programs.

OPG's owned and co-owned thermal generating stations operate under ESAs with the IESO or other long-term agreements. While OPG expects that its thermal generating stations will continue to provide capacity to the market over the term of the respective agreements, there is a risk that, upon expiry of the current agreements, subsequent contracts for these stations may not be available or may not be financially viable. The Thunder Bay Biomass ESA is the first such contract to reach the end of its term, scheduled for early 2020.

Ontario Electricity Market

OPG's revenue can be impacted by external factors related to the electricity market including: the entrance of new participants into the Ontario market; the competitive actions of market participants; Ontario electricity demand; changes in the regulatory environment; and wholesale electricity prices in the interconnected markets.

The IESO is in the preliminary stages of a Market Renewal Program, which is expected to result in a fundamental redesign of Ontario's electricity markets and may impact OPG depending on the market design that is implemented. To mitigate this risk, OPG is actively participating in Market Renewal stakeholder committees as well as continuing to collaborate with the IESO.

Ownership by the Province

The Province owns all of OPG's issued and outstanding common shares. Accordingly, the Province, as represented by the Ontario Ministry of Energy, has the authority to make appointments to OPG's Board of Directors. OPG could be subject to Shareholder direction, under Section 108 of the OBCA that can directly influence major decisions. These directions could include those related to project development, timing and strategy of applications for regulated prices, acquisitions and asset divestitures, financing and capital structure. As a result, OPG could be required to undertake activities that result in increased expenditures, or that reduce revenues or cash flows relative to the business activities or strategies that would have otherwise been undertaken. In addition, the obligation of OPG's Shareholder to respond to a broad range of matters in its role as the Government of Ontario may compete with OPG's commitment to maximize the return on the Shareholder's investment in the Company. This includes, but is not limited to, the Province's response to mitigate the impact of rising electricity prices on consumers.

Government Legislation and Regulation Change

OPG's core business and strategy may be impacted by changes in federal and provincial legislation and regulations. Matters that are subject to regulation include, among others, rate regulation, electricity generating operations, nuclear waste management and nuclear decommissioning, the Ontario electricity market and taxation. Regulatory bodies may change or enact regulations or rules that could increase OPG's costs, decrease OPG's revenue, or limit the Company's ability to recover appropriate costs or earn a return on the assets.

The next Ontario provincial election is set to take place in June 2018 and electricity rates are a focus of each party's platform. Depending on the outcome of the election, there may be significant legislative changes that could impact OPG.

Since legal requirements are subject to change and to interpretation, OPG is unable to predict the impact of such changes on the Company and its operations. To mitigate legislative risks, OPG continues to monitor and actively engage with the federal and provincial governments in order to determine if future legislation will impact the Company.

Litigation

OPG or its subsidiaries are involved in various legal proceedings covering a range of matters arising out of their business activities. Each of these matters is subject to various uncertainties and some of these matters may be resolved unfavourably. Refer to Note 16 of OPG's 2017 audited consolidated financial statements under the heading, *Litigation* for further details.

Risks to Maintaining Social Licence

OPG is exposed to risks associated with its social licence and public profile due to changes in the opinions of:

- Various stakeholders, including Ontario electricity customers, local communities, government agencies; and
- Indigenous communities.

Maintaining public trust and meeting stakeholders and Indigenous communities' expectations are critical to OPG's success. OPG focuses on building and maintaining its social licence and corporate reputation through safe, reliable, environmentally-responsible operations as well as corporate citizenship initiatives across the province. The inability to maintain safe, reliable operations could negatively impact OPG's reputation and result in a loss of public support.

Ontario Fair Hydro Plan Act

The Fair Hydro Act received Royal Assent and came into force on June 1, 2017. As the Financial Services Manager under the Act, OPG's reputation could potentially be adversely impacted through this involvement and through stakeholder opinions related to this involvement.

Indigenous Communities

The quality of OPG's relationships and the outcome of negotiations with Indigenous communities may impact OPG's project and financial performance, as well as its social licence to operate.

OPG may be subject to claims by Indigenous communities. These claims stem from projects and generation development related to the operations of OPG and historic operations of OPG's predecessor company, Ontario Hydro, which may have impacted the Aboriginal and/or Treaty rights of Indigenous communities.

OPG has an Indigenous Relations Policy, which sets out the Company's commitment to proactively build and maintain positive relationships with Indigenous communities. OPG has been successful in working collaboratively with Indigenous communities to resolve a number of past grievances. However, the outcome of ongoing and any future negotiations depends on a number of factors, including legislation and regulations and precedents created by court rulings, which are subject to change over time. OPG pursues generation-related developments in partnerships with Indigenous communities on the basis of long-term mutually beneficial commercial arrangements.

Environmental Risks

OPG's operations and facilities are subject to environmental compliance obligations at the municipal, provincial and federal levels that include protection of land, water, air, living organisms and natural systems. A failure to comply with applicable environmental laws may result in enforcement actions, remediation actions or restrictions to operations. Changes in compliance obligations can result in new operational requirements and increased costs.

OPG has an ISO 14001 registered EMS to manage its environmental responsibilities. For further information, see discussion in the section, *Core Business, Strategy, and Outlook* under the heading, *Environmental Performance*.

OPG recognizes that efforts are required to plan for the impacts of climate change and has identified climate change adaptation as a strategic priority for the company. OPG monitors developments in climate science, adaptation activities, and potential changes to policy and regulatory requirements. OPG continues to work with stakeholders to better define adaptation requirements through analysis and understanding of impacts on watersheds, equipment and the electricity market. OPG undertakes a risk-based analysis to determine the extent of adaptation requirements to reduce the impact of climate change on its operations, and also collaborates with all levels of government and industry to increase the resiliency of the electricity infrastructure.

A carbon cap and trade program became effective in Ontario in January 2017. The program is not expected to have a material adverse economic impact on OPG due to the Company's low GHG emissions. Further details can be found in the section, *Core Business, Strategy and Outlook* under the heading, *Environmental Performance*.

RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One, the IESO and the OEFC. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly-owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions for the years ended December 31 are summarized below:

	2017		2016	
(millions of dollars)	**Revenue**	**Expense**	**Revenue**	**Expense**
Hydro One				
Electricity sales	**8**	**-**	6	-
Services	**1**	**10**	1	5
Dividends	**7**	**-**	6	-
Province of Ontario				
Change in Decommissioning Segregated Fund amount due to Province [1]	**-**	**456**	-	192
Change in Used Fuel Segregated Fund amount due to Province [1]	**-**	**591**	-	235
Hydroelectric gross revenue charge	**-**	**110**	-	120
ONFA guarantee fee	**-**	**8**	-	8
Other	**-**	**2**	-	-
OEFC				
Hydroelectric gross revenue charge	**-**	**216**	-	203
Interest expense on long-term notes	**-**	**158**	-	169
Income taxes, net of investment tax credits	**-**	**246**	-	104
IESO				
Electricity related revenue	**4,802**	**-**	5,082	-
Fair Hydro Trust	**4**	**3**	-	-
	4,822	**1,800**	5,095	1,036

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at December 31, 2017 and December 31, 2016, the Nuclear Segregated Funds were reported net of amounts due to the Province of $4,462 million and $3,415 million, respectively.

The receivable, AFS securities, payable and long-term debt balances between OPG and its related parties are summarized below:

(millions of dollars)	**December 31 2017**	**December 31 2016**
Receivables from related parties		
Hydro One	**1**	1
IESO – Electricity related receivables	**354**	421
IESO – Fair Hydro Trust [1]	**7**	-
OEFC	**-**	1
PEC	**4**	4
Province of Ontario	**3**	2
Financing receivables		
IESO – Fair Hydro Trust	**1,179**	-
Available-for-sale securities		
Hydro One shares	**188**	212
Accounts payable and accrued charges		
Hydro One	**1**	-
OEFC	**52**	61
Province of Ontario	**9**	2
IESO – Electricity-related payables	**5**	2
IESO – Fair Hydro Trust	**3**	-
Long-term debt (including current portion)		
Notes payable to OEFC	**3,195**	3,295

[1] Balance consists of unbilled revenue.

OPG holds interest-bearing Province of Ontario bonds in the Nuclear Segregated Funds and the OPG registered pension fund. As at December 31, 2017, the Nuclear Segregated Funds held $1,503 million of interest-bearing Province of Ontario bonds. As at December 31, 2016, the Nuclear Segregated Funds and the registered pension fund held $1,652 million and $284 million of interest-bearing Province of Ontario bonds, respectively. These bonds are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

In December 2017, the Trust purchased its first tranche of Investment Interest from the IESO for an exchange amount of $1.18 billion, which has been classified as a financing receivable on OPG's consolidated balance sheet. The transaction was settled in cash using proceeds from the Trust's issuance of senior and subordinated debt. Pursuant to the general regulation of the Act, the IESO is required to pay and remit carrying costs of the Trust, excluding repayment of principal on any debt obligations, up to July 31, 2021. Commencing May 1, 2021, Specified Consumers will be invoiced by their local distribution company for the Clean Energy Adjustment to pay financing and other costs of the Trust. These funds will be remitted to the Trust through the IESO and will be used to settle all funding and other related expenses of the Trust that underlie the financing receivable.

As at December 31, 2017, OPG's consolidated balance sheet included approximately $7 million of unbilled revenue from the IESO primarily for OPG's general fee for 2017 as Financial Services Manager relating to incurred third-party and certain direct labour costs. In February 2018, OPG submitted to the OEB its proposed general fee for 2017 in the amount of approximately $6 million for review pursuant to the requirements of the general regulation of the Fair Hydro Act. Once approved, the fees will be remitted to the Trust by the IESO and the Trust will pay OPG's fees as Financial Services Manager.

INTERNAL CONTROLS OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

Management, including the President and Chief Executive Officer (President and CEO) and the Chief Financial Officer (CFO), are responsible for maintaining Disclosure Controls and Procedures (DC&P) and Internal Controls over Financial Reporting (ICOFR). DC&P is designed to provide reasonable assurance that all relevant information is gathered and reported to senior management, including the President and CEO and the CFO, on a timely basis so that appropriate decisions can be made regarding public disclosure. ICOFR is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the financial statements in accordance with US GAAP.

There were no changes in OPG's ICOFR during the year ended December 31, 2017 that have materially affected or are reasonably likely to materially affect OPG's ICOFR.

Management, including the President and CEO and the CFO, concluded that, as of December 31, 2017, OPG's DC&P and ICOFR (as defined in National Instrument 52-109 – *Certification of Disclosure in Issuers' Annual and Interim Filings*) were effective.

FOURTH QUARTER

Discussion of Results

(millions of dollars) (unaudited)	Three Months Ended December 31 2017	2016
Revenue	**1,619**	1,388
Fuel expense	**171**	186
Gross margin	**1,448**	1,202
Operations, maintenance and administration	**770**	686
Depreciation and amortization	**162**	316
Accretion on fixed asset removal and nuclear waste management liabilities	**251**	233
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(222)**	(126)
Earnings from Fair Hydro Trust	**(1)**	-
Income from investments subject to significant influence	**(9)**	(9)
Property taxes	**10**	11
Restructuring	**-**	6
Income before other losses, interest, and income taxes	**487**	85
Other losses	**1**	6
Income before interest and income taxes	**486**	79
Net interest expense	**39**	28
Income before income taxes	**447**	51
Income tax expense	**81**	59
Net income (loss)	**366**	(8)
Net income (loss) attributable to the Shareholder	**362**	(13)
Net income attributable to non-controlling interest	**4**	5

Net income attributable to the Shareholder for the fourth quarter was $362 million, compared to a net loss of $13 million for the same quarter in 2016.

Income before interest and income taxes was $486 million during the fourth quarter of 2017, an increase of $407 million compared to income before interest and income taxes of $85 million during the same period in 2016. The following summarizes the significant factors which contributed to the variance:

Significant factors that increased income before interest and income taxes:

- Higher revenue from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments totaling approximately $480 million recorded in the fourth quarter of 2017 to reflect the OEB's decision on OPG's application for new regulated rates issued in December 2017 with a retrospective effective date of June 1, 2017.
- Higher earnings of $77 million from the Regulated – Nuclear Waste Management segment, primarily due to higher earnings from the Nuclear Segregated Funds reflecting the growth rate in the present value of the funding liabilities, partially offset by an increase in accretion expense on the Nuclear Liabilities.

Significant factors that decreased income before interest and income taxes:

- Lower revenue from the nuclear base regulated price of approximately $55 million, partially offset by a decrease in fuel expense of $9 million, reflecting lower electricity generation of 0.9 terawatt hours (TWh) from the Regulated – Nuclear Generation segment. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS since October 2016, partially offset by an increase in generation from the Pickering GS. The increase in generation from the Pickering GS was primarily due to outage cycle optimization, favourable unit conditions and execution of planned outage work resulting in fewer unplanned and planned outage days at the station.
- Higher OM&A expenses of $55 million, mainly in the Regulated – Nuclear Generation segment, reflected planned expenditures related to the major maintenance expenditures occurring at the nuclear stations.

The increase in income tax expense during the fourth quarter of 2017, compared to the same quarter in 2016, was primarily due to higher income before income taxes, partially offset by a higher amount of tax expense deferred in regulatory assets in 2017.

Average Sales Prices

The average sales price for the Regulated – Nuclear Generation segment during the fourth quarter of 2017 was 11.0 ¢/kWh, compared to 6.9 ¢/kWh during the same quarter in 2016. The increase in the average sales price was primarily due to the OEB ruling issued in December 2017, in which OPG received a base rate increase, retroactive to June 1, 2017. The average sales price for the Regulated – Hydroelectric segment during 2017 was 4.3 ¢/kWh, compared to 4.4 ¢/kWh during 2016. The decrease in this average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized regulated hydroelectric rate rider of $3.19/MWh for the recovery of variance and deferral account balances. The rate riders were established to recover approved balances recorded in the variance and deferral accounts in prior years. As such, the year-over-year changes in revenue from the rate riders were largely offset by changes in amortization expense related to these balances.

Electricity Generation

OPG's electricity generation for the three months ended December 31, 2017 and 2016 was as follows:

(TWh)	Three Months Ended December 31 2017	2016
Regulated – Nuclear Generation	**10.1**	11.0
Regulated – Hydroelectric	**7.2**	6.7
Contracted Generation Portfolio [1]	**0.8**	0.6
Total OPG electricity generation	**18.1**	18.3
Total electricity generation by all other generators in Ontario [2]	**18.8**	18.9

[1] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

[2] Non-OPG generation is calculated as the Ontario electricity demand plus net exports, as published by the IESO, minus OPG electricity generation.

The decrease in OPG's electricity generation of 0.2 TWh during the fourth quarter of 2017, compared to the same quarter in 2016, was mainly due to lower electricity generation of 0.9 TWh from the Regulated – Nuclear Generation segment. This was mainly the result of more planned outage days at Pickering in 2017 as well as the refurbishment of Unit 2 at the Darlington GS, which began in mid-October 2016 and continued for all of 2017. This was largely offset by higher production from the Regulated - Hydroelectric and Contracted Generation Portfolio segments mainly due to higher water flows on the eastern Ontario river systems.

Ontario's electricity demand as reported by the IESO was 33.6 TWh during the fourth quarter of 2017, compared to 33.2 TWh during the fourth quarter of 2016.

Liquidity and Capital Resources

Cash flow provided by operating activities during the three months ended December 31, 2017 was $246 million, compared to $606 million for the same period in 2016. The decrease in cash flow was primarily due to lower generation revenue receipts and higher OM&A expenditures during the fourth quarter of 2017.

Cash flow used in investing activities during the three months ended December 31, 2017 was $1,758 million, compared to $666 million during the same period in 2016. The increase was primarily due to the acquisition of the Fair Hydro Trust financing receivables and higher expenditures on the Darlington Refurbishment project in 2017.

Cash flow provided by financing activities during the three months ended December 31, 2017 was $1,466 million, compared to cash flow used in financing activities of $180 million for the same period in 2016. The increase in cash flow provided by financing activities was primarily due to higher net issuance of long-term debt and short-term notes by the Trust, as well as issuance of Class A shares in the four quarter of 2017. The increase was partially offset by the repayment of short term notes.

QUARTERLY FINANCIAL HIGHLIGHTS

The following tables set out selected annual financial information for the last three years and financial information for each of the eight most recently completed quarters. This information is derived from OPG's unaudited interim consolidated financial statements and the audited consolidated financial statements, and has been prepared in accordance with US GAAP.

Annual Financial Information

(millions of dollars – except where noted)	**2017**	**2016**	**2015**
Revenue	**5,158**	5,653	5,476
Net income attributable to the Shareholder	**860**	436	402
Earnings per common share *(dollars)*	**$3.35**	$1.70	$1.57
Total assets	**48,822**	44,372	44,250
Total long-term liabilities	**34,933**	31,460	32,404
Weighted average common shares outstanding *(millions)*	**256.7**	256.3	256.3

Quarterly Financial Information

(millions of dollars – except where noted) *(unaudited)*	**2017 Quarters Ended**				
	December 31	**September 30**	**June 30**	**March 31**	**Total**
Revenue	**1,619**	**1,217**	**1,146**	**1,176**	**5,158**
Net income	**366**	**140**	**307**	**68**	**881**
Less: Net income attributable to non-controlling interest	**4**	**9**	**4**	**4**	**21**
Net income attributable to the Shareholder	**362**	**131**	**303**	**64**	**860**
Earnings per common share, attributable to the Shareholder *(dollars)*	**$1.41**	**$0.51**	**$1.18**	**$0.25**	**$3.36**

Quarterly Financial Information

(millions of dollars – except where noted) *(unaudited)*	**2016 Quarters Ended**				
	December 31	**September 30**	**June 30**	**March 31**	**Total**
Revenue	1,388	1,400	1,387	1,478	5,653
Net (loss) income	(8)	198	135	128	453
Less: Net income attributable to non-controlling interest	5	4	3	5	17
Net (loss) income attributable to the Shareholder	(13)	194	132	123	436
Per common share, attributable to the Shareholder *(dollars)*	($0.05)	$0.76	$0.51	$0.48	$1.70

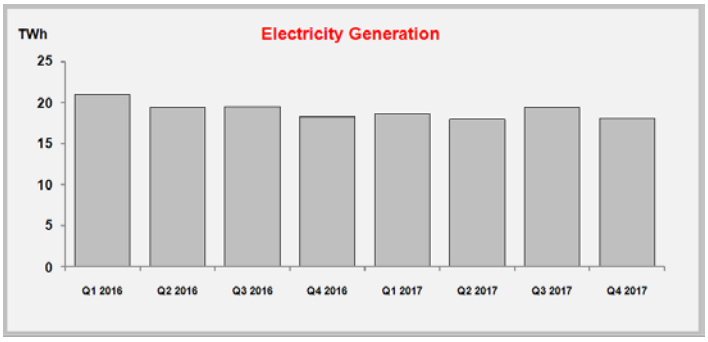
Trends

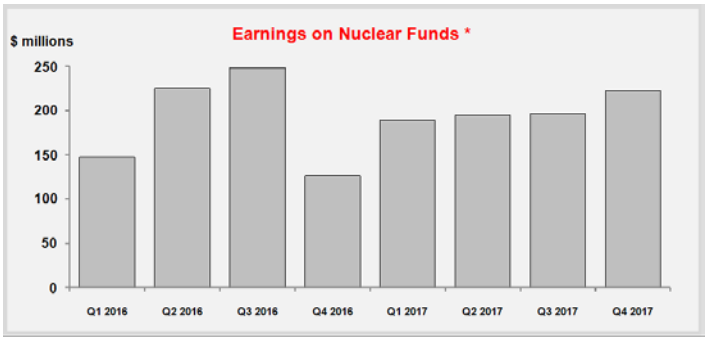
OPG's quarterly results are affected by changes in grid-supplied electricity demand, primarily resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. Weather conditions affect water flows, electricity demand, and prevalence of SBG conditions. Historically, OPG's revenues have been higher in the first quarter of a fiscal year as a result of winter heating demands and in the third quarter due to air conditioning and cooling demands. The financial impact of forgone production due to SBG conditions at the regulated hydroelectric stations and the financial impact of differences between forecast water flows reflected in OEB-approved regulated prices and the actual water flows are offset by regulatory variance accounts authorized by the OEB.

The timing of planned outages at a nuclear generating station during the year can cause variability in year-over-year operating results for partial periods of a fiscal year, including the impact on revenue and OM&A expenses, but is not a significant driver of variability for full fiscal year results.

OPG's electricity generation was reduced as a result of the Unit 2 refurbishment outage at the Darlington GS, which began in October 2016 and is expected to continue until early 2020.

OPG's financial results are also affected by the earnings on the Nuclear Segregated Funds, net of the impact of the Bruce Lease Net Revenues Variance Account. The volatility of the earnings on the Nuclear Segregated Funds is mitigated by their funded status.





*net of regulatory variance account

SUPPLEMENTARY NON-GAAP FINANCIAL MEASURES

In addition to providing net income and other financial information in accordance with US GAAP, certain non-GAAP financial measures are also presented in OPG's MD&A. These non-GAAP measures do not have any standardized meaning prescribed by US GAAP and, therefore, may not be comparable to similar measures presented by other issuers. OPG utilizes these measures to make operating decisions and assess performance. Readers of the MD&A would utilize these measures in assessing the Company's financial performance from ongoing operations. The Company believes that these indicators are important since they provide additional information about OPG's performance, facilitate comparison of results over different periods, and present measures consistent with the Company's strategies to provide value to the Shareholder, improve cost performance, and ensure availability of cost effective funding. These non-GAAP financial measures have not been presented as an alternative to net income, cash flow provided by operating activities, or any other measure in accordance with US GAAP, but as indicators of operating performance.

The definitions of the non-GAAP financial measures are as follows:

(1) ROE Excluding AOCI is defined as net income attributable to the Shareholder divided by average equity attributable to the Shareholder excluding AOCI, for the period.

ROE Excluding AOCI is measured over a 12-month period and is calculated as follows for the period ended December 31:

(millions of dollars – except where noted) (unaudited)	**2017**	**2016**
ROE Excluding AOCI		
Net income attributable to the Shareholder	**860**	436
Divided by: Average equity attributable to the Shareholder, excluding AOCI	**11,498**	10,442
ROE Excluding AOCI *(percent)*	**7.5**	4.2

(2) **FFO Adjusted Interest Coverage** is defined as FFO before interest divided by adjusted interest expense. FFO before interest is defined as cash flow provided by operating activities adjusted for interest paid, interest capitalized to fixed and intangible assets, and changes to non-cash working capital balances for the period. Adjusted interest expense is calculated as net interest expense plus interest income, interest capitalized to fixed and intangible assets, interest related to regulatory assets and liabilities, and the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets, for the period.

FFO Adjusted Interest Coverage is measured over a 12-month period and is calculated as follows for the period ended December 31:

(millions of dollars – except where noted) (unaudited)	**2017**	**2016**
FFO before interest		
Cash flow provided by operating activities	**944**	1,817
Add: Interest paid	**258**	269
Less: Interest capitalized to fixed and intangible assets	**(162)**	(141)
Less: Changes to non-cash working capital balances	**(54)**	(180)
FFO before interest	**986**	1,765
Adjusted interest expense		
Net interest expense	**95**	120
Add: Interest income	**9**	7
Add: Interest capitalized to fixed and intangible assets	**162**	141
Add: Interest related to regulatory assets and liabilities	**30**	30
Add: Excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets [1]	**-**	45
Adjusted interest expense	**296**	343
FFO Adjusted Interest Coverage *(times)*	**3.3**	5.1

[1] A value of nil is used in the calculation when interest on pension and OPEB projected benefit obligations is equal to, or lower than, expected return on pension plan assets.

(3) **Enterprise Total Generating Cost per MWh** is used to measure OPG's overall organizational cost performance. Enterprise TGC per MWh is defined as OM&A expenses (excluding the Darlington Refurbishment project and other generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to OPG's electricity generation business), fuel expense for OPG-operated stations including hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures (excluding the Darlington Refurbishment project and other generation development projects) incurred during the period, divided by total electricity generation from OPG-operated generating stations plus electricity generation forgone due to SBG conditions during the period.

Enterprise TGC per MWh is calculated as follows for the 12-month period ended December 31:

(millions of dollars – except where noted)	**2017**	**2016**
Enterprise TGC		
Total OM&A expenses	**2,824**	2,747
Total fuel expense	**689**	727
Total capital expenditures	**1,926**	1,704
Less: Darlington Refurbishment capital and OM&A costs	**(1,285)**	(1,022)
Less: Other generation development project capital and OM&A costs	**(65)**	(163)
Add: OM&A and fuel expenses (refundable through) deferred in regulatory variance and deferral accounts	**(1)**	62
Less: Nuclear fuel expense for non OPG-operated stations	**(57)**	(67)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**69**	49
Less: OM&A expenses ancillary to electricity generation business	**(18)**	(28)
Other adjustments	**(43)**	(19)
	4,039	3,990
Adjusted electricity generation *(TWh)*		
Total OPG electricity generation	**74.1**	78.2
Adjust for electricity generation forgone due to SBG conditions and OPG's share of electricity generation from co-owned facilities	**5.6**	4.1
	79.7	82.3
Enterprise TGC per MWh *($/MWh)* [1]	**50.66**	**48.45**

[1] Amounts may not calculate due to rounding.

(4) **Nuclear Total Generating Cost per MWh** is used to measure the cost performance of OPG's nuclear generating assets. Nuclear TGC per MWh is defined as OM&A expenses of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the nuclear electricity generation business), nuclear fuel expense for OPG-operated stations (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs) incurred during the period, divided by nuclear electricity generation for the period.

Nuclear TGC per MWh is calculated as follows for the 12-month period ended December 31:

(millions of dollars – except where noted)	**2017**	**2016**
Nuclear TGC		
Regulated – Nuclear Generation OM&A expenses	**2,293**	2,210
Regulated – Nuclear Generation fuel expense	**284**	315
Regulated – Nuclear Generation capital expenditures	**1,631**	1,338
Less: Darlington Refurbishment capital and OM&A costs	**(1,285)**	(1,022)
Add: Regulated – Nuclear Generation OM&A and fuel expenses deferred in regulatory variance and deferral accounts	**35**	81
Less: Nuclear fuel expense for non OPG-operated stations	**(57)**	(67)
Less: Regulated – Nuclear Generation OM&A expenses ancillary to electricity generation business	**(6)**	(10)
Other adjustments	**(10)**	(4)
	2,885	2,841
Nuclear electricity generation *(TWh)*	**40.7**	45.6
Nuclear TGC per MWh *($/MWh)* [1]	**70.95**	62.30

[1] Amounts may not calculate due to rounding.

(5) **Hydroelectric Total Generating Cost per MWh** is used to measure the cost performance of OPG's hydroelectric generating assets. Hydroelectric TGC per MWh is defined as OM&A expenses of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the hydroelectric electricity generation business), hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding expenditures related to the Peter Sutherland Sr. GS, Ranney Falls GS, and other hydroelectric generation development projects) incurred during the period, divided by total hydroelectric electricity generation plus hydroelectric electricity generation forgone due to SBG conditions during the period. OPG reports hydroelectric gross revenue charge and water rental payments as fuel expense.

Hydroelectric TGC per MWh is calculated as follows for the 12-month period ended December 31:

(millions of dollars – except where noted)	**2017**	**2016**
Hydroelectric TGC		
Regulated – Hydroelectric OM&A expenses	**330**	325
Regulated – Hydroelectric fuel expense	**351**	353
Contracted Generation Portfolio OM&A expenses	**169**	178
Contracted Generation Portfolio fuel expense	**53**	58
Regulated – Hydroelectric and Contracted Generation Portfolio capital expenditures	**226**	330
Less: Regulated – Hydroelectric and Contracted Generation Portfolio Generation Portfolio generation development project capital and OM&A costs	**(63)**	(158)
Less: Thermal OM&A and fuel expenses and capital expenditures in the Contracted Generation Portfolio	**(166)**	(177)
Less: Regulated – Hydroelectric OM&A and fuel expenses refundable through regulatory variance and deferral accounts	**(36)**	(24)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**69**	49
Other adjustments	**(1)**	(1)
	932	933
Adjusted hydroelectric electricity generation *(TWh)*		
Regulated – Hydroelectric electricity generation	**30.7**	29.5
Contracted Generation Portfolio electricity generation	**2.7**	3.1
Adjust for hydroelectric electricity generation forgone due to SBG conditions and non-hydroelectric electricity generation of the Contracted Generation Portfolio, including OPG's share of electricity generation from co-owned facilities	**5.5**	4.0
	38.9	36.6
Hydroelectric TGC per MWh *($/MWh)* [1]	**23.91**	25.49

[1] Amounts may not calculate due to rounding.

(6) **Gross margin** is defined as revenue less fuel expense**.**

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www.opg.com

www.sedar.com

ONTARIO POWER GENERATION INC.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2017

[DRAFT]

March 8, 2018

ANNUAL INFORMATION FORM
FOR THE YEAR ENDED DECEMBER 31, 2017

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PRESENTATION OF INFORMATION

References in this Annual Information Form (AIF) to the "Company", the "Corporation" or "OPG" are made to Ontario Power Generation Inc. Unless otherwise noted, the information contained in this AIF is as at or for the year ended December 31, 2017. Amounts are expressed in Canadian dollars unless otherwise indicated. Financial information is presented in accordance with United States generally accepted accounting principles (US GAAP). This AIF is dated March 8, 2018.

ADDITIONAL INFORMATION

Additional information relating to the Company may be found on SEDAR at www.sedar.com. Additional financial information relating to the Company is provided in the Company's annual Management's Discussion and Analysis (MD&A) and audited consolidated financial statements as at and for the year ended December 31, 2017, which is available on SEDAR at www.sedar.com or on the Company's website at www.opg.com. ***The above information is made available in accordance with legal requirements of an AIF and is not, unless otherwise specifically stated, incorporated by reference into this AIF.***

Details regarding compensation paid to directors and executive officers of the Company during the financial year ended December 31, 2017 is included in OPG's Statement of Executive Compensation (Form 51-102F6), which is available on SEDAR at www.sedar.com and is incorporated by reference herein.

FORWARD-LOOKING INFORMATION

This AIF contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could", and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

All forward-looking statements involve inherent assumptions, risks, and uncertainties. All forward-looking statements could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's generating station performance and availability, fuel costs, surplus baseload generation (SBG), cost of fixed asset removal and nuclear waste management, performance and earnings of investment funds, refurbishment of existing facilities, development and construction of new facilities, pension and other post-employment benefit (OPEB) obligations and funds, income taxes, proposed new legislation, the ongoing evolution of Ontario's electricity industry, environmental and other regulatory requirements, health, safety and environmental developments, business continuity events, the weather, financing and liquidity, applications to the Ontario Energy Board (OEB) for regulatory prices, the impact of regulatory decisions by the OEB, Ontario's Fair Hydro Plan (Fair Hydro Plan or the Plan), OM&A expenditures, retention of critical talent, supplier and third party performance, and project expenditures. Accordingly, undue reliance should not be placed on any forward-looking statement. The forward-looking statements included in this AIF are made only as of the date of this AIF. Except as required by applicable securities laws, OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events, or otherwise.

OPG faces various risks that could have a material adverse effect on its business, strategy, generating stations, reputation, financial condition, operating results, generation development and other projects. There may be further risks and uncertainties that are not presently known, or that are not currently believed to be material, that may in the future adversely affect the Company's performance or financial condition. OPG may be exposed to a significant event that it is not fully insured or indemnified against, or to a party that fails to meet its indemnification obligations. For details on risks faced by OPG, refer to the section, *Risk Management*, in the Company's 2017 year-end MD&A.

CORPORATE STRUCTURE

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG was formed in April 1999 through the restructuring of Ontario Hydro's integrated electricity business. OPG was established under the *Business Corporations Act* (Ontario) (OBCA) and is wholly owned by the Province of Ontario (Province or Shareholder). OPG and the Province are parties to a Memorandum of Agreement (MOA) that sets out OPG's role and responsibilities. The current MOA was executed in July 2015 and reaffirmed for continuance by both the Ontario Minster of Energy and the OPG Board of Directors' Chair in the fourth quarter of 2016, as required by the MOA following a change in the Minister of Energy. Further details on the MOA are discussed in the section, *Interest of Management and Others in Material Transactions* under the heading, *Relationship with the Province and the OEFC*.

OPG's registered head office is located at 700 University Avenue, Toronto, Ontario, M5G 1X6, Canada.

OVERVIEW OF OPG

OPG is Ontario's largest clean energy generator. As at December 31, 2017, OPG operated two nuclear generating stations, three thermal generating stations, 66 hydroelectric generating stations, and one wind power turbine. The majority of OPG's generation is from its rate-regulated nuclear and rate-regulated hydroelectric stations. In addition, OPG and TransCanada Energy Ltd. co-own the 550 megawatt (MW) Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS). OPG and ATCO Power Canada Ltd. co-own the 560 MW Brighton Beach gas-fired combined cycle GS (Brighton Beach). Including its share of the co-owned facilities, OPG's total in-service generating capacity was 16,210 MW as at December 31, 2017, which represented approximately 45 percent of installed generation capacity in Ontario's electricity grid as reported by the Independent Electricity System Operator (IESO). OPG's in-service generating capacity as of December 31, 2017 excludes Unit 2 of the Darlington Nuclear GS. The unit, which has a generating capacity of 878 MW, was taken offline in mid-October 2016 and is currently undergoing refurbishment. OPG operates under an electricity generation licence issued by the OEB, which is valid until October 30, 2023. OPG expects the licence to be renewed in the future.

OPG also owns two other nuclear generating stations, the Bruce A GS and the Bruce B GS, which are leased on a long-term basis to Bruce Power L.P. (Bruce Power) and are not included in the generation and other operating statistics set out in this AIF.

All of OPG's owned and co-owned generating facilities are located in Ontario.

Effective in the fourth quarter of 2017, following the establishment of the Fair Hydro Trust (the Trust) as the financing entity to implement the Fair Hydro Plan under the *Ontario Fair Hydro Plan Act, 2017* (the Fair Hydro Act or the Act), OPG has modified its reportable business segments to include the Fair Hydro Trust segment. Through its control over the key activities of the Trust and its obligation to absorb losses through ownership of the Trust's subordinated debt, the Company consolidates the financial results of the Trust in accordance with US GAAP. The Fair Hydro Trust segment reports the income related to OPG's role as Financial Services Manager under the Act and holder of subordinated debt issued by the Trust, including the financial results of the Trust. The Fair Hydro Plan and the Fair Hydro Trust are discussed in the section, *General Development of the Business* under the heading, *General Development* and in the section, *Description of the Business* under the heading, *Fair Hydro Trust Segment*.

OPG's business operations are divided into six business segments and are discussed under the heading, *General Development* and in their respective sections. The six business segments are as follows:

- Regulated – Nuclear Generation
- Regulated – Nuclear Waste Management
- Regulated – Hydroelectric
- Contracted Generation Portfolio
- Services, Trading, and Other Non-Generation
- Fair Hydro Trust

Pursuant to the *Ontario Energy Board Act, 1998* and *Ontario Regulation 53/05,* OPG receives OEB-authorized regulated prices for electricity generated from the Pickering and Darlington nuclear generating stations and the 54 hydroelectric facilities prescribed for rate regulation (collectively, prescribed facilities or regulated facilities). The OEB is an independent, quasi-judicial tribunal that regulates market participants in Ontario's natural gas and electricity industries, and reports to the Legislature of the Province through the Ontario Ministry of Energy. OPG is Ontario's only electricity generator subject to rate regulation by the OEB.

Of OPG's 54 regulated hydroelectric facilities, 48 facilities were prescribed for rate regulation effective July 1, 2014 pursuant to a November 2013 amendment to *Ontario Regulation 53/05*. The remaining six regulated hydroelectric facilities and the Pickering and Darlington nuclear generating stations have been subject to rate regulation by the OEB since 2008.

Electricity generated from most of OPG's non-regulated assets is subject to Energy Supply Agreements (ESAs) with the IESO. The IESO is a non-profit corporate entity governed by an independent Board of Directors appointed by the Province and is responsible for operating the electricity market and directing the operation of the bulk electrical system in Ontario. Effective January 1, 2015, the Ontario Power Authority (OPA), an organization previously established by the Province with a mandate to contribute to the development of a reliable and sustainable electricity system in Ontario, merged with the IESO. The new entity continued under the name IESO. The IESO is the counterparty to the ESAs and other agreements that were previously executed with the OPA.

ESAs are in effect for the capacity and production from OPG's three operating thermal generating stations – the oil/gas dual-fuelled Lennox GS, the biomass powered Atikokan GS and the advanced biomass fuelled unit at the Thunder Bay GS. The results of these stations are reported under the Contracted Generation Portfolio segment. The expiry dates of these ESAs range from January 2020 to July 2024. In addition, 50-year ESAs are in place for the hydroelectric facilities reported under the Contracted Generation Portfolio segment. The hydroelectric ESAs for the operating stations have expiry dates ranging from February 2059 to March 2067. The ESAs for the contracted generating stations result in a relatively stable stream of revenues from the Contracted Generation Segment.

OPG's revenue and electricity generation by business segment for the years ended December 31, 2017, 2016 and 2015 and OPG's in-service generating capacity as at December 31, 2017, 2016 and 2015 are summarized in the table below.

		Regulated – Nuclear Generation	Regulated – Nuclear Waste Management	Regulated – Hydroelectric	Contracted Generation Portfolio [1]	Services, Trading, and Other Non-Generation	Fair Hydro Trust
2017	Revenue *(millions of dollars)* [2]	**3,095**	**121**	**1,436**	**579**	**43**	**1** [4]
	Electricity Generation *(terawatt hours)*	**40.7**	**N/A**	**30.7**	**2.7**	**N/A**	**N/A**
	In-service Generating Capacity *(MW)* [3]	**5,728**	**N/A**	**6,426**	**4,056**	**N/A**	**N/A**
2016	Revenue *(millions of dollars)* [2]	3,481	138	1,527	573	68	N/A
	Electricity Generation *(terawatt hours)*	45.6	N/A	29.5	3.1	N/A	N/A
	In-service Generating Capacity *(MW)* [3]	5,728	N/A	6,421	4,028	N/A	N/A
2015	Revenue *(millions of dollars)* [2]	3,245	122	1,619	535	73	N/A
	Electricity Generation *(terawatt hours)*	44.5	N/A	30.4	3.1	N/A	N/A
	In-service Generating Capacity *(MW)*	6,606	N/A	6,428	4,021	N/A	N/A

[1] The in-service generating capacity includes OPG's share of 275 MW for PEC and 280 MW for Brighton Beach, and the electricity generation includes OPG's share of its 50 percent ownership in these stations.
[2] Revenue for each segment is shown before inter-segment elimination.
[3] Regulated – Nuclear Generation segment excludes the generating capacity of 878 MW from Unit 2 of the Darlington GS, which has been undergoing refurbishment since mid-October 2016.
[4] This represents OPG's earnings from the Fair Hydro Trust, which consist of income related to OPG's role as Financial Services Manager under the Act and holder of subordinated debt issued by the Trust, including the financial results of the Trust.

For the year ended December 31, 2017, OPG's electricity generation accounted for over 50 percent of the total energy generated on Ontario's electricity grid, as reported by the IESO.

OPG is subject to a number of provincial and federal legislation and regulations, including the decisions of administrative tribunals or other regulatory bodies, and to Canada's international obligations under certain international treaties. Collectively, these sources dictate many of the constraints within which OPG is permitted to operate its facilities and manage its business.

Strategic Imperatives

OPG's mission is to provide low cost power in a safe, clean, reliable and sustainable manner for the benefit of its customers and its Shareholder. OPG also seeks to pursue, on a commercial basis, generation development projects and other business growth opportunities to the benefit of the Shareholder. The four strategic imperatives of OPG are briefly described below.

Operational Excellence

Operational excellence at OPG is accomplished by the safe and environmentally responsible generation of reliable and cost-effective electricity from the Company's generating assets through a highly trained and engaged workforce. Workplace safety and public safety are overriding priorities in all activities performed at OPG.

Project Excellence

OPG is pursuing a number of generation development and other projects in support of Ontario's electricity planning initiatives. OPG's major generation projects include the refurbishment of the Darlington GS, the expansion of the Ranney Falls hydroelectric GS, and the construction of a solar facility at the Nanticoke GS site. OPG aims to be an industry leader in project management capability and performance.

Financial Strength

As a commercial enterprise, OPG's financial priority is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future growth. Inherent in this priority are the following objectives:

- Increasing revenue, reducing costs and achieving appropriate return;
- Ensuring availability of cost effective funding for operational needs, generation development projects and other business opportunities, and long-term obligations;
- Pursuing opportunities to expand the existing core business and capitalize on new growth paths including emerging renewable energy opportunities; and
- Managing risks. Refer to the section, *Risk Management*, in the Company's 2017 year-end MD&A for more details.

Social Licence

As the largest, publicly-owned electricity generator in Ontario with geographically diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust. OPG is committed to maintaining high standards of public safety and corporate citizenship, including environmental stewardship, transparency, community engagement, and Indigenous relations.

OPG has in place a Code of Business Conduct that establishes the standards, expectations, and accountabilities for ethical behaviour. All employees and all parties with whom the Company does business are expected to abide by OPG's Code of Business Conduct. A copy of the Code of Business Conduct can be found on SEDAR at www.sedar.com and also is available on the Company's website at www.opg.com.

Further details on OPG's strategic imperatives can be found in the corresponding sections of the Company's 2017 year-end MD&A in the section, *Core Business, Strategy, and Outlook.*

GENERAL DEVELOPMENT OF THE BUSINESS

The following is a summary of key developments in OPG's business since January 2015.

General Development

OPG's Regulated Prices and Other OEB-Related Developments

Energy revenue generated from the Company's regulated nuclear and regulated hydroelectric facilities is based on regulated prices determined by the OEB through public proceedings. To date, the regulated prices have included a volumetric base regulated price, and volumetric rate riders for the recovery or repayment of approved variance and deferral account balances. As the regulated operations account for the majority of the Company's electricity generation, the outcomes of OPG's applications for regulated prices to the OEB determine a large portion of the Company's revenues and can have a significant impact on the Company's financial performance.

The following are the OEB-authorized regulated prices for electricity generated from the Company's regulated facilities in effect during the years ended December 31:

	2017		2016	2015	
($/megawatt hour)	**January 1 to May 31**	**June 1 to December 31** [1]		**January 1 to June 30**	**July 1 to December 31**
Regulated – Nuclear Generation					
Base regulated price	**59.29**	**80.65**	59.29	59.29	59.29
Variance and deferral account rate riders	**-**	**-**	10.84 [2]	1.33	12.17 [2]
	59.29	**80.65**	70.13	60.62	71.46
Regulated – Hydroelectric					
Hydroelectric generating stations prescribed for rate regulation prior to 2014					
Base regulated price	**40.20**	**41.67**	40.20	40.20	40.20
Variance and deferral account rate riders	**-**	**-**	3.19 [2]	6.04	9.23 [2]
	40.20	**41.65**	43.39	46.24	49.43
Hydroelectric generating stations prescribed for rate regulation effective in 2014					
Base regulated price	**41.93**	**41.67**	41.93	41.93	41.93
Variance and deferral account rate riders	**-**	**-**	3.19 [2]	-	3.19 [2]
	41.93	**41.67**	45.12	41.93	45.12

[1] Regulated prices for the June 1, 2017 to December 31, 2017 period were calculated and submitted to the OEB by OPG in January 2018 based on the OEB's December 28, 2017 decision on OPG's 2017-2021 application for new regulated prices. The final regulated prices will be determined by the OEB as part of the final payment amounts order process, which is expected to be completed in the first half of 2018. As part of the process, the OEB is expected to authorize separate rate riders to allow for the recovery of the shortfall between the new regulated prices and the previous regulated prices that OPG continues to receive during the period between June 1, 2017 and the implementation date of the new regulated prices pending the issuance of the final payment amounts order. The incremental revenue for the period between June 1, 2017 and December 31, 2017 arising from this retrospective application of new regulated prices was accrued in 2017. **[MONITOR]**

[2] The OEB authorized interim period rate riders for the period from October 1, 2015 to December 31, 2016 to allow for the recovery of the riders effective July 1, 2015 for the period from July 1, 2015 to September 30, 2015. The nuclear interim period rate rider was $2.17 per megawatt hour (MWh) and the regulated hydroelectric interim period rate rider was $0.64/MWh. These interim period rate riders have not been included in the above table. All rate riders in effect during 2016 expired on December 31, 2016.

Base Regulated Prices

The OEB's decision on OPG's May 2016 five-year application for new regulated prices for its nuclear and regulated hydroelectric generation was issued on December 28, 2017, following a public hearing process. Based on the OEB's December 2017 decision, the new base regulated prices are determined on an incentive ratemaking methodology for the hydroelectric operations and under a custom incentive regulation framework for the nuclear operations. For the hydroelectric facilities, the new base regulated price is determined using a formula that annually escalates the previous regulated prices, subject to some adjustments, based on inflation less a stretch factor to incent additional innovation and efficiency. For the nuclear facilities, the new regulated price is determined under a rate smoothing approach that defers a portion of the approved nuclear revenue requirement for future collection, with the aim of making more stable changes in OPG's production-weighted regulated prices year over year. The nuclear revenue requirement is based on the OEB-approved forecasts of operating costs as reduced by a stretch factor and a return on rate base. Rate base for OPG represents the average net level of investment in regulated fixed and intangible assets in service and an allowance for working capital.

For the first time since OPG's prescribed facilities became subject to rate regulation, the new prices have been determined on an incentive ratemaking methodology for the hydroelectric operations and a custom incentive regulation framework for the nuclear operations.

For the hydroelectric facilities, effective June 1, 2017, the base regulated prices in effect prior to June 1, 2017, with some adjustments, will be escalated for each of years 2017 to 2021 using a formula equal to an industry-specific weighted inflation factor based on indices published annually by the OEB for use in incentive regulation formulas, less a stretch factor adjustment. The OEB accepted OPG's proposal to set the annual stretch factor adjustment at 0.3 percent. Based on the approved formula, the 2017 increase in the base regulated price for the regulated hydroelectric facilities is 1.4 percent as of June 1, 2017 and the 2018 increase is 0.9 percent as of January 1, 2018. For the 2019-2021 period, the base regulated price for the regulated hydroelectric facilities will be determined annually before the beginning of each year using the approved formula and inflation indices published by the OEB.

For the nuclear operations, a revenue requirement is determined for each of the years 2017 to 2021 based on the OEB-allowed level of OPG's forecast operating costs, reduced by a stretch factor amount, as well as a return on rate base determined using OEB's generic prescribed rate of return and an OPG-specific deemed capital structure. OPG has calculated that the findings of the OEB's December 2017 decision with respect to the forecast operating costs, rate base and deemed capital structure for the nuclear generating facilities will result in nuclear revenue requirements totalling $15.9 billion over the five years.

The OEB's findings with respect to the nuclear revenue requirement include approval for inclusion in rate base of in-service amounts related to the Darlington Refurbishment of $5.5 billion by 2021, including $4.8 billion forecast in the first quarter of 2020 upon return to service of Unit 2, $0.4 billion forecast for pre-requisite projects excluding the construction of the Heavy Water Storage and Drum Handling Facility (HWSF) over the 2016-2021 period and $0.3 billion for pre-requisite projects placed in service prior to 2016. The OEB is expected to review the HWSF project as part of a future application. In the decision, the OEB concluded that it is appropriate to evaluate OPG's performance on the Darlington Refurbishment project at an overall level rather by individual cost component, with recovery of any increases over the approved in-service amounts subject to a future prudence review. The revenue requirement impact of differences between the approved in-service additions and the actual in-service additions will be recorded in the Capacity Refurbishment Variance Account authorized by the OEB pursuant to *Ontario Regulation 53/05*. The $4.8 billion forecast in-service amount upon return to service of Unit 2 includes expenditures incurred during the definition and planning phase of the project.

The OEB also approved OPG's requested forecast costs of approximately $292 million for activities to enable Pickering commercial operations beyond 2020 and agreed to inclusion of operating cost and generation impacts associated with continued operation of Pickering in 2021 in nuclear regulated prices. The differences between approved forecast enabling costs for continued Pickering operations and the actual amounts will be recorded in the Capacity Refurbishment Variance Account for future review and disposition by the OEB.

Excluding amounts that otherwise would have been recorded in OEB-authorized regulatory accounts for repayment to, or recovery from, customers in the future, the OEB's decision reduced OPG's proposed five-year nuclear revenue requirement by $0.6 billion. The main adjustments made by the OEB included a reduction of $100 million per year to requested OM&A costs , a reduction of 10 percent per year to forecast non-Darlington refurbishment capital in-service additions entering rate base over the 2017-2021 period, an increase and expansion of the scope of the stretch factor for nuclear costs that further reduced the revenue requirement, and a rejection of OPG's request to increase the equity component of the existing deemed capital structure of 45 percent equity and 55 percent debt. The OEB increased and expanded the annual stretch factor to 0.6 percent to most of OPG's OM&A expenses incurred directly for, or allocated to, the nuclear facilities, as well as to non-Darlington refurbishment capital in-service additions. The stretch factor is applied starting in 2018 and compounds in each year to 2021.

In accordance with *Ontario Regulation 53/05*, the nuclear revenue requirement continues to be adjusted by the amount of OPG's revenues, net of costs, from leasing the Bruce nuclear generating stations to Bruce Power. As directed by the OEB, OPG's revenues and costs related to the Bruce nuclear generating stations continue to be determined in accordance with US GAAP for the purposes of establishing the nuclear revenue requirement and are subject to the Bruce Lease Net Revenues Variance Account in accordance with *Ontario Regulation 53/05*. This includes costs related to the portion of the Nuclear Liabilities associated with the Bruce nuclear generating stations. The OEB's decision maintained the previously approved cost recovery methodology for the costs of the Nuclear Liabilities for the prescribed facilities and for the Bruce facilities, directing OPG to file a future study examining such methodologies jurisdictionally and for OPG's assets specifically. The decision fully incorporated the impacts of the updated estimate of OPG's obligations for nuclear waste management and nuclear facilities decommissioning as at December 31, 2016, including through a new ONFA reference plan effective January 1, 2017 and the change in the Nuclear Liabilities recorded on December 31, 2016.

As proposed by OPG, the OEB set recovery of pension and OPEB costs in the nuclear revenue requirement on the basis of OPG's cash payments for pension and OPEB plans, with differences between pension and OPEB accrual costs and cash payments continuing to be recorded in the Pension & OPEB Cash to Accrual Differential Deferral Account. The regulatory treatment of pension and OPEB costs is discussed further under the heading, *Pension and OPEB Cost Recovery Methodology*.

To reflect the OEB's decision, in the fourth quarter of 2017, OPG recorded incremental revenue of approximately $480 million for the period June 1, 2017 to December 31, 2017 based on the draft payment amounts order. The revenue was recorded as an increase in regulatory assets for the June 1, 2017 to December 31, 2017 revenue shortfall based on proposed new regulated prices for nuclear facilities and regulated hydroelectric facilities, net of a regulatory liability recognized in relation to OPG's rate smoothing proposal. The OEB's approval of the final payment amounts order, including the allocation of the approved revenue requirement between nuclear regulated prices and rate smoothing deferrals, is not expected to have a material impact on the net revenue increase recorded in the fourth quarter of 2017. The OEB is expected to issue the final payment amounts order and implement new regulated prices in the first half of 2018. **[MONITOR]**

The base regulated prices in effect from January 2015 through May 2017 were established by the OEB's November 2014 decision and December 2014 order on OPG's September 2013 rate application. This included regulated prices effective November 1, 2014 for the 48 hydroelectric facilities that were prescribed for rate regulation effective July 1, 2014. Prior to November 1, 2014, the generation revenue for these hydroelectric facilities was based on the Ontario electricity spot market price, including for the period from

July 1, 2014 to November 1, 2014 as determined by the OEB. The base regulated prices effective November 1, 2014 remained in effect until May 31, 2017.

The regulated prices in effect from January 2015 through May 2017 for the nuclear facilities and the hydroelectric facilities prescribed for rate regulation prior to 2014 were determined by the OEB based on approved 24-month revenue requirements for the 2014 to 2015 period totaling approximately $7.3 billion. This reflected a reduction of $833 million from the revenue requirements submitted by OPG. The regulated price for the 48 hydroelectric facilities prescribed for rate regulation beginning in 2014 was established based on an approved 18-month revenue requirement for the period from July 1, 2014 to December 31, 2015 of approximately $750 million, a reduction of $101 million from OPG's submission. The most significant adjustments made by the OEB to OPG's September 2013 rate request included the following:

- Allowed pension and OPEB costs were limited to the forecast 2014 and 2015 cash expenditures for these plans, which were approximately $600 million lower, including related tax impacts, than the forecast accrual costs submitted by OPG. The difference between accrual costs and cash expenditures is being recorded in a deferral account authorized by the OEB. For further details, see *Pension and OPEB Cost Recovery Methodology* in this section. **[CONFIRM]**
- A reduction in overall forecast compensation costs of $100 million in each of 2014 and 2015 across all of OPG's regulated facilities.
- An increase in the forecast nuclear production of 0.5 terawatt hours (TWh) annually used to set the nuclear regulated prices, which had the effect of reducing the approved nuclear regulated price.
- The rate base addition for the Niagara Tunnel project to construct a third tunnel to divert additional water to OPG's generating stations on the Niagara River was limited to $1,365 million, which resulted in a write-off of $77 million being charged to operations in 2014.
- A reduction in the 2014 income tax expense included in the regulated prices by the amount of the regulatory tax loss calculated for 2013, which reduced the 2014/2015 revenue requirement by approximately $70 million.

In December 2014, OPG filed a motion with the OEB asking it to review and vary the parts of its November 2014 decision related to the disallowance of the Niagara Tunnel project expenditures and the application of the 2013 regulatory tax loss against the 2014/2015 revenue requirement. In its January 2016 decision on the motion, the OEB reversed a portion of the Niagara Tunnel project disallowance and upheld the original tax loss decision. In the first quarter of 2016, OPG recorded a gain of $22 million to recognize the expected future recovery from customers of the reversed portion of the Niagara Tunnel project disallowance.

In its November 2014 decision, the OEB adjusted the deemed capital structure applied to OPG's total regulated rate base to 45 percent equity and 55 percent debt, from 47 percent equity and 53 percent debt used previously. In making this adjustment, the OEB found that there had been an overall improvement in the risk profile of OPG's regulated operations, based on the increased proportionate share of rate base related to hydroelectric facilities. This reduced the 2014/2015 revenue requirements. In general, OPG's actual capital structure contains a significantly higher proportion of equity than has been reflected in the OEB-approved deemed capital structure, which has had the effect of reducing OPG's return on shareholder's equity.

Variance and Deferral Accounts and Rate Riders

Consistent with the requirements of *Ontario Regulation 53/05*, OPG's overall production-weighted regulated prices will be smoothed, with a resulting portion of the approved annual nuclear revenue requirements for the 2017-2021 period deferred in the Rate Smoothing Deferral Account for future collection. The non-deferred portion of each year's nuclear revenue requirement is divided by the OEB-approved forecast of OPG's nuclear electricity generation for the corresponding year to determine the base nuclear regulated price. The OEB approved the nuclear electricity generation forecast as requested by OPG.
As amended in March 2017, *Ontario Regulation 53/05* requires rate smoothing to be applied in a manner that makes changes in OPG's weighted-average nuclear and hydroelectric regulated prices more stable year over year. Previously, the regulation required that rate smoothing be applied with a view of making

more stable year-over-year changes in OPG's nuclear regulated prices only. Per the regulation, the deferral account records interest at a long-term debt rate reflecting OPG's cost of long-term borrowing approved by the OEB, compounded annually. The regulation requires the OEB to authorize recovery of the balance in the account on a straight line basis over a period not to exceed 10 years following the end of the Darlington Refurbishment project. OPG recognizes positive amounts deferred under rate smoothing as an increase in net regulatory assets and an increase in revenue in the period to which the underlying approved revenue requirement relates. Negative amounts determined under rate smoothing are correspondingly recorded as a decrease in net regulatory assets and a decrease to revenue.

On January 17, 2018, OPG submitted a draft payment amounts order to the OEB that proposed nuclear base regulated prices for each year of the 2017-2021 period, including a rate smoothing proposal, based on the December 2017 decision's findings. The rate smoothing proposal takes into account the near-term and future impacts on customers, while seeking to ensure that resulting nuclear regulated prices allow for sufficient cash flow to maintain the Company's investment grade credit rating and support availability of cost effective funding, while taking into account both near-term and future impacts on customers. Based on the OEB's direction, the draft payment amounts order also included proposed periods for recovery, through interim period shortfall rate riders, of the retrospective revenue shortfall for the period between June 1, 2017 and the implementation date of the new regulated prices based on proposed new regulated prices that would have been in effect during that period. The draft payment amounts also included proposed recovery periods, through variance and deferral account rate riders, for regulatory account balances approved for recovery in this application. **[MONITOR]**

Variance and deferral accounts are typically established by the OEB to capture, for subsequent review and approval, differences between actual costs and revenues and the corresponding forecast amounts approved by the OEB in setting regulated prices, or to record the impact of items not reflected in the approved regulated prices. Such accounts generally help to mitigate risks and uncertainties to the regulated entity and its customers.

The OEB has authorized several variance and deferral accounts for OPG, including those required by *Ontario Regulation 53/05*. The authorized accounts include, among others, those related to the gross margin impact of variability in regulated hydroelectric electricity production due to differences between the forecast and actual water conditions and due to the effect of SBG conditions, changes in liabilities for nuclear waste management and nuclear facilities decommissioning, changes in revenues and costs related to the lease and related agreements with Bruce Power for the Bruce nuclear generating stations, and variances in the revenue requirement impact of capital and non-capital costs incurred to increase the output of, refurbish, or add operating capacity to the regulated facilities, including the Darlington Refurbishment project. A number of these accounts are subject to an OEB prudence review. There is currently no regulatory variance or deferral account related to the impact of generation performance of OPG's nuclear stations on revenue from the base regulated prices. The Darlington Refurbishment project is discussed in the section, *General Development of the Business* under the heading, *Nuclear Business Development – Darlington Refurbishment*.

Approved balances in the regulatory variance and deferral accounts authorized by OPG are recovered or refunded through volumetric rate riders. The additional revenue from the riders is largely offset by a corresponding increase in amortization expense related to the variance and deferral account balances, which are typically recognized as assets (amounts recoverable from customers) or liabilities (amounts payable to customers) on the Company's balance sheet. Differences in amounts recovered or repaid through rate riders due to differences between actual and forecast production volumes are recorded in separate variance accounts for future disposition. **[MONITOR]**

The OEB accepted all variance and deferral account balances proposed for recovery that were not already accepted as part of the Settlement Agreement, resulting in approval of recovery of $305 million recorded in variance and deferral variance accounts as at December 31, 2015, without adjustments. The Settlement Agreement provided for the continuation of all applicable existing variance and deferral accounts. In addition to the Rate Smoothing Deferral Account, the OEB established, as of the effective date of the new regulated prices, new variance and deferral accounts to record costs related to implementing the Canadian

Nuclear Safety Commission's (CNSC) Fitness for Duty program and to record differences between forecast and actual amount of Scientific Research & Experimental Development investment tax credits attributable to the nuclear facilities. In January 2018, OPG filed a motion asking the OEB to review and vary the effective date of the new regulated prices to January 1, 2017. The motion did not impact OPG's financial results for the year ended December 31, 2017.

Consistent with the effective date of the OEB's December 2017 decision, for the period from January 1, 2017 to May 31, 2017, OPG continued to record additions to the existing variance and deferral accounts for the nuclear and regulated hydroelectric facilities pursuant to the OEB's previous decisions and orders. These additions reflected differences between actual and forecast amounts embedded in the regulated prices in effect prior to the June 1, 2017 effective date.

The rate riders in effect in 2015 and 2016 included those authorized by the OEB's October 2015 order on OPG's application in 2014 to recover or repay most of the December 31, 2014 variance and deferral account balances, discussed below. The 2015 rate riders also included those established by the OEB's December 2014 order on OPG's September 2013 rate application for the period January 1, 2015 to December 31, 2015. The December 2014 order allowed for recovery of $189 million recorded in certain variance and deferral accounts as at December 31, 2013, without adjustments.

The total balances approved for recovery by the OEB's October 2015 order were approximately $1.8 billion, of which approximately $1.5 billion was the subject of an OEB-approved partial settlement agreement reached by OPG and intervenors. The remaining balances of $263 million were approved by the OEB's September 2015 decision, without adjustments. The rate riders authorized by the October 2015 order were in effect from July 1, 2015 to December 31, 2016 and allowed for recovery of $933 million of the total approved balances.

Amendments to Ontario Regulation 53/05

In November 2015, the Province amended *Ontario Regulation 53/05* to establish a deferral account, effective January 1, 2017, that will record, for future recovery, a portion of the annual OEB-approved revenue requirements for OPG's regulated nuclear facilities during the period from January 1, 2017 to the end of the Darlington Refurbishment project. The amended regulation requires the OEB to determine the revenue requirements for OPG's nuclear facilities on a five-year basis for the ten-year period beginning on January 1, 2017. The portion of the approved revenue requirement deferred in the new account each year also will be determined by the OEB on a five-year basis during this ten-year period. The regulation stipulates that the deferral account will record interest at a long-term debt rate reflecting OPG's cost of long-term borrowing approved by the OEB, compounded annually, and that the OEB shall authorize recovery of the balance in the account on a straight line basis over a period not to exceed 10 years following the end of the Darlington Refurbishment project. OPG expects to recognize the deferred amounts as income in the period to which the underlying approved revenue requirements relate.

The November 2015 amendment required the portion of the approved annual nuclear revenue requirements deferred for future recovery to be determined with a view of making more stable year-over-year changes in OPG's nuclear regulated prices only. In March 2017, the Province amended *Ontario Regulation 53/05* to require that the deferred portion of the approved annual nuclear revenue requirements be determined with a view of making more stable year-over-year changes in OPG's weighted-average nuclear and hydroelectric regulated prices, including rate riders. The amendment is intended to make more predictable the impact on customer bills resulting from changes in OPG's overall regulated prices, reducing the average year-over-year change in customer bills over the term of OPG's May 2016 application for new regulated prices.

The regulation was also amended in November 2015 to require the OEB to accept the need for the Darlington Refurbishment project in light of Ontario's 2013 Long-Term Energy Plan (LTEP) and the related policy of the Province endorsing the need for nuclear refurbishment. Furthermore, the 2017 LTEP reaffirms the Province's support for nuclear refurbishment. The 2017 LTEP is discussed in the section, *General*

Development of the Business under the heading, *General Development – Ontario's Long-Term Energy Plan*.

Pension and OPEB Cost Recovery Methodology

Using the methodology previously applied by the OEB in setting OPG's regulated prices, the revenue requirements submitted by OPG in its September 2013 rate application included a forecast of 2014 and 2015 pension and OPEB costs determined on an accrual basis in accordance with US GAAP. In its November 2014 decision and December 2014 order on the application, the OEB approved revenue requirements based on OPG's estimated minimum required contributions to its registered pension plan, and a forecast of OPG's expenditures on the OPEB and supplementary pension plans. In directing this reduction in the revenue requirement, the OEB agreed with OPG and certain other parties that a generic proceeding on the regulatory treatment and recovery of pension and OPEB costs would be beneficial. The OEB also indicated that a change in the recovery methodology for OPG's pension and OPEB amounts from the accrual basis, if required, would be addressed in a future OPG rate proceeding, informed by the outcome of the generic proceeding.

Pending the generic proceeding, the OEB established the Pension & OPEB Cash Versus Accrual Differential Deferral Account. Effective November 1, 2014, this deferral account records the difference between OPG's actual pension and OPEB costs for the regulated business determined on an accrual basis and the corresponding actual cash expenditures for these plans. The OEB's November 2014 decision indicated that the future recovery, if any, of amounts recorded in the deferral account would be subject to the outcome of a future generic OEB proceeding on the regulatory treatment and recovery of pension and OPEB costs. The balance in the account is recognized as a regulatory asset on OPG's balance sheet.

On September 14, 2017, the OEB issued its final report on the guiding principles and policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the Ontario electricity and natural gas sectors. The report establishes the accrual basis of accounting as the method of determining pension and OPEB amounts for rate-setting purposes, unless the OEB finds that this method does not result in just and reasonable rates in the circumstances of a particular utility. The report also provides for the establishment of a generic variance account to record asymmetric carrying charges in favour of ratepayers on the differences between the accrual costs recovered and cash payments made by a utility in respect of pension and OPEB plans. Carrying charges on this differential are to be assessed at the OEB's prescribed interest rate, on a prospective basis from the effective date of the new variance account. For OPG, this differential will include amounts going back to November 1, 2014, with the charges calculated on the portion of the differential that has been recovered through regulated prices. None of this differential has been recovered to date. The prescribed interest rate is set quarterly by the OEB based on the quarterly return of a mid-term corporate bond index yield.

The OEB's September 2017 report and the OEB's December 2017 decision on OPG's application for new regulated prices require OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the Pension & OPEB Cash to Accrual Differential Deferral Account in effect since November 1, 2014, until such time as the OEB approves resumption of the accrual basis of recovery for OPG. The future recovery of amounts recorded in the account will be subject to this approval. The OEB's report did not impact OPG's financial results for the year ended December 31, 2017.

The Company recognizes the amount set aside in the Pension & OPEB Cash Versus Accrual Differential Deferral Account as a regulatory asset. As at December 31, 2017, the regulatory asset had a balance of $614 million. Consistent with the expectations set out in the OEB's December 2017 decision, in 2018, OPG plans to file an application with the OEB requesting disposition of the Pension & OPEB Cash Versus Accrual Differential Deferral Account balance as well as balances accumulated since December 31, 2015 in other regulatory accounts.

Supreme Court of Canada's Decision on 2011 OEB Ruling

In September 2015, the Supreme Court of Canada (Supreme Court) issued its decision upholding the OEB's disallowance of $145 million of OPG's forecast nuclear compensation costs for the 2011 to 2012 period. The majority of these costs were based on previously negotiated collective bargaining agreements. This disallowance was part of the OEB's March 2011 decision on OPG's application for regulated prices effective March 1, 2011. The Supreme Court decision underscores that OPG must continue to establish the reasonableness of both committed and future costs as part of the rate-setting process.

Ontario's Fair Hydro Plan

On March 2, 2017, the Province announced the Fair Hydro Plan aimed at reducing electricity bills for eligible residential, farm, small businesses ~~and other eligible~~ consumers (Specified Consumers) in the province by refinancing a portion of the Global Adjustment costs over a longer period of time. The Global Adjustment includes the difference between Ontario's electricity market clearing price used to dispatch generation and the prices paid to contracted and regulated generators in the province, and the cost of conservation and demand management programs. On June 1, 2017, the Fair Hydro Act received Royal Assent and the associated general regulation came into force in June 2017. The Act established a framework under which the costs and benefits associated with the Government of Ontario's clean energy initiatives are to be allocated between present and future consumers of electricity under the Fair Hydro Plan. The general regulation provides details on the structural, operational and financial elements required to implement the Fair Hydro Plan.

Pursuant to the Act, effective May 1, 2017, the IESO began to defer a portion of the Global Adjustment costs. The Act allows the IESO to transfer a portion of the deferred balance to a financing entity that would fund the deferral in exchange for an irrevocable right to recover the balance and associated financing and other costs from Specified Consumers in the future (Investment Interest). The legislation appointed OPG as the Financial Services Manager under the Act and conveyed upon the Financial Services Manager statutory obligations, including the creation of one or more financing entities that may acquire Investment Interests from the IESO.

In November 2017, OPG's Board of Directors provided its final approval regarding OPG's involvement with the Trust on commercial terms following the fulfilment of all conditions it established in May 2017. Accordingly, the Fair Hydro Trust was established as the financing entity contemplated by the Act in December 2017. The majority unitholder and beneficiary of the Trust is a wholly-owned subsidiary of OPG. The Trust is structured to be bankruptcy remote and ring fenced from OPG in order to protect the Company's assets and operations.

In order for the Trust to finance the Investment Interest acquired from the IESO, it will incur senior debt from capital markets and subordinated debt from OPG. The Trust's investment will attract financing amounts and other related fees, which, under the general regulation, will be payable by the IESO as carrying costs until July 2021 and by Specified Consumers through the Clean Energy Adjustment to be invoiced by local distribution companies commencing in May 2021, with the three-month lag in 2021 intended to cover the billing and collection lag from the introduction of the Clean Energy Adjustment. The carrying costs include all financing and third-party costs other than payment of principal on debt.

Concurrent with every issuance of the Trust's senior notes, it is expected that OPG will purchase subordinated debt of the Trust in an aggregate amount not to exceed 49 percent of the Trust's total outstanding debt, with 44 percent of the funding to be provided by the Province through equity injections and five percent to be provided by OPG. The subordination level may vary over time, but must at least equal to, or be greater than 35 percent of all outstanding debt. Through OPG's control over the key activities of the Trust and its obligation to absorb losses through ownership of the Trust's subordinated debt, the Company consolidates the financial results of the Trust in accordance with US GAAP.

On December 21, 2017, the Trust purchased its first tranche of Investment Interest from the IESO in the amount of approximately $1.18 billion. Fifty-one percent of the funding requirement or $601 million was financed by the Trust through a revolving warehouse facility ranked as senior notes, and the remaining 49

percent was funded through the issuance of short-term subordinated debt to OPG. The Investment Interest has been classified as a financing receivable on OPG's consolidated balance sheet.

OPG's subordinated debt investment in the Trust was funded through the following sources:

- The Province provided 44 percent of the total funding requirement or $519 million, through an equity injection in OPG in exchange for approximately 12.2 million non-voting Class A common shares at a price of $42.46 per share. The Company's Articles of Amalgamation were amended effective December 1, 2017 to allow for the creation and issuance of Class A shares. Refer to Note 14 to the Company's audited annual financial statements as at and for the year ended December 31, 2017 for further details; and
- OPG provided five percent of the total funding requirement or approximately $60 million.

In February 2018, the Trust issued $500 million of senior notes payable with a coupon interest rate of 3.36 percent and an effective interest rate of 3.42 percent, payable semi-annually until maturity on May 15, 2033. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility issued in December 2017. By the end of the first quarter of 2018, the Trust is expected to acquire another tranche of Investment Interest from the IESO, which is expects to fund using its revolving warehouse facility.

Refer to the section, *Liquidity and Capital Resources* under the heading, *Financing Activities* for further details on the Trust's financing arrangements and OPG's public debt offering in the Company's 2017 year-end MD&A.

Ontario's Long-Term Energy Plan

On October 26, 2017, Ontario's Ministry of Energy issued the 2017 LTEP that outlines the Province's plans for the future development of Ontario's electricity system. The 2017 LTEP focuses on the affordability, reliability and flexibility of a clean energy supply in the province. The 2017 LTEP replaces the previous LTEP issued in 2013.

As it relates to the supply of electricity, the 2017 LTEP recognizes the refurbishment of Ontario's nuclear generating stations as the most cost-effective option for producing emission-free baseload generation to meet Ontario's needs and reaffirms the Province's support for the refurbishment of the four units at the Darlington GS and the six units at the Bruce generating stations, subject to the principles established in the 2013 Long-Term Energy Plan. The 2017 LTEP also recognizes the value to customers of continuing to operate the Pickering GS until 2024, as planned. With respect to hydroelectric electricity generation, the 2017 LTEP highlights the opportunity to continue to invest in optimizing existing hydroelectric facilities, noting that pumped hydroelectric storage could play an important role in the reliability of the electricity system.

Additionally, the 2017 LTEP discusses the potential impact of a number of innovative technologies on the future of the electricity system. Among others, these include the increased electrification of the transportation sector, the emergence of energy storage, and the opportunity for Ontario to foster nuclear innovation technologies. OPG continues to assess how best to capitalize on potential business opportunities in these and other areas. The 2017 LTEP also recognizes the importance of Indigenous peoples' continuing role in shaping Ontario's energy planning, projects and policies.

Renewal of Collective Agreements and Acquisition of Hydro One Limited Shares

Most of OPG's regular employees are represented by one of two unions: the Power Workers' Union (PWU) and The Society of Energy Professionals (The Society). As at December 31, 2017, the PWU represented approximately 53 percent of OPG's regular workforce, while The Society represented approximately 35 percent of the regular workforce.

The previous collective agreement between OPG and the PWU expired on March 31, 2015. In May 2015, the parties agreed to renew the collective agreement for a three-year term, expiring on March 31, 2018.

The changes to the collective agreement included increases to employee pension plan contributions in each year of the agreement. Negotiations for a new labour agreement with the PWU are underway. **[MONITOR]** The previous collective agreement between OPG and The Society expired on December 31, 2015. In November 2015, the parties agreed to renew the collective agreement for a three-year term, expiring on December 31, 2018. Changes to the collective agreement included increases to employee pension plan contributions in each of the first two years of the agreement. The changes in pension plan contributions apply to current employees and future employees of both unions, and do not have an end date.

The changes to both collective agreements provided existing employees with lump sum payments for each of the first two years of the respective contract and eligibility to annually receive shares in Hydro One Limited (Hydro One) for up to 15 years starting in the third year of the contract, as long as these employees continue to make contributions to the OPG pension plan and have less than 35 years of pensionable service. The lump sum payments and future share awards are intended to compensate current eligible employees, over a defined period, for their increased pension plan contributions.

In April 2016, OPG acquired nine million common shares of Hydro One at $23.65 per share as part of a secondary share offering by the Province through a syndicate of underwriters. The acquisition, totaling $213 million, was made for investment purposes to mitigate the risk of future price volatility related to OPG's future share delivery obligations under the collective agreements. The shares acquired in this transaction represent the substantial majority of OPG's currently anticipated purchases of Hydro One shares.

In addition to the regular workforce, construction work is performed through 19 craft unions with established bargaining rights at OPG facilities. These bargaining rights are established either through the Electrical Power Systems Construction Association (EPSCA) or directly with OPG. Collective agreements between the Company and its construction unions are negotiated either directly or through EPSCA. All of these collective agreements currently have multi-year terms, expiring on April 30, 2020.

Shareholder Declarations and Shareholder Resolutions to Sell Certain Non-Core Real Estate Properties

In December 2015, OPG received a Shareholder Declaration and a Shareholder Resolution requiring the Company to sell its head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street in Toronto, Ontario. The sale was completed in April 2017, with a gain on sale of $283 million, which is net of tax effects of $95 million, recognized in net income in the second quarter of 2017. The pre-tax gain on sale was recorded as an item of Other gains in the consolidated statement of income in the Services, Trading and Other Non-Generation segment. Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. The amount of designated proceeds transferred into the Consolidated Revenue Fund are expected to approximate ~~will be equal to~~ the after-tax gain on sale. **[MONITOR]** The transfer is expected to take place in the first quarter of 2018, through a special dividend authorized by OPG's Board of Directors in March 2018. **[MONITOR]**

Commented [DS1]: The amount of designated proceeds will be determined by regulation and therefore uncertain until the regulation is filed and made public.

In June 2016, OPG received a Shareholder Declaration and a Shareholder Resolution that requires the Company to sell its former Lakeview GS site located in Mississauga, Ontario. OPG has entered into a purchase and sale agreement with a purchaser with the sale scheduled to close in March 2018. An estimated after-tax gain on sale of approximately $200 million is expected to be recognized in net income upon completion of the transaction in the first quarter of 2018. **[MONITOR]** Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. OPG anticipates the amount of designated proceeds transferred into the Consolidated Revenue Fund to approximate the after-tax gain on the sale. In accordance with the Shareholder Resolution, approximately one-third of the site is to be transferred to the City of Mississauga, by the purchaser, for parkland, institutional, and cultural uses.

Neither the former Lakeview GS site nor the Company's head office premises and associated parking facility are considered core assets to OPG's business.

For a complete list of Shareholder directives, refer to the section, *Interest of Management and Others in Material Transactions* under the heading, *Relationship with the Province and the OEFC – Shareholder Directives*.

Business Transformation **[UPDATE]**

OPG has completed a multi-year initiative with the objective of transforming itself into a more streamlined, agile and efficient organization. The business transformation initiative was intended to drive sustainable change across the Company, while ensuring that there is no adverse impact on the safety, reliability and environmental sustainability of OPG's operations. OPG's cumulative savings from reductions in regular headcount from ongoing operations, through the business transformation and other initiatives, since the beginning of 2011, reached $1 billion in 2016.

The business transformation initiative involved aggressively pursuing cost control and efficiency improvements at the enterprise and business unit level, including realignment of work, streamlining of processes and leveraging workforce attrition. As part of the initiative, OPG implemented a centre-led organizational model intended to more efficiently utilize resources. In 2015, OPG successfully completed a large-scale initiative, the Enterprise System Consolidation Project, to streamline the company's software systems and improve business processes by implementing a common enterprise software platform.

Although business transformation has concluded as a discrete initiative, improving organizational performance and building on efficiency gains achieved to date remains a key priority for the Company. OPG continues to review its cost structure, identify cost improvement strategies and embed an outcomes-driven culture that reinforces low cost, efficiency, and organizational agility as part of business decision-making.

Nuclear Business Development

Darlington Refurbishment

Government's Endorsement and Execution Phase

The Darlington generating units are approaching their originally designed end-of-life. Refurbishment of the four generating units to extend the operating life of the station by approximately 30 years, into the 2050s. In January 2016, the Government of Ontario's support for the Darlington Refurbishment project was affirmed through the Ontario Minister of Energy's announcement endorsing OPG's plan to refurbish the four Darlington units at a total project budget of $12.8 billion, including capitalized interest and escalation. The Province's announcement followed the approval of the project budget and schedule by OPG's Board of Directors in November 2015. The refurbishment of the last unit is scheduled to be completed by 2026. *Ontario Regulation 53/05* requires the OEB to ensure that OPG recovers capital and non-capital costs and firm financial commitments in respect of the Darlington Refurbishment project, if the OEB is satisfied that the costs were prudently incurred and that the firm financial commitments were prudently made.

The refurbishment project is a multi-phase program comprising several sub-projects. The major work streams include: de-fuelling of reactors and refurbishment of the fuel handling equipment; removal and replacement of feeder tubes and fuel channel assemblies in each reactor (Retube and Feeder Replacement or RFR); inspections and repairs of turbine generator sets and replacement of associated control systems; mechanical cleaning, water lancing, and inspection and maintenance work on steam generators; and replacement or repairs of certain other station components referred to as balance of plant. The RFR is the largest sub-project and represents a majority of the critical path schedule.

In 2016, the Darlington Refurbishment project transitioned from the planning phase to the execution phase, as OPG commenced the refurbishment of the first unit, Unit 2, in October 2016 as planned. The unit was

taken offline on October 15, 2016. De-fuelling of the reactor was completed in January 2017, with a total of 480 fuel channels de-fuelled. Islanding of Unit 2, the physical separation of the unit under refurbishment from the three operating units, was completed in April 2017, signifying the completion of the first major segment of the project.

The second major segment includes preparatory work to support the removal of feeder tubes and fuel channel assemblies, followed by the removal of reactor components. The preparatory work was completed in the second quarter of 2017. The Re-tube Tooling Platform for hosting the tooling for the removal, inspection and installation activities, and the setup of specialized tooling and equipment needed for the removal and replacement of the reactor components were completed in the third quarter of 2017. The disassembly of reactor components commenced in August 2017, with the removal of all 960 feeder tubes completed safely in September 2017. The removal of fuel channel assemblies commenced in October 2017. As part of the fuel channel assemblies, the removal of pressure tubes is in progress and will be followed by the removal of calandria tubes. The second major segment and the removal of all reactor components is expected to be completed by mid-2018. Key projects in the second major segment finished in 2018 include the completion of the primary side steam generator layup and installation of steam generator access ports to support future inspections. Other key project activities being executed during the second segment include the continuation of the major turbine generator overhaul, which will be completed in the second quarter of 2018, and continued execution of the major electrical scope. OPG is also continuing to execute work to support the requirements set out in the CNSC-approved Integrated Implementation Plan (IIP) for the station.

Most of the pre-requisite projects, including construction of facilities, infrastructure upgrades and installation of safety enhancements, have been completed and placed in-service. The Re-tube Waste Processing Building was completed in November 2017. Completion of the HWSF has been delayed due to challenges with construction. OPG suspended the project in the second quarter of 2017 to evaluate the best approach to optimize cost and schedule and complete the project. Construction to complete the facility recommenced in the fourth quarter of 2017. The HWSF is expected to be completed by the second quarter of 2019 and is not on the critical path for the Darlington Refurbishment project, which continues to track on schedule. The increase in the cost estimate for the HWSF will be accommodated within the overall Darlington Refurbishment budget of $12.8 billion. Taking into account the execution performance of the Unit 2 refurbishment, the overall Darlington Refurbishment project continues to track on budget.

The OEB accepted OPG's rate application with respect to the refurbishment of the Darlington units including an increase in the nuclear rate base, effective in the first quarter of 2020, to reflect the planned in service of $4.8 billion in capital expenditures upon the return to service of Unit 2, which includes expenditures incurred during the definition and planning phase of the project. Based on OPG's proposal in the application, the revenue requirement impact of the differences between the forecast Unit 2 in-service amount included in the regulated prices and the actual amounts placed in service would be subject to true up via the Capacity Refurbishment Variance Account established by the OEB pursuant to *Ontario Regulation 53/05*.

In addition to the execution of refurbishment activities on Unit 2, OPG is continuing planning activities for the refurbishment of the second unit, Unit 3, and is entering into associated commitments to procure major components that require long lead times. These planning activities are being undertaken in accordance with the refurbishment project schedule. In February 2018, the Province confirmed its commitment to proceed with Darlington's Unit 3 refurbishment in 2020. **[MONITOR]**

On November 21, 2017, the Financial Accountability Office of Ontario issued a report, "*An Assessment of the Financial Risks of the Nuclear Refurbishment Plan*". The report assesses the impact of OPG and Bruce Power's nuclear refurbishments on customers and the Province based on mechanisms in place for the recovery of the costs to refurbish and subsequently operate the nuclear stations. The report concludes that refurbishment of the four units at the Darlington GS and the six units at the Bruce nuclear generating stations provides the most cost effective, low emission generation source available to meet Ontario's baseload electricity requirements.

CNSC Regulatory Approvals

In December 2013, OPG submitted an application to the CNSC for the operating licence renewal for the Darlington GS. The CNSC granted the Darlington GS a ten-year operating licence in December 2015, which is the longest licence ever granted by the CNSC to a Canadian nuclear power plant. The new licence, which is effective from January 1, 2016 to November 30, 2025, spans most of the planned duration of the Darlington Refurbishment project.

In line with the CNSC's regulatory requirements related to life extensions of nuclear power plants in effect at the time that OPG began to undertake the Darlington Refurbishment project, OPG completed a series of assessments, including an environmental assessment (EA), an Integrated Safety Review, and a Global Assessment Report (GAR). The EA decision, issued by the CNSC and Fisheries and Oceans Canada in March 2013 following public hearings, confirmed that, taking into account identified mitigation measures, the project was not likely to cause significant adverse environmental effects. In April 2014, the CNSC accepted the GAR as meeting all regulatory requirements related to life extensions of nuclear power plants. In November 2014 and April 2016, respectively, certain intervenors' request for a judicial review and subsequent appeal to the Federal Court of Appeal related to the EA decision were dismissed by the courts.

Actions identified as part of the above assessments to meet updated codes, standards and practices, and to ensure that the operation of the station continues to pose minimal risk to health, safety, security and the environment, were integrated into the IIP. As part of the Darlington operating licence renewal in December 2015, the CNSC approved the regulatory scope defined in the IIP. OPG has been undertaking activities in support of the IIP requirements, including the commissioning of two safety enhancements at the station, the Third Emergency Power Generator and the Containment Filtered Venting System, which were placed in-service in April 2017. There were 17 IIP commitments scheduled and completed for 2017.

Extension of Commercial Operations at Pickering to 2024

In 2015, OPG completed the necessary work to demonstrate with sufficient confidence that the Pickering fuel channel life, a key life-limiting component of the station, will allow all six operating units of the station to operate to the end of 2020. OPG's early technical work at that time also showed that the Pickering GS can be operated safely beyond 2020. OPG's objective is to maximize the safe and reliable operating life of the Pickering units. As announced in 2016 and approved by the Province, OPG is continuing to execute on a plan to extend safe and reliable operation of the Pickering GS to 2024. Extending operations at the Pickering GS will provide Ontario with a clean, reliable source of baseload electricity during the Darlington GS and initial Bruce nuclear unit refurbishments, providing continued employment for up to 4,000 full-time employees at OPG.

OPG's current five-year operating licence for the Pickering GS was approved by the CNSC in 2013 and expires on August 31, 2018. This current licence was issued assuming that the station would shut down in 2020. On June 28, 2017, OPG confirmed to the CNSC that it intends to cease commercial operation of all Pickering units on December 31, 2024. On August 28, 2017, OPG submitted a ten-year licence renewal application to the CNSC. The requested licence term spans the planned extended commercial operations period, through to the planned period of de-fuelling, de-watering and beginning to place the station in a safe storage state in 2028. In support of the licence renewal, OPG undertook a Periodic Safety Review (PSR), a comprehensive assessment of the station's design and operation to confirm that there is a high level of safety throughout the operating life and to determine what reasonable and practical enhancements can be made to further improve safety. The PSR also includes a component condition assessment of the station to identify the work required to support the station's continued operation. The PSR has confirmed that extending operations of the Pickering units will continue to pose minimal risk to the health, safety and security of workers, the public and the environment. The final major component of the PSR was submitted to the CNSC in November 2017. The CNSC's review of the PSR submission and licence application is in progress. Based on the evidence and documentation submitted to the CNSC, OPG is confident in obtaining a licence renewal that would support our extended operations plan for Pickering GS.

As part of the plan to extend Pickering operations, OPG has been continuing to undertake the required technical work to confirm that the station's pressure tubes, a key life-limiting component of the station, will remain fit for service for operation to 2024. In the fourth quarter of 2017, OPG has confirmed that technical assessments completed to date provide sufficient confidence in the programs and provisions in place to assure fitness-for-service of fuel channel components in line with the planned extended operations period. This evaluation is consistent with the safety case reflected in OPG's operating licence renewal application for the Pickering GS submitted to the CNSC in 2017, discussed above. Taking these factors into account, OPG revised the accounting end-of-life assumptions for the Pickering GS from December 31, 2020 for all units to December 31, 2022 for Units 1 and 4 and December 31, 2024 for Units 5 to 8, effective December 31, 2017.

The change in the Pickering GS accounting end-of-life assumptions did not impact OPG's net income in 2017. The change is expected to decrease depreciation expense by $77 million in 2018, including the associated impact on the nuclear asset retirement obligation recorded as of December 31, 2017 but before the impact of regulatory accounts. Regulatory accounts, including a new deferral account proposed by OPG in a December 2017 application to the OEB, are expected to largely offset the decrease in depreciation expense. As of December 31, 2017, OPG recorded an increase of $188 million in the Nuclear Liabilities and associated asset retirement costs capitalized as part of carrying value of property, plant and equipment reflecting the change in the Pickering GS accounting end-of-life assumptions from December 31, 2020 for all operating units to December 31, 2022 for Units 1 and 4 and December 31, 2024 for Units 5 to 8. The increase in the liabilities is primarily due to higher fixed costs associated with the Used Fuel Disposal and L&ILW Storage programs, discounted using the current credit-adjusted risk-free rate of 2.94 percent. The adjustment did not impact net income for 2017. The adjustment is not expected to have a material impact on net income in 2018 as the associated impact on expenses is expected to be largely offset by OEB-authorized regulatory accounts. On December 29, 2017, OPG applied for an accounting order to establish a variance account to record, from January 1, 2018 until the effective date of the OEB's next payment amounts order, the revenue requirement impact of changes to nuclear liabilities and depreciation and amortization expense resulting from changes to station end-of-life dates for OPG's Pickering prescribed nuclear facilities that will be effective December 31, 2017. Pending the OEB's review of the application, an interim order was issued January 31, 2018 establishing the proposed variance account effective January 1, 2018. The OEB's final decision in the account is expected later in 2018.

The income statement impacts associated with the changes to the Nuclear Liabilities are offset by the Bruce Lease Net Revenues Variance Account and the Nuclear Liability Deferral Account authorized by the OEB or new variance account to be authorized by OEB for the prescribed facilities.

Bruce Power Refurbishment and Bruce Lease Agreement

OPG leases the four-unit Bruce A (Units 1 to 4) and the four-unit Bruce B (Units 5 to 8) nuclear generating stations and associated lands and facilities to Bruce Power on a long-term basis. Bruce Units 1 and 2 were refurbished by Bruce Power under a refurbishment agreement with the IESO and returned to service in 2012. While Bruce Power is responsible for operating all of the leased units, OPG is primarily responsible for the management of the nuclear used fuel and other nuclear waste associated with the Bruce nuclear generating facilities, as well as the decommissioning of the facilities at the Bruce site. Under the lease agreement between Bruce Power and OPG (Bruce Lease) and related agreements, OPG receives base rent and supplemental rent payments from Bruce Power, fees for nuclear waste management other than used fuel, and fees for certain other services. The output from the Bruce nuclear generating stations is not subject to rate regulation by the OEB.

In December 2015, the Province announced that the refurbishment agreement between the IESO and Bruce Power had been updated and that Bruce Power will proceed with the refurbishment of the six un-refurbished units of the Bruce nuclear generating stations. In order to facilitate Bruce Power's refurbishment plans, the Bruce Lease and related agreements were amended in December 2015 to extend Bruce Power's future options to renew the lease up to the end of 2064. To achieve better alignment with OPG's costs, the agreements were also amended to revise, starting in 2016, the approach for calculating supplemental rent payments and fees for nuclear waste management other than used fuel, and to modify the fee structure for

OPG's heavy water detritiation services starting in 2017. Beginning in 2016, supplemental rent payments wholly represent fees for nuclear used fuel management. Amendments were also made to enable certain adjustments to future base rent, supplemental rent and other fees for potential future changes in OPG's decommissioning and nuclear waste management cost estimates related to the Bruce facilities, and to remove a conditional supplemental rent rebate provision effective December 4, 2015. Certain of the above amendments were executed by OPG pursuant to a Shareholder Declaration and Shareholder Resolutions issued in November 2015. For a complete list of Shareholder directives, refer to the section, *Interest of Management and Others in Material Transactions* under the heading, *Relationship with the Province and the OEFC – Shareholder Directives*.

The refurbishment of Bruce Power's Unit 6 is scheduled to commence on January 1, 2020. As part of the preparation activities, OPG is working with Bruce Power to develop a fixed price cost estimate for the non-routine nuclear waste that will be generated from the Unit 6 refurbishment. The parties will execute a separate agreement that sets out the terms and conditions that will apply to this refurbishment waste. Pursuant to a Memorandum of Understanding dated November 12, 2015, OPG and Bruce Power have committed to ongoing collaboration to improve their respective refurbishment programs.

Ontario Nuclear Funds Agreement Reference Plan Update

OPG is responsible for the management of radioactive used nuclear fuel and low and intermediate level radioactive waste material (L&ILW) and the decommissioning of its nuclear stations and waste management facilities. Pursuant to the Ontario Nuclear Funds Agreement (ONFA), OPG is required to set aside monies into two segregated funds, the Used Fuel Segregated Fund and the Decommissioning Segregated Fund, to fund the future life cycle costs of long-term nuclear used fuel and L&ILW management and nuclear facilities decommissioning. OPG's required contributions to the Nuclear Segregated Funds are determined based on periodically updated reference plans approved by the Province under the ONFA, at least once every five years. As part of the reference plan update process, OPG estimates the total funding liabilities for future nuclear waste management and nuclear decommissioning based on life cycle cost estimates and a set of underpinning assumptions, including remaining useful lives of the nuclear stations, proposed methods and timing of nuclear waste disposal, and economic indicators. In accordance with US GAAP, OPG carries a present value asset retirement obligation on the balance sheet related to its nuclear waste management and nuclear decommissioning liabilities. In accordance with *Ontario Regulation 53/05*, the OEB is required to ensure that OPG recovers the revenue requirement impact of its nuclear waste management and nuclear decommissioning liabilities arising from the current approved ONFA reference plan. The current methodology applied by the OEB for including OPG's costs associated with these liabilities in the regulated prices was established by the OEB in its 2008 decision on OPG's first application for new regulated prices.

In 2016, OPG completed a comprehensive update of the estimate for its obligations for nuclear waste management and nuclear facilities decommissioning, in line with the required ONFA reference plan update process. The results of the update were reflected in a new ONFA reference plan as well as a downward adjustment in the asset retirement obligation carried on OPG's balance sheet as at December 31, 2017. The new ONFA reference plan was approved by the Province in December 2016, with an effective date of January 1, 2017 (the 2017 ONFA Reference Plan). Reflecting the funded status of the Used Fuel Segregated Fund and the Decommissioning Segregated Fund based on the revised lower life cycle liability estimates per the 2017 ONFA Reference Plan, no overall contributions to either the Used Fuel Segregated Fund or the Decommissioning Segregated Fund are currently required starting in 2017. Contributions may be required in the future should either or both of the funds be in an underfunded position when a new reference plan is approved. Such may be the case as a result of future variability in asset performance due to volatility inherent in financial markets and economic conditions. Future contribution levels also are dependent on changes in baseline cost estimates and underpinning planning assumptions used to establish the funding obligations in subsequent ONFA reference plans.

The overall reduction in OPG's nuclear waste management and nuclear decommissioning liabilities resulting from the comprehensive update was mainly due to a decrease in cost estimates to reflect a proposed new, more cost effective container design and engineered barrier concept to house used nuclear fuel for disposal, updated cost escalation rates, and a later expected in-service date for Nuclear Waste Management Organization's (NWMO) planned deep geologic repository for the long-term permanent disposal of Canada's used nuclear fuel. These decreases were partly offset by higher cost estimates related to station decommissioning, primarily due to a better definition of work required during the preparation for safe storage after station shutdown and a higher volume of waste expected to be generated during the decommissioning.

Further details on OPG's nuclear waste management and nuclear decommissioning obligations, the ONFA and proposed methods for long-term used fuel and L&ILW disposal are discussed in the section, *Description of the Business* under the heading, *Regulated – Nuclear Waste Management Segment.*

Hydroelectric Business Development

Peter Sutherland Sr. Hydroelectric Generating Station

In March 2015, OPG's Board of Directors approved a project to construct the Peter Sutherland Sr. GS, a new 28 MW hydroelectric station on the New Post Creek near its outlet to the Abitibi River, with a budget of $300 million. The station was constructed through PSS Generating Station LP, a partnership between OPG and Coral Rapids L.P., a wholly owned subsidiary of the Taykwa Tagamou Nation.

In March 2017, final testing and commissioning of the turbine and generator units were successfully completed and both units were declared substantially complete. On March 31, 2017, the project received a permit from the Ontario Ministry of the Environment and Climate Change (MOECC) to take water for operations to allow the station to operate commercially. The project is expected to close below the approved budget of $300 million. Project close-out activities are in progress. OPG began to receive contracted revenue for the project following the IESO's confirmation of the station's commercial operations as of March 31, 2017, under a 50-year hydroelectric ESA.

In April 2017, Coral Rapids Power Corporation (CRP) exercised its right under the partnership agreement to increase its interest in PSS to 33 percent.

Sir Adam Beck Pump Generating Station Reservoir Refurbishment

In August 2015, OPG's Board of Directors approved a project to refurbish the 300-hectare storage reservoir at the Sir Adam Beck Pump GS. The Sir Adam Beck Pump GS facility allows OPG to pump and store water diverted from the Sir Adam Beck generating complex during periods of low electricity demand to be used to generate up to 600 MW of electricity during subsequent periods of high electricity demand.

The refurbishment construction began in April 2016 and was completed in February 2017, ahead of the originally planned schedule date of April 2017 and below the approved budget of $58 million. The reservoir refurbishment work included the installation of a partial new reservoir liner and construction of a grout curtain in the bedrock foundation of the reservoir dyke. The refurbishment is expected to add approximately 50 more years to the reservoir's life. The Sir Adam Beck Pump GS is reported in the Regulated – Hydroelectric segment.

Ranney Falls Hydroelectric Generating Station

In 2017, OPG began construction work on a 10 MW single-unit powerhouse on the existing Ranney Falls GS site, as part of the Regulated – Hydroelectric segment. The new unit will replace an existing unit that reached its end of life in 2014. The existing forebay structure has been demolished and the new concrete structure has been completed. Excavation has been completed and construction continues in the expanded forebay, powerhouse and spillway area. The new forebay concrete wall has been completed, and concrete placement of the new powerhouse and the spillway integrated structure is in progress. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget.

Thermal and Solar Business Development

Nanticoke Solar Facility

In March 2016, Nanticoke Solar LP, then a partnership between OPG, SunEdison Canadian Construction LP (SECCLP) and a subsidiary of Six Nations of the Grand River Development Corporation, was selected through the first phase of IESO's Large Renewable Procurement (LRP) program to develop a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands in Haldimand County, Ontario. The LRP program was a competitive bidding process for procuring large renewable energy projects in Ontario. In March 2016, Nanticoke Solar LP and the IESO executed a 20-year LRP contract, which formalized the terms and conditions for the development and operation of the new solar facility. In the first quarter of 2017, OPG purchased SECCLP's interests in Nanticoke Solar LP and is working to obtain approvals and permits required to enable the commencement of construction planned for the first quarter of 2018. Significant contracts for equipment and engineering construction services were executed in the first quarter of 2018. The 20-year term of the LRP contract takes effect once the station achieves commercial operation, which is expected in the first quarter of 2019. The facility is expected to be completed in the first quarter of 2019, with a budget of $107 million. **[MONITOR]**

Decommissioning of Lambton and Nanticoke Coal-Fired Generating Stations

OPG ceased coal-fired generation at the Lambton and Nanticoke generating stations in September 2013 and December 2013, respectively. In November 2016 and July 2015, respectively, OPG announced that it would decommission the Lambton and Nanticoke generating stations as it could not commercially support continued preservation of these sites in light of the outlook for long-term electricity demand in the province that does not support the need for their future conversion. OPG has begun executing decommissioning plans for these two stations, which will ensure that they are closed safely, securely, and in an environmentally responsible manner. The decommissioning of the Nanticoke GS will accommodate the construction and operation of the Nanticoke solar facility.

During 2017, OPG substantially completed the demolition of the Nanticoke coal yard equipment and structures and issued a contract for the demolition of the Nanticoke powerhouse and associated structures. In the fourth quarter of 2017, the demolition contractor had been mobilized to prepare for the removal of the powerhouse and associated structures and initiated the preparatory work for the demolition of the stacks. The demolition of the stacks took place in February 2018. **[MONITOR]** A competitive bidding process for the demolition of the Lambton GS is in progress, with a contract for the removal of the powerhouse and associated structures expected to be issued during 2018. An update of the associated asset retirement obligations related to the Nanticoke and Lambton sites has been completed. For a discussion of the revaluation of this liability for non-nuclear fixed asset removal as at December 31, 2017, refer to the section, *Critical Accounting Policies and Estimates* under the heading, *Asset Retirement Obligations* in the Company's 2017 year-end MD&A.

DESCRIPTION OF THE BUSINESS

The Electricity Industry

The electricity industry is principally comprised of four components: generation, transmission, distribution, and marketing of energy and other services in wholesale and retail markets.

Generation is the production of electricity. Transmission is the transfer of electricity across high-voltage power lines from generating facilities to local areas. Distribution is the delivery of electricity within local areas to homes and businesses using relatively low-voltage power lines. Energy marketing relates to the purchase of large amounts of electricity or equivalent financial products, and the subsequent re-selling in smaller quantities to third parties in either the wholesale or retail markets.

Electricity has traditionally been generated in large, multi-unit, centralized facilities. These facilities are usually classified by: (i) the type of fuel used; (ii) capacity, typically expressed in MW; and (iii) dispatch mode (being whether or not the electricity generated by a particular facility is dispatched to meet peak, intermediate or baseload demand). The energy produced by a facility is generally expressed as its output over the time the facility operates, typically in terms of MWh. New supply from smaller scale, largely intermittent, renewable sources such as wind, solar, and bio-energy is being integrated into the power system, connected either directly to the transmission system or embedded in distribution networks. Distributed generation involves production of electricity closer to end users and away from large scale production facilities that require more transmission. Electricity systems typically require new capital expenditures and processes in order to accommodate intermittent generators.

Electricity is an essential commodity that cannot be stored without converting to other forms, a process that is more difficult in large volumes. Therefore, electricity supply must instantaneously match demand to maintain the stability and reliability of the electrical power system. This is accomplished by coordinating the supply of and demand for electricity, a responsibility typically assigned to regulated regional system operators. Electricity systems have evolved on a regional basis and are connected to neighbouring regional power grids. Such connections enhance system reliability and permit the economic purchase and sale of electricity between electricity markets.

Ontario's Electricity Industry

OPG's predecessor, Ontario Hydro, served as a vertically integrated electric utility in Ontario. Following the adoption of a restructuring plan for Ontario's electricity industry pursuant to the *Energy Competition Act, 1998,* five principal successors to Ontario Hydro's integrated electricity business began operating as separate entities on April 1, 1999:

- OPG, which purchased and assumed the electricity generation, wholesale energy, and ancillary services businesses of Ontario Hydro;
- Hydro One, which purchased and assumed the transmission, distribution, and retail energy services businesses of Ontario Hydro;
- the Independent Electricity Market Operator (later renamed the IESO), which was formed to act as both the independent electricity system operator and the market operator. The IESO is responsible for the dispatch of generation to meet demand, the control of the Ontario transmission grid, and the operation of energy and ancillary markets;
- the Electrical Safety Authority, which was established to carry out electrical equipment and electrical wiring safety and inspection functions; and
- the Ontario Electricity Financial Corporation (OEFC), which is the legal continuation of the former Ontario Hydro and is responsible for managing the debt and certain other obligations not transferred to other successor companies of Ontario Hydro.

OPG purchased and assumed all of the interest of Ontario Hydro in and to all officers, employees, assets, liabilities, rights and obligations of Ontario Hydro directly or indirectly relating in any manner to the applicable activities carried on by Ontario Hydro as of April 1, 1999, pursuant to the transfer orders made

by Order-in-Council under the *Electricity Act, 1998*. The transfer orders provide that if they fail for any reason to fully and effectively in law transfer any such asset, right, liability or obligation or that if such transfer would constitute a breach of the terms of the asset, right, liability or obligation or of any applicable law, such assets, rights, liabilities or obligations are not transferred, but are held by the OEFC for the benefit of OPG.

Ontario's competitive electricity market was opened by the IESO in 2002. The market is used to manage the purchase and sale of wholesale electricity in the province.

Since the opening of the competitive market, Ontario's power supply mix has experienced significant change. A significant amount of new capacity has been added, while coal-fired generation, which at its peak accounted for approximately 6,500 MW of capacity, has been eliminated. New natural gas powered capacity of approximately 5,000 MW as of the end of 2017 has largely replaced the peaking capacity previously provided by coal-fired generation, while the return to service of Units 1 and 2 at the Bruce A GS in 2012 added approximately 1,500 MW of baseload nuclear generation. New wind and solar capacity of over 7,000 MW has also been added as of the end of 2017, toward Ontario's longer-term target for total wind and solar capacity of about 10,000 MW.

While electricity supply in Ontario has increased, the province's electricity demand as reported by the IESO has fallen, by approximately 13 percent over the last decade, largely due to changes in economic conditions and conservation measures, and also in part due to the addition of small scale solar generation embedded in the distribution system. Embedded generation reduces the demand supplied by grid-connected generation. Reducing electricity demand by encouraging conservation and demand management has been a key part of the Government of Ontario's plan to reduce greenhouse gas (GHG) emissions from the province's electricity sector. Shorter-term fluctuations in electricity demand are impacted by variations in seasonal weather conditions. Ontario's electricity demand as reported by the IESO was 132 TWh in 2017, which excludes electricity exports out of the province.

In October 2017, Ontario's Ministry of Energy issued the 2017 LTEP that outlines the Province's plans for the future development of Ontario's electricity system. The 2017 LTEP focuses on the affordability, reliability and flexibility of a clean energy supply in the province. For further details on the LTEP, refer to the section, *General Development of the Business* under the heading, *General Development – Ontario's Long-Term Energy Plan.*

Ontario Electricity Market Activities

Real-time energy supply needs are met through the wholesale electricity market administered by the IESO, with the market clearing price, the Hourly Ontario Energy Price, set by offers or bids into the market. OPG offers its generation into this real-time energy market, or spot market, to be dispatched by the IESO. The IESO receives hourly offers from electricity generators and importers to provide energy, along with bids to withdraw energy from a few flexible loads and exporters, and then schedules the lowest-cost offers and bids needed to meet demand every five minutes.

Virtually all non-OPG generators in Ontario have bilateral contracts with the IESO that provide for payments that are different from the market price of electricity. In addition, the prices for all of OPG's nuclear and most of its hydroelectric stations are set by the OEB. The difference between the market price and the prices paid for regulated and contracted generation, as well the cost of conservation and demand management programs, are charged to Ontario electricity consumers through the Global Adjustment portion of the total price of electricity.

Maintaining power system reliability requires a continuous balance of supply and demand. Some generators are needed to produce a constant supply of energy to meet basic energy needs (baseload generation), while others are needed to adjust energy output to match changes in demand (peaking and intermediate generation). OPG's nuclear generating stations operate as baseload facilities, whereas its hydroelectric stations operate as baseload, intermediate or peaking stations, depending on their physical characteristics and hydrological conditions. OPG's thermal stations operate as peaking facilities.

SBG occurs when electricity production from the baseload facilities is greater than the market demand for electricity. Baseload generation supply surplus in Ontario is managed by the IESO, mainly through generation reductions at hydroelectric and certain nuclear stations and other grid-connected renewable resources. The prevalence of SBG conditions is impacted by weather conditions which affect electricity demand, wind and solar generation quantities, and through the impact on water flows, the availability of hydroelectric power. In 2017, OPG lost 5.9 TWh of hydroelectric generation due to SBG conditions. In each of 2016 and 2015, OPG lost 4.7 TWh and 3.2 TWh of hydroelectric generation due to SBG conditions. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions, which represents the majority of such production forgone by OPG to date, has been offset by a regulatory variance account authorized by the OEB. During 2017, 2016 and 2015, generation losses at OPG's regulated hydroelectric stations due to SBG conditions were 5.2 TWh, 4.3 TWh and 2.8 TWh, respectively.

The OEB has authorized an additional pricing mechanism for OPG's regulated hydroelectric generation that provides a financial incentive to OPG to shift hydroelectric generation from lower market price periods to higher market price periods. This is intended to benefit customers through the displacement of generation from the relatively higher cost sources such as natural gas. The time-shifting is made possible by the ability to store water in reservoirs located at a number of OPG's hydroelectric facilities, including the Sir Adam Beck Pump GS.

The IESO also administers the operating reserve market and a market for ancillary services. The objective of the operating reserve market is to ensure that additional supplies of energy are available to maintain power system reliability following an unforeseen event. Ancillary services include regulation service, reactive support, black start capacity, and other services required to maintain the reliability of the Ontario electricity system. OPG participates in these markets. Revenues earned by OPG's regulated facilities from providing services into these markets are applied by the OEB to reduce regulated prices for electricity generated from these facilities.

OPG and other Ontario electricity market participants are required to comply with market rules issued by the IESO. As an owner and operator of generating stations, OPG is also subject to reliability standards as set out by the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC) and the IESO. NERC, NPCC and IESO are standards authorities with the ability to create or modify reliability standards. Such standards are binding on OPG pursuant to the OEB-issued electricity generating license and the IESO market rules. The IESO monitors compliance with and enforces the market rules and coordinates with system operators and reliability agencies in other jurisdictions to ensure energy adequacy and security across the interconnected bulk electricity market in North America.

Interconnected Markets

The interconnected markets are electricity markets in neighbouring provinces and states whose transmission systems are connected to the Ontario power grid, either directly or through other contiguous interconnected markets. Ontario's market is interconnected with New York, Michigan, Minnesota, Manitoba, and Québec. Market intermediaries wishing to import or export electricity between Ontario and the interconnected markets are required to schedule these transactions through the Ontario spot market. OPG and its wholly owned subsidiary, OPG Energy Trading (OPGET), participate in the interconnected markets. Further details on OPGET are discussed under the heading, *Services, Trading, and Other Non-Generation Segment.*

Interconnection transmission capabilities between Ontario and the interconnected markets are subject to physical and weather dependent limitations. These limitations include planned or forced outages to transmission lines and other equipment that reduce transmission capacity. They also include wind and temperature conditions that affect the transfer capability of all transmission lines on the electrical system. For example, higher ambient air temperature lowers capacity, while higher wind speeds increase capacity. Overall power system parameters and conditions also can result in limitations on particular interties, being one or more transmission lines that connect Ontario to a neighbouring region. For example, high flow on one intertie may result in a reduction in the limit on another intertie.

Water Rights

OPG's management of available water resources directly affects the generation output, efficiency, and ultimately return on investment for the Company's hydroelectric assets. The watersheds on which OPG's hydroelectric generating facilities are located are shared by many users and are subject to various governance requirements, such as international, federal and provincial agreements, water power leases, and regulations. Accordingly, OPG must balance the economic, environmental, social and legal requirements associated with the watersheds when utilizing water to optimize electricity generation.

International Rivers

The six OPG hydroelectric generating stations subject to OEB rate regulation since 2008 are directly or indirectly supplied by two major international waterways, the Niagara River and the St. Lawrence River, and are subject to treaties with the U.S. relating to water use. These stations represent approximately 45 percent of OPG's total in-service hydroelectric capacity.

Through a series of agreements between the Government of Canada and the Province, and certain federal and provincial laws, OPG has been granted the right to exercise Canada's rights with respect to the construction, maintenance, and operation of generating facilities under the *Boundary Waters Treaty of 1909* and the *Niagara Diversion Treaty of 1950* between Canada and the U.S. Both of these treaties continue in perpetuity but are terminable by either party with 12 months prior written notice. Given the significance of these treaties, OPG does not expect either party to exercise their respective termination rights in the foreseeable future.

The *Boundary Waters Treaty of 1909* established the International Joint Commission with the mandate of regulating shared water uses and preventing and resolving disputes between U.S. and Canada. In December 2016, the International Joint Commission issued an order implementing a new plan to manage water levels and flows in Lake Ontario and the St. Lawrence River, effective January 7, 2017. The new plan, which replaced the existing plan in use since 1963, is intended to allow for more natural water levels, while minimizing impacts to other users, including hydroelectric power production. No significant changes in OPG's operations are expected as a result of the new plan.

The *Niagara Parks Act* (Ontario) gives the Niagara Parks Commission the authority to grant certain rights for the use of the waters of the Niagara River for purposes of power generation. By agreement with OPG, the Niagara Parks Commission has agreed not to grant any rights to third parties until after 2056.

Under an agreement between OPG and the St. Lawrence Seaway Management Corporation, a federal agency, the DeCew Falls generating stations use water that is transported along the Welland Canal from Lake Erie. The agreement has been renewed through June 30, 2038.

The Province has granted OPG the right to use water from the International Rapids section of the St. Lawrence River for power generation at the R.H. Saunders GS, subject to an agreement between the Government of Canada and the Province. The Government of Canada has the right, upon notice and after unsuccessful arbitration, to take over the operation of and title to the R.H. Saunders GS in the unlikely event of a breach of the agreement by the Province.

Interprovincial Rivers

Four of OPG's hydroelectric stations are located on the Ottawa River, which forms part of the Ontario-Québec border. These stations represent approximately 12 percent of OPG's total in-service hydroelectric capacity. Three of these stations are subject to 999-year leases with each of the Provinces of Ontario and Québec. The fourth station is subject to a water power lease with the Province of Ontario, which is renewable to 2031, subject to certain conditions. OPG's use of water from the Ottawa River basin is subject to guidelines established by the Ottawa River Regulation Planning Board, comprised of government and industry representatives.

Interior Rivers

Fifty-six of OPG's hydroelectric stations, representing approximately 43 percent of OPG's total in-service hydroelectric capacity, are located on 20 other Ontario river systems. OPG holds water power leases, Crown leases and licences with the Province on the river systems that supply 37 of these stations. A land use permit, issued for the Peter Sutherland Sr. GS, remains in effect while a water power lease for the site is prepared by the Ontario Ministry of Natural Resources and Forestry (MNRF). These leases and licences have expiry dates, including renewal periods, ranging between 2023 and 2075. Certain of these leases provide that the leased property and any fixed improvements, including generating stations and dams, will revert to the Province on the expiry of the lease. OPG intends to work towards new leases and licenses for these stations. OPG's use of Ontario's interior watersheds is constrained by restrictions contained in certain of the water power leases and licences. Eight of the 56 stations are located on the Trent and Rideau Waterways and are operated pursuant to licences from the federal government. These licences expire in February 2020. The process to renew the licences is currently underway with Parks Canada. Ten of the 56 stations are not subject to leases or licences.

The current provincial regulatory framework requires the development of Operational Plans for new storage dams and generating stations in Ontario, except for those on international rivers, interprovincial rivers, or rivers under federal jurisdiction. These plans include any limitations on water flows and elevations, and historically have been a component of formal Water Management Plans (WMPs). WMPs were established under the *Lakes and Rivers Improvement Act* (Ontario) and *Water Management Planning Guidelines for Waterpower (2002)*, on a watershed basis, in consultation with the Ontario Ministry of Natural Resources and Forestry, federal fisheries authorities, stakeholders, such as recreational and commercial users, local communities, environmental groups, and partners, such as Indigenous groups. In October 2016, the MNRF published a Technical Bulletin, *Maintaining Water Management Plans (2016),* eliminating the need for WMPs where they are not already in place, removing the expiry date from existing WMPs, and outlining the requirements for Operational Plans for new waterpower works going forward. Existing WMPs continue to be in effect. WMPs and Operational Plans may be amended as certain conditions change or new data becomes available. OPG operates in compliance with WMPs and Operational Plans.

The operations of certain OPG stations in northwestern Ontario can impact users in Manitoba and are subject to guidelines and directions provided by the Lake of the Woods Control Board, which is comprised of Ontario, Manitoba and federal government representatives.

Dams and Waterways

In Canada, dams fall under provincial jurisdiction, with the exception of dams situated in interprovincial and international boundary waters and canals, and those owned by the Government of Canada. The majority of OPG's dams fall within the jurisdiction of the Province, with approximately 20 dams falling within the jurisdiction of the Province of Québec and 13 dams associated with the Trent-Severn and Rideau Waterways falling under federal jurisdiction. The International Joint Commission has an oversight role for dams and associated works on international boundary waters, including the St. Lawrence River and the Niagara River.

The Province regulates dams under the *Lakes and Rivers Improvement Act* (Ontario) administered by the MNRF. The legislation requires MNRF approval for activities such as the construction, alteration, improvement, or repair of dams.

In August 2011, the MNRF published a revised set of Technical Guidelines for dams, following a period of public consultation. The Technical Guidelines represent the government standards for dam safety. OPG was an active participant in developing the Technical Guidelines through the MNRF's advisory panel. In general, OPG practices in the area of dam safety and public safety around dams exceed the minimum requirements outlined in the Technical Guidelines. In cooperation with the MNRF, OPG is developing a new risk-informed approach to prioritize the outcomes of dam safety assessments.

Currently, there is no federal or provincial regulation with respect to public safety around dams that addresses dam public safety issues relating to changes in operating water levels, discharges from the hydroelectric or dam facilities, and other waterways-based hazards posed by such facilities. The *Navigation Protection Act* (Canada) does, however, require OPG to obtain approvals for the installation of all in-water works, such as safety booms and buoys associated with the OPG Waterways Public Safety Program. Additional details on OPG's Dam Safety and Waterways Public Safety Programs are discussed under the heading, *Workplace Safety and Public Safety – Dam Safety and Waterways Public Safety*.

Generation Operations

Nuclear (Regulated – Nuclear Generation Segment)

Overview of Generating Facilities

OPG owns and operates two nuclear generating stations, the results of which are reported in the Regulated – Nuclear Generation business segment. The Pickering GS, comprised of six operating units and two units in a permanent safe shutdown state, is located on the shore of Lake Ontario in Pickering, Ontario. As at December 31, 2017, the station's total in-service capacity was 3,094 MW. Four of the eight Pickering units originally went into service in the 1970s. A decision was made by Ontario Hydro in the late 1990s to place these four units in voluntary lay-up. In 2003 and 2005, respectively, two of the four laid-up units were returned to commercial operation, with the two remaining units placed in a permanent safe shutdown state. The other four operating units have been in service since the mid 1980s.

The Darlington GS, comprised of three operating units and one unit, Unit 2, undergoing refurbishment as of mid-October 2016, is located on the shore of Lake Ontario in the Municipality of Clarington, Ontario. As at December 31, 2017, the total in-service capacity of the three operating units was 2,634 MW. Unit 2 has a capacity of 878 MW. All four Darlington units have been in service since the early 1990s. Both the Pickering GS and the Darlington GS have been designed to operate at full power as baseload facilities.

The performance of OPG-operated nuclear generating stations during 2017, 2016 and 2015 was as follows:

Regulated – Nuclear Generation Performance (2015 to 2017)

Station	No. of In-Service Units	Unit Capability Factor [1] (%)		
		2017	2016	2015
Darlington [2]	3	**85.2**	89.5	76.9
Pickering	6	**80.0**	75.2	79.4
Total	9			

[1] Unit capability factor is the amount of energy a generating unit is capable of producing as a percentage of its maximum output assuming no external constraints such as transmission limitations. The nuclear unit capability factor excludes unit(s) during the period in which they are undergoing refurbishment.

[2] Excluding Unit 2, which has been undergoing refurbishment since mid-October 2016.

The lower Unit Capability Factor at the Darlington GS in 2017, compared to 2016, reflected the higher number of planned outage days in 2017, largely driven by constraints related to the transition of the station's operating units toward refurbishment. The increase in the Unit Capability Factor at the Pickering GS in 2017, compared to 2016, was primarily due to outage cycle optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station compared to 2016.

OPG's Bruce A and Bruce B nuclear generating stations have been leased on a long-term basis to Bruce Power. The stations are located in the Municipality of Kincardine, Ontario on the shore of Lake Huron.

For additional information on OPG's nuclear operations, refer to the section, *Core Business, Strategy, and Outlook* under the heading, *Operational Excellence – Electricity Generation Production and Reliability* in the Company's 2017 year-end MD&A.

Nuclear Generation Technology

Nuclear generation harnesses the energy released during controlled nuclear fission reactions to produce steam that is used to drive turbines to generate electricity. Nuclear generation has two main advantages. It is a relatively low marginal-cost generation technology, and it produces virtually no GHG, sulphur dioxide, nitrogen oxide, or mercury emissions. The latter advantage has become more significant as governments implement climate change action plans and stricter air emission standards.

However, in contrast to other types of generating facilities, notwithstanding the lower fuel costs, nuclear generating stations incur nuclear waste management and decommissioning costs and greater operating and maintenance expenses. In addition, the construction of nuclear generating stations entails greater initial capital costs than other generation technologies. The higher initial costs reflect the complexity of the technical processes fundamental to nuclear electricity generation, and the additional design and safety precautions taken to protect the public from potential risks associated with nuclear operations.

All of OPG's nuclear generating stations use CANada Deuterium Uranium (CANDU) technology reactors. CANDU is a pressurized-heavy-water, natural-uranium power reactor, originally designed in the 1960s by a consortium of Canadian government agencies and private industry. CANDU reactors are unique in their use of natural-uranium fuel and deuterium oxide, or heavy water, as both a moderator to slow down the fission process and a coolant within the reactor. The refuelling system is also unique in that CANDU reactors can be refuelled at full power. This is due to the subdivision of the reactor core into hundreds of separate fuel channels, each holding a single string of natural uranium fuel bundles, allowing for greater fuel efficiency. In contrast, U.S. reactors, which use enriched uranium fuel, must be shut down during refuelling. All nuclear power reactors in Canada use CANDU technology. CANDU reactors are currently operating in Ontario, New Brunswick, Argentina, Romania, South Korea, India, Pakistan and China.

Nuclear Fuel Procurement

OPG's nuclear fuel supply chain engages in the purchase of uranium concentrate, the purchase of services for the conversion of uranium concentrate to uranium dioxide, and the purchase of services for the manufacture of fuel bundles containing uranium dioxide pellets. OPG currently establishes contractual arrangements with each of these components separately and as appropriate maintains ownership of the uranium throughout the supply chain. OPG maintains a portfolio of multi-year supply contracts for uranium concentrate with domestic and foreign suppliers and commodity traders. Occasionally, short-term spot market purchases are acquired to support a portion of its uranium concentrate needs. OPG's nuclear fuel bundles are supplied by a Canadian-based manufacturer.

Nuclear Regulation

The *Nuclear Safety and Control Act* (NSCA) establishes the mandate and authority of the CNSC to make regulations governing all aspects of the development and application of nuclear energy in Canada. The NSCA grants the CNSC the power to act as a court of record, the right to make regulations, the power to require financial guarantees for nuclear waste management and nuclear facilities decommissioning as a condition of granting a licence, order-making powers, and the power to impose monetary penalties for licence infractions. The NSCA also grants the CNSC the power to require periodic re-certification of nuclear operators and to set requirements for various nuclear facility security measures. It also provides for regulatory authority over environmental matters, including a requirement that licence applicants make adequate provision for the protection of the environment. The NSCA grants the CNSC licensing authority for all nuclear activities in Canada, including but not limited to the issuance of new licences to operators, the renewal of existing licences, protection of the environment arising from nuclear activities, and making regulations related to nuclear activities.

A fundamental principle in nuclear regulation is that the licensee bears the responsibility for safe operation, with the CNSC setting safety objectives in areas such as radiation protection and physical security for nuclear generating stations and the transport of radioactive materials. The CNSC verifies compliance with the licence and performs audits and inspections of the licensee's performance against these objectives. The CNSC also has issued guidance documents to assist licensees in complying with regulatory requirements. Requirements specified in these guidance documents have been incorporated into the design and operating documents for OPG's nuclear generating stations.

Since the operation and regulation of nuclear energy has transboundary impacts, Canada has become a signatory to various international conventions relating to nuclear energy and emergency responses and is bound by conventions that it has ratified. In addition, the CNSC has a bilateral information exchange and co-operation agreement with the U.S. Nuclear Regulatory Commission, which provides, among other things, for the prompt, reciprocal notification of reactor safety problems that could affect both U.S. and Canadian nuclear generation facilities.

The CNSC publishes an annual Regulatory Oversight Report on the safety performance of Canada's nuclear power plants. The report assesses how well plant operators are meeting regulatory requirements and program expectations in the areas of operational performance, safety analysis, radiation protection, waste management and conventional health and safety. On September 8, 2017, the CNSC issued an executive summary of its 2016 annual report, giving both the Darlington GS and the Pickering GS the highest possible safety rating of "Fully Satisfactory". The Darlington GS achieved this rating for the eighth consecutive year, while the Pickering GS achieved this rating for the second consecutive year.

In 2017, the CNSC approved regulatory document *REGDOC 2.2.4 – Fitness for Duty – Managing Alcohol and Drug Use* for use at Canadian nuclear power plants. This document sets out requirements for managing fitness for duty of workers in relation to alcohol and drug use at high-security sites, including for-cause alcohol and drug testing for workers in positions identified as safety-sensitive or safety-critical and random alcohol and drug testing for workers holding safety-critical positions. OPG intends to enhance its existing Fitness for Duty program to comply with these new requirements. OPG is working with its partners in the Canadian nuclear industry to develop a program suitable for Canada and its workers.

All of OPG's nuclear power reactor operating licences and waste facility licences are current and up to date. In 2016, OPG submitted applications with the CNSC seeking a ten-year licence renewal for the Western Waste Management Facility (WWMF), located at the Bruce generating stations' site, to May 31, 2027, and a ten-year licence renewal for the Pickering Waste Management Facility (PWMF) to August 31, 2028. The licence renewal applications were presented to the CNSC at public hearings in April 2017. On May 30, 2017, the CNSC announced that the WWMF licence was renewed for a ten-year period and will be valid until May 31, 2027. On February 7, 2018, the CNSC announced that the PWMF licence was renewed for a ten-year period and will be valid until August 31, 2028. Further details on the operating licence for the Darlington GS are found in the section, *General Development of the Business* under the heading, *Nuclear Business Development – Darlington Refurbishment* and for the Pickering GS in the section, *General Development of the Business* under the heading, *Nuclear Business Development – Extension of Commercial Operations at Pickering to 2024*.

Details on Canada's nuclear liability regime and related insurance coverage can be found under the heading, *Insurance*.

Fukushima Daiichi Response

In response to the 2011 Fukushima Daiichi incident in Japan, OPG has confirmed that its stations are safe and that systems and procedures are in place to withstand significant emergencies. In 2013, a systematic review and verification of defences against external hazards was completed at OPG-operated stations. The review showed that:

- the nuclear safety systems and multiple back-up power systems in place at the stations are effective; and
- the current design of the stations is strong and the stations are able to withstand extreme external events.

The review also provided recommendations for further opportunities to enhance the safety margin and to develop preparedness for unexpected events that go beyond the extreme events already considered in the design of the stations.

OPG's action plan in response to the Fukushima Daiichi event is well aligned with the CNSC's Fukushima Action Plan, issued in mid-2012. In 2013, OPG submitted its plans for the majority of the CNSC's Fukushima Action Plan items applicable to OPG-operated stations to the CNSC. In January 2015, the CNSC recognized OPG's efforts in this area and confirmed that all of the Fukushima action items were closed. OPG's Fukushima Implementation Plan included a number of key safety enhancements for providing additional back-up capability to increase OPG's flexibility to respond to unexpected and highly unlikely external events that can impact either a single unit or multiple units at the same time. CNSC staff concluded that OPG had strengthened reactor defence and enhanced its emergency response at both the Darlington GS and the Pickering GS in response to the lessons learned from the Fukushima Daiichi incident.

Nuclear Generating Station Life

Service life predictions for OPG-operated nuclear stations are developed by assessing the impacts of a number of operating, technical, and regulatory considerations on both unit and station economics. A decision by OPG to remove a unit from service would be primarily an economic decision that becomes more likely as the number of components requiring replacement and the frequency and duration of inspections required to ensure a unit's fitness for service increases. The key life-limiting components at OPG's nuclear stations include fuel channels, feeder tubes, steam generators, and other reactor components. End-of-service life predictions are reviewed as new information on possible degradation mechanisms becomes available and as future generation expectations are revised.

In December 2015, OPG revised the accounting assumptions for the estimated useful lives of the nuclear generating stations it operates. Effective December 31, 2015:

- the average service life of the Darlington GS was extended by one year to 2052 to reflect the approval of the refurbishment schedule in 2015; and
- the average service life of the Pickering GS was extended by less than one year to reflect the technical confidence that all six operating units of the station will operate to the end of 2020.

The accounting end of life assumptions for the Pickering GS have been reassessed in December 2017 based on the technical work performed to confirm that the longer fuel channel life necessary to extend Pickering operations can be achieved and that the units would be fit to operate beyond 2020, taking into account the requirement for the CNSC's approval. Further information can be found in the section, *General Development of the Business* under the heading, *Nuclear Business Development – Extension of Commercial Operations at Pickering to 2024*.

Nuclear Facility Planning

OPG uses a structured approach to identify and prioritize projects to optimize returns from nuclear station reinvestment within the constraints imposed by technical and financial requirements, while ensuring that safety, environmental, and other regulatory programs are of the highest priority. Input from predictive maintenance programs, life cycle management plans, and system health monitoring is used to determine the activities necessary to sustain and improve nuclear unit performance.

A structured framework modeled on the best practices identified by the Electric Power Research Institute, the Institute for Nuclear Power Operations and the World Association of Nuclear Operators (WANO) is used to optimize the maintenance of the nuclear generating stations and assess the health of the facilities. The structured framework includes predictive maintenance programs, which combine technologies and human expertise to analyze equipment performance, maintenance and design data in order to make timely decisions about the scope and timing of inspections and maintenance for major or critical equipment. The predictive maintenance program for each station is prioritized on the basis of the importance of the equipment for reactor safety. Life cycle management plans are maintained for critical station components and are updated annually to incorporate operating experience and new information. The life cycle plans define the inspection and maintenance programs required to ensure that these components perform in accordance with their design basis. In addition, system engineers conduct performance monitoring of station systems according to system performance monitoring plans that are based on a comparison of performance indicators against established targets to improve system performance. System performance is assessed by collecting, trending and analyzing station data. This information is reported in system health reports which are updated, at a minimum, annually.

OPG's practices impacting the performance of the nuclear stations are audited regularly by WANO, with identified areas for improvement acted upon with priority. In May 2016, OPG hosted a WANO peer evaluation that compared the Darlington GS against standards of excellence through an in-depth and objective review by an international panel of industry experts. The review maintained Darlington's excellent standing as one of the top performing nuclear plants in the world. In December 2017, OPG hosted a WANO peer evaluation for the Pickering GS, which focused on the safe and reliable operation of the station while evaluating the plant material condition, functional and cross-functional areas of the organization. Pickering showed significant improvement since its last review and has sustained its strong rating in 2018, resulting in its best ever WANO peer review.

In September 2016, OPG hosted a team of experts from the International Atomic Energy Agency (IAEA) at the Pickering GS to conduct a standard Operational Safety Review Team mission. The team conducted an in-depth review of performance and adherence to international safety standards. In the second quarter of 2017, the IAEA's Operational Safety Review Team released the final report and confirmed that the Pickering GS demonstrates strong commitment to safety.

Nuclear planned outages are necessary to execute inspection and maintenance work related to asset management and regulatory requirements for systems and equipment where access is not possible under normal operating conditions. Planned outages also give OPG an opportunity to perform system and equipment upgrades, project work, configuration changes, and other improvements and modifications. The nuclear generation plan, by reference to the station's life cycle management plans, establishes the number, frequency and duration of the outages for each year required to ensure the continued safe and reliable long-term operation of the plant and its compliance with CNSC regulatory requirements.

The outage cycle determines the number of planned outages at each station in a particular year. The Darlington GS is on a 36-month outage cycle, where each of the four units undergoes an outage every three years, resulting in one or two outages per year for the station. The Pickering GS was on a 24-month outage cycle. Supported by technical assessments undertaken for the extension of Pickering GS, the outage frequency has been optimized and extended from 24 to 30 months. In addition, on a periodic basis all units at each station are required to be shut down to allow for inspection and maintenance on the station vacuum building, containment systems and other safety systems. The CNSC currently requires these

outages every 12 years at the Darlington GS and every ten years at the Pickering GS. The most recent vacuum building outage took place at the Darlington GS in 2015 and at the Pickering GS in 2010.

Nuclear Ancillary Operations

OPG's nuclear generating units contain approximately 7,500 tonnes of deuterium oxide, or heavy water, not including heavy water contained at the leased Bruce stations. The heavy water is required to operate CANDU reactors. Ontario Hydro ceased the operation of its heavy water plants in 1997 and the plants were subsequently decommissioned. There are currently no heavy water plants in Canada. OPG believes that its existing inventory of heavy water will be sufficient to replenish supplies as a result of normal operating losses at its nuclear stations, including the refurbishment of the Darlington GS. OPG also believes that sufficient quantities of heavy water are available for possible changes in operating conditions or for new nuclear generating facilities. OPG seeks opportunities to sell available surplus quantities of heavy water from its inventory.

Tritium is a radioactive substance produced as a by-product of operating CANDU reactors, through the use of heavy water in the reactor moderator and heat transport systems. OPG operates a specialized facility at its Darlington site, the Darlington Tritium Removal Facility (TRF), which removes tritium from the tritiated heavy water (detritiation) used at the nuclear generating stations, in order to control the occupational dose exposure to employees and limit the amount of tritium released to the environment. The extracted tritium is chemically immobilized, placed in special containers, and safely stored in a vault. The Darlington TRF is also expected to be used to detritiate heavy water during the eventual decommissioning of OPG's nuclear generating stations. Some tritium is sold to government-approved organizations for authorized commercial and health industry uses. OPG also provides detritiation services to Bruce Power. Opportunities for providing detritiation services to other third parties are limited because of storage and capacity restrictions at the Darlington TRF.

Cobalt-60 produced and sold by OPG is used mainly in the health industry to sterilize surgical and medical supplies. Cobalt-60 is produced in Units 6, 7 and 8 at the Pickering GS. Cobalt-60 can be produced in reactors which, like the CANDU reactors, use adjuster rods to regulate power. The production process involves replacing the stainless steel rod by a rod containing Cobalt-59, which is isotopically converted into Cobalt-60 after lengthy exposure to the atomic reaction in the reactor core. During planned maintenance outages, the rods are removed, cut, and packaged for sale as Cobalt-60, and new rods are inserted in the reactor to continue the production cycle.

Hydroelectric (Regulated – Hydroelectric and Contracted Generation Portfolio Segments)

Overview of Generating Facilities

Hydroelectric generating stations use the energy of falling water to drive hydraulic turbines that generate electricity. OPG's hydroelectric stations provide one of the Company's competitive advantages – a reliable, relatively low-cost source of renewable energy free of air emissions. Electricity generation from OPG's hydroelectric facilities depends primarily upon the availability of water, which is affected largely by natural factors such as precipitation and evaporation. It is also impacted by the prevalence of SBG conditions.

OPG currently owns and operates 66 hydroelectric generating stations and 241 associated dams located on 24 river systems across Ontario. The results of 54 of these stations that are rate regulated by the OEB are reported in the Regulated – Hydroelectric segment. The results of the remaining 12 stations are subject to long-term ESAs with the IESO and are included in the Contracted Generation Portfolio segment. The 54 regulated hydroelectric stations include the 48 stations prescribed for rate regulation beginning in 2014 and the six stations that have been rate regulated by the OEB since 2008.

As at December 31, 2017, OPG's regulated hydroelectric facilities had a total in-service capacity of 6,426 MW and the non-regulated hydroelectric facilities had a total in-service capacity of 1,042 MW. OPG's hydroelectric generating stations range in age from the newly in-serviced Peter Sutherland Sr. GS to over 119 years and include the oldest assets in OPG's generation portfolio.

Hydroelectric ESAs with 50-year terms are in place for the following hydroelectric facilities:

- Lac Seul and Ear Falls generating stations, with an expiry date of February 2059;
- Healey Falls GS, with an expiry date of April 2060;
- Sandy Falls, Wawaitin, Lower Sturgeon, and Hound Chute generating stations, with an expiry date of December 2060;
- Little Long, Harmon, Smoky Falls, and Kipling generating stations, with an expiry date of January 2064; and
- Peter Sutherland Sr. GS placed in-service in March 2017, with an expiry date of March 2067.

In 2017, the number of regional groups was reduced from five to four, by integrating the central operations work centers into three of the other existing regional operations groups. The following are the four regional operations groups that operate and maintain OPG's hydroelectric facilities:

- Niagara Operations – includes the three Sir Adam Beck stations located on the Niagara River and the two DeCew Falls facilities located on the Welland River. These facilities have been rate regulated by the OEB since 2008. As part of the change in the regional groups, the Gravenhurst work centre joined with seven regulated stations on the Muskoka, Severn and Beaver Rivers. This operations group also includes OPG's wind turbine.
- Eastern Operations – includes the following ten regulated hydroelectric generating stations: the R.H. Saunders GS on the St. Lawrence River; the Otto Holden, Des Joachims, Chenaux, and Chats Falls generating stations on the Ottawa River; and the Mountain Chute, Barrett Chute, Calabogie, Stewartville, and Arnprior generating stations on the Madawaska River. The R.H. Saunders GS has been regulated by the OEB since 2008. As part of the change in the regional groups, the Campbellford work centre joined with eleven regulated stations and one non-regulated station on the Trent, Mississippi and Rideau Rivers.
- Northeast Operations – includes five regulated and eight non-regulated hydroelectric stations in northeastern Ontario. The regulated stations are the Chute and Lower Notch generating stations on the Montreal River; the Abitibi Canyon and Otter Rapids generating stations on the Abitibi River; and the Matabitchuan GS on the Matabitchuan River. The non-regulated stations are the Little Long, Harmon, Smoky Falls, and Kipling generating stations on the Lower Mattagami River; the Wawaitin, Sandy Falls, and Lower Sturgeon generating stations on the Upper Mattagami River; and the Hound Chute GS on the Montreal River. The North Bay and Coniston work centres joined this regional operations group with seven regulated stations on the Wanapitei and French Rivers.
- Northwest Operations – includes nine regulated and two non-regulated generating stations in northwestern Ontario. The regulated stations are the Pine Portage, Cameron Falls, and Alexander generating stations on the Nipigon River; the Silver Falls and Kakabeka Falls generating stations on the Kamanistikwia River; the Manitou Falls and Caribou Falls generating stations on the English River; the Aguasabon GS on the Aguasabon River; and the Whitedog Falls GS on the Winnipeg River. The non-regulated stations are the Lac Seul and Ear Falls generating stations on the English River.

These operations groups are also responsible for the operation and maintenance of OPG's thermal facilities discussed under the heading, *Generation Operations – Thermal (Contracted Generation Portfolio Segment)*.

The performance of OPG's hydroelectric generating stations during 2017, 2016 and 2015 was as follows:

Hydroelectric Generation Performance (2015 to 2017)

	Regulated – Hydroelectric			Contracted Generation Portfolio – Hydroelectric			Total Hydroelectric		
	2017	**2016**	**2015**	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Availability *(%)* [1]	**88.0**	89.0	91.2	**74.6**	77.3	88.6	**86.2**	87.5	90.9

[1] Availability is represented by the percentage of time the generating unit is capable of providing service, whether or not it is actually generating electricity, compared to the total time for the respective period.

Lower availability of the Regulated – Hydroelectric facilities during 2017 was primarily due to a higher number of unplanned outage days at the Northwestern Ontario, Niagara, and Eastern Ontario regions' hydroelectric stations, partially offset by higher availability from the Sir Adam Beck Pump GS due to a higher number of planned outages days in 2016 as a result of the refurbishment of the station's reservoir. Lower availability of the Contracted Generation Portfolio hydroelectric facilities in 2017 was primarily due to an increase in the number of planned outage days at the Lower Mattagami River hydroelectric generating stations.

Lower availability of the Regulated – Hydroelectric facilities during 2016 was primarily due to the planned reservoir refurbishment project at the Sir Adam Beck Pump GS. Lower availability of the Contracted Generation Portfolio hydroelectric facilities in 2016 was primarily due to a higher number of planned outage days at the Kipling and Harmon generating stations.

OPG's objectives for the hydroelectric operations include operating and maintaining the generating facilities in a safe, efficient and cost-effective manner, while increasing the output from the facilities and pursuing opportunities to increase capacity. OPG aims to increase the facilities' output by improving operational flexibility, enhancing reliability, optimizing outage planning and, subject to water conditions, increasing availability to meet electricity system demand. The Company continues to evaluate and implement plans to increase capacity, maintain and improve operational performance, and extend the operating life of its hydroelectric generating assets. These plans are accomplished through multi-year capital investment and other programs, including replacements and upgrades of turbine runners, and refurbishment or replacement of existing generators, transformers, and controls. Over the next four years, OPG plans to increase the total capacity of its renewable generating fleet by approximately 150 MW, which in addition to the runner replacement and upgrade program, includes the Ranney Falls GS and Sir Adam Beck frequency conversion projects. OPG is also planning to repair, rehabilitate, or replace a number of aging civil structures. Where economical and practical, OPG also pursues opportunities to refurbish, expand or redevelop its existing hydroelectric stations.

Additional information on OPG's hydroelectric operations are discussed in the section, *Core Business, Strategy, and Outlook* under the heading, *Operational Excellence – Electricity Generation Production and Reliability* in the Company's 2017 year-end MD&A.

Hydroelectric Facility Planning

Major components of hydroelectric facilities typically include: generating equipment such as turbines, generators and transformers; civil works such as powerhouses, dams, headworks, spillways and water conveyance canals and tunnels; and facilities required to operate and maintain the stations such as control rooms and work centres. Although there is a link between the age of a facility and the capital investment required to maintain that facility, age does not establish an upper limit on the expected useful life of hydroelectric facilities and dams. Regular maintenance and the replacement of specific components typically allow stations to operate for very long periods, especially for facilities built after 1925.

OPG operates six staffed control rooms across Ontario that provide remote control and monitoring for all of OPG's hydroelectric generating facilities. These control rooms are designed to minimize the number of staffed control rooms, reduce control system failures, and increase the amount of information available for production planning.

OPG uses a structured portfolio approach to identify and prioritize projects for its hydroelectric asset investment program. Engineering reviews and station condition assessments are performed to determine short-term and long-term expenditure requirements to sustain or improve the performance of each facility. These may be followed by the preparation of a facility life cycle plan, which is performed on an as-needed basis for marginal assets or assets potentially requiring significant expenditures relative to the value of the facility. This approach is designed to identify necessary capital, operating and maintenance expenditures for each facility and to direct resources towards those facilities that can best maintain or enhance their value.

OPG utilizes a preventive maintenance program that provides a consistent method of identifying, scheduling, and executing maintenance activities at the hydroelectric facilities. The maintenance program is based on the concept of streamlined reliability-centred maintenance, whereby the type and frequency of preventive maintenance applied to an individual component is determined based on the nature and consequences of failure, balancing cost and risk.

The cornerstone of OPG's project prioritization and preventive maintenance approaches for the hydroelectric assets is that safety, environmental, and other regulatory programs are of the highest priority.

Water Management

OPG's water management strategy for its hydroelectric facilities is to safely utilize available water for generation of electricity in conformance with legal, environmental, operational, and WMP and Operational Plan requirements. OPG uses hydrological and meteorological data to manage water levels, water flows and water storage, and strives to schedule water use for optimum utilization and to minimize controllable water spills due to SBG conditions.

Gross Revenue Charge and Water Rental Payments

Hydroelectric generating stations in Ontario are subject to taxes and charges as prescribed by *Ontario Regulation 124/02* under the *Electricity Act, 1998*. These taxes and charges, referred to as Gross Revenue Charge (GRC), are based on station gross revenue, which, for this purpose, is determined as the product of annual station energy generation and the prescribed revenue rate of $40/MWh (Gross Revenue). All OPG hydroelectric generating stations are subject to GRC Property Tax, which is determined by applying graduated tax rates, ranging from 2.5 percent to 26.5 percent through four tiers of production, to a station's annual Gross Revenue. GRC Property Tax payments are made to the OEFC. Hydroelectric generating stations that are subject to water power lease agreements with the MNRF are also subject to GRC Water Rental charges in addition to GRC Property Tax payments. The GRC Water Rental charge is determined as 9.5 percent of a station's annual Gross Revenue. GRC Water Rental payments are made to the Ontario Ministry of Finance.

Annual land rental fees are paid to the MNRF as prescribed by Crown leases and licences of occupation which authorize OPG's tenure (including flooding rights), typically at storage dam sites.

The eight OPG hydroelectric generating stations located on the Trent River and Rideau Canal are subject to rental charges prescribed by licences with Parks Canada. These licences authorize OPG to occupy the lands, maintain and operate the powerhouses and dams, and utilize water that is surplus to navigation needs for the generation of electricity.

Water conveyance charges are paid to the St. Lawrence Seaway Management Corporation as prescribed by a lease agreement providing for the withdrawal of water surplus to navigation needs from the Welland

Canal for utilization at the DeCew Falls generating stations. The water conveyance charges apply to the transport of water from Lake Erie through the Welland Canal to OPG's intakes at Allanburg.

Water rental payments are made to the Government of Québec, as prescribed by an agreement dated January 2, 1943 and a rate amending agreement effective January 2, 1993. These agreements pertain to the sharing of the water powers of the Ottawa River and were ratified by the Governments of Ontario and Québec. Water rental charges payable to the Province of Québec are based on one-half of the energy produced at the three regulated OPG hydroelectric generating stations located on the Ottawa River. The GRC payments made to the Province of Ontario with respect to these three sites are also based on one-half of the energy produced at the stations.

Under the aforementioned 1943 agreement, OPG also provides compensation to Hydro Québec for the generating value at OPG's stations on the Ottawa River attributed to the water diverted into the Ottawa River through the Dozois Reservoir in Québec. OPG shares in operation and maintenance costs pertaining to the dam enabling the Dozois diversion.

The GRC and water rental payments for the regulated hydroelectric stations are recoverable through OEB-approved regulated prices applicable to these stations.

Further details on water rights can be found in the section, *Description of the Business* under the heading, *Water Rights*.

Thermal (Contracted Generation Portfolio Segment)

Overview of Generating Facilities

Thermal generating stations use heat energy to drive steam turbines that generate electricity. OPG's wholly-owned operating thermal facilities are comprised of biomass-fuelled generating units at both Atikokan GS and Thunder Bay GS, and the dual-fuelled generating Lennox GS, which is capable of burning either oil or natural gas. The results of these facilities are reported in the Contracted – Generation Portfolio business segment.

The combined in-service capacity of the three operating thermal facilities was 2,458 MW as at December 31, 2017. The Lennox GS is located in Greater Napanee, Ontario and accounts for approximately 2,100 MW of this in-service capacity. The Atikokan GS is located in Atikokan, Ontario and has an in-service capacity of 205 MW. The Thunder Bay GS is located in Thunder Bay, Ontario and its advanced biomass fuelled unit has an in-service capacity of 153 MW.

Capacity and production from the Lennox GS are subject to an ESA with the IESO for the period from January 2013 to September 2022. Capacity and production from the Atikokan GS are subject to a ten-year ESA expiring in July 2024. For the Thunder Bay GS advanced biomass fuelled unit, capacity and production are subject to a five-year ESA expiring in January 2020.

OPG's three thermal generating stations operate as peaking facilities, depending on electricity demand. This provides Ontario's electricity system with the flexibility to meet changing daily system demand and capacity requirements and has enabled the system to accommodate the expansion of Ontario's renewable generation portfolio. The continued operation of these stations will continue to provide Ontario with capacity and peaking generation.

The three thermal generating stations are operated and maintained as part of regional operations groups used to operate and maintain the Company's hydroelectric facilities. The Lennox GS is operated under Eastern Operations, and the Atikokan and Thunder Bay generating stations are part of Northwest Operations.

Thermal stations that are no longer available to generate electricity are included in the Services, Trading, and Other Non-Generation business segment once they are removed from service. This includes the Lambton GS and Nanticoke GS sites, which ceased coal-fired generation in 2013.

Contracted Generation Portfolio – Thermal Performance (2015 to 2017)

	2017	2016	2015
Equivalent Forced Outage Rate (%) [1]	**2.4**	1.6	11.2

[1] Equivalent Forced Outage Rate is an index of the reliability of a generating unit at OPG's thermal stations. It is measured by the ratio of time a generating unit is forced out of service by unplanned events, including any forced deratings, compared to the amount of time the generating unit was available to operate.

The higher thermal EFOR in 2017, compared to 2016, was primarily due to a higher number of unplanned outage days at a Lennox GS unit as a result of a transmission outage and a generator-related outage in 2017. The change in thermal EFOR in 2016, compared to 2015, was primarily due to an outage in 2015 to perform repair work at the Lennox GS.

Additional information on OPG's thermal operations can be found in the section, *Core Business, Strategy, and Outlook* under the heading, *Operational Excellence – Electricity Generation Production and Reliability* in the Company's 2017 year-end MD&A.

Thermal Fuel Procurement

Due to the relatively low capacity factor of the Lennox GS, natural gas is purchased on the spot market, other than a small volume of fixed term natural gas required for non-generation operational services. Oil for the Lennox GS is contracted for and purchased on an as needed basis. Fuel switching at the station is based on market and fuel economics. Annual procurement of biomass fuel quantities for Atikokan GS and Thunder Bay GS is pre-determined by the corresponding ESAs. Agreements are in place with suppliers for the purchase of all biomass fuel pellets needed to provide fuel for the Atikokan GS for the duration of its ESA, and for most of the advanced biomass fuel pellets needed to provide fuel for the duration of the ESA for the Thunder Bay GS.

Thermal Facility Planning

OPG's facility planning approach is designed to identify necessary capital and operating and maintenance expenditures for each thermal facility. This planning approach aims to sustain facility availability for the remaining service life through station reinvestment within constraints imposed by technical, financial, safety, and system requirements, as well as regulatory and contractual limits. Periodic engineering reviews of major systems are conducted to identify performance issues, provide reinvestment recommendations where appropriate, and ensure that regulatory, safety and operating standards continue to meet expectations. OPG undertakes projects at thermal stations that are expected to achieve an appropriate return within the service life of the stations.

Thermal Station Decommissioning

OPG has recognized, and carries on its balance sheet, a liability to cover future expenditures to decommission and dismantle each of its thermal stations at the end of their estimated service lives. This provision is not funded and is estimated on the basis of station closure. Costs previously incurred by OPG to preserve Lambton and Nanticoke generating stations for potential conversion to natural gas in the future were not charged to the provision, as they were charged against net income as incurred.

Portlands Energy Centre Partnership

OPG has a 49.95 percent partnership interest in Portlands Energy Centre L.P., a limited partnership formed with TransCanada Energy Ltd. (49.95 percent) and the general partner of the partnership, Portlands Energy Centre Inc. (0.1 percent). The shareholders of Portlands Energy Centre Inc. are OPG (50 percent) and TransCanada Energy Ltd. (50 percent). PEC is a 550 MW combined cycle generation natural gas turbine electricity generating facility located on the former R. L. Hearn GS site in the port area of downtown Toronto, Ontario. The station was declared in-service in a combined cycle mode in April 2009. PEC operates under an Accelerated Clean Energy Supply contract with the IESO and trades electricity in the Ontario electricity market.

The Contracted Generation Portfolio segment includes OPG's share of equity income from its 50 percent ownership interest in the station. OPG's share of the in-service generating capacity and generation volume from its interest in the station are included in the operating statistics for the segment.

Brighton Beach Power Partnership

OPG has a 49.95 percent partnership interest in Brighton Beach Power L.P., a limited partnership formed with ATCO Power Canada Ltd. (49.95 percent) and the general partner of the partnership, Brighton Beach Power Ltd. (0.1 percent). The shareholders of Brighton Beach Power Ltd. are OPG (50 percent) and ATCO Power Canada Ltd. (50 percent). Brighton Beach is a 560 MW combined cycle gas turbine electricity generating facility located on the former J.C. Keith GS site in Windsor, Ontario. The station began commercial operation in July 2004. Brighton Beach operates under a tolling arrangement with Shell Energy North America (Canada) Inc. (Shell Energy), pursuant to which Shell Energy owns and trades the electricity produced by the facility in return for the supply of gas and the fees payable under the tolling agreement. Shell Energy's financial obligations are guaranteed by Shell Energy North America (US) L.P. (Shell L.P.), and Shell L.P.'s obligations are in turn guaranteed by Shell Oil Company.

The Contracted Generation Portfolio segment includes OPG's share of equity income from its 50 percent ownership interest in the station. OPG's share of the in-service generating capacity and generation volume from its interest in the station are included in the operating statistics for the segment.

Regulated – Nuclear Waste Management Segment

Overview

OPG is responsible for the ongoing management of radioactive wastes generated by its nuclear operations. In addition, OPG has the obligation for decommissioning its nuclear generating stations and nuclear waste facilities after the end of their useful lives and for managing radioactive wastes that arise in connection with the decommissioning. The handling and disposal of radioactive waste in Canada is subject to federal legislation.

The radioactive wastes generated by OPG's nuclear operations include the following:

- Used nuclear fuel bundles;
- Intermediate-level waste – material that has come in close contact with the reactors, but is less radioactive than used fuel, such as ion exchange resins and reactor equipment and components; and
- Low-level waste – material used in connection with station operation that is not highly radioactive, such as tools and protective clothing.

The Company's Regulated – Nuclear Waste Management segment reports the results of the Company's operations associated with the following:

- management of used nuclear fuel and L&ILW;

- decommissioning of OPG's nuclear generating stations including the stations on lease to Bruce Power and other nuclear facilities;
- management of the Nuclear Segregated Funds established under the ONFA to fund OPG's obligation for nuclear facilities decommissioning and the long-term management of nuclear waste; and
- Other related activities including the inspection and maintenance of the waste storage facilities.

The nuclear accretion expense, which is the increase in the carrying amount of the present value liabilities for nuclear fixed asset removal and nuclear waste management liabilities reported on the balance sheet due to the passage of time, and the earnings from the Nuclear Segregated Funds are reported under this segment. The Regulated – Nuclear Waste Management segment is considered rate regulated because OPG's costs associated with nuclear waste management and nuclear facilities decommissioning liabilities have been included by the OEB in the determination of regulated prices for production from the Pickering and Darlington nuclear generating stations.

Federal Government Policy

In accordance with the requirements of the *Nuclear Fuel Waste Act* (Canada) (NFWA), in 2002, OPG and the other owners of nuclear fuel waste in Canada established a separately incorporated NWMO, with a mandate to manage and coordinate the full range of activities relating to the long-term management of nuclear fuel waste in Canada. This includes the design and implementation of Canada's plan for the long-term management of used nuclear fuel. In 2007, the federal government approved NWMO's submitted option, the Adaptive Phased Management (APM) plan, as the long-term solution for nuclear fuel waste. The APM plan contemplates the eventual long-term permanent disposal of radioactive nuclear fuel waste in a deep geologic repository (DGR) after a collaborative process of communication and engagement with Canadians aimed at selecting a suitable geological site with an informed and willing host community. The NWMO is in the process of undertaking a multi-year site selection process for the used fuel DGR.

The NFWA also requires the nuclear fuel waste owners in Canada to establish and make payments into trust funds for the purpose of funding the implementation of the long-term management plan for used fuel. Accordingly, OPG has established the Ontario NFWA Trust (the NFWA Trust), which forms part of the Nuclear Segregated Funds under the ONFA. Additional details can be found in the section, *Description of the Business* under the heading, *Regulated – Nuclear Waste Management Segment – Funding Mechanisms.*

Current Practices

Used Nuclear Fuel

Used nuclear fuel bundles from OPG's reactors and leased reactors at the Bruce Nuclear site are temporarily stored at each nuclear generating station in water-filled pools, known as wet bays, for a cooling-off period of at least ten years, during which time their radioactivity is substantially reduced. Each nuclear generating station has sufficient capacity to store used nuclear fuel bundles in the wet bays for approximately 15 to 20 years of operation.

After the used nuclear fuel bundles have been stored for the cooling-off period, the bundles are transferred from the wet bays to above-ground dry storage containers at the corresponding nuclear station site. Currently, there is used nuclear fuel bundles in dry storage at the Pickering, Darlington and Bruce Nuclear sites.

OPG's planning assumption for the long-term management of used nuclear fuel bundles is consistent with the NWMO's APM concept of disposal in a deep geological repository. The NWMO has indicated that it currently expects an in-service date of 2043 at the earliest for the used fuel DGR.

Low and Intermediate Level Waste

The majority of OPG's L&ILW is stored at the radioactive waste management facility at WWMF located on the Bruce site. This facility, which continues to be owned and operated by OPG following the lease of the Bruce generating stations, operates under a separate licence issued by the CNSC. A smaller volume of ILW is stored at each of the radioactive waste management facilities at Pickering and Darlington sites. Respectively, these ILW storage facilities house the components from Pickering A's retube in the 1980's and from the recent Darlington Refurbishment of Unit 2. OPG's planning assumption for the long-term management of L&ILW is the placement of this nuclear waste in a separate L&ILW DGR.

Additional details can be found in the section, *Description of the Business* under the heading, *Regulated – Nuclear Waste Management Segment – Deep Geologic Repository for Low and Intermediate Level Waste.*

Station Decommissioning

OPG's planning assumption for the decommissioning of its nuclear generating stations is a deferred dismantlement strategy. Under this strategy, each station will be de-watered and de-fuelled immediately after it has ceased operations and prepared for safe storage and monitoring. Thereafter, OPG intends to monitor the station for approximately 30 years while in safe storage, after which time the station will be dismantled and the site restored over a period of approximately ten years. This strategy has been communicated to the CNSC through regular updates of OPG's preliminary decommissioning plans and liability estimates for the nuclear generating stations. Currently, OPG has received CNSC acceptance of the OPG Financial Guarantee for the five year period from 2018 to 2022 based on the fund performance and estimate for decommissioning the OPG nuclear assets. OPG's nuclear operating licences have been issued based on, amongst other things, CNSC's understanding of this strategy.

Deep Geologic Repository for Low and Intermediate Level Waste

OPG has proposed a deep geologic repository as the preferred solution for the safe long-term management of the L&ILW produced from the continued operation of OPG-owned nuclear generating stations and their eventual decommissioning. Agreement has been reached with local municipalities for OPG to develop the L&ILW DGR on lands adjacent to the WWMF in Kincardine, Ontario.

Under the NSCA, OPG requires licences from the CNSC for activities to be undertaken with respect to the L&ILW DGR project. Before the CNSC can make licensing decisions for the proposal, an EA must be conducted in compliance with the requirements of the *Canadian Environmental Assessment Act*. As part of the EA process for the L&ILW DGR, Environmental Impact Statement, Preliminary Safety Report, and Technical Support Documents were submitted to the CNSC in 2011. The purpose of these submissions was to obtain EA approval and a site preparation and construction licence from the Joint Review Panel (JRP) for the project. The responsibility of the JRP, which was appointed by the Canadian Environmental Assessment Agency (CEAA) and the CNSC in 2012, was to examine the environmental effects of the proposed DGR to meet the requirements of the *Canadian Environmental Assessment Act.* In May 2015, the JRP submitted its report and recommendations on the EA to the federal Minister of Environment. The report concluded that, given mitigation, there is unlikely to be significant environmental impact from the project and recommended that the Minister approve the EA. The report suggested that the project should be implemented expeditiously.

In August 2015, OPG responded to the CEAA's list of potential environmental conditions relating to the JRP report. In February 2016, the federal Minister of Environment and Climate Change requested additional information on certain aspects of the EA, including information related to alternate locations for the project and the impact on environmental effects if Canada's planned used fuel deep geologic repository being developed by the NWMO were to be located in close proximity to OPG's proposed L&ILW DGR. OPG has completed the requested studies and submitted the requested information in December 2016, as planned. Following its review of OPG's submission and a period of public comment, the CEAA requested further information that OPG subsequently provided in May 2017. In June 2017, the CEAA notified OPG that it had sufficient and adequate information to proceed with the next step of the environmental assessment

process and advised that a draft report and updated terms and conditions would be prepared for public review.

On August 21, 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of potential cumulative effects of the project on the Saugeen Ojibway Nation's (SON) physical and cultural heritage, including a description of the potential effects of the project on the Nation's spiritual and cultural connection to the land, taking into account the results of the SON Community Process. OPG is working closely with the SON to formulate a response to the information request.

The L&ILW DGR at the WWMF site remains OPG's preferred solution for the safe long-term management of the L&ILW. The in-service date of the L&ILW DGR is expected to be approximately six to seven years from the start of construction.

Funding Mechanisms

On April 1, 1999, Ontario Hydro's obligation for nuclear facilities decommissioning and nuclear waste management was transferred to OPG. The responsibility for funding the liabilities for nuclear facilities decommissioning and the long-term nuclear waste management between the Province and OPG is described in the ONFA. The key provisions of the ONFA are: (i) for OPG to establish two segregated funds, the Used Fuel Segregated Fund to fund the future costs of long-term nuclear used fuel waste management and certain costs of used fuel storage incurred after the stations are shut down, and the Decommissioning Segregated Fund to fund the future costs of nuclear decommissioning and long-term L&ILW management, and certain costs of used fuel storage incurred after the stations are shut down; (ii) for the OEFC to be responsible for funding approximately $2.4 billion present value as at April 1, 1999 that had been an accumulated liability of Ontario Hydro, which the OEFC has since then fully funded through an initial contribution to the Decommissioning Segregated Fund; (iii) for the Province to limit OPG's financial exposure in relation to the cost of used fuel management for the first 2.23 million bundles of used fuel; and (iv) for the Province to provide financial guarantees to the CNSC for OPG's nuclear decommissioning and nuclear waste management obligations, as required by the CNSC.

The Used Fuel Segregated Fund and the Decommissioning Segregated Fund are administered by a third party custodian and held in accounts segregated from OPG's other assets. OPG has granted a security interest in both funds to the Province. As a result, these funds are not available to satisfy the claims of OPG's creditors.

OPG's required contributions to the Used Fuel Segregated Fund and the Decommissioning Segregated Fund are determined based on reference plans and associated life cycle cost estimates periodically approved by the Province under the ONFA. These reference plans are prepared by OPG with the assistance of external consultants and based on external practices and international benchmarks. Under the ONFA reference plans, the total present value of OPG's future nuclear facilities decommissioning and nuclear waste management costs is determined based on baseline cost estimates and a set of underpinning major planning assumptions, including remaining useful lives of the nuclear stations, proposed methods and timing of nuclear waste disposal, and economic indicators. Given the long-term duration of these life cycle programs, the multiple assumptions involved and the evolving technology to handle nuclear waste, there is a significant degree of inherent uncertainty surrounding the measurement of the underlying costs, which may increase or decrease over time.

The limits to OPG's financial exposure under the ONFA with respect to the life cycle cost of long-term management of the first 2.23 million bundles of used fuel are as follows (all amounts are expressed in January 1, 1999 present value dollars): (i) OPG will bear all costs up to $4.6 billion; (ii) OPG and the Province will share, on an equal basis, costs incurred between $4.6 billion and $6.6 billion; (iii) OPG will be responsible for 10 percent of the costs incurred between $6.6 and $10 billion, and the Province will be responsible for the remaining 90 percent; (iv) the Province will be wholly responsible for any costs above $10 billion. As a result, OPG's funding liability for these used fuel costs under the ONFA is capped at $5.9 billion in January 1, 1999 present value dollars, which is equivalent to approximately $15.7 billion in December 31, 2017 present value dollars. OPG is responsible for all incremental costs

relating to the management of used fuel bundles in excess of the 2.23 million threshold. As at December 31, 2017, approximately 2.6 million bundles of used fuel waste had been produced. The 2.23 million fuel bundles threshold represents the estimated total life cycle bundles based on the initial estimated useful lives of the nuclear stations assumed in the ONFA.

Under the ONFA, the Province guarantees OPG's annual return earned in the Used Fuel Segregated Fund at 3.25 percent plus the rate of change in the Ontario Consumer Price Index, as defined in the ONFA, for funding related to the first 2.23 million used fuel bundles. Upon approval of a new or amended ONFA reference plan, the Province is obligated to make an additional contribution to the Used Fuel Segregated Fund in relation to the first 2.23 million bundles if the fund's assets earned a rate of return that is less than the guaranteed rate of return. If the return on the fund's assets exceeds the Province's guaranteed rate of return, the Province is entitled to withdraw any portion of the excess related to the first 2.23 million bundles, upon approval of a new or amended ONFA reference plan. OPG is responsible for cost increases and investment returns for the portion of the fund attributable to the used fuel bundles in excess of the 2.23 million threshold. OPG also is responsible for cost increases and investment returns for the Decommissioning Segregated Fund.

The investments in the Nuclear Segregated Funds include a diversified portfolio of equities and fixed income securities that are invested across geographic markets, as well as investments in real assets including infrastructure, real estate and agriculture. As the Nuclear Segregated Funds are invested to fund long-term liability requirements, the portfolio asset mix is structured to achieve the required return over a long-term horizon. While the Nuclear Segregated Funds are manage to achieve, in the long term, the target return rate based on the discount rate specified in the ONFA, the rates of return earned in a given period may be subject to various external factors including financial market conditions and changes in the Ontario Consumer Price Index, which, in the short-term, can be volatile and cause fluctuations in the Company's financial results. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

Under the current OEB-approved cost recovery methodology for OPG's nuclear waste management and nuclear facilities decommissioning liabilities, OPG's income is exposed to the rate of return risk for the portion of the Nuclear Segregated Funds related to the Pickering and Darlington nuclear generating stations.

Contributions to the Nuclear Segregated Funds

OPG's contribution requirements under the ONFA are recalculated each time there is an approved new or amended reference plan and under certain other events. Reference plans are required to be prepared at least every five years, or more frequently if there is an underlying change in the assumptions of the reference plan that both OPG and the Province agree are significant enough to trigger a recalculation of the contribution levels during the five-year period.

Prior to 2017, OPG made contributions to the Used Fuel Segregated Fund every quarter, including a one-time special payment in earlier years, as required by the ONFA. These contributions reflected ONFA requirements to fund the majority of the underlying used fuel liability by the end of the initial estimated useful lives of the nuclear stations assumed in the ONFA, resulting in significantly higher contributions to the Used Fuel Segregated Fund in the earlier years of OPG's existence. OPG has not been required to make contributions to the Decommissioning Segregated Fund, which was fully funded at its inception through the initial contribution made by the OEFC and, taking into account asset performance and changes in underlying funding obligations over time, at the time of every subsequent approved ONFA reference plan.

Based on the funded status of the Used Fuel Segregated Fund and the Decommissioning Segregated Fund reflecting the lower life cycle liability estimates per the 2017 ONFA Reference Plan, no overall contributions to either fund were required starting in 2017. Contributions to either or both funds may be required in the future should the funds be in an underfunded position when a new reference plan is approved. Such may be the case as a result of future variability in asset performance due to volatility inherent in financial markets and economic conditions. Future contribution levels also are dependent on changes in baseline cost

estimates and underpinning planning assumptions used to establish the funding obligations in subsequent ONFA reference plans, as well as any changes in the tax treatment of fund earnings. OPG's required contributions could increase, for example, if cost estimates increased, if the operating lives of the nuclear stations were revised, if fund assets earned less than the target rate of return, if the income earned in the funds became subject to tax, or if the NWMO were unable to receive the same sales tax treatment that OPG would be entitled to receive if the NWMO had not been established.

OPG is required to make annual contributions to the NFWA Trust based on a funding formula approved by the federal Minister of Natural Resources for OPG and the other nuclear fuel waste owners in Canada. The NFWA Trust forms part of the Used Fuel Segregated Fund. Any OPG contributions to the Used Fuel Segregated Fund as well as any portion of the Used Fuel Segregated Fund currently not in the NFWA Trust can be applied to satisfy the trust's annual contribution requirements. The funds in the Ontario NFWA Trust will be used for the purposes of long-term management of nuclear used fuel waste, in accordance with the NFWA. OPG and the Province are beneficiaries of the NFWA Trust.

If there is a surplus in the Decommissioning Segregated Fund such that the funding liabilities, as defined by the most recently approved ONFA Reference Plan, are at least 120 percent funded, OPG may direct, at the time a new or amended reference plan is approved, up to 50 percent of the surplus over 120 percent to the Used Fuel Segregated Fund, with the OEFC entitled to a distribution of an equal amount.

If there is a surplus in the Used Fuel Segregated Fund such that the funding liabilities, as defined by the most recently approved ONFA Reference Plan, are at least 110 percent funded, the Province has the right, at any time, to access the excess amount greater than 110 percent. Neither OPG nor the Province have a right to direct any amounts from the Used Fuel Segregated Fund to the Decommissioning Segregated Fund.

Upon termination of the ONFA, the Province has the sole right to any excess funds in the Decommissioning Segregated Fund and the Used Fuel Segregated Fund.

OPG has the responsibility for the management and disposal of the used nuclear fuel and L&ILW generated by the Bruce generating stations and for the eventual decommissioning of these stations. These obligations on the part of OPG are recovered from Bruce Power through annual rent payments and volume based fees per the Bruce Lease and related agreements. Pursuant to the lease agreement, Bruce Power must return the two Bruce stations to OPG together, in a de-fuelled and de-watered state. As such, these de-watering and de-fuelling costs will not be funded by OPG. Further details on the 2015 amendments to these agreements are found in the section, *General Development of the Business* under the heading, *Nuclear Business Development – Bruce Power Refurbishment and Bruce Lease Agreement*.

Provincial Guarantee

In accordance with the NSCA, the CNSC requires OPG to have sufficient funds available to discharge its existing nuclear waste management and nuclear decommissioning obligations. The CNSC process requires the CNSC financial guarantee requirement to be updated once every five years and for OPG to provide an annual report to the CNSC on the assumptions, asset values, and resulting financial guarantee requirements. The CNSC financial guarantee requirement calculation takes into account nuclear waste expected to be generated to the end of each year.

In November 2017, the CNSC accepted OPG's proposed 2018-2022 CNSC financial guarantee requirement to be satisfied by the forecast fair market value of the Nuclear Segregated Funds without the requirement of a Provincial Guarantee for the 2018-2022 period. As required by the terms of the ONFA, the Province is committed to provide a Provincial Guarantee to the CNSC, on behalf of OPG, should there be a shortfall between the CNSC financial guarantee requirement and the value of the Nuclear Segregated Funds in the 2018-2022 period, as it has been done in the past. OPG pays the Province an annual guarantee fee equal to 0.5 percent of the outstanding amount, if any, of the Provincial Guarantee.

Services, Trading, and Other Non-Generation Segment

The Services, Trading, and Other Non-Generation segment is a non-generation segment that is not subject to rate regulation. It includes the revenue and expenses related to OPG's trading and other non-hedging activities. As part of trading activities, OPG transacts with counterparties in Ontario and neighbouring energy markets in predominantly short-term trading activities of typically one year or less in duration. These activities relate to electricity that is purchased and sold at the Ontario border, financial energy trades, financial risk management energy product revenues, and sales of energy-related products.

In addition, the segment includes the results of OPGET, which engages in U.S.-based wholesale energy trading activities in the U.S. northeast. The activities of OPGET include trading electricity in the U.S. using over-the-counter energy-related derivatives. OPGET retains Federal Energy Regulatory Commission market-based rate authorization.

The segment also includes revenue from real estate rentals and non-regulated services, gains or losses on disposition of non-regulated real estate assets, costs associated with non-regulated business development activities, and costs related to the Lambton GS and Nanticoke GS sites.

Fair Hydro Trust Segment

The Fair Hydro Trust segment is a non-generation segment that is not subject to rate regulation. It includes OPG's earnings from the Fair Hydro Trust, which includes the financial results of the Trust, as well as income related to OPG's role as Financial Services Manager of the Fair Hydro Trust and holder of subordinated debt issued by the Trust. Earnings include interest income from OPG's investment in subordinated debt of the Trust of up to 49 percent of the Trust's total outstanding debt, recovery of related to third-party costs and fees for financial management and ongoing administration services, partially offset by interest costs on debt issued by OPG to fund five percent of the subordinated investment in the Trust, incurred third-party costs, and other incurred costs related to the management and administration of the Trust.

Indigenous Relations

The Aboriginal and treaty rights of Indigenous communities are recognized and affirmed in the *Constitution Act, 1982*. OPG's corporate governance includes an Indigenous Relations policy to help build and develop mutually beneficial working relationships with Indigenous communities proximate to the Company's present and future operations. The policy focuses on building respectful relationships with Indigenous communities, businesses and organizations through partnership, collaboration, and support for procurement, employment and educational opportunities. The Company seeks to establish and maintain these relationships based on a foundation of respect for the languages, customs, and political, social and cultural organizations of the indigenous communities.

OPG may be subject to claims by Indigenous communities or other Indigenous groups and individuals. These claims may stem from generation development activities, historic operations of Hydro Electric Power Commission of Ontario and Ontario Hydro that may have impacted Aboriginal and treaty rights, or the absence of legal permits, rights-of-way, or easements. Legal precedents created by court rulings may impact negotiations and resolution of past grievances. To date, OPG has resolved 23 past grievance claims with 21 communities, achieving final settlement agreements.

In line with the company's Indigenous Relations policy, OPG is pursuing prospective generation-related developments and other joint projects with Indigenous communities. OPG currently has four generation development partnerships with Indigenous communities. OPG's first such partnership became operational in early 2009 as part of the Obishikokaang Waasiganikewigamig/Lac Seul GS project. The signing of the "*Amisk-oo-Skow*" Agreement with the Moose Cree First Nation (MCFN) in early 2010 marked the second such partnership. In 2011, the Lower Mattagami Limited Partnership agreement was amended and restated to include the MCFN and their wholly owned Amisk-oo-Skow Finance Corporation as limited partners and to enable the MCFN to acquire up to 25 percent limited partnership interest in the Lower Mattagami River

project. During 2014, the MCFN acquired a 25 percent interest in the assets through its investment in the Lower Mattagami Limited Partnership as incremental units of the project were placed in-service.

OPG and CRP, a wholly owned corporation of the Taykwa Tagamou Nation, established Peter Sutherland Sr. GS Limited Partnership in January 2015. In March 2017, the Peter Sutherland Sr. GS was placed in-service and, in April 2017, the Taykwa Tagamou Nation, through CRP, increased their partnership interest in PSS to 33 percent under the partnership agreement.

Following selection by the IESO in March 2016, OPG and a subsidiary of the Six Nations of Grand River Development Corporation have partnered to develop a new 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands. The Nanticoke Solar Limited Partnership was formed in July 2015, and the Six Nations of Grand River Develop Coproration through its subsidiary acquired a 10 percent ownership interest in August 2015.

Other recent joint projects with Indigenous partners include two shoreline remediation projects completed in 2016. The Whitesand First Nation, working closely with OPG, completed a project to remediate nearly two kilometers of shoreline, while the Long Lake #58 First Nation undertook the management of a five-year shoreline remediation project. OPG also engaged the Mississaugas of New Credit regarding the sale of the Lakeview generating station site. OPG also has been engaging proactively with Indigenous communities regarding the Company's nuclear waste management operations, through regularly scheduled meetings and an ongoing dialogue in connection with OPG's proposed L&ILW DGR, the re-licensing of the PWMF and the WWMF, and the Pickering generating station's relicensing. Further engagement was conducted with First Nations in southwestern Ontario regarding the demolition of the Lambton and Nanticoke generating stations.

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OPG is also committed to improving Indigenous access to procurement and employment opportunities, including increasing the profile of the nuclear generation industry in Indigenous communities. In 2017, OPG launched an Indigenous Business Engagement (IBE) Initiative. The purpose of this initiative is to increase access to procurement opportunities for Indigenous businesses interested in supplying materials and services to OPG. The IBE Initiative is based on a strategy that will identify opportunities in contracts, scopes of work and business plans for potential Indigenous business engagement; include criteria related to suppliers' ability to engage or partner with Indigenous people or businesses in assessing procurement proposals; and invest in relationships with Indigenous communities by increasing outreach efforts to enhance understanding of how to do business with OPG. OPG has been engaging with Indigenous businesses and communities as well as its suppliers to promote the IBE Initiative including the Mohawk Council of Akwesasne as well as the Williams Treaties First Nations, located proximate to the Pickering and Darlington nuclear generating stations.

OPG has been actively developing recruitment plans targeting Indigenous peoples. As part of this initiative, during the fourth quarter of 2017, OPG participated in several Indigenous-specific career fairs, hosted a Day in the Trades event for Indigenous students and job seekers as part of an open house at the Darlington Energy Centre, and approved additional plans aimed at increasing the number of Indigenous apprentices as part of the nuclear operations' recruitment program.

In November 2016, OPG was recognized for its ongoing commitment to engaging local Indigenous communities with the Canadian Electricity Association's (CEA) 2016 Sustainable Electricity award for Leadership in External Collaboration and Partnerships.

Workplace Safety and Public Safety

Workplace Health and Safety

In the area of workplace safety, OPG is committed to achieving excellent performance through continuous improvement and a strong safety culture, with the ultimate goal of zero injuries. OPG utilizes an integrated health and safety management system and a set of operational risk control procedures to ensure continued monitoring of health and safety performance and to support continuous learning and improvement in this area. Over the past five years, OPG has repeatedly stood in the top quartile of its comparator Canadian electrical utilities in various safety performance metrics.

Workplace safety performance is measured using two primary indicators at OPG, All Injury Rate (AIR) and Accident Severity Rate (ASR). OPG's AIR and ASR results for employee workplace safety were as follows for the year ended December 31:

	2017	2016	2015
AIR *(injuries per 200,000 hours worked)*	**0.48**	0.56	0.39
ASR *(days lost per 200,000 hours)*	**3.57**	2.59	0.50

In 2017, OPG's AIR improved from 2016 and was the third-best performance year in the history of the company. For those employee injuries that caused lost time from work, the total time lost from work in 2017 was greater than the previous year. OPG's analysis of the underlying safety events indicated that major contributors to the injuries and near misses included inadequate situational awareness and attention to detail, and suboptimal risk-based decisions, rather than missing or inadequate standards or programs. OPG continues to implement a number of initiatives to target the injury trends based on the analysis of the safety events, with a focus on the use of human performance tools including increased field supervisory oversight, situational awareness, communication, and procedural use and adherence.

In order to strengthen its safety performance, OPG continues to progress an organization-wide "iCare Enough to Act" initiative launched in 2016 and aimed at renewing employees' commitment to their own and each other's safety and well-being. Approaches to supervisory oversight, communication and safe work planning are being modified and updated to further strengthen safety as a foundational element of the Company's values-based culture.

Contractors are required to conduct work safely at OPG sites. In support of this requirement, OPG utilizes an independent contractor pre-qualification process, provides on-site safety support for many of its major projects, and works with contract partners to improve their health and safety programs to meet OPG's requirements. In the past nine years, OPG has consistently shown a better than average Construction Contractor AIR as compared to the Infrastructure Health and Safety Association Contractor AIR, a metric of construction contractor safety performance across Ontario. OPG has maintained this performance while engaging in the refurbishment of the Darlington GS, one of the largest infrastructure projects in Canada. The hours worked by contractors in 2017 were the largest in OPG's history, largely attributable to this project.

Since 2014, OPG has been operating under a single integrated health and safety management system and set of operational risk control procedures across the Company, providing consistent performance expectations for all employees. The control procedures are designed to ensure continued enterprise-wide monitoring of health and safety performance and to support continuous learning and improvement in these areas. Oversight and reporting by corporate and site safety functions is in place to provide senior management with regular information on the effectiveness of the safety management efforts, compliance with legal and corporate requirements, and safety performance trends. OPG's incident management system requires that all incidents, including near misses, be reported and investigated and that where beneficial, corrective action plans be developed and completed in order to prevent reoccurrences.

In 2014, OPG launched a Total Health initiative that aims to embed a health culture that supports employees and their families in their efforts to achieve an optimal level of health and functioning, through health education, health promotion, disease and injury prevention, and crisis intervention. In 2016, the Company launched the Mental Health First Aid training course for employees, an accredited training program facilitated by the Mental Health Commission of Canada. The training aims to increase awareness and empathy for mental illness, reduce stigma, support affected employees, and improve return to work outcomes. By the end of 2017, over 1600 "people leaders" had participated in this training.

Nuclear Radiation Safety

OPG manages a radiation protection program designed to minimize detrimental health effects to employees and members of the public. OPG follows developments in the field of radiation protection as documented by the International Commission on Radiological Protection (ICRP), the United Nations Scientific Committee on the Effects of Atomic Radiation, and the U.S. National Council on Radiation Protection and Measurements. Widely recognized as the main source of expert advice regarding protection from the harmful effects of ionizing radiation, the ICRP periodically issues recommendations concerning principles of radiation protection. These recommendations are usually adopted by most countries without significant modification and are incorporated into the applicable laws. The Canadian Radiation Protection Regulations are based on the recommendations of the ICRP, and OPG's nuclear facilities conform to these regulations. The CNSC is the federal agency that regulates radiation protection in Canada.

Radiation exposures to station personnel and the public are limited by station design and adherence to approved operating procedures. Over the years, OPG has been a leader in applying the principles of keeping radiation doses as low as reasonably achievable. OPG's internal operating limits for occupational exposure are set well below the regulatory limits to ensure that the regulatory limits are not exceeded. OPG's operating targets for radiological emissions are set at even more restrictive levels and typically represent small fractions of the regulatory limits.

To ensure continued public safety, radiation exposure to members of the public resulting from the operation of OPG's nuclear generating stations is estimated on an annual basis for individuals living or working near the stations. The annual dose to the public resulting from operations of each nuclear facility is expressed in microsieverts (μSv), an international unit of radiation dose measurement. For 2015, the annual public doses resulting from the Darlington GS operations and the Pickering GS operations were 0.5 μSv and 1.2 μSv, respectively, which is approximately 0.1 percent of the annual legal limit of 1,000 μSv. For 2016, the annual public doses resulting from the Darlington GS operations and the Pickering GS operations were 0.6 μSv and 1.5 μSv, respectively, which is less than 0.1 and 0.2 percent of the annual legal limit of 1,000 μSv, respectively. While the public doses from OPG's nuclear operations for the 2017 operating year will not be finalized until the second quarter of 2018, they are not expected to differ significantly from the 2016 levels.

As a condition of receiving operating licences for its nuclear facilities, OPG has developed comprehensive emergency plans that detail the Company's planned response to reactor accidents, as well as accidents involving the transportation of radioactive materials. These plans dictate how OPG will work with municipal, regional, provincial, and federal agencies to safeguard station personnel and members of the public in the unlikely event of a radiation emergency at one of OPG's facilities. Station staff are required to regularly participate in emergency exercises to maintain and continuously improve response capability for such events.

Dam Safety and Waterways Public Safety

OPG manages dam safety and other risks associated with the production of hydroelectric power through OPG's Safe Operations Policy and Dam Safety Program. The Safe Operations Policy directs that dams be designed, constructed, operated, and maintained in a manner that meets all regulatory requirements, or, in the absence of regulations, the safety guidelines published by the Canadian Dam Association or other industry best practices. OPG is one of the first dam owners in Canada to have developed and implemented a dam safety program and is considered an industry leader in many aspects of the program.

In addition to effectively managing the safety of dams against catastrophic failure, OPG has developed a number of technical standards and procedures concerning public safety around dams, and materials to educate the public and raise awareness of the hazards associated with the operation of the hydroelectric facilities. This includes the implementation of control measures in the form of signage, safety booms, buoys, fencing and audible alerts at the appropriate facilities. These measures are actively managed to maintain their effectiveness. OPG also strives to entrench a "Stay Clear – Stay Safe" message as part of its public education program, through strategically placed advertisements and engagement of other agencies, such as the MNRF, Ontario Provincial Police, Life Saving Society, Ontario Waterpower Association, and other stakeholders.

Since 2007, OPG has engaged an independent advisory panel consisting of internationally recognized experts to conduct an annual review of its Dam Safety Program. The Chair of the independent panel establishes areas of in-depth review and presents the observations to OPG's Board of Directors. The panel has consistently found that the risks associated with the dams owned and operated by OPG are being managed in alignment with industry best practices and guidelines. OPG remains committed to high standards of public safety on waterways around hydroelectric generating stations and dams, and continues to make investments in waterway and dam safety upgrades.

Additional details on the regulatory regime related to dams and waterways can be found in the section, *Description of the Business* under the heading, *Water Rights.*

Environment

Overview

OPG is committed to meeting compliance obligations, including any environmental commitments that it makes, with the objective of exceeding these compliance obligations where it makes business sense. OPG's Environmental Policy specifically commits the Company to:

- Establish an environmental management system (EMS) and maintain registration for this system to the ISO 14001 Environmental Management System standard;
- Work to prevent or mitigate adverse impacts on the environment with a long-term objective of continual improvement;
- Strive to be a leader in climate change mitigation; and
- Manage sites in a manner that strives to maintain, or enhance where it makes business sense, significant natural areas and associated species of concern.

The policy is implemented through OPG's EMS. Within the EMS, OPG sets environmental objectives and maintains planning, operational control, and monitoring programs to manage its negative and positive impacts on the environment. The most significant environmental aspects of OPG's operations include: chemical emissions to water, spills, fish impingement and entrainment, thermal effluent emissions, displacement of fossil fuels, enhancement and disruption of wildlife habitat, radiological emissions, radioactive waste generation, and water flow and level changes. The policy is reviewed annually as part of the EMS to ensure that it remains appropriate to the nature, scale and environmental impacts of OPG's activities.

OPG communicates its environmental performance to external and internal stakeholders through a range of engagement methods such as reports and correspondence to regulators, meetings, newsletters, open houses, consultations, news releases, advertising campaigns, social media, and participation in community events.

Details of OPG's environmental performance and initiatives to fulfill the Environmental Policy can be found in OPG's annual *Sustainability Report*, which is available on the Company's website at www.opg.com. ***Unless otherwise specifically stated, none of the information contained on, or connected to the Company's website nor any of the contents of the Sustainability Report are incorporated by reference herein.***

Environmental Compliance

OPG must comply with a large number of environmental requirements contained in statutes, regulations, by-laws, licences, permits and approvals. Failure to comply with applicable environmental laws may result in enforcement action, including the potential for orders or charges. OPG reports any incidents of non-compliance to the appropriate federal, provincial or municipal authorities as required, with corrective action plans developed and implemented accordingly.

Changes in environmental regulatory requirements may result in existing operations being in a state of non-compliance, a potential inability to comply, and potential costs and liabilities for OPG. To ensure compliance, such circumstances may require OPG to install control technologies, develop new processes, allowances or offsets, or place constraints on electricity production.

Protection of Fish

Electricity generating facilities located on waterways can impact fish in a number of ways. At nuclear and thermal stations, the intake of water for cooling purposes can result in fish being impinged on station equipment and fish larvae and eggs being entrained in the water as it passes through the station. The warmer water returned to the water body also has the potential to impact aquatic organisms and habitat near the station. At hydroelectric stations, the flow of water through the station turbines can result in fish entrainment and mortality, while physical barriers such as dams can prevent the migration of fish.

OPG utilizes measures such as fish ladders, trap and transport programs, stocking programs, barriers and deterring structures, water flow alterations, habitat protection and creation, and station effluent temperature limits to manage and mitigate impacts to fish. Potential regulatory changes being monitored and managed as risks by the Company include electricity production constraints and water flow management requirements to protect fish and fish habitat, and expanded fish passage requirements.

Biodiversity and Habitat Stewardship

The generation of electricity can have an impact on biodiversity, either directly through habitat loss and fragmentation or indirectly through emissions to the environment. OPG is committed to managing its sites in a manner that strives to maintain significant natural areas and associated species of concern. OPG also works with its community partners to support regional ecosystems and biodiversity through science-based habitat stewardship. OPG's regional biodiversity program strategically funds and promotes efforts to protect and restore biodiversity in areas of Ontario where genetic, species or ecosystem diversity have been most impacted, and substantive threats remain. In 2017, OPG continued efforts to protect and restore habitat, promote biodiversity education and awareness, and help the recovery of species at risk. In November 2017, OPG's biodiversity program was recognized by the CEA with the 2017 Sustainable Electricity award for Commitment to Continuous Performance Improvement.

Climate Change Mitigation and Air Quality

OPG's operational and growth strategies support reductions in GHG emissions and improved air quality. After safely ending coal-fired generation in the province, OPG has become Ontario's largest clean energy provider, producing and selling electricity that is 99 percent free of GHG and smog-causing emissions. The elimination of coal-fired electricity production at OPG's generating stations resulted in coal being reduced from one-quarter of Ontario's energy supply mix in 2003 to zero in 2014.

OPG monitors and reports GHG emissions from its facilities in accordance with the regulatory requirements set out by Environment and Climate Change Canada and the MOECC. In 2016, the Government of Ontario passed the *Climate Change Mitigation and Low-Carbon Economy Act, 2016* and the associated *Cap and Trade Program Regulation*. The legislation provides the foundation for regulating GHG emissions in Ontario and includes a cap and trade program, with the first compliance period being from January 1, 2017 to December 31, 2020. The cap and trade program is a market mechanism intended to give Ontarians an

incentive to reduce GHG emissions by putting a price on carbon. The program requirements are expected to result in increased fuel costs for some OPG-owned and co-owned generating facilities. Fuel costs for these stations are generally recovered from the electricity market. With OPG's low GHG emitting fleet, this is not expected to have a material adverse financial impact on the Company. OPG has established the necessary processes to comply with the cap and trade program requirements.

OPG is monitoring actions being taken by the Government of Ontario and the Government of Canada to reduce GHG emission levels and transition to a low-carbon economy. In support of efforts to mitigate climate change, the Company continues to evaluate and implement plans to increase the generation capacity of its hydroelectric generating fleet, where economical, and invest in other low-carbon technologies. OPG also has a strategy to help position the Company as a leader in transportation electrification in the province. The strategy aims to leverage the Company's clean, reliable and cost-effective electricity to power transportation, capitalize on future commercial growth opportunities, and enhance the Company's social licence. OPG is pursuing initiatives to increase the use of electric vehicles within its operations, and is assessing vehicle grid integration and hydrogen applications for the transportation sector. Ontario's climate change plan aims for electric and hydrogen passenger vehicles to represent five percent of new vehicle sales in the province by 2020.

As part of its commitment to help de-carbonize Ontario's transportation sector, OPG is a founding sponsor of Plug'n Drive, a non-profit organization working to accelerate the adoption of electric vehicles and to maximize their environmental and economic benefits. In May 2017, Plug'n Drive announced the opening of the world's first experiential learning facility dedicated to electric vehicle education and awareness, with OPG sponsoring the Centre's training facility.

Radiological Emissions

Very low levels of radioactivity are released to air and water as a result of operating the reactors at OPG's nuclear generating stations. OPG maintains an effluent monitoring and control program to ensure radiological emissions are kept well below the release limits specified in the station operating licences. OPG also has environmental monitoring programs in the vicinity of the nuclear stations to ensure operations have no adverse impacts on human health and the environment. These programs are designed to assess impacts, demonstrate compliance with regulatory limits, validate the effectiveness of containment and effluent controls, and verify predictions made by environmental risk assessments. Results from the monitoring programs have confirmed OPG's radiological emissions are a small fraction of the regulatory release limits.

In June 2016 and August 2016, the CNSC released sampling results from its independent environmental monitoring program, which confirmed that the public and the environment around OPG's nuclear generating stations continued to be safe.

Further details are discussed under the heading, *Workplace Safety and Public Safety – Nuclear Radiation Safety.*

People and Culture

Workforce Resourcing Strategies

Electricity generation involves complex technologies that require highly skilled and trained workers, and a well trained and engaged workforce is fundamental to the achievement of OPG's strategic imperatives. The Company is focused on improving the capability of its workforce through leadership development, knowledge management, diversity and inclusion programs, and hiring in key areas. Ability to secure the right talent mix in order to effectively meet the Company's immediate and longer term business needs on a timely basis is supported through workforce planning, resourcing and on-boarding strategies, both to acquire external talent into the organization and to develop existing employees. The goal of resourcing strategies and workforce planning is to ensure that the Company's workforce is diverse and has the right skill set and capability for the safe and effective operation of the generating facilities and successful delivery

of major projects, including the Darlington Refurbishment. These strategies are being designed to take into account anticipated staffing requirements to the end of planned commercial operations of the Pickering GS, through to the end of the planned period to de-fuel, de-water and place the station in a safe state condition.

As part of the strategy to develop and engage employees and to build leadership talent in support of the Company's long-term success, OPG has an active succession planning program with a focus on accelerating development. This includes a company-wide high potential leadership development program for qualified internal candidates. This 14-month cross-functional, competitive-entry program is designed to identify and develop candidates for future leadership positions while they are relatively early in their careers. OPG also has a talent management monitoring process to proactively assess staffing risks, challenges and opportunities.

Many positions at OPG have significant educational prerequisites and rigorous requirements for continuous training and periodic requalification. In addition to maintaining its internal training infrastructure, OPG relies on partnerships with government agencies, other electrical industry partners, and educational institutions to meet the required level of qualification.

Effective January 1, 2017, OPG implemented an Executive Compensation Program that is compliant with *Ontario Regulation 304/16: Executive Compensation Framework*, introduced in September 2016. While the Province released two subsequent amendments, *Ontario Regulation 187/17* and *Ontario Regulation 400/17* in June 2017 and November 2017, respectively, OPG's Executive Compensation Program continues to be subject to the original regulation's requirements. The regulation sets out how all employers designated under the *Broader Public Sector Executive Compensation Act, 2014*, including OPG, must establish and post compensation programs for executives. The program must include the compensation philosophy, salary and performance-related pay caps, comparative analysis details, and a description of other elements of compensation. OPG's Executive Compensation Program is designed to provide compensation that is at the 50th percentile of the market and focused on at-risk, performance based pay. The program will better enable OPG to attract, align and retain the executive talent critical to delivering Shareholder and customer value, while ensuring continued safe and reliable operations. For further information, refer to the section, *Corporate Governance* under the heading, *Compensation.*

Employees

OPG's average number of full-time employees and average number of seasonal, casual construction and non-regular staff (Other Staff) in 2017 were as follows:

Business Segment	**Full-time Employees**	**Other Staff**
Regulated – Nuclear Generation [1]	7,360	1,432
Regulated – Hydroelectric	1,125	54
Contracted Generation Portfolio	531	49
Services, Trading, and Other Non-Generation [2]	96	7
Total	**9,111**	**1,541**

[1] Including employees associated with the Regulated – Nuclear Waste Management segment.
[2] The Fair Hydro Trust, a non-generation segment that is not subject to rate regulation, was established in December 2017. As of December 31, 2017 there were 3 full-time employees in the Fair Hydro Trust segment.

The majority of OPG's employees are represented by the PWU and The Society. The PWU includes most workers below the level of first line manager – from clerical staff to technicians and trades staff and station operators. The Society includes supervisors, professional engineers, scientists, and other professionals. Bargaining rights with the 19 craft unions that perform construction work at OPG's generating facilities in addition to the regular workforce are established either through the EPSCA or directly with OPG. EPSCA is a voluntary association of owners and contractors who perform work in the electrical power systems sector. The primary purpose of EPSCA is negotiating and administering collective agreements on behalf of employers performing work on what is now OPG property. Collective agreements between the Company and its construction unions are negotiated either directly or through EPSCA. OPG currently has 17

agreements through EPSCA and two direct trade agreements. The two direct trade agreements are with the Canadian Union of Skilled Workers and the Brick and Allied Craft Union.

Insurance

The principal types of discretionary insurance carried by OPG include directors' and officers' liability, excess commercial general liability, all risks property, boiler and machinery breakdown, including statutory boiler and pressure vessel inspections, and business interruption. In addition to providing coverage for OPG's non-nuclear facilities, this insurance applies to the conventional operations at OPG's nuclear generating stations. OPG also maintains nuclear property insurance, including nuclear boiler and machinery breakdown, for damage to the nuclear portions of its generating stations and for perils propagating from the nuclear to the conventional side of its assets. This coverage complements the conventional property insurance program.

OPG also purchases or requires contractors to purchase discretionary insurance for construction projects. For the Darlington Refurbishment project, the insurance coverage for the pre-requisite construction works was placed in 2013 and for refurbishment execution in 2016. The owner-controlled insurance program for the refurbishment consists of wrap-up liability, course of construction and marine transit insurance.

OPG purchases certain insurance coverage as required by statute, namely owned and leased motor vehicle liability, aviation liability (for drone operations) and nuclear energy liability insurance. The federal *Nuclear Liability and Compensation Act* (NLCA) that came into effect on January 1, 2017, and its predecessor legislation, the *Nuclear Liability Act* (NLA), impose absolute liability on a licensed operator of a nuclear generating station for any damage to property of, or injury to, the public arising from a nuclear incident, other than damage resulting from sabotage or acts of war. As such, the legislation protects all other persons from liability, including suppliers of nuclear fuel and components used in nuclear reactors.

The NLCA requires all operators of nuclear generating stations in Canada to maintain specified amounts of nuclear liability insurance purchased from a federal government approved insurer or other equivalent forms of financial security approved by the federal government. Under the NLCA, OPG is required to maintain an initial $650 million per incident of nuclear energy liability insurance for each of its nuclear installations as defined by the NLCA effective in 2017, for which there is no deductible amount, with successive annual increases to $750 million, $850 million, and $1 billion over the 2018-2020 period. The Pickering GS site and the Darlington GS site are considered to be two separate nuclear installations under the NLCA. OPG is also required to maintain $13 million per incident of nuclear energy liability insurance for the WWMF. OPG is not responsible for purchasing nuclear liability insurance for the Bruce nuclear generating stations. Previously, the NLA required OPG to maintain $75 million per incident of nuclear energy liability insurance for each of the Pickering GS site and the Darlington GS site and $6 million for the WWMF, purchased from a federal government approved insurer. OPG continues to maintain nuclear liability insurance or other forms of financial security that have been approved by the federal government equal to the required liability limits.

Under Part I of the NLCA, an operator is liable for all damages resulting from a nuclear incident. If, in the opinion of the Governor in Council, OPG's liability could exceed the specified insured amount in respect of a nuclear incident, or it would be in the public interest to do so, the Governor in Council shall proclaim Part II of the NLCA as applicable in respect of a nuclear incident. Under Part II of the NLCA, OPG's liability would be effectively limited to the amount of required abovementioned insurance, and the Governor in Council may authorize additional funds to be paid by the federal government as may be specified in an order.

RISK FACTORS

For details on risks faced by OPG, see *Risk Management* in the Company's 2017 year-end MD&A.

DIVIDENDS

The declaration and payment of dividends remains at the sole discretion of OPG's Board of Directors and is dependent on the results of OPG's operations, the Company's financial condition and cash requirements, securities legislation requirements, and other factors considered relevant by the Board of Directors in exercising its discretion and judgment on an ongoing basis. OPG did not declare or pay any dividends for the years 2015 to 2017.

There are no restrictions in the articles of the Company that could prevent the Company from paying dividends. However, the declaration and payment of dividends are subject to financial tests set forth in the OBCA.

DESCRIPTION OF CAPITAL STRUCTURE

The authorized share capital of OPG consists of an unlimited number of common shares (the voting shares of the Company) and Class A shares. As at December 31, 2017, OPG had 256,300,010 common shares issued and outstanding, all of which are owned directly by the Province at a stated value of $5,126 million. As at December 31, 2017, OPG had 12,217,616 Class A shares issued and outstanding, all of which are owned directly by the Province at a stated value of approximately $519 million. OPG is authorized to issue an unlimited number of common shares and Class A shares without nominal or par value. Holders of common shares are entitled to one vote per share at meetings of the shareholders of the Company and, along with Class A shares, to receive dividends if, as, and when declared by the Board of Directors of the Company. Holders of common shares and Class A shares would participate, pro rata to their holding of common shares, and Class A share, in any distribution of the assets of the Company upon its liquidation, dissolution, or winding up. Any issuance of new shares is subject to the consent of all of OPG's shareholders.

All of the Company's voting securities are held by the Province. Accordingly, the Company is controlled by the Province.

CREDIT RATINGS

DBRS Limited (DBRS) and S&P Global Ratings (S&P) provide credit ratings for commercial entities. A credit rating generally provides investors with an independent measure of credit quality of an issue of securities. Credit rating categories for long-term debt instruments range from highest credit quality (generally 'AAA') to default in payment (generally 'D').

In April 2017, DBRS re-affirmed the long-term credit rating on OPG's debt at 'A (low)' and the commercial paper rating at 'R-1 (low)', each with a stable outlook. In July 2017, S&P re-affirmed OPG's long-term credit rating at BBB+ with a stable outlook. On July 7, 2015, S&P lowered OPG's long-term corporate credit rating from 'A-' to 'BBB+' with a stable outlook. S&P's rating action followed its July 6, 2015 downgrade to the Province's rating from 'AA-' to 'A+'. The link between the Province and OPG through ownership and financial support may impact OPG's credit rating. S&P's commercial paper rating for OPG is 'A-1 (low)'.

Long-term debt instruments that are rated in the 'A' category by DBRS are considered to be of good credit quality. The capacity for the payment of financial obligations by the obligor of such instruments is considered to be substantial, but of lesser credit quality than higher-rated entities. Entities in the 'A' category may be vulnerable to future events, but qualifying negative factors are considered manageable. The addition of a "high" or "low" modifier indicates relative standing within the rating category.

A 'BBB' rating category by S&P for long-term debt instruments means that the obligor has adequate capacity to meet its financial commitments, but is considered more subject to adverse economic conditions than higher-rated entities. The addition of a plus '+' or minus '-' designation after a rating indicates the relative standing within a particular rating category.

DBRS's commercial paper credit rating scale ranges from 'R-1(high)' to 'D', which represents the highest to lowest quality of such securities rated. The rating of 'R-1(low)' is the third highest and is considered to be of good credit quality. S&P's Canadian commercial paper rating scale ranges from 'A-1 (high)' to 'D', which represents the highest to lowest quality of such securities rated. The rating of 'A-1 (low)' is the third highest and is considered to be satisfactory.
There can be no assurance that a credit rating will remain in effect for any given period of time or that a credit rating will not be lowered, withdrawn or revised by either or both rating agencies if, in their judgment, circumstances so warrant. The rating of any securities is not a recommendation to buy, sell or hold such securities, and such ratings do not comment as to market price or suitability for a particular investor.

During the past two years, OPG has made payments to DBRS and S&P's credit rating agencies for their credit rating services and for other services. OPG reasonably expects such payments will continue in the future for the services acquired.

MARKET FOR SECURITIES

In October 2017, OPG issued Series 1 Notes with a coupon rate of 3.315 percent for a principal amount of $500 million are currently outstanding and are not listed on any exchange or similar market for securities. The Notes are due in 2027.

CORPORATE GOVERNANCE

National Instrument 58-101 *Disclosure of Corporate Governance Practices* (NI 58-101), has been implemented by Canadian securities regulatory authorities to provide greater transparency for the marketplace regarding issuers' corporate governance practices. OPG's corporate governance practices align with NI 58-101 and National Policy 58-201 *Corporate Governance Guidelines.* In addition, OPG has reviewed its governance practices against the principles discussed in the 2013 Report on Building High Performance Boards issued by the Canadian Coalition for Good Governance and concluded that OPG compares favourably to those principles that apply to OPG.

Information with respect to OPG's Board of Directors is as follows:

Board of Directors

OPG's Board of Directors (Board) is made up of 14 individuals with the following capabilities:

- managing large businesses;
- managing and operating nuclear stations;
- understanding of the Canadian nuclear environment;
- engineering and/or project management, including large infrastructure project management;
- managing capital intensive companies;
- knowledge and expertise in mergers and acquisitions;
- overseeing regulatory, government and public relations;
- human resources management;
- financial, investment, legal and corporate governance expertise;
- knowledge of information technology/cybersecurity;
- knowledge of Indigenous communities; and
- stakeholder management.

The Board exercises its independent supervision over management as follows: the majority of members of the Board are independent of the Company; meetings of the Board are held at least five times a year; a formal Charter for the Board and for each Board committee has been adopted and the charters are reviewed annually; the Board and each Board committee is chaired by an independent Director; and a portion of each Board and Board committee meeting is reserved for independent Directors to meet without management present.

OPG has a written position description for the Chief Executive Officer (CEO). This position is accountable to the Board for: ensuring a culture of integrity and ethical conduct; increasing Shareholder value; defining and executing a corporate strategy, including a sustainable business model that will service the long-term power generation needs of the province; and providing a standard of leadership that will achieve operational excellence with respect to matters of safety, stakeholder relationships, financial performance, asset reliability, and health, environmental and regulatory compliance. In addition, the Board delineates the President and CEO role and responsibilities through the By-laws, the Board Charter, the Board policies, and the corporate and CEO annual goals and objectives. The Board sets, and monitors performance against, annual corporate and CEO targets and objectives.

Director Independence

On an annual basis, the Compensation, Leadership and Governance Committee of the Board reviews the disclosures made by Directors in the annual Director Questionnaire and reviews each disclosed affiliation's relationship with OPG in order to determine whether the Director is (or remains) independent. The Compensation, Leadership and Governance Committee reports on its review to the Board.

Based on the meaning of Independence in Section 1.4 of National Instrument 52-110 *Audit Committees* (NI 52-110) and a review of the applicable factual circumstances against this standard, the Compensation, Leadership and Governance Committee has determined that all Directors listed are independent, except for Jeffrey Lyash, who is considered to have a material relationship with OPG by virtue of his position as President and CEO of OPG.

The Board has a Board of Directors Conflict of Interest Policy and Procedure that governs the disclosure and mitigation of Director conflicts or potential conflicts of interest and has adopted an annual process of written disclosure by Directors in order to:

(i) identify potential conflicts of interest for the purposes of complying with the Board of Directors Conflict of Interest Policy and the OBCA;
(ii) validate the Directors' independence and financial literacy for the purposes of complying with securities regulations related to boards of directors and audit committees; and
(iii) satisfy other disclosures and regulatory filings.

To further minimize potential conflicts of interest, the Board has a policy on interlocking directorships. This policy states that no more than two OPG Directors may sit on a board of directors of another reporting issuer at the same time. Directors must confirm that they are in compliance with OPG's policy on interlocking directorships when disclosing to the Board Chair appointments to other boards of directors.

Strategic Planning

OPG's Board holds an annual strategy session and devotes a significant portion of each regular Board meeting to discussion of strategic matters. Management is responsible for developing the strategy and presenting it to the Board for discussion.

In 2017, the Board received reports on key strategic issues, risks, competitive developments, and corporate opportunities facing the Company. Management ensures that the key strategic elements are incorporated into OPG's annual budget and business plan, which are reviewed and approved by the Board. The Board also periodically receives briefings from external advisors on broad energy industry developments and/or special strategic matters.

Overseeing the Management of Risk

The Board oversees OPG's approach of identifying, reporting and mitigating the risks that could significantly impact the Company's capacity to achieve its long-term strategic objectives, as well as specific business plan objectives. To fulfill its risk oversight responsibilities, the Board has established an Enterprise Risk Management Policy and an Audit and Risk Committee, comprised of independent Directors. The

committee's mandate includes oversight of the Enterprise Risk Management (ERM) framework that management uses to manage the Company's risk profile. The ERM framework assists the Board in understanding how risks may affect the Company and how they are being addressed by management. The Audit and Risk Committee receives quarterly reports from OPG's Chief Risk and Audit Executive (CRAE) on enterprise-wide risks.

Through the Compensation, Leadership and Governance Committee, the Board also monitors the risks associated with the executive compensation program, to preclude the Company's decision-makers from taking excessive risk in order to achieve incentives under the compensation plans. The CRAE and Senior Vice President, People & Culture and Chief Ethics Officer jointly review the executive compensation framework on an annual basis to identify any potential for unintended risk-taking. The CRAE and Senior Vice President, People & Culture and Chief Ethics Officer provide an annual joint report to the Compensation, Leadership and Governance Committee on the results of their review.

Directors

The following tables set forth the name, age, municipality of residence, position with the Company and principal occupation of each of the Directors of the Company as of March 8, 2018. Each Director holds office until he or she resigns or a successor is elected or appointed. For a discussion of the Board Committee structure, refer to the heading, *Committees of the Board of Directors*.

Bernard Lord
Age: 52
Moncton, New Brunswick, Canada

Bernard Lord was appointed Board Chair for Ontario Power Generation on April 1, 2014. Mr. Lord is the CEO of Médavie, a not-for-profit Canadian medical care insurance company headquartered in Moncton, New Brunswick.

Mr. Lord earned a bachelor's degree with a major in economics as well as a bachelor's degree in common law from l'Université de Moncton. He has also received honorary doctorate degrees from University of New Brunswick, l'Université de Moncton and Saint Thomas University. He was admitted to the New Brunswick Law Society in 1993 and was appointed as Queen's Counsel in 2011.

Mr. Lord was the CEO of the Canadian Wireless and Telecommunications Association from October 2008 until August 2016. He also served on several other boards of directors.

In 1999, Mr. Lord became one of Canada's youngest Premiers at the age of 33. His majority government was re-elected in 2003 and he served as Premier of New Brunswick until October 2006. He was elected four times as a Member of the New Brunswick Legislative Assembly.

Mr. Lord's government introduced several new initiatives to support the development of natural resources while also protecting the environment, including a new energy policy that lead to the restructuring of NB Power and the refurbishment of the Point Lepreau nuclear generating station.

During Mr. Lord's terms as Premier, New Brunswick saw the lowest unemployment rate in 30 years and tax cuts each year, combined with balanced budgets and debt reduction. His government made record investments in health care and education while strengthening local democracy and modernizing the Official Languages Act.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since November 2013) *****	8 of 8	100%
Special Committee (since March 2017)	14 of 15	93%
The Board Chair is not a member of any standing Committee. The Board Chair attends all Committee meetings.	18 of 18	100%

Principal Occupation: CEO of Médavie

Board Memberships for other Reporting Issuers: None

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

*Chair

Jeffrey Lyash
Age: 56
Toronto, Ontario, Canada

Jeff Lyash is the President and CEO of OPG. Mr. Lyash was formerly the president of CB&I Power, a position he held from 2013 to 2015, where he was responsible for a full range of engineering, procurement and construction of multi-billion dollar electrical generation projects in both domestic and international markets. He also provided operating plant services for nuclear, coal, gas, oil and renewable generation.

Prior to joining CB&I in 2013, Mr. Lyash served as Executive Vice President of Energy Supply for Duke/Progress Energy from 2008 to 2012. With Duke Energy, he led engineering, maintenance and operations of the company's 42,000-megawatt generation fleet, fuel procurement, power trading, major projects and construction, environmental programs, and health and safety programs.

Before the merger of Progress Energy and Duke Energy, Mr. Lyash served as Executive Vice President of Energy Supply for Progress Energy. In this role, he oversaw Progress Energy's diverse 22,000-megawatt fleet of generating resources including nuclear, coal, oil, natural gas and hydroelectric stations. In addition, he was responsible for generating fleet fuel procurement and power trading operations.

Mr. Lyash began his career in the utility industry in 1981, joining Progress Energy in 1993. Before assuming the role of Executive Vice President of Energy Supply, he served as Executive Vice President of Corporate Development, President and Chief Executive Officer of Progress Energy Florida, Senior Vice President of Energy Delivery Florida, and Vice President of Transmission. He also held a wide range of management and executive roles in Progress Energy's nuclear program, including Operations Manager, Engineering Manager, Plant Manager, and Director of Site Operations.

Before joining Progress Energy, Mr. Lyash worked for the U.S. Nuclear Regulatory Commission (NRC) in a number of senior technical and management positions throughout the northeast United States and in Washington, D.C, receiving the NRC Meritorious Service Award in 1987.

Mr. Lyash earned a Bachelor's Degree in Mechanical Engineering from Drexel University, and was honored with the Drexel University Distinguished Alumnus Award in 2009. He has held a Senior Reactor Operator License from the NRC, and is a graduate of the U.S. Office of Personnel Management Executive Training Program and the Duke Fuqua School of Business Advanced Management Program.

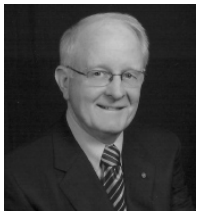
2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since August 2015)	8 of 8	100%
The President and CEO attends all Committee meetings, excluding independent Director in-camera meetings/sessions.	18 of 18	100%

Principal Occupation: President & Chief Executive Officer, Ontario Power Generation Inc.

Board Memberships for other Reporting Issuers: None

Independence from OPG: Not Independent

Interlocking Directorships on Boards of other Reporting Issuers: None



William Coley
Age: 74
Charlotte, North Carolina, U.S.A

Bill Coley served as Chief Executive of British Energy from 2005 to 2009 when he retired following the successful combination of British Energy and EDF Energy. He was President of Duke Power from 1997 until his retirement in February 2003, holding various officer level positions in engineering, operations and senior management during his 37-year career with the company.

Mr. Coley is a director of E.R. Jahna Industries. He also served on the WANO Fukushima Commission

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since January 2013)	8 of 8	100%
Compensation, Leadership and Governance Committee (since February 2016)	5 of 5	100%
Generation Oversight Committee (since February 2016)	4 of 4	100%
Darlington Refurbishment Committee (since May 2015)	4 of 4	100%
Special Committee (since March 2017)	15 of 15	100%

Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: None

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

Elisabeth (Lisa) DeMarco
Age: 50
Toronto, Ontario Canada

Lisa DeMarco is a senior partner at DeMarco Allan LLP with over two decades of experience in law, regulation, policy, and advocacy relating to energy and climate change. Ms. DeMarco was previously a partner at Macleod Dixon LLP from 2002 to 2012, partner at Norton Rose Canada LLP from 2012 to 2013 and partner at Norton Rose Fulbright LLP from 2013 to 2014. She represents several governments and leading energy companies in a wide variety of natural gas, electricity, pipeline and energy storage matters before various regulatory agencies, including the OEB and the National Energy Board. She has been an adjunct professor at Osgoode Hall Law School, is a guest lecturer at a number of law schools and presents regularly.

Ms. DeMarco also assists leading Canadian energy companies and Indigenous business organizations on domestic and overseas power project development, renewable power projects, alternative fuel projects, cleantech development and finance, energy storage, carbon capture and storage, corporate social responsibility, environmental disclosure, clean energy finance, and sustainable business strategy.

She is ranked by Chambers Global as one of the world's leading climate change lawyers and regularly attends and advises on related United Nations negotiations. She is ranked and repeatedly recommended by LEXpert, Expert Guide, International Who's Who, and Chambers Canada as a leading energy (oil, gas, and electricity) and environment lawyer. Ms. DeMarco has worked for multilateral development banks and energy companies on deals and projects in India, Brazil, Sri Lanka, Thailand, Argentina, Chile, Ireland, Africa, Mexico, China, Russia, California, Alberta, Ontario, Nova Scotia, British Columbia, Saskatchewan, Prince Edward Island and Québec. She plays an ongoing and active role in the development and drafting of energy and greenhouse gas emissions policy, regulation, and law throughout Canada, and in various countries around the world. She was also lead counsel on all aspects of the successful sale of an Ontario power distribution company to Hydro One. Lisa was an appointed member of Ontario Premier's Clean Energy Task Force and Climate Action Group.

Ms. DeMarco is a member of theBoard of Directors of the Advanced Energy Centre at MaRS, and Ontario Power Generation. She is a graduate of the University of Western Ontario (BSc Hon. – 1990), the University of Toronto (MSc. – 1992), Osgoode Hall Law School, York University (LLB – 1995) and the Vermont Law School (MSEL, summa cum laude – 1995) and is called to the bar in England and Ontario.

2017 Board/Committee Membership:	**2017 Attendance**	
Board (since April 2014)	8 of 8	100%
Audit and Risk Committee (since February 2016)	5 of 5	100%
Generation Oversight Committee (since February 2016)	4 of 4	100%
Special Committee (since March 2017)	15 of 15	100%

Principal Occupation: Senior Partner, DeMarco Allan LLP

Board Memberships for other Reporting Issuers: None

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

Jean Paul (JP) Gladu
Age: 44
Toronto, Ontario, Canada

JP Gladu is currently the President and CEO of the Canadian Council for Aboriginal Business (CCAB) based in Toronto. Anishinaabe from Thunder Bay, Mr. Gladu is a member of Bingwi Neyaashi Anishinaabek located on the eastern shores of Lake Nipigon. Mr. Gladu has over two decades of experience in the natural resource sector including work with Aboriginal communities and organizations, environmental non-government organizations, industry and governments from across Canada, including involvement in business development for the Bingwi Neyaashi Anishinaabek Nation from 2009 to 2012. He has produced a number of publications related to Aboriginal issues including: forest certification, Native values collection, biofuel opportunities, First Nation community land use plans, criteria and indicators for sustainable forestry, and cedar product development.

Mr. Gladu holds a Forest Technician Diploma from the Sault College of Applied Arts and Technology, a Bachelor of Science degree in forestry from Northern Arizona University, and an Executive Masters of Business Administration from Queens University in Kingston. In 2014, he was a recipient of the Community Service Award – Transformation Awards from Diversity Magazine. Mr. Gladu was nominated for the 2013 Premier's Award for Outstanding Ontario College Graduates, was recognized as one of five Northern Leaders in 2012 by Northern Ontario Business and was elected Class President of the 2012 Queens Executive Masters of Business Administration.

Mr. Gladu currently serves on the Canadian Electricity Associations' Public Advisory Panel, Noront Resources and Chancellor of St, Paul's University Board of Governors. He has also held previous board positions with Colleges and Institutes Canada (previously the Association of Canadian Community Colleges), Northern Policy Institute, Canadian Foundation for Economic Education boards of directors, Centre for Research and Innovation in the Bio-Economy, Papasay Management Corporation, and a board member of the Canadian Bioenergy Association. He also held advisory positions with the Canadian Association of Petroleum Producers Renewable Clean Energy Committee and the Ontario Provincial Forest Policy Committee.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since November 2015)	6 of 8	75%
Compensation, Leadership and Governance Committee (since February 2016)	5 of 5	100%
Generation Oversight Committee (since February 2016)	3 of 4	75%

Principal Occupation: President and CEO, Canadian Council for Aboriginal Business

Board Memberships for other Reporting Issuers: Noront Resources Ltd. *(TSX)*

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

John Herron
Age: 64
Punta Gorda, Florida, U.S.A.

John Herron retired from Entergy in April 2013 where he was the President, CEO and Chief Nuclear Officer of Entergy Nuclear, with responsibility for Entergy's nuclear plants located in New York, Massachusetts, Vermont, Michigan, Louisiana, Mississippi and Arkansas as well as the company's management service to the Cooper Nuclear Station for the state of Nebraska.

He previously served as Entergy's Senior Vice President for Nuclear Operations handling the operational side of fleet management. Mr. Herron joined Entergy in February 2001 as Vice President, Operations at the Waterford 3 Nuclear Station in Killona, Louisiana. He then moved to New York as the Senior Vice President of the Indian Point Energy Center in February 2002.

Mr. Herron began his career in nuclear operations in 1979 at Vermont Yankee Nuclear Power Corporation. His positions there included technical services superintendent, operations manager, technical programs manager, shift supervisor, and supervisory control room operator. In 1994, he moved to Brownville, Nebraska to become plant manager at Nebraska Public Power District's Cooper Nuclear Station.

Mr. Herron then joined the Tennessee Valley Authority as plant manager at Sequoyah Nuclear Plant in Soddy-Daisy, Tennessee, from October 1996 through July 1999. From July 1999 to February 2001, Mr. Herron served as site Vice President at TVA's Browns Ferry Nuclear Plant.

Prior to his career in utilities, Mr. Herron served in the U.S. Navy from 1972 to 1978. He was attached to the USS Tullibee and the S1C NPTU Windsor, where he was an instructor at the Nuclear Submarine Prototype School.

Mr. Herron holds a bachelor's degree in Business Management from Franklin Pierce College in Rindge, New Hampshire. He also attended the Advanced Management Program at the Harvard Business School in May 2005.

Mr. Herron currently serves on the board of directors for Duke Energy. He also served on the board of directors for the Institute of Nuclear Power Operations and on the Nuclear Strategic Issues Advisory Committee of the Nuclear Energy Institute. In the aftermath of Japan's 2011 earthquake, he was named to the WANO Post-Fukushima Commission and the U.S. nuclear industry's Fukushima response steering committee.

2017 Board/Committee Membership:	**2017 Attendance**	
Board (since November 2013)	8 of 8	100%
Generation Oversight Committee* (since February 2016)	4 of 4	100%
Darlington Refurbishment Committee (since May 2015)	4 of 4	100%

Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: Duke Energy (NYSE)

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

* Chair of Committee

Ani Hotoyan-Joly
Age: 56
Markham, Ontario, Canada

Ani Hotoyan-Joly is currently Chief Financial Officer and Corporate Secretary of Coventree Inc. Prior to Coventree, she was V.P. Finance and Chief Financial Officer at Swiss Reinsurance Company Canada (P&C) and prior to that held senior positions at Zurich Canada. Ms. Hotoyan-Joly is a member of the Board of Directors of Women's College Hospital and is a member of the Executive Committee and Chair of the Governance and Nominations Committee. She is currently a member of the Executive Board of Armenian Relief Society's Roubina (Toronto) Chapter and was the Past Chair of A.R.S. Armenian Private School's Board of Trustees.

Ms. Hotoyan-Joly is a Chartered Professional Accountant and Chartered Accountant and holds a Bachelor of Commerce degree from the University of Toronto and the ICD.D designation from the Institute of Corporate Directors. She was elected as a 2016 Diversity 50 Candidate by the Canadian Board Diversity Council.

2017 Board/Committee Membership:	**2017 Attendance**	
Board (since March 2017)	6 of 6	100%
Audit and Risk Committee (since March 2017)	4 of 4	100%
Compensation, Leadership and Governance Committee (since March 2017)	4 of 4	100%

Principal Occupation: Chief Financial Officer and Corporate Secretary, Coventree Inc.

Board Memberships for other Reporting Issuers: None

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

Wendy Kei
Age: 50
Toronto, Ontario, Canada

Ms. Wendy Kei currently serves on the Board of Guyana Goldfields, Inc., as the Chair of the Audit Committee, a member of the Human Resources & Compensation Committee and a member of the Corporate Governance & Nominating Committee. She is an accomplished Finance Executive with over 25 years of business experience in a variety of industries. For the past 14 years, Ms. Kei has been working within the mining industry and brings a strong focus on corporate governance, financial and risk management and a strong expertise in executing complex mergers and acquisitions.

Ms. Kei is a Chartered Professional Accountant and Chartered Accountant and previously served as Chief Financial Officer of Dominion Diamond Corporation (formerly Harry Winston Diamond Corporation and Aber Diamond Corporation).

Ms. Kei is a member of the Chartered Professional Accountants of Ontario, and holds a Bachelor of Mathematics from the University of Waterloo. Ms. Kei was selected as a Diversity 50 2016 Candidate by the Canadian Board Diversity Council.

2017 Board/Committee Membership:	**2017 Attendance**	
Board (since March 2017)	6 of 6	100%
Audit and Risk Committee (since March 2017)	4 of 4	100%
Generation Oversight Committee (since March 2017)	3 of 3	100%

Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: Guyana Goldfields Inc. *(TSX)*

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

M. George Lewis
Age: 57
Toronto, Ontario, Canada

From February 2007 until November 2015, George Lewis was a member of RBC's Group Executive, one of eight executives responsible for setting the overall strategic direction for Royal Bank of Canada, Canada's largest bank. In that capacity, he served as Group Head of RBC Wealth Management from 2007 and RBC Insurance from 2012. As Group Head, Wealth Management, Mr. Lewis led the RBC businesses that serve the wealth management needs of affluent clients globally, and units that provide asset management and trust products. He was also Chairman of RBC Global Asset Management Inc.

From July 2000 to May 2008, Mr. Lewis was Chief Executive Officer of RBC Global Asset Management, which under his leadership became Canada's largest single mutual-fund family (RBC Funds) and one of Canada's largest asset management firms. He previously served as Head of Wealth Management for the Canadian Personal and Business segment and, from 2003 to 2006, was Head of all banking and investment products for RBC's Canadian Business.

From 1998 to 2000, Mr. Lewis was Managing Director, Head of Institutional Equity with RBC Capital Markets, responsible for global institutional-equity sales, trading and research. He was previously a top-rated equity analyst and Director of Research. He began his career with RBC in 1986, in the investment banking division of RBC Capital Markets.

Mr. Lewis has extensive experience in the investment industry, has a Masters of Business Administration degree with distinction from Harvard University and a Bachelor of Commerce degree with high distinction from Trinity College at the University of Toronto. He is also a Chartered Financial Analyst and an FCA/FCPA and has been certified by the Institute of Corporate Directors.

Mr. Lewis serves on the board of directors of Enbridge Income Fund Holdings Inc., the Canadian Film Centre and the Anglican Diocese of Toronto Foundation. He is a current member and past chair of the Bishop's Company of the Anglican Diocese of Toronto, as well as a patron and member of the Cabinet of the United Way of Toronto and York Region. Mr. Lewis also serves as the Honorary Colonel Commandant of the Royal Canadian Chaplain Service of the Canadian Armed Forces.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since February 2005)	8 of 8	100%
Audit and Risk Committee* (since February 2016)	5 of 5	100%
Compensation, Leadership and Governance Committee (since February 2016)	5 of 5	100%
Special Committee* (since March 2017)	15 of 15	100%

Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: Enbridge Income Fund Holdings Inc. *(TSX)*

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

* Chair of Committee

Margaret (Peggy) Mulligan
Age: 59
Cameron, Ontario, Canada

Peggy Mulligan was the Executive Vice President and Chief Financial Officer, Valeant Pharmaceuticals International, Inc. until December 2010. Prior to this, she was a Principal at Priiva Consulting, and before that she served as Executive Vice President and Chief Financial Officer of Linamar Corporation. Prior to Linamar, Mrs. Mulligan was with the Bank of Nova Scotia for eleven years as Executive Vice President, Systems and Operations and Senior Vice President, Audit and Chief Inspector. Before joining Scotiabank, she was an Audit Partner with PricewaterhouseCoopers in Toronto. She holds a B. Math (Honours) from the University of Waterloo and was named a Fellow of the Institute of Chartered Professional Accountants of Ontario in 2003.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since December 2005)	7 of 8	88%
Compensation and Leadership and Governance Committee* (since February 2016)	5 of 5	100%
Darlington Refurbishment Committee (since May 2015)	4 of 4	100%
Special Committee (since March 2017)	14 of 15	93%

Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: Canadian Western Bank (*TSX),* ClearStream Energy Services Inc. *(TSX)* (*previously Tuckamore Capital*)

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

* Chair of Committee

Yezdi Pavri
Age: 68
North York, Ontario, Canada

Yezdi Pavri retired as Vice Chairman of Deloitte Canada in June 2012 after a career of more than 30 years. Prior to being named Vice Chairman, Mr. Pavri was a member of the firm's national Management Committee for over ten years and was the Managing Partner of the Toronto practice since June 2004. He founded Deloitte's national Enterprise Risk Services practice in 1990 and led it for 15 years. He was a founding member of the global firm's India Steering Committee and co-chaired the firm's first Diversity and Inclusion Committee.

Mr. Pavri holds a Bachelor's degree in Aeronautical Engineering from the Indian Institute of Technology in Bombay and a Master's degree in Thermal Power Engineering from Imperial College in London. He is a Fellow of the Chartered Professional Accountants of Ontario.

Mr. Pavri currently serves on the boards of ICICI Bank of Canada, Enterra Holdings Limited (the global parent of Golder Associates) and MD Financial Services, and is a past member of the board of directors of Hydro One. Mr. Pavri is also the immediate past chairman of the board of trustees of United Way Toronto.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since September 2015)	8 of 8	100%
Audit and Risk Committee (February 2016)	5 of 5	100%
Compensation, Leadership and Governance Committee (since February 2016)	5 of 5	100%
Special Committee (since March 2017)	15 of 15	100%

Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: None

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

Gerry Phillips
Age: 77
Ajax, Ontario, Canada

Gerry Phillips was the Member of Provincial Parliament in the Legislative Assembly of Ontario for the east Toronto riding of Scarborough-Agincourt from 1987 to 2011. He served in six cabinet portfolios, including twice as Ontario Minister of Energy, where he was OPG's Shareholder from 2007 to 2008 and again on an interim basis from November 2009 to January 2010, as well as, Minister responsible for Securities Regulation in Ontario. He was also the Chair of the Management Board of Cabinet from 2008 to 2011 and the Chair of the Select Committee on the TMX Transaction in 2011.

Before entering public life, Mr. Phillips graduated from the University of Western Ontario's School of Business and worked in the marketing department of Procter and Gamble. In 1970, he joined the consulting firm of Canadian Marketing Associates and became President in 1977. He later founded two successful spin-off companies – the Sales Development Group in 1979 and the Retail Resource Group in 1982. By 1987, he was Chair of all three companies, with a combined workforce of approximately 300.

Mr. Phillips has an Honours B.A. from the Western School of Business.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since January 2013)	8 of 8	100%
Audit and Risk Committee (since February 2016)	5 of 5	100%
Darlington Refurbishment Committee (since May 2015)	4 of 4	100%

Principal Occupation: Retired

Board Memberships for other Reporting Issuers: None

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

Jim Reinsch
Age: 74
Frederick, Maryland, U.S.A.

Jim Reinsch retired from the Bechtel Group where he was Senior Vice President and Partner, and past President of Bechtel Nuclear. In this role, he was responsible for the global profit/loss, customer relations, operations, project management, marketing and business development of Bechtel's three nuclear business segments: nuclear operating plant services, steam generator replacement, and operations of Bechtel's global nuclear activities. During his 40 years with Bechtel, he also presided over Bechtel Canada, and managed large regions in the United States and Asia. He served as the President of the American Nuclear Society, and was a member of the Nuclear Energy Institute as well as a member of their Executive Committee. Mr. Reinsch is also a member of several international nuclear energy organizations, including the WANO and the World Nuclear Association.

Mr. Reinsch holds a Bachelor of Science degree from the University of Maryland.

Mr. Reinsch currently serves on the board of directors for Frederick Memorial Hospital and the Hood College Board of Trustees, and is a past board member of Duke Energy and the Smithsonian National Portrait Gallery. Additionally, he serves on the Emirate Nuclear Energy Corporation's committee on nuclear power which reports to the board of directors, and is a member of the international advisory board of Terrestrial Power.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since August 2015)	7 of 8	88%
Generation Oversight Committee (since February 2016)	4 of 4	100%
Darlington Refurbishment Committee* (since August 2015)	4 of 4	100%

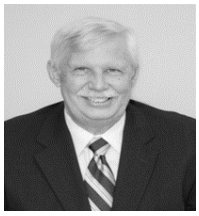
Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: None

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

*Chair of Committee



James Sheppard
Age: 69
Toronto, Ontario, Canada

Mr. Sheppard serves as an Independent Consultant. Mr. Sheppard served as Interim Senior Vice President for Southern California Edison Company and served as its Interim Chief Nuclear Officer from September 2010 to December 9, 2010. From 1993 to 2009, he held several senior positions associated with the South Texas Project nuclear power plant, including Chairman, President and Chief Executive Officer of STP Nuclear Operating Company, which operated the facility for its three owners. He served as Executive Officer of South Texas Project Electric Generating Station. He served as an executive at STP for ten years, he held the positions of Vice President and Assistant to the President and Chief Executive Officer; Vice President of Engineering and Technical Services; Vice President of Business Systems; Assistant to the executive vice president; and General Manager of Licensing. He has been an Independent Director at Xcel Energy Inc. since March 2011.

Mr. Sheppard holds a bachelor of science degree in aerospace engineering from the U.S. Naval Academy and a master's degree in business administration from the Duke University.

2017 Board/Committee Membership:	**2017 Attendance:**	
Board (since March 2017)	6 of 6	100%
Darlington Refurbishment Committee (since March 2017)	3 of 3	100%
Generation Oversight Committee (since March 2017)	3 of 3	100%

Principal Occupation: Corporate Director

Board Memberships for other Reporting Issuers: Xcel Energy Inc. *(NYSE)*

Independence from OPG: Independent

Interlocking Directorships on Boards of other Reporting Issuers: None

Nicole Boivin served as a Director from April 2014 to March 2017 and was a member of the Compensation, Leadership and Governance Committee and the Darlington Refurbishment Committee. Brendan Hawley was a Director from April 2014 to March 2017 and was a member of the Audit and Risk Committee and Darlington Refurbishment Committee. Ira Kagan was a Director from April 2014 to March 2017 and served as a member of the Audit and Risk Committee and the Generation Oversight Committee.

Orientation and Continuing Education

The Compensation, Leadership and Governance Committee is responsible for reviewing and recommending appropriate orientation programs for new Directors. New directors are provided relevant documentation relating to OPG's governance practices and policies and to its business. Directors attend plant tours of OPG generating facilities, where they also receive comprehensive introductory briefings from OPG senior executives on OPG's operations and business activities.

The Board supports and sponsors the continuing education of OPG Directors, both in the business of OPG and in their duties as Directors. This includes plant tours of OPG's major facilities, site visits to projects with OPG's Indigenous business partners, and special presentations by internal and external experts on topical business-related issues or on specific aspects of OPG's operations. In 2017, such topics included pension plan governance, the cap and trade program and OPG's dam safety program. Directors also are provided with articles and publications on current topics of interest. Board members have full access to all Board and Board committee materials and records. OPG has developed a Director Governance Handbook, which provides Directors with information necessary to fulfill their roles, including director duties and obligations under the OBCA, and relevant corporate policies and procedures. OPG also sponsors Director attendance at the Institute of Corporate Directors' Director Education Program, or equivalent, and sponsors attendance at the Goizueta Director program for members of Board committees responsible for oversight of nuclear operations.

Ethical Business Conduct

The Board has adopted a policy for ethical business behaviour and a Code of Business Conduct. The mandate of the Audit and Risk Committee requires that it receive regular reports throughout the year on the Code of Business Conduct in order to satisfy itself that appropriate code of conduct and compliance programs are in place and are being enforced, and remedial action is being taken. The Audit and Risk Committee receives quarterly reports from management on the Code of Business Conduct (including reports on any substantiated cases of fraud) and the disposition of cases including disciplinary action, as well as an annual report on the Code of Business Conduct and a report on the annual review of the Board policy. A copy of the Code of Business Conduct can be found on SEDAR at www.sedar.com and also is available on the Company's website at www.opg.com. The Audit and Risk Committee has procedures for the receipt, retention and treatment of complaints received pertaining to accounting, internal controls or auditing matters, and for the confidential anonymous submission by employees concerning such matters.

Nomination of Directors

The Compensation, Leadership and Governance Committee, which is comprised of six independent Directors within the meaning of NI 52-110, is responsible for conducting an annual review of the OPG Board's principles and systems of governance, and oversight of annual Board, Board committee and Director evaluations. The Compensation, Leadership and Governance Committee recommends candidates to the Shareholder. Nominations of Directors by the Shareholder also may be considered by the Compensation, Leadership and Governance Committee. When considering a potential candidate, the committee considers the qualities, experience, and skills that the Board, as a whole, should have in light of the business opportunities and risks facing OPG. The attributes the Compensation, Leadership and Governance Committee considers in a candidate include integrity, business judgment and experience, diversity, professional expertise, independence from management, financial literacy, and communication skills, as well as sufficient time available to fulfill his or her obligations as a Board member. The Board's policy on diversity is to interview a diverse candidate for every vacancy on the Board. OPG defines diversity to include: women, aboriginal peoples, people with disabilities, and visible minorities. These four

enumerated groups mirror the four enumerated groups in the definition of "designated groups" in the federal *Employment Equity Act*.

From time to time, the Compensation, Leadership and Governance Committee may engage outside advisors to assist in identifying potential candidates.

Director Tenure/Board Renewal

The OPG Board Charter guideline for board tenure is 10 to 15 years. When considering board renewal, the Compensation, Leadership and Governance Committee regularly reviews the OPG Board skills profile. The Board maintains an "evergreen list" of potential Board candidates. From time to time, the committee makes recommendations to add skills to the Board that reflect OPG's business opportunities and risks.

Diversity in Leadership

Board of Directors

As noted under the heading, *Nomination of Directors*, the Compensation, Leadership and Governance Committee interviews a diverse candidate for every vacancy on the Board, where diversity is defined as: women, aboriginal peoples, people with disabilities, and visible minorities. The Board has signed on to the Catalyst Accord, set a target for "diverse" representation on the Board of 50 percent, including 40 percent women by 2019 and adopted a target of 25 percent women on the Board by 2017. In 2017, three members were added to the Board, two of whom meet the diversity definition. As of the date of this AIF, overall diversity of the Board is at 50 percent. Representation of women on the Board is 29 percent (four Directors) as of the date of this AIF.

Senior Management

OPG strives to create a workforce that reflects diverse populations of the communities in which it operates. As of December 31, 2017, women filled 25 percent of Corporate Officer roles and 26 percent of senior management (senior managers and above) positions. In total, there were three women in Corporate Officer roles and 153 women in senior management positions. OPG tracks and monitors diversity succession planning metrics and strives to have a diverse candidates list for senior management positions.

Compensation

Executive Compensation Framework

In September 2016, the Government of Ontario introduced *Regulation 304/16: Executive Compensation Framework*. The regulation sets out how all employers, including OPG, designated under the *Broader Public Sector Executive Compensation Act, 2014* must establish and post compensation programs for executives. The regulation requires all designated employers to have a written Executive Compensation Program that describes the compensation they may provide to executives. The program must include the compensation philosophy, salary and performance-related pay caps, comparative analysis details, and a description of other elements of compensation. The regulation also requires that designated employers post their program on their website and provide a reasonable opportunity for members of the public to provide comments. OPG met the requirements of *Ontario Regulation 304/16* and posted its Executive Compensation Framework on the Company's website for public comment on November 30, 2016. OPG reviewed the comments received through the public consultation process and determined that there was no need to alter its Executive Compensation Program, which became effective on January 1, 2017. OPG's Executive Compensation Program applies to employees at the Vice President level and higher. A copy of OPG's Executive Compensation Program can be found on SEDAR at www.sedar.com and is also available on the Company's website at www.opg.com.

Director Compensation

As at March 8, 2018, OPG's Director compensation framework provides each Director who is not an employee of OPG with an annual retainer of $25,000. Directors also receive a $3,000 retainer for each Board committee of which they are a member. There are four standing committees of the Board and Directors serve on at least two committees. Directors receive an additional retainer for serving as committee chairs. The retainer for the chair of the Audit and Risk Committee is $8,000. The chairs of the other three committees receive retainers of $5,000.

In addition to the above, Directors are compensated for each regular and/or special meeting that they attend and receive a fee of $2,000 or $1,000 for a long or short meeting, respectively. The Board Chair may also determine that no fee is warranted.

In order to retain national and international expertise, non-resident Directors are compensated in U.S. dollars and Directors who travel over certain distances receive a travel fee to cover travel time related to Board and Board committee meetings they attend.

Since 2004, the Chair of the Board, in his role as non-executive Chair, receives an all-inclusive annual fee of $150,000 and is reimbursed for out-of-pocket expenses including travel and other expenses.

CEO Compensation

Among its other responsibilities, the Compensation, Leadership and Governance Committee oversees, on behalf of the Board, the setting of the CEO's annual goals and objectives and the annual review of CEO performance, and makes recommendations to the Board with respect to CEO compensation. The Committee may seek input from an independent advisor with regard to monitoring and benchmarking compensation trends.

In August 2015, when the current CEO was appointed, the CEO compensation terms were established based on the benchmarks recommended in the 2007 Report of the Agency Review Panel on Phase 1 of its Review of Ontario's Provincially Owned Electricity Agencies. The CEO's base pay and incentives compensation are compliant with *Ontario Regulation 304/16*. Other elements of the CEO's compensation will be compliant within the three-year period provided in the regulation to bring all elements of compensation into compliance.

For details regarding compensation paid to Directors and executive officers during the financial year ended December 31, 2017, see OPG's Statement of Executive Compensation (Form 51-102F6), which is available on SEDAR at www.sedar.com and incorporated by reference herein.

Committees of the Board of Directors

The following are the current standing Board committees as at March 8, 2018:

Audit and Risk Committee

This committee is responsible for the integrity, quality, and transparency of OPG's financial information, the adequacy of the financial reporting process, the systems of internal controls, and related principles, policies and procedures established by management. The Committee is responsible for the oversight of the Company's regulatory filings, financial statements, MD&A and press releases prior to their disclosures to the public, including approval of quarterly financial statements and recommending approval of the annual financial statements and various other annual disclosures to the Board. The committee is also responsible for recommending the appointment and compensation of the external auditor to the Board and for oversight of the external auditor.

The committee also provides oversight of OPG's corporate financing strategies including:

- policies related to financial exposure management;
- processes for identifying major financial risks;
- performance of the OPG Pension Fund, the Used Fuel Segregated Fund and the Decommissioning Segregated Fund;
- review and approval of the audited financial statements of the OPG Pension Fund, the Used Fuel Segregated Fund and the Decommissioning Segregated Fund; and
- review and approval of the statements of investment policies and procedures for the OPG Pension Fund and the Decommissioning Segregated Fund.

The Audit and Risk Committee also oversees risk and associated risk management activities, including the review of management's assessment of significant risks to achieving OPG's business plan objectives. The committee also is responsible for ensuring that an effective Code of Business Conduct is in place at OPG and monitors compliance with this code.

As of November 22, 2017, the Audit and Risk Committee assumed oversight of OPG's role as Financial Services Manager of the Fair Hydro Trust.

As of the date of this AIF, the Audit and Risk Committee consists of George Lewis (Chair), Elisabeth (Lisa) DeMarco, Ani Hotoyan-Joly, Wendy Kei, Yezdi Pavri, and Gerry Phillips.

For further details regarding the Audit and Risk Committee, see *Audit and Risk Committee Information*.

Compensation, Leadership and Governance Committee

This committee provides oversight of OPG's human resources and compensation policies and practices, including CEO objectives and compensation, disclosure on compensation and human resources matters, leadership talent review, succession planning, and collective bargaining negotiations. The committee also provides oversight of the design of OPG's benefit and pension plans.

The Compensation, Leadership and Governance Committee oversees the Board's governance program and practices to ensure that they are consistent with high standards of corporate governance, including annually reviewing and assessing the Board's system of corporate governance with a view to maintaining these high standards. The committee also is responsible for overseeing OPG's reputation management plan, and for identifying and recommending to the Board candidates for nomination to the Shareholder. Finally, the committee oversees OPG's processes for Board, Board committee, and Director assessments, as well as Director compensation and new Director orientation.

As of the date of this AIF, the Compensation, Leadership and Governance Committee consists of Margaret (Peggy) Mulligan (Chair), Bill Coley, JP Gladu, Ani Hotoyan-Joly, George Lewis and Yezdi Pavri.

Darlington Refurbishment Committee

The Darlington Refurbishment Committee is responsible for the oversight of the execution of the Darlington Refurbishment Program, including retaining external independent oversight advisors. The committee was also responsible for making a recommendation to the Board with respect to a final budget and schedule for the Darlington Refurbishment Program, which was subsequently approved by the Board of Directors in November 2015. The committee monitors and reports on the progress of the refurbishment program against the approved budget and schedule. The committee will make a recommendation to the Board with respect to the refurbishment of subsequent Darlington units, and other recommendations for approvals related to the refurbishment program as may be required from time to time.

As of the date of this AIF, the Darlington Refurbishment Committee consists of Jim Reinsch (Chair), Bill Coley, John Herron, Margaret (Peggy) Mulligan, Gerry Phillips, and James Sheppard.

Generation Oversight Committee

This committee is responsible for the oversight of safe, secure and efficient operations of OPG's generating facilities. Additionally, the committee is responsible for the development, risk management, financing, and execution of the Company's major generation projects including those related to nuclear waste management, other than the Darlington Refurbishment Program. The committee also is responsible for the oversight of OPG's environment and dam safety management systems and OPG's Indigenous relations. The committee reviews reports of internal and external advisors/assessors in respect of OPG's generation operations and management's response to the findings from such assessments. The committee provides oversight to ensure that OPG's generating facilities are in compliance with nuclear safety, industrial and occupational health and safety, and environmental laws and regulations.

As of the date of this AIF, the Generation Oversight Committee consists of John Herron (Chair), Bill Coley, Elisabeth (Lisa) DeMarco, JP Gladu, Wendy Kei, Jim Reinsch, and James Sheppard.

Special Committee of the Board

This Special Committee of the Board was established on March 10, 2017. The Special Committee was responsible for providing timely strategic and other guidance to OPG management in connection with the Province's announcement of Ontario's Fair Hydro Plan on March 2, 2017, which includes refinancing a portion of the Global Adjustment. The Committee was also responsible for making recommendations to the Board with respect to OPG's participation in the Province's implementation of the refinancing proposal. The mandate of the Special Committee concluded on November 22, 2017 and the Audit and Rick Committee will be responsible for the oversight of this process.

Assessments

The Compensation, Leadership and Governance Committee is responsible for the annual process for evaluating the performance of the Board, its committees and individual Directors. The Board and committee evaluations are based upon the completion of confidential questionnaires regarding assessment of performance and compliance with the Board and Committee Charters. The individual Director evaluations are based on self-assessment questionnaires, which are submitted in confidence to the Board Chair and the Chair of the Compensation, Leadership and Governance Committee. In addition, the process includes a follow-up one-on-one meeting between each Director and the Board Chair. The Compensation, Leadership and Governance Committee reports the results of the evaluations to the Board and the results are discussed amongst the Board. The Compensation, Leadership and Governance Committee makes recommendations to the Board for enhancing the Board's governance and effectiveness.

Further Information on OPG Governance

OPG provides additional information on the Company's governance on its website (www.opg.com) including:

- Memorandum of Agreement with the Shareholder
- Shareholder Directives
- List of Corporate Officers
- Board and Committee Charters
- Board and Committee Chair Position Descriptions
- Board of Directors Conflict of Interest Policy
- Indigenous Relations Policy
- Code of Business Conduct
- Disclosure Policy
- Environmental Policy
- Employee Health and Safety Policy
- Nuclear Safety Policy

- Safe Operations Policy
- Cyber Security Policy

Unless otherwise specifically stated, none of the information contained on, or connected to the Company's website nor any of the contents of the aforementioned additional information on OPG's governance are incorporated by reference herein.

EXECUTIVE OFFICERS

The following table sets forth the name, municipality of residence, position with the Company, and the date of commencement for each of the executive officers of the Company as of March 8, 2018:

Name and Municipality of Residence	**Current Position Held**	**Executive Officer Since**
Bernard Lord *Moncton, New Brunswick*	Board Chair	April 2014
Jeff Lyash *Toronto, Ontario*	President and Chief Executive Officer	August 2015
Carlo Crozzoli *Toronto, Ontario*	Senior Vice President, Corporate Business Development and Strategy	December 2011
Chris Ginther *Newmarket, Ontario*	Chief Administrative Officer	July 2012
Ken Hartwick *Milton, Ontario*	Chief Financial Officer & Senior Vice President – Finance	March 2016
Glenn Jager *Clarington, Ontario*	President, OPG Nuclear and Chief Nuclear Officer	November 2013
David Kaposi *Toronto, Ontario*	Vice President, Chief Investment Officer	November 2013
Barb Keenan *Toronto, Ontario*	Senior Vice President, People & Culture and Chief Ethics Officer	March 2010
Catriona King *Richmond Hill, Ontario*	Vice President, Corporate Secretary	February 2005
John Lee *Toronto, Ontario*	Vice President, Treasurer	July 2011
Mike Martelli *Etobicoke, Ontario*	President, Renewable Generation **[CONFIRM]**	July 2013
Dietmar Reiner *Clarington, Ontario*	Senior Vice President, Nuclear Projects	June 2014
Jennifer Rowe *Toronto, Ontario*	Senior Vice President, Corporate Affairs	January 2017

All of the executive officers of the Company have been engaged for more than five years in their current principal occupations, except as set out below:

- Mr. Lyash was Executive Vice President at Duke Energy from May 2008 to January 2012 and President at CB&I Power from July 2013 to July 2015.
- Mr. Crozzoli was Senior Vice President, Corporate Business Development and Chief Risk Officer at OPG from December 2011 to November 2015, Acting Senior Vice President, Finance, Strategy & Risk and Chief Financial Officer at OPG from November 2015 to March 2016 and Senior Vice-President, Corporate Business Development and Chief Risk Officer at OPG from March 2016 to August 2016.
- Mr. Ginther was Senior Vice President, Law and General Counsel and Chief Ethics Officer at OPG from July 2012 to January 2016 and Senior Vice President, Legal, Ethics and Compliance at OPG from January 2016 to February 2017.
- Mr. Hartwick was President and CEO at Just Energy Corp. from February 2008 to April 2014, Interim President and CEO at Atlantic Power Corporation from September 2014 to January 2015, Chief Financial Officer at Wellspring Financial Corporation from February 2015 to March 2016 and Senior Vice President, Finance, Strategy, Risk and Chief Financial Officer at OPG from March 2016 to February 2017.
- Mr. Jager was Senior Vice President, Pickering Nuclear Generating Station at OPG from January 2010 to November 2013 and Chief Nuclear Officer at OPG from November 2014 to March 2015.
- Mr. Kaposi was Global Head of Alternatives for Mercer (Canada) Inc. from November 2007 to June 2012 and Partner, Investor Relations at Bastion Infrastructure Group Inc. from July 2012 to September 2013.
- Ms. Keenan was Senior Vice President, People and Culture at OPG from March 2012 to January 2016 and Senior Vice President, People, Culture and Communications from January 2016 to February 2017.
- Ms. King was Vice President, Corporate Secretary at OPG from June 2005 to May 2012, Vice President, Corporate Secretary & Executive Operations from May 2012 to March 2017.
- Mr. Martelli was Plant Manager for the Niagara Plant Group at OPG from June 2010 to July 2013 and Senior Vice President, Hydro-Thermal Operations at OPG from July 2013 to January 2016.
- Mr. Reiner was Senior Vice President, Nuclear Refurbishment at OPG from March 2010 to April 2014.
- Ms. Rowe was Senior Managing Director – Marketing and Communications and VP Corporate Affairs at Manulife from January 2010 to October 2012 and Senior Vice President and Chief Marketing Officer at Meridan Credit Union from October 2012 to April 2016.

INDEBTEDNESS OF DIRECTORS AND EXECUTIVE OFFICERS

As of the date of this AIF, no director or executive officer of the Company or any of its subsidiaries had any outstanding indebtedness to the Company or any of its subsidiaries except routine indebtedness or had any indebtedness that was the subject of a guarantee, support agreement, letter of credit or other similar arrangement or understanding provided by the Company or any of its subsidiaries.

CEASE TRADE ORDERS, BANKRUPTCIES, PENALTIES OR SANCTIONS

To the knowledge of OPG, no director or executive officer is, at the date of the AIF, or was within 10 years before the date of the AIF, a director, chief executive officer, or chief financial officer of any company, that (a) was subject to an order that was issued while the director or executive officer was acting in the capacity as director, chief executive officer, or chief financial officer, or (b) was subject to an order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer, or chief financial officer, except for:

- Ani Hotoyan-Joly was the Chief Financial Officer of Coventree Inc. on November 8, 2011, when the Ontario Securities Commission issued an order that trading in any securities by Coventree cease and any exemptions contained in Ontario Securities law do not apply to Coventree until such time as Coventree completes it winding up. The order was made on the basis that Coventree had contravened Ontario Securities law by failing to issue and file certain news releases and material change reports in 2007.

- The events in question occurred before she became CFO of Coventree Inc. in May 2009. Coventree Inc. continues in the process of a court-supervised winding up and the order is still in effect.

To the knowledge of OPG, no director or executive officer of OPG, or a shareholder holding a sufficient number of securities of OPG to affect materially the control of OPG (a) is, as at the date of the AIF, or has been within the 10 years before the date of the AIF, a director or executive officer of any company (including OPG) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (b) has, within the 10 years before the date of the AIF, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager, or trustee appointed to hold the assets of the director, executive officer, or shareholder, except for:

- Bernard Lord was a director of AEA Technology from the fall of 2010 until the fall of 2012 when it became insolvent.
- Ani Hotoyan-Joly is currently the CFO and Corporate Secretary of Coventree Inc. from May 2009. On February 15, 2012 Coventree Inc. announced that the winding up of the Company will commence and that Duff & Phelpe Canada Restructuring Inc. (now known as KSV Advisory Inc.) was appointed the liquidator of the Company for the purpose of winding up its affairs.
- Peggy Mulligan was a director of MethylGene Inc. from May 2012 to June 2014. On May 9, 2013, MethylGene announced a plan of arrangement that was successfully completed on June 28, 2013.
- Bernard Lord, was a director of Clean Air Power, during September 2015 while it was subject to liquidation proceedings under the laws of Bermuda. Mr. Lord is no longer a director of Clean Air Power.
- William Coley is a director of Peabody Energy Corporation which declared voluntary Chapter 11 bankruptcy protection in April 2016 for most of its U.S. entities and is currently restructuring. As of April 13, 2017, Mr. Coley is no longer a director of the entity.

AUDIT AND RISK COMMITTEE INFORMATION

NI 52-110 has been implemented by Canadian securities regulatory authorities to encourage reporting issuers to establish and maintain strong, effective, and independent audit committees, to enhance the quality of financial disclosure, and to foster increased investor confidence in Canada's capital markets. The Audit and Risk Committee's Charter is attached to this AIF as Appendix A. Information on OPG's Audit and Risk Committee is as follows:

Composition of the Audit and Risk Committee

As at March 8, 2018, the members of the Audit and Risk Committee were George Lewis (Chair), Elisabeth (Lisa) DeMarco, Ani Hotoyan-Joly, Wendy Kei, Yezdi Pavri and Gerry Phillips. All members are independent within the meaning of NI 52-110 and have experience in business and financial matters. Each member has an understanding of internal controls and procedures for financial reporting. As part of OPG's Continuing Education Program for Directors, Audit and Risk Committee members are provided with access to both internal and external educational resources, including seminars and courses, in order to maintain or enhance their financial literacy.

Activities of the Audit and Risk Committee

The Chartered Professional Accountants of Canada (CPA Canada) and the Canadian Public Accountability Board have recommended that audit committees perform a comprehensive review of the external audit firm at least once every five years. CPA Canada issued guidelines in early 2014 to assist audit committees in implementing these recommendations. The Audit and Finance Committee of the Board conducted its first comprehensive review of the Company's external auditor, Ernst & Young LLP (EY) in 2014, for the period from 2009 to 2013, using the guidelines and format recommended by CPA Canada. EY has been OPG's external auditor since the Company's inception in 1999. EY provides audit and audit related services to OPG, including the audit of OPG's annual consolidated financial statements, reviews of OPG's quarterly financial statements, and audits of the financial statements of OPG's consolidated subsidiaries and other financial information.

In conducting the 2017 review of EY's performance, the Audit and Risk Committee considered input from management, EY, and OPG's internal audit function. The Committee performed this review taking into consideration the information submitted by these parties, as well as their individual experience. The results of the 2017 annual review were discussed at the Audit and Risk Committee meeting in August 2017. As part of the review, the Committee considered factors such as the auditor's independence, engagement team quality including the Committee's involvement in the selection of EY's lead engagement partner, and communication effectiveness between EY and OPG. Upon completion of the review, the Committee was satisfied with the performance of EY, concluded that their reappointment was in the best interests of OPG, and, in November 2017, recommended that the Board reappoint EY as the Company's auditor for the 2018 fiscal year. The Board reappointed EY as the Company's auditor for the 2018 fiscal year in November 2017.

External Auditor Service Fees [UPDATE]

The following fees were accrued by EY:

(thousands of dollars)	**2017**	**2016**
Audit fees		1,959
Audit-related fees		554
All other fees [1]		17

[1] Comprised of fees related to the subscription of an online accounting research tool and training.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Relationship with the Province and the OEFC

Relationship with the Shareholder

As a corporation created under and governed by the OBCA, OPG's management is supervised by its Board of Directors, which is obligated by law to act in the best interests of the Company. The Company's sole Shareholder, the Province, owns all of the Company's issued and outstanding common shares and thereby has the power to determine the composition of the Company's Board of Directors.

As one of several wholly-owned government business enterprises of the Province, OPG has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

Memorandum of Agreement

On August 17, 2005, OPG entered into the MOA with the Shareholder regarding OPG's role and responsibility as a power producer in Ontario. In July 2015, the MOA was revised. The MOA serves as the basis of agreement between OPG and the Shareholder regarding OPG's mandate, governance, performance, reporting and communications, and establishes the accountabilities between OPG and the Province. OPG's strategic imperatives are based on the Company's mandate as set out in the MOA. The MOA was reaffirmed for continuance by both the Ontario Minister of Energy and the OPG Board of Directors' Chair in the fourth quarter of 2016, as required by the MOA following a change in the Minister of Energy.

A copy of the MOA can be found on the Company's website at www.opg.com. ***Unless otherwise specifically stated, none of the information contained on, or connected to the Company's website nor any of the contents of the MOA are incorporated by reference herein.***

Shareholder Directives

The Shareholder may at times direct OPG to undertake special initiatives. A Shareholder directive is issued when the Shareholder finds it necessary to assume decision-making power and authority over certain aspects of the business operations of the Corporation. Under a Shareholder directive, the Shareholder assumes all the rights, powers, duties and liabilities of the Directors to manage or supervise the management of the business and the Directors are relieved of their duties and liabilities. Shareholder directives are communicated as written pursuant to section 108 of the OBCA. Copies of each Shareholder directive can be found on the Company's website at www.opg.com. ***Unless otherwise specifically stated, none of the information contained on, or connected to the Company's website nor any of the contents of the Shareholder directives are incorporated by reference herein.*** The Shareholder directives issued by the Shareholder to date are listed below in reverse chronological order:

- Sale of the Corporation's Lakeview site (June 9, 2016);
- Sale of the Corporation's Head Office (December 14, 2015);
- Bruce Power L.P. Lease Agreement and Used Fuel Agreement (November 30, 2015) – For further details, see *General Development of Business – Nuclear Business Development – Bruce Power Refurbishment and Bruce Lease Agreement*;
- Bruce Power L.P. Amended and Restated Heavy Water and Associated Services Agreement (November 30, 2015) – For further details, see *General Development of Business – Nuclear Business Development – Bruce Power Refurbishment and Bruce Lease Agreement*;
- Conversion of One Unit of Thunder Bay Generating Station to Advanced Biomass (May 1, 2014);
- Thunder Bay Generating Station Conversion (December 16, 2013);
- Early Closure of Ontario Power Generation's Lambton and Nanticoke Coal-Fired Generation Stations (March 7, 2013);
- First Nation Directive (April 1, 2011) – OPG was directed to pay a part of the Shareholder's portion of the settlement liability with a First Nation on its behalf;
- Atikokan Generating Station Conversion (March 8, 2011);
- Addressing Carbon Dioxide Emissions from the Use of Coal at Coal-Fired Generating Stations (May 20, 2010);
- Request for Indicative Prices for the Supply of Wood Pellet Fuel Declaration (Atikokan) (March 18, 2010);

- Request for Expressions of Interest for Supply and Transportation of Solid Biomass Fuel Declaration (January 13, 2009);
- Addressing Carbon Dioxide Emissions from the Use of Coal at Coal-Fired Generating Stations (May 15, 2008);
- Thunder Bay Gas Conversion Cancellation (July 12, 2006);
- Nuclear Directive (June 16, 2006) – OPG was directed to begin feasibility studies on refurbishing existing nuclear units, an environmental assessment on refurbishing Pickering B units, and federal approvals processes (including environmental assessment) for new nuclear units;
- Lower Mattagami River Agreement (May 23, 2006);
- Bruce Power Lease Agreement (October 14, 2005); and
- Thunder Bay Gas Conversion Declaration (October 6, 2005).

Ontario Nuclear Funds Agreement

The ONFA between OPG and the Province sets out the responsibility for funding the liabilities for the decommissioning of OPG's nuclear facilities and the long-term management of OPG's used nuclear fuel and other nuclear waste. Pursuant to the ONFA, the Company has established a Used Fuel Segregated Fund and a Decommissioning Segregated Fund to fund the future costs of these activities. Additional details can be found in the section, *Description of the Business* under the heading, *Regulated – Nuclear Waste Management Segment – Funding Mechanisms*.

OPG Debt Held by the OEFC

OPG's long-term debt has been financed predominantly by the OEFC. As at December 31, 2017, the OEFC held approximately $3.2 billion of OPG's long-term debt with maturities ranging from one month to 30 years. For additional details, see Note 6 to the Company's audited annual financial statements as at and for the year ended December 31, 2017.

Payments-In-Lieu of Corporate Income Taxes and Property Taxes

OPG and its wholly-owned subsidiaries are exempt from tax under the *Income Tax Act* (Canada) and *Taxation Act, 2007* (Ontario). However, under the *Electricity Act, 1998*, OPG is required to make proxy tax payments to the OEFC. These payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by the *Electricity Act, 1998* and related regulations. This results in OPG paying taxes similar to those imposed under the federal and Ontario tax acts.

OPG is subject to income tax audits by the Ontario Ministry of Finance. As of the date of this AIF, income tax audits up to and including the 2013 taxation year have been completed.

The *Electricity Act, 1998* also provides that OPG and certain of its subsidiaries are required to make payments in lieu of property tax to the OEFC on their non-hydroelectric generating station buildings and structures. These payments generally equal the difference between property taxes that would be otherwise payable if these assets were privately owned, and the amount payable to municipalities in respect of these assets as determined under the *Assessment Act, 1990* (Ontario). As with other hydroelectric generators in Ontario, OPG's hydroelectric generation operations are not subject to payments in lieu of property taxes because they are subject to the GRC regime. Additional details on the GRC regime can be found in the section, *Description of the Business* under the heading, *Generation Operations – Hydroelectric (Regulated – Hydroelectric and Contracted Generation Portfolio segments)*.

Stranded Debt

One of the OEFC's purposes under the *Electricity Act, 1998* is to manage "stranded debt," which was not transferred to any of Ontario Hydro's successor entities. The *Electricity Act, 1998* defines stranded debt as the amount of the debt and other liabilities of the OEFC that, in the opinion of the Minister of Finance, cannot reasonably be serviced and retired in a competitive electricity market. Although OPG has no obligations in connection with the stranded debt, the *Electricity Act, 1998* does provide for participants in the electricity sector, including OPG, Hydro One, and the municipal electricity utilities, to make payments to the OEFC, which the OEFC uses in managing the debt and other obligations. These payments include proxy taxes, payments in lieu of tax, including property tax, the Debt Retirement Charge levied on certain electricity consumers, and certain amounts that may be payable by municipal electricity utilities on the transfer of their electricity business.

Commented [GH3]: Not sure if we need to note that Hydro One no longer pays PILs here, given this is OPG's AIF.

Commented [JK4]: If this refers to PILs, then the next change is not needed.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Legal Proceedings

OPG is potentially the subject of various legal proceedings and claims that arise in the ordinary course of business. The outcome of these proceedings and claims is uncertain. Based on information available as of the date of this AIF, management believes that none of the proceedings and claims, individually and in the aggregate, are expected to have a material impact on OPG.

British Energy Claim

On August 9, 2006, a Notice of Action and Statement of Claim filed with the Ontario Superior Court of Justice in the amount of $500 million was served against OPG and Bruce Power by British Energy Limited and British Energy International Holdings Limited (together British Energy). The action is for contribution and indemnity of any amounts British Energy was liable for in an arbitration against it by some of the owners of Bruce Power regarding an alleged breach of British Energy's representations and warranties to the claimants when they purchased British Energy's interest in Bruce Power (the Arbitration). Both the action and the Arbitration relate to corrosion to a steam generator unit discovered after OPG leased the Bruce nuclear generating stations to Bruce Power.

In 2012, the arbitrator found that British Energy was liable to the claimants for some of the damages they claimed. The final settlement amount was valued by British Energy at $71 million. In September 2014, British Energy amended its Statement of Claim (Amended Claim) to reduce the claim amount to $100 million to reflect that the purchasers of British Energy's interest in Bruce Power did not receive the full damages they originally claimed in the Arbitration. British Energy also added an allegation to its Amended Claim that OPG breached a covenant to maintain the steam generator between the time of the initial agreement to lease and the effective date of the lease in accordance with "Good Utility Practices".

In November 2016, British Energy obtained consent to a timetable for the remaining steps in the litigation, pursuant to which the matter must be set down for trial by December 31, 2018. OPG has delivered a statement of defence in accordance with an extension of the original June 30, 2017 delivery deadline set out in the timetable.

Regulatory Actions

OPG is not aware of any penalties or sanctions imposed by a court or securities regulatory authority or other regulatory body against the Company, nor has the Company entered into any settlement agreements before a court or with a securities regulatory authority.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business (unless otherwise required by applicable securities requirements to be disclosed), there were no material contracts entered into by the Company or

its subsidiaries during the most recently completed financial year, or before the most recently completed financial year that are still in effect.

INTERESTS OF EXPERTS

The external auditor of the Company is Ernst & Young LLP, Chartered Professional Accountants, 100 Adelaide Street West, P.O. Box 1, Toronto, Ontario M5H 0B3. Ernst & Young LLP has been the Company's auditors since OPG was formed in 1999, and is independent in accordance with the Rules of Professional Conduct of the Chartered Professional Accountants of Ontario.

GLOSSARY

ancillary service	a service necessary to maintain the reliability of the IESO-controlled grid.
availability	when used in reference to a generating unit, a measure of mechanical reliability represented by the percentage of time a generating unit is capable of providing service, whether or not it is actually in-service, relative to the total time for the period.
baseload facilities	electricity generation facilities that produce a constant supply of energy. In Ontario, baseload facilities are made up of nuclear, run-of-the-river hydroelectric and variable generation facilities such as wind and solar.
bilateral contract	a contract for the purchase and sale of notional electricity usually entered into directly between a generator and an end-user, or between a generator or end-user and a market intermediary.
biomass	plant material from agricultural and forest sources that can be used to produce energy, including beneficiated biomass, which includes torrefied, carbonized, and steam exploded biomass.
CANDU	an acronym for CANada Deuterium Uranium, a family of nuclear fission reactors developed in Canada which use pressurized heavy water coolant or deuterium oxide as a moderating agent and natural uranium (uranium dioxide) as fuel.
capacity factor	the ratio (usually specified as a percentage) of the amount of energy that a generating asset actually generated over a period of time divided by the amount of energy that the generating asset would have produced over the same period of time if it had operated continuously at full capacity.
decommissioning	actions taken in the interest of health, safety, security and protection of the environment to retire a facility permanently from service and render it to a predetermined end-state condition.
detritiation	the removal of tritium from heavy water.
deuterium oxide	see heavy water.
equivalent forced outage rate	the hours of unit failure given as a percentage of the total hours of the availability of that unit.
government business enterprises	Government organizations that are separate legal entities with the power to contract in their own name, have the financial and operating authority to carry on a business, are principally focused on the selling of goods and services to individuals and non-government organizations, and are able to maintain their operations and meet their obligations through revenues generated outside the government reporting entity.
heavy water (deuterium oxide)	water containing significantly more than the natural proportion of heavy hydrogen (deuterium) atoms to ordinary hydrogen atoms, used as a moderator in CANDU reactors.
in-service capacity	the portion of installed capacity (the highest level of output which a generating unit is designed to maintain indefinitely without damage to the unit) that has not been removed from service.

interconnection	a transmission line which carries power across the service area boundary of geographically adjacent jurisdictions.
kWh	a kilowatt hour, the commercial unit of electric energy (the amount of electricity consumed by ten 100 watt light bulbs burning for one hour).
load	the quantity of electricity consumption measured as either the energy consumed over a given period of time or the rate of energy consumption at a given time by a particular customer or group of customers.
MW	a megawatt, equal to 1,000,000 watts or 1,000 kilowatts.
MWh	a megawatt hour, equal to 1,000 kWh.
OEFC	an acronym for the Ontario Electricity Financial Corporation, the legal continuation of the former Ontario Hydro. The OEFC is responsible for managing the debt and certain other obligations not transferred to other successor companies of Ontario Hydro.
ONFA	an acronym for the Ontario Nuclear Funds Agreement between OPG and the Province that sets out the responsibility for funding the liabilities for the decommissioning of OPG's nuclear stations and the long-term management of OPG's used nuclear fuel and other nuclear waste.
Ontario NFWA Trust	a trust established by OPG pursuant to the *Nuclear Fuel Waste Act* (Canada) for the purpose of funding the implementation of Canada's long-term nuclear fuel waste management plan.
operating reserve	the capacity that can be called upon on short notice by the IESO to replace scheduled energy supply that is unavailable as a result of an unexpected outage or to augment scheduled energy as a result of unexpected demand or other contingencies.
reactive support	the control and maintenance of prescribed voltages on the IESO-controlled grid.
refurbishment	the work needed to extend the life of a reactor unit by replacing the major life-limiting components (such as pressure tubes, steam generators, etc).
Shareholder	the sole shareholder of OPG, the Province of Ontario.
surplus baseload generation	a condition that occurs when electricity generation from baseload facilities is greater than the electricity market demand.
tonne	1,000 kilograms or 2,204.6 pounds.
tritium	a radioactive substance that is created within CANDU reactors as a result of heavy water in the reactor moderator and heat transport systems.
TWh	a terawatt hour, equal to 1,000,000 MWh.
unit	an electrical generator, together with its driving turbine and auxiliary equipment.
watt	a scientific unit of electric power representing the rate of work of one joule per second.

APPENDIX A

ONTARIO POWER GENERATION INC.

AUDIT AND RISK COMMITTEE CHARTER

Audit and Risk Committee Charter

Purpose

The function and purpose of the Audit and Risk Committee is to assist the Board of Directors in their responsibility for oversight of matters relating to:

1. The integrity of OPG's financial statements and reporting
2. The integrity and adequacy of internal controls and standards of Codes of Conduct and ethics
3. The performance of OPG's internal audit function
4. The performance and independence of OPG's external auditors
5. Business and financial planning
6. The performance of OPG's pension, nuclear decommissioning, and used fuel investment funds
7. OPG's Enterprise Risk Management
8. Assessment of committee performance and board policies.

Management is responsible for the preparation, presentation and integrity of OPG's interim and annual financial statements and related disclosure documents. Management is responsible for maintaining appropriate accounting and financial reporting principles and policies and systems of internal and disclosure controls and procedures to comply with accounting standards and applicable laws and regulations which

provide reasonable assurance that the assets of the Company are safeguarded and transactions are authorized, executed, recorded and properly reported.

Management is also responsible for the identification, assessment, monitoring, and management of the risks to achieving OPG's strategic and business plan objectives and the development and implementation of policies and procedures to respond to such risks.

The Committee's role is to provide oversight that ensures the Company's assets are protected and safeguarded within reasonable business limits and report such to the Board.

Committee Responsibilities and Duties

The Committee shall perform the duties set out in this Charter and shall perform such other duties as may be necessary or appropriate under applicable law or securities rules, or as may be delegated to the Committee by the Board from time to time.

1. *The integrity of OPG's financial statements and reporting*

   The Committee reviews and makes recommendations to the Board with respect to:

   a) appointment or replacement of the Chief Financial Officer.

   b) OPG's annual financial statements and external audit report, including financial statements, MD&A, related footnotes and any documentation required by the Securities Act to be prepared and filed by OPG or that OPG otherwise files with securities regulators.

   c) OPG's Annual Information Form, if required, prior to filing with securities regulators.

   The Committee reviews and approves:

   d) OPG's quarterly financial statements and interim financial information and disclosures in the Management Discussion and Analysis (MD&A) and earnings press release, prior to filing.

   In carrying out its responsibilities for oversight of the integrity of OPG's financial statements and reporting the Committee will include in its review:

   e) Adequacy of procedures in place for the review of OPG's public disclosure of financial information extracted or derived from OPG's financial statements.

   f) significant accounting principles and reporting issues and impact on the financial statements, including complex or unusual transactions, highly judgmental areas, major issues regarding or changes to OPG's selection/application of accounting principles, financial presentations, the effect of regulatory and accounting initiatives, as well as off-balance sheet arrangements on OPG's financial statements.

   g) analysis prepared by Management and/or the external auditor detailing financial reporting issues and judgments made in connection with the preparation of financial information, including analysis of the effects of alternative generally accepted accounting principles methods.

   h) whether any other matters related to conduct have come to the Committee's attention that causes it to believe that the financial statements contain an untrue statement of material fact or omit to state a necessary material fact.

2. *Integrity and adequacy of Internal Controls and standards of Codes of Conduct and ethics*

In carrying out its responsibilities for the integrity and adequacy of internal controls, including compliance with legal and regulatory requirements and standards of codes of conduct and ethics, the Committee reviews:

a) legal, tax, or regulatory matters that may have a material impact on OPG's operations and the financial statements, including, but not limited to, violations of securities law or breaches of fiduciary duty.

b) the scope of review of internal control over financial reporting, significant findings, recommendations and Management's responses for implementation of actions to correct weaknesses in internal controls.

c) disclosures made by the Chief Executive Officer and Chief Financial Officer during the certification process regarding significant deficiencies in the design or operation of internal controls or any fraud that involves Management or other employees who have a significant role in OPG's internal controls.

d) procedures for the receipt, recording and treatment of complaints received by OPG regarding accounting, internal accounting controls, or auditing matters, and procedures for the confidential and anonymous submission by OPG employees of concerns regarding accounting or auditing matters.

e) expenses of the Board Chair, Board of Directors, President/CEO and the President/CEO's direct reports on an annual basis, and of any other senior officers and employees the Committee considers appropriate.

f) reports from the Chief Ethics Officer on independent reviews and investigations of fraud allegations, matters that may involve fraud and/or Codes of Conduct violations and compliance.

3. *Performance of OPG's internal audit function*

The Committee reviews and makes recommendations to the Board with respect to:

a) Appointment or replacement of the Chief Risk and Audit Executive.

The Committee reviews and approves:

b) The annual internal audit plan and all major changes to the plan, including the organizational structure, budget and the adequacy of resources.

c) the charter of the internal audit function triennially.

In carrying out its responsibilities for the performance of OPG's internal audit function the Committee reviews:

d) results of Internal audit reports, including: significant findings, the adequacy of the control processes, Management's response and the timetable for implementation of Management actions

to correct weaknesses, any difficulties encountered in the course of their work (such as restrictions on the scope of their work or access to information).

e) Internal Audit's confirmation of organizational independence and disclosure of any conflict of interest.

f) Internal Audit performance relative to the annual internal audit plan.

4. *Performance and Independence of External Auditor*

The Committee reviews and makes recommendations to the Board with respect to:

a) the external auditor to be annually appointed on behalf of the Shareholder and related compensation, including results of a cyclical performance review, and a comprehensive review of the external audit firm at least once every five years.

The Committee reviews and approves:

b) pre-approval of additional audit services and fees to be provided by the external auditors if such services are required further to the annual compensation approved by the Board. The Committee may delegate such pre-approval authority to the Committee Chair up to a limit of $250,000. Any decisions of the Committee Chair to whom pre-approval authority is delegated must be presented to the full Audit and Risk Committee at its next scheduled meeting.

In carrying out its responsibilities for the performance and independence of OPG's external audit function the Committee reviews:

c) the work and report of the external auditor engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for OPG, including the resolution of disagreements between Management and the external auditor regarding financial reporting.

d) the independence and qualifications of the external auditor.

e) the annual report by the external auditor describing the auditing firm's internal quality control procedures, any material issues raised by the most recent internal quality-control review or peer review of the auditing firm or by any inquiry or investigation by governmental or professional authorities within the preceding five years respecting one or more independent audits carried out

by the external auditor and any steps taken to deal with any such issues and all relationships between the external auditors and OPG.

f) scope and approach of the annual audit plan with the external auditors.

g) quality and acceptability of OPG's accounting principles including all critical accounting policies and practices used, any alternative treatments that have been discussed with Management as well as any other material communications with Management.

h) external auditor's process for identifying and responding to key audit and internal control risks.

i) rotation of the lead audit partner and other audit partners every seven years, and consider regular rotation of the audit firm.

j) all related-party transactions.

k) OPG's hiring policies regarding partners, employees and former partners and employees of the present and former external auditor of OPG.

5. *Business and Financial Planning*

The Committee reviews and makes recommendations to the Board on:

a) OPG's business plan, including overall financing plan in support of the Company's capital expenditures and medium – long term forecast.

b) OPG's rate applications to the Ontario Energy Board, including proposed payment amounts and any agreement arising from a Settlement Conference with intervenors.

c) corporate financing vehicles, credit facilities, including any plans to access capital debt markets and other related financing activities. The Board may delegate to an officer of the company authority to enter into such financing activities in such a manner as the Board shall determine at the time of

such delegation. Any decisions of the officer to whom authority is delegated must be presented to the full Audit and Risk Committee at its next scheduled meeting.

6. *Pension, Nuclear Decommissioning and Used Fuel Investment Funds*

The Committee reviews and makes recommendations to the Board on:

a) the appointment or replacement of the Chief Investment Officer.

b) the appointment of the auditor for the OPG Pension Fund and the Used Fuel Segregated Fund and Decommissioning Segregated Fund.

c) the broad objectives, governance frameworks and risk posture for the OPG Pension Fund and the Used Fuel Segregated Fund and Decommissioning Segregated Fund and annual status report on these Funds.

d) the tri-ennial valuation of the Pension Fund and annual valuation of the Supplementary Employee Retirement Pension Plans. (The Committee provides advice to the Compensation, Leadership and Governance Committee on the affordability of proposed pension benefit changes.)

The Committee reviews and approves:

e) the appointment of the members of OPG's Pension Committee. In addition, the Committee may, at any time, remove or replace any member of the Pension Committee or fill a vacancy on the Pension Committee. The Pension Committee Chair may temporarily appoint a senior management

employee to fill a vacancy on the Pension Committee until the next regularly scheduled Audit and Risk Committee meeting.

f) the annual audited financial statements for the OPG Pension Fund, the Used Fuel Segregated Fund and the Decommissioning Segregated Fund.

g) the investment policies and procedures, including the design of modifications, for the OPG Pension Fund, as required by the Ontario Pension Benefits Act and its regulations, and for the Decommissioning Segregated Funds, as required by the Ontario Nuclear Funds Agreement.

h) the appointment of the Pension Plan actuary.

In carrying out its responsibilities for the oversight of financial planning and investment funds the Committee reviews:

i) reports on a quarterly, annual or by exception basis, on compliance with and appropriateness of the asset mix policy; total fund and asset class returns relative to benchmarks; material compliance with breaches of policies or procedures; and work conducted by the plan actuary.

j) periodic reports on the calculation of OPG's nuclear waste liability.

7. *OPG's Enterprise Risk Management*

The Committee reviews and makes recommendations to the Board on:

a) the appointment or replacement of the Chief Risk and Audit Executive.

b) the Company's enterprise risk policy, framework, overall risk appetite and targets.

In carrying out its responsibilities for oversight of OPG's Enterprise Risk Management the Committee reviews:

c) the processes employed by Management for identifying and assessing the Company's principal risks.

d) periodic reports on Management's assessment of the principal risks to achieving the Company's strategic and business plan objectives, and the strategies for monitoring, managing and responding to those risks.

e) periodic reports on significant emerging and evolving risks and relevant external events that could potentially impact OPG's risk profile.

f) compliance metrics related to OPG's commercial operations trading, treasury, and fuels management.

g) regular reports on OPG's cyber security position and programs.

h) periodic reports on OPG's Insurance Program.

8. *Assessment of committee performance and board policies*

In carrying out its responsibilities for assessment of committee performance and board policies the Committee shall:

a) Review and assess Committee performance, including a review of the adequacy of and its compliance with this Charter, in accordance with the evaluation process approved by the Board and taking into account all legislative and regulatory requirements applicable to the Committee as well as any best practice guidelines recommended by regulators with whom OPG has a reporting relationship.

b) Provide oversight of the implementation of the following Board of Directors' policies, and review these policies at least annually (or as otherwise noted below) to ensure their continuing adequacy:

   i. Delegation and Exercise of Authority Policy
   ii. Disclosure Policy
   iii. Code of Business Conduct and Supplier Code of Conduct, including anti-bribery and corruption
   iv. Enterprise Risk Management Policy (reviewed every three years)
   v. Cyber Security Policy

c) Provide oversight of the development of any new policies deemed necessary by the Committee.

Organization

Members

The Audit and Risk Committee shall consist of three or more Directors as determined by the Board of Directors. All members of the Committee shall be independent as defined by the Ontario Securities Commission, and not "affiliated" with OPG.

The Board shall appoint the members of the Committee and the Chair of the Committee annually. The Board may appoint a member to fill a vacancy which occurs in the Committee between annual elections of Directors. Any member of the Committee may be removed or replaced at any time by the Board.

If a member of the Committee becomes "affiliated" with OPG, the member may continue as a member of the Committee with the approval of the Board Chair, in consultation with the Corporate Secretary.

As a "venture issuer", OPG is exempt from the statutory requirements of National Instrument 52-110 requiring members of Audit Committees be independent and financially literate. However, OPG considers such independence and financial literacy to be "best practice" and therefore each of the members of the Audit and Risk Committee shall satisfy the applicable independence and financial literacy requirements of the laws and regulations governing Audit Committees.

The Board of Directors shall confirm that each member of the Audit and Risk Committee is financially literate; as such qualification is interpreted by the Board of Directors in its business judgment, and in compliance with National Instrument 52-110 and its Companion Policy.

Meetings

The Committee shall meet as frequently as it determines but not less than quarterly. During quarterly meetings, the Committee will hold separate in camera sessions with the external auditors, the Chief Internal Audit Executive, the Chief Risk Officer and Management to discuss any matters that the Committee believes should be discussed and to provide a forum for any relevant issues to be raised.

Notice of the time and place of each meeting of the Committee must be given to each member of the Committee not less than 48 hours before the time of the meeting.

A quorum of the Committee shall be a majority of its members, but not less than two. The powers of the Committee may be exercised at a meeting at which a quorum of the Committee is present in person or by

telephone or other electronic means, or by a resolution signed by all members entitled to vote on that resolution at a meeting of the Committee. Each member is entitled to one vote in Committee proceedings.

The Chair shall preside at all meetings of the Committee at which he or she is present (or if not able to be present designate another member of the Committee to chair the meeting) and shall develop the agenda for each Committee meeting. The agenda for each meeting of the committee shall be delivered to each member of the Committee at least 48 hours prior to any meeting of the Committee, together with such other materials as the chair determines necessary.

Minutes shall be kept of all meetings of the Committee and shall be maintained by OPG's Corporate Secretary. The procedure at meetings is to be determined by the Committee unless otherwise determined by the by-laws of OPG, by a resolution of the Board or by this Charter.

The Committee may meet in camera (without management present) at any time during the meeting consistent with the Board guideline on the conduct of in camera sessions and the keeping of minutes from in camera sessions.

The Committee may invite any Director, officer or employee of OPG or OPG's counsel or any other person to attend meetings of the Committee to assist in the discussion and examination of the matters under consideration by the Committee.

Reports

The Committee will report its activities and actions to the Board of Directors with recommendations, as the Committee deems appropriate.

The Committee will provide for inclusion in OPG's financial information or regulatory filings any report from the Audit and Risk Committee required by applicable laws and regulations and stating among other things whether the Committee has:

i. Reviewed and discussed the audited financial statements with Management.
ii. Discussed pertinent matters with the internal and external auditors.
iii. Received disclosures from the external auditors regarding the auditors' independence and discussed with the auditors their independence.
iv. Recommended to the Board of Directors that the audited financial statements be included in OPG's Annual Report.

Authority

The Audit and Risk Committee shall have the authority to:

a) conduct or authorize investigations into any matters within the Committee's scope of responsibilities.

b) set and pay the compensation for any advisors employed by the Committee.

c) to communicate directly with the internal and external auditors.

While the Audit and Risk Committee has the responsibilities and powers set forth in this Charter, it is not the duty of the Audit and Risk Committee to plan or conduct audits or risk assessments, or to determine that OPG's financial statements and disclosures are complete and accurate and are in accordance with

generally accepted accounting principles and applicable rules and regulations. These are the responsibility of Management and, as appropriate, the external auditor.

Delegation of Authority

The Committee may not delegate its oversight responsibilities. The Committee may delegate to a sub-committee, the Chief Executive Officer or any employee of OPG the authority to exercise any right, power or responsibility that the Committee may have on such terms and conditions and within such limits as the Committee deems appropriate provided that the sub-committee, Chief Executive Officer or employee subsequently advises the Committee of any right, power or responsibility so exercised.

Access to Management and Outside Advisors

The Audit and Risk Committee shall have unrestricted access to members of Management and relevant information.

The Audit and Risk Committee has the authority to retain legal counsel, accountants or other advisors to assist it in the conduct of any investigation, as it determines necessary to carry out its duties.

From: Ronald Kwan
To: John Kim
Cc: Usman Zahid
Subject: RE: OPG Q4 2017 Submission to Province
Date: Monday, February 26, 2018 6:39:38 PM

Thanks John.

Ron

From: John Kim
Sent: February-26-18 18:36
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Usman Zahid <Usman.Zahid@ofina.on.ca>
Subject: RE: OPG Q4 2017 Submission to Province

Thanks Ron….done and also FYI'ed Energy on Energy-related comments.

John

From: Ronald Kwan
Sent: Monday, February 26, 2018 5:53 PM
To: John Kim <John.Kim@ofina.on.ca>
Cc: Usman Zahid <Usman.Zahid@ofina.on.ca>
Subject: RE: OPG Q4 2017 Submission to Province

Hi John,

Go ahead and consolidate my comments with the other ones. I won't have time to review the F/S and AIF documents today, so please get back to OPG ASAP.

Thanks,
Ron

From: John Kim
Sent: February-26-18 17:38
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Usman Zahid <Usman.Zahid@ofina.on.ca>
Subject: FW: OPG Q4 2017 Submission to Province

Hi Ron,

Would you have any issues adding these edits to your comments (or vice versa)?

Thanks,

John

From: John Kim
Sent: Saturday, February 24, 2018 11:31 AM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Usman Zahid <Usman.Zahid@ofina.on.ca>; Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>; Darren Scanlan <Darren.Scanlan@ofina.on.ca>
Subject: RE: OPG Q4 2017 Submission to Province

Hi Ron,

Pls. see attached. No issue on the NR.

Thanks,

John

Z:\Users\CEF\Hydro 2018\OPG\Financials\Q4 2017

From: HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
Sent: February-16-18 5:11 PM
To: Shruti.Talwar@ontario.ca; Manu.Sud@ontario.ca; John Kim <John.Kim@ofina.on.ca>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: GORE Michael -FIN & C CTRL <michael.gore@opg.com>; PAN Rebecca -FIN & C CTRL <rebecca.pan@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>
Subject: OPG Q4 2017 Submission to Province

Hi All,

Please find attached OPG's draft Q4 2017 Financial Results Press Release, Management's Discussion and Analysis (MD&A), Annual Information Form (AIF) and Financial Statements for the Province's review.

We would greatly appreciate comments on the above **no later than Thursday, Feb 22nd**.

These documents will be filed with the Ontario Securities Commission on **Thursday, March 8th** following OPG's Board of Directors meeting.

Kindly forward all comments directly to Philip Ho – philip.ho@opg.com.

To assist the review process, the following are the key items in the Q4 2017 MD&A:

Highlights	
Recent Developments	MD&A p.13-19
OEB's Decision on OPG's Application for New Regulated Prices	MD&A p.13-15
Darlington Refurbishment	MD&A p.16-17; 28-30

Philip Ho, CPA, CA | Senior Manager, External Reporting & Accounting Policy | Ontario Power Generation
700 University Avenue, Toronto ON M5G 1X6 | Phone: (416) 592-3320| E-mail: philip.ho@opg.com

From:	John Kim
To:	Tobias P. Whitfield (MOF); Mike Manning; Ken Kandeepan
Cc:	Ronald Kwan; Malle Hanslep (MOF); Carlos Yep; John Psinas; Shajee Kathirgamanathan
Subject:	RE: OPG Q4 reporting - relevant excerpts for FHP
Date:	Monday, February 26, 2018 5:38:13 PM

Thanks Toby….will send these back.

John

From: Whitfield, Tobias P. (MOF) [mailto:Tobias.Whitfield@ontario.ca]
Sent: Monday, February 26, 2018 11:32 AM
To: John Kim <John.Kim@ofina.on.ca>; Mike Manning <Mike.Manning@ofina.on.ca>; Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
Cc: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; Malle Hanslep (MOF) <Malle.Hanslep@ontario.ca>; Carlos Yep <Carlos.Yep@ofina.on.ca>; John Psinas <John.Psinas@ofina.on.ca>; Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>
Subject: RE: OPG Q4 reporting - relevant excerpts for FHP

Please find attached comments on the excerpts. Let me know if you have any other questions.

Toby

Tobias Whitfield
Counsel, Legal Services Branch
Ministry of Finance
tobias.whitfield@ontario.ca
Phone: 416-325-1456

From: John Kim [mailto:John.Kim@ofina.on.ca]
Sent: February 26, 2018 11:04 AM
To: Manning, Mike (OFA); Kandeepan, Ken (OFA)
Cc: Kwan, Ronald (OFA); Hanslep, Malle (MOF); Whitfield, Tobias P. (MOF); Yep, Carlos (OFA); John Psinas; Kathirgamanathan,Shajee (OFA)
Subject: OPG Q4 reporting - relevant excerpts for FHP

Hi Mike, Ken,

We have the attached excerpts from OPG's draft Q4. Let me know if you have any comments on the draft wording, as highlighted.

I had shared these with Toby and Malle earlier this morning.

Thanks,

John

Y. John Kim

Director, Electricity Finance Branch
Ontario Financing Authority
e-mail: john.kim@ofina.on.ca
Ph: 416-212-6996

This message, including any attachments, is meant only for the use of the individual(s) to whom it is intended and may contain information that is privileged/confidential. Any unauthorized use, copying or disclosure is strictly prohibited. If you are not the intended recipient or have received this message in error, please notify us immediately by reply e-mail and permanently delete this message, including any attachments, without reading them, and destroy all copies. Thank you.

From:	John Kim
To:	Ronald Kwan
Subject:	RE: OPG Q4 reporting - relevant excerpts for FHP
Date:	Monday, February 26, 2018 5:33:31 PM

Hi Ron,

No others….will consolidate and send back now.

John

From: Ronald Kwan
Sent: Monday, February 26, 2018 5:32 PM
To: John Kim <John.Kim@ofina.on.ca>
Subject: RE: OPG Q4 reporting - relevant excerpts for FHP

Hi John,

Any other responses, besides Toby`s?

Ron

From: John Kim
Sent: February-26-18 11:04
To: Mike Manning <Mike.Manning@ofina.on.ca>; Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
Cc: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; Malle Hanslep (MOF) <Malle.Hanslep@ontario.ca>; Tobias P. Whitfield (MOF) <Tobias.Whitfield@ontario.ca>; Carlos Yep <Carlos.Yep@ofina.on.ca>; John Psinas <John.Psinas@ofina.on.ca>; Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>
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Y. John Kim
Director, Electricity Finance Branch
Ontario Financing Authority

e-mail: john.kim@ofina.on.ca
Ph: 416-212-6996

From: Ronald Kwan
To: John Kim
Subject: RE: OPG Q4 reporting - relevant excerpts for FHP
Date: Monday, February 26, 2018 5:32:30 PM

Hi John,

Any other responses, besides Toby`s?

Ron

From: John Kim
Sent: February-26-18 11:04
To: Mike Manning <Mike.Manning@ofina.on.ca>; Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
Cc: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; Malle Hanslep (MOF) <Malle.Hanslep@ontario.ca>; Tobias P. Whitfield (MOF) <Tobias.Whitfield@ontario.ca>; Carlos Yep <Carlos.Yep@ofina.on.ca>; John Psinas <John.Psinas@ofina.on.ca>; Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>
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John

Y. John Kim
Director, Electricity Finance Branch
Ontario Financing Authority
e-mail: john.kim@ofina.on.ca
Ph: 416-212-6996

From:	Whitfield, Tobias P. (MOF)
To:	John Kim; Mike Manning; Ken Kandeepan
Cc:	Ronald Kwan; Malle Hanslep (MOF); Carlos Yep; John Psinas; Shajee Kathirgamanathan
Subject:	RE: OPG Q4 reporting - relevant excerpts for FHP
Date:	Monday, February 26, 2018 11:32:14 AM
Attachments:	Q4 2017 OPG MDA - DRAFT - Feb 25_230PM_RPT excerpt for Prov (TPW Comments).docx Q4 2017 OPG FS Feb 25_230PM_RPT excerpt for Prov(TPW Comments).docx

Please find attached comments on the excerpts. Let me know if you have any other questions.

Toby

Tobias Whitfield
Counsel, Legal Services Branch
Ministry of Finance
tobias.whitfield@ontario.ca
Phone: 416-325-1456

From: John Kim [mailto:John.Kim@ofina.on.ca]
Sent: February 26, 2018 11:04 AM
To: Manning, Mike (OFA); Kandeepan, Ken (OFA)
Cc: Kwan, Ronald (OFA); Hanslep, Malle (MOF); Whitfield, Tobias P. (MOF); Yep, Carlos (OFA); John Psinas; Kathirgamanathan,Shajee (OFA)
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Y. John Kim
Director, Electricity Finance Branch
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e-mail: john.kim@ofina.on.ca
Ph: 416-212-6996

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ONTARIO POWER GENERATION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

DECEMBER 31, 2017

[DRAFT]

RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One, the IESO and the OEFC. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly-owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions for the years ended December 31 are summarized below:

	2017		2016	
(millions of dollars)	**Income**	**Expense**	**Income**	**Expense**
Hydro One				
Electricity sales	**8**	**-**	6	-
Services	**1**	**10**	1	5
Dividends	**7**	**-**	6	-
Province of Ontario				
Change in Decommissioning Segregated Fund amount due to Province [1]	**-**	**456**	-	192
Change in Used Fuel Segregated Fund amount due to Province [1]	**-**	**591**	-	235
Hydroelectric gross revenue charge	**-**	**110**	-	120
ONFA guarantee fee	**-**	**8**	-	8
Other	**-**	**2**	-	-
OEFC				
Hydroelectric gross revenue charge	**-**	**216**	-	203
Interest expense on long-term notes	**-**	**158**	-	169
Income taxes, net of investment tax credits	**-**	**246**	-	104
IESO				
Electricity related revenue	**4,802**	**-**	5,082	-
Earnings from Fair Hydro Trust	**1**	**-**	-	-
	4,819	**1,797**	5,095	1,036

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at December 31, 2017 and December 31, 2016, the Nuclear Segregated Funds were reported net of amounts due to the Province of $4,462 million and $3,415 million, respectively.

The receivable, AFS securities, payable and long-term debt balances between OPG and its related parties are summarized below:

(millions of dollars)	December 31 2017	December 31 2016
Receivables from related parties		
Hydro One	**1**	1
IESO – Electricity related receivables	**354**	421
IESO – Fair Hydro Trust [1]	**7**	-
OEFC	**-**	1
PEC	**4**	4
Province of Ontario	**3**	2
Financing receivables		
IESO – Fair Hydro Trust	**1,179**	-
Available-for-sale securities		
Hydro One shares	**188**	212
Accounts payable and accrued charges		
Hydro One	**1**	-
OEFC	**52**	61
Province of Ontario	**9**	2
IESO – Electricity-related payables	**5**	2
IESO – Fair Hydro Trust	**3**	-
Long-term debt (including current portion)		
Notes payable to OEFC	**3,195**	3,295

[1] Balance consists of unbilled revenue.

OPG holds interest-bearing Province of Ontario bonds in the Nuclear Segregated Funds and the OPG registered pension fund. As at December 31, 2017, the Nuclear Segregated Funds held $1,503 million of interest-bearing Province of Ontario bonds, while the registered pension fund had no such holdings. As at December 31, 2016, the Nuclear Segregated Funds and the registered pension fund held $1,652 million and $284 million of interest-bearing Province of Ontario bonds, respectively. These bonds are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

In December 2017, the Fair Hydro Trust purchased its first tranche of Investment Interest from the IESO for an exchange amount of $1.18 billion, which has been classified as a financing receivable on OPG's consolidated balance sheet. The transaction was settled in cash using proceeds from the Trust's issuance of senior and subordinated debt. Pursuant to the general regulation of the Fair Hydro Act, the IESO is required to pay and remit carrying costs of the Trust, excluding repayment of principal on any debt obligations, up to July 31, 2021. Commencing May 1, 2021, Specified Consumers will be invoiced by their local distribution company for the Clean Energy Adjustment to pay the carrying costs of the Trust. These funds will be remitted to the Trust through the IESO and will be used to settle all funding and other related expenses of the Trust that underlie the financing receivable.

As at December 31, 2017, OPG's consolidated balance sheet included approximately $7 million of unbilled revenue from the IESO, primarily for OPG's general fee for 2017 as the Financial Services Manager under the Act relating to incurred third-party and certain direct labour costs.

~~Under one of the Trust's program agreements,~~ The~~the~~ Province has provided a limited guarantee to specified creditors of the Fair Hydro Trust. The limited guarantee would be triggered in the event that the Trust's ability to receive amounts in respect of its Investment Interest to pay for certain funding obligations is adversely affected due to the occurrence of any one of the following: the Province changes the Fair Hydro Act or any other legislation or

regulation; Ontario's electricity market significantly changes due to actions undertaken by the Province; or a court declares that the Act is ~~declared~~ invalid or unconstitutional.

ONTARIO POWER GENERATION INC.

CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2017

[DRAFT]

19. RELATED PARTY TRANSACTIONS

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[1] Balance consists of unbilled revenue.

OPG holds interest-bearing Province of Ontario bonds in the Nuclear Segregated Funds and the OPG registered pension fund. As at December 31, 2017, the Nuclear Segregated Funds held $1,503 million of interest-bearing Province of Ontario bonds, while the registered pension fund had no such holdings. As at December 31, 2016, the Nuclear Segregated Funds and the registered pension fund held $1,652 million and $284 million of interest-bearing Province of Ontario bonds, respectively. These bonds are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

In December 2017, the Fair Hydro Trust purchased its first tranche of Investment Interest from the IESO for an exchange amount of $1.18 billion, which has been classified as a financing receivable on OPG's consolidated balance sheet. The transaction was settled in cash using proceeds from the Trust's issuance of senior and subordinated debt. Pursuant to the general regulation of the Fair Hydro Act, the IESO is required to pay and remit carrying costs of the Trust, excluding repayment of principal on any debt obligations, up to July 31, 2021. Commencing May 1, 2021, Specified Consumers will be invoiced by their local distribution company for the Clean Energy Adjustment to pay the carrying costs of the Trust. These funds will be remitted to the Trust through the IESO and will be used to settle all funding and other related expenses of the Trust that underlie the financing receivable.

As at December 31, 2017, OPG's consolidated balance sheet included approximately $7 million of unbilled revenue from the IESO, primarily for OPG's general fee for 2017 as the Financial Services Manager under the Act relating to incurred third-party and certain direct labour costs.

~~Under one of the Trust's program agreements, the~~The Province has provided a limited guarantee to specified creditors of the Fair Hydro Trust. The limited guarantee would be triggered in the event that the Trust's ability to receive amounts in respect of its Investment Interest to pay for certain funding obligations is adversely affected due to the occurrence of any one of the following: the Province changes the Fair Hydro Act or any other legislation or

regulation; Ontario's electricity market significantly changes due to actions undertaken by the Province; or a court declares that the Act is ~~declared~~ invalid or unconstitutional.

From:	John Kim
To:	Ken Kandeepan
Cc:	Tobias P. Whitfield (MOF); Mike Manning; Ronald Kwan; Malle Hanslep (MOF); Carlos Yep; John Psinas; Shajee Kathirgamanathan
Subject:	RE: OPG Q4 reporting - relevant excerpts for FHP
Date:	Tuesday, February 27, 2018 7:19:22 AM

Great, thanks Ken

From: Ken Kandeepan
Sent: Monday, February 26, 2018 6:56 PM
To: John Kim <John.Kim@ofina.on.ca>
Cc: Tobias P. Whitfield (MOF) <Tobias.Whitfield@ontario.ca>; Mike Manning <Mike.Manning@ofina.on.ca>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>; Malle Hanslep (MOF) <Malle.Hanslep@ontario.ca>; Carlos Yep <Carlos.Yep@ofina.on.ca>; John Psinas <John.Psinas@ofina.on.ca>; Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>
Subject: Re: OPG Q4 reporting - relevant excerpts for FHP

Sorry for the delay, agree with Toby's edits, I don't have any to add.

Thanks

Ken k

On Feb 26, 2018, at 5:38 PM, John Kim <John.Kim@ofina.on.ca> wrote:

> Thanks Toby….will send these back.
>
> John
>
> **From:** Whitfield, Tobias P. (MOF) [mailto:Tobias.Whitfield@ontario.ca]
> **Sent:** Monday, February 26, 2018 11:32 AM
> **To:** John Kim <John.Kim@ofina.on.ca>; Mike Manning <Mike.Manning@ofina.on.ca>; Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
> **Cc:** Ronald Kwan <Ronald.Kwan@ofina.on.ca>; Malle Hanslep (MOF) <Malle.Hanslep@ontario.ca>; Carlos Yep <Carlos.Yep@ofina.on.ca>; John Psinas <John.Psinas@ofina.on.ca>; Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>
> **Subject:** RE: OPG Q4 reporting - relevant excerpts for FHP
>
> Please find attached comments on the excerpts. Let me know if you have any other questions.
>
> Toby
>
> Tobias Whitfield
> Counsel, Legal Services Branch

Ministry of Finance
tobias.whitfield@ontario.ca
Phone: 416-325-1456

From: John Kim [mailto:John.Kim@ofina.on.ca]
Sent: February 26, 2018 11:04 AM
To: Manning, Mike (OFA); Kandeepan, Ken (OFA)
Cc: Kwan, Ronald (OFA); Hanslep, Malle (MOF); Whitfield, Tobias P. (MOF); Yep, Carlos (OFA); John Psinas; Kathirgamanathan,Shajee (OFA)
Subject: OPG Q4 reporting - relevant excerpts for FHP

Hi Mike, Ken,

We have the attached excerpts from OPG's draft Q4. Let me know if you have any comments on the draft wording, as highlighted.

I had shared these with Toby and Malle earlier this morning.

Thanks,

John

Y. John Kim
Director, Electricity Finance Branch
Ontario Financing Authority
e-mail: john.kim@ofina.on.ca
Ph: 416-212-6996

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From: Bruno Amara
To: Ronald Kwan
Cc: John Kim
Subject: RE: OPG changes
Date: Thursday, February 15, 2018 7:24:13 PM
Attachments: OPG Comparisons.xlsx

Sorry, fixed a couple of labelling issues

Bruno

From: Ronald Kwan
Sent: Thursday, February 15, 2018 7:19 PM
To: Bruno Amara <Bruno.Amara@ofina.on.ca>
Cc: John Kim <John.Kim@ofina.on.ca>
Subject: Re: OPG changes

Thanks Bruno.

Ron

On Feb 15, 2018, at 7:17 PM, Bruno Amara <Bruno.Amara@ofina.on.ca> wrote:

> Hi Ron
>
> For what it's worth, I put these tables together to help make more clear the changes in OPG's Outlook when comparing OPG's current 2018-2021 BP to a) 2017 Budget and b) our previous January 2018 Outlook distribution.
>
> Bruno
>
> Bruno Amara
> Sr. Manager, Financial and Regulatory Analysis
> Electricity Finance Branch
> Corporate and Electricity Finance Division
> Ontario Financing Authority
>
> Tel: 416-325-1489
> Email: bruno.amara@ofina.on.ca
>
> <OPG Comparisons.xlsx>

OPG Business Plan 2018-2021

	$ Millions				2017 Budg $ Millions
	2017-18	**2018-19**	**2019-20**	**2020-21**	**2017-18**
Net Income	712	795	1,053	877	480
OPG Headquarters**	283				
OPG Lakeview**	200				
Sub-total	**1,195**	**795**	**1,053**	**877**	**480**
OPG Fair Hydro Plan Amounts	10	80	150	225	17
Sub-total	**1,205**	**875**	**1,203**	**1,102**	**497**
IFRS Adjustment	(400)	(475)	(700)	(750)	(400)
Sub-total	**805**	**400**	**503**	**352**	**97**
PILs					
GRC to OEFC	206	209	212	212	205
Property Tax to OEFC	13	14	14	13	18
Sub-total	**219**	**223**	**226**	**225**	**223**
Income Tax PLs	58	54	175	169	92
OPG Headquarters**	93				74
OPG Lakeview**	70				-
Sub-total	**221**	**54**	**175**	**169**	**166**
Total OPG	**1,245**	**677**	**904**	**746**	**486**

* 2017 Budget is based on OPG 2017-2019 Business Plan. 2020-21 is EFB estimate

** OPG Headquarters and Lakeview amonts were reported in Sales and Rentals at the time of the 2017 Budget

get*			Change $ Millions				
2018-19	**2019-20**	**2020-21**	**2017-18**	**2018-19**	**2019-20**	**2020-21**	
678	726	913	232	117	327	(36)	
			283	-	-	-	
			200	-	-	-	
678	**726**	**913**	**715**	**117**	**327**	**(36)**	
54	99	153	(7)	26	51	72	
732	**825**	**1,066**	**708**	**143**	**378**	**36**	
	(200)		-	(475)	(500)	(750)	
732	**625**	**1,066**	**708**	**(332)**	**(122)**	**(714)**	see change table line 7
212	219	220	1	(3)	(7)	(8)	
19	19	19	(5)	(5)	(5)	(6)	
231	**238**	**239**	**(4)**	**(8)**	**(12)**	**(14)**	
135	170	298	(34)	(81)	5	(129)	
			19	-	-	-	
			70	-	-	-	
135	**170**	**298**	**55**	**(81)**	**5**	**(129)**	
1,098	**1,033**	**1,603**	**759**	**(421)**	**(129)**	**(857)**	

OPG Business Plan 2018-2021

	$ Millions					$ Millions
	2017-18	**2018-19**	**2019-20**	**2020-21**		**2017-18**
Net Income	1,037	795	1,053	877		574
OEB Impact*	(325)	na	na	na		(320)
OPG Headquarters**	283					283
OPG Lakeview**	200					
Sub-total	**1,195**	**795**	**1,053**	**877**		**537**
OPG Fair Hydro Plan Amounts	10	80	150	225		12
Sub-total	**1,205**	**875**	**1,203**	**1,102**		**549**
IFRS Adjustment	(400)	(475)	(700)	(750)		(400)
Sub-total	**805**	**400**	**503**	**352**	-	**149**
PILs						
GRC to OEFC	206	209	212	212		214
Property Tax to OEFC	13	14	14	13		18
Sub-total	**219**	**223**	**226**	**225**		**232**
Income Tax PLs	58	54	175	169		67
OEB Impact*	-	na	na	na		(107)
OPG Headquarters**	93					95
OPG Lakeview**	70					
Sub-total	**221**	**54**	**175**	**169**		**55**
Total OPG	**1,245**	**677**	**904**	**746**		**436**

* OPG Business Plan noted that impavct of deferred effective date was $325M (impact note separated out in pre

** OPG Headquarters and Lakeview amonts were reported in Sales and Rentals at the time of the 2017 Budget.c

lectricty Outlook Distribution

Change
$ Millions

2018-19	2019-20	2020-21	2017-18	2018-19	2019-20	2020-21	
678	726	913	463	117	327	(36)	
(109)	(115)	(136)	(5)				
			-	-	-	-	
			200	-	-	-	
569	**611**	**777**	**658**	**226**	**442**	**100**	
42	82	128	(2)	38	68	97	
612	**693**	**906**	**656**	**263**	**510**	**196**	
(475)	(700)	(750)	-	-	-	-	
137	**(7)**	**156**	**656**	**263**	**510**	**196**	see change table line 7
224	222	222	(8)	(15)	(10)	(10)	
19	19	19	(5)	(5)	(5)	(6)	
243	**241**	**241**	**(13)**	**(20)**	**(15)**	**(16)**	
135	170	298	(9)	(81)	5	(129)	
			107				
			(2)	-	-	-	
			70	-	-	-	
135	**170**	**298**	**166**	**(81)**	**5**	**(129)**	
515	**404**	**695**	**809**	**162**	**500**	**51**	

evious table)

distribution included OPG Headquarters but not Lakeview.

7

From:	Ronald Kwan
To:	John Kim; Shajee Kathirgamanathan; Gavin He
Cc:	Usman Zahid
Subject:	RE: OPG submission - April 10th TB/MBC
Date:	Friday, April 06, 2018 7:11:55 PM
Attachments:	5 2018-04-10 RAN OPG Business Plan v2-Markup.doc

Hi,

Some comments and suggestions, as attached.

When is James expecting this?

Ron

From: Shajee Kathirgamanathan
Sent: April-06-18 14:02
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Usman Zahid <Usman.Zahid@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>
Subject: RE: OPG submission - April 10th TB/MBC

Hi Ron,

TBS shared their note for the OPG BP submission. We've made a few edits for TB and some comments for them to follow up with Energy on.

Please see file attached and found here:
S:\Users\CEF\Hydro 2018\Cabinet Submissions\OPG BP\TB Note

If it looks good we can send it over to James.

Thanks,
Shajee

Shajee Kathirgamanathan
Office: 416-325-1402 | Mobile: 647-294-3359
shajee.kathirgamanathan@ofina.on.ca

From: Strang, James (TBS) [mailto:James.Strang@ontario.ca]
Sent: Wednesday, April 04, 2018 9:26 AM
To: Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>
Cc: Usman Zahid <Usman.Zahid@ofina.on.ca>
Subject: RE: OPG submission - April 10th TB/MBC

Morning Shajee,

Draft note OPG BP attached. Also the note for the MNO item for Usman (Ron may be interested in it given cash management).

TB/MBC Chair's briefing for both Energy items scheduled for 1pm with the OPG item going second at 1:05pm.

James

From: Shajee Kathirgamanathan [mailto:Shajee.Kathirgamanathan@ofina.on.ca]
Sent: April 3, 2018 1:20 PM
To: Strang, James (TBS)
Cc: He, Gavin (OFA); Kim, John (OFA)
Subject: RE: OPG submission - April 10th TB/MBC

Hi James,

Hope you had a good weekend.

Just a friendly follow up on this, would you have details on the Chair's briefing?

Thanks,
Shajee

TREASURY BOARD / MANAGEMENT BOARD OF CABINET
REQUEST ASSESSMENT NOTE

Ministry:	Energy
Meeting Date:	April 10, 2018
Agenda Class:	Discussion (In Camera)
Last reviewed by: TB/MBC (May 9, 2017)	**Tracking to:** Cabinet (April 18, 2018)

SUBMISSION TITLE:	2018-2021 Business Plan for Ontario Power Generation

I. DECISION BEFORE THE BOARD

- Receive Ontario Power Generation's (OPG) 2018-2021 Business Plan

II. RECOMMENDATIONS:

• Receive the 2018-2021 business plan for Ontario Power Generation	*Receive*
• Note Minister of Energy will provide concurrence with OPG's Business Plan	*Note*

III. FINANCIAL SUMMARY

$ Millions	**2018-19**	**2019-20**	**2020-21**
Initiative cost requested	0.0	0.0	0.0
Initiative cost recommended	0.0	0.0	0.0
Recommended program base	0.0	0.0	0.0
Offset Recommended (Specify Ministry/Program)	0.0	0.0	0.0
Total Fiscal Impact	0.0	0.0	0.0

IV. KEY COMMENTS AND CONSIDERATIONS

As stipulated as part of the 2013-14 Results-based Planning process, the Ministry of Energy is submitting OPG's annual business plans for review by Treasury Board to facilitate incorporating implications into the Province's fiscal plan.

It is under the responsibility of the Minister of Energy on whether or not to provide the Minister's concurrence of OPG's annual multi-year business plan. The Treasury Board submission provides the Minister of Energy with an opportunity to highlight why concurrence is being given and any conditions placed on it. Appendix C provides more information on the concurrence process and the 2013-14 minute.

Under the memorandum of agreement (MOA, July 2015) between the Province (as sole shareholder and the Ministry of Energy as representative of the shareholder) and OPG, the company is required to annually submit its board-approved multi-year business plan to the Minister of Energy for concurrence. The concurrence letter from the Minister to the company will note key elements of the business plan, how these elements relate to the policy direction and priorities of the Province, and the government's expectation for the performance of the company including indicating any elements of the business plan the government does not concur.

In February 2018, OPG submitted its Board approved 2018-2021 Business Plan to the Ministry.

Ontario's Fair Hydro Plan (OFHP) is reflected in OPG's latest Business Plan. The Ministry notes the following OFHP implications for OPG:

- As part of supporting the financing and administration of the global adjustment refinancing, OPG's Special Purpose Vehicle (OPG Trust) uses 100 per cent debt financing to purchase the right to future cash flows from IESO. The OPG Trust raises 51% of required funding directly from capital markets while OPG ~~provides~~lends the Trust 49% of the financing requirements. The latter is ~~financ~~raised by OPG ~~rais~~borrowing up to 5% from capital markets, with the remaining 44~~-49~~% from share issuances (an equity injection ~~[and/or debt financing]~~ from the Province, which is debt-financed through the OFA. (Estimates provides for a Ministry of Energy operating asset to make the equity injection.)~~.~~
    - As Provincial borrowing for an equity injection is ~~be~~ offset by an increase in an investment asset in OPG, the Province's net debt position ~~would~~ remains unchanged.
    - ~~Changes are~~Provincial borrowing is not expected to have a negative ~~be~~ fiscal~~ly~~ impact ~~neutral~~ as the~~y result in an~~ increase in Provincial interest on debt is expected to be~~,~~ offset by increases in OPG net income from the interest charged to the OPG Trust.

The Ministry of Energy indicates it is supportive of the fiscal, financial and operational strategies laid out in the business plan, and that the Minister of Energy intends to provide concurrence.

Financial figures from the OPG Business Plan are included and supplemented with more recent forecast adjustments from the Ontario Financing Authority, MOF, for more recent OPG in-year, 2017-18 forecast updates, and for estimated OFHP implications, as part of Province's finalized fiscal plan for the 2018 Budget.

The earnings before tax (net income and income tax payments in lieu – PILs) of OPG are consolidated on the Province's financial statements and have a one-for-one impact on the Province's surplus/deficit position, excluding adjustments that the Province make upon consolidation of OPG's financials (e.g., unrealized gains or losses in the nuclear funds). OPG is expected to submit its next multi-year business plan later this year for the period starting January 1, 2019.

Overview of Current Business Plan

OPG's 2018-21 Business Plan details key company undertakings such as ~~business transformation and~~ nuclear refurbishment that will have a substantial electricity system benefit, ratepayer and shareholder impacts. These items were flagged in the previous year's multi-year business plan as well.

- Key Income Statement Forecasts *(Confirmation pending from Ontario Financing Authority)*:
    - 2018 Budget projections were based on the figures in the OPG Board approved 2018-2021 Business Plan, with adjustments made by OFA/MOF~~, and~~ OPG's 2018-21 Business Plan shows an increase in earnings before tax of $528M in 2018 (includes gain on sale of 700 University Ave and an estimate of the sale of Lakeview), $4M in 2019, $307M in 2020, above projections in the previous 2017-2019 OPG Business Plan (last year's plan). These figures exclude earnings before taxes from Fair Hydro Plan.

      OPG continues to forecast net income attributable to the Shareholder (excluding Fair Hydro Trust) to reach $1B in 2021~~, from $463M in 2016~~. Net income is forecast to grow from $860M in 2017 to $1,373M in 2021, reflecting regulated rates based on the OEB's 2017-2021 rate decision inclusive of a significant increase in rate base upon return to service of Darlington Unit 2, continuous operational improvement, and the impact of the Fair Hydro Trust.

Commented [GH1]: How has or will OPG's credit metrics be impacted by (borrowing for) the Fair Hydro Plan?

Commented [SK2]: 5% and 44%

Commented [RK3]: Did we have in-year updates, aside from adjustments for IFRS and ONFA?

Commented [RK4]: Did we make an adjustment, beyond what was included in OPG's BP for this?

Commented [RK5]: Isn't this old language from the BTI in the first half of the decade?

Commented [GH6]: Breaking up the sentence as the 2018 Budget did not show this information.

Commented [RK7]: Isn't this now included?

Commented [RK8]: ?

Commented [GH9]: Suggest to delete this. The 2016 actual is not in the new BP, and $463M is the actual for fiscal year 2015-16, but the OPG numbers outlined here are in calendar year, not fiscal year.

- The Trust is forecast to contribute over $500M in net income over the planning period, reflecting the spread earned on the zero cost to OPG of the equity contributions from the Province to fund 44% of OPG's financing of the Trust). This net income will offset the Province's interest on debt costs to finance the equity contributions.

Although net income is projected to grow, return-on-equity (ROE) is estimated to decrease from 7.6% in 2017 to 7.1% by 2021 as the effect of higher earnings is more than offset by a forecast increase in the equity base (r~~R~~eflecting the Province's equity contributions funding 44% of the Fair Hydro Trust financing).

These estimates are highly dependent on electricity and financial market conditions, regulatory decisions by the Ontario Energy Board (OEB), potential changes to accounting standards or the basis of consolidation in Public Accounts, including a consolidation adjustment to International Financial Reporting Standards (IFRS) for Public Accounts purposes, operational performance, and/or government policy, which can change materially.

The current Provincial Fiscal Plan projects net income from OPG of $1,099M in 2017-18, and ~~will~~is expected to decrease in the following 3 years, in part, due to higher IFRS consolidation risk adjustments. Below is a summary table of OPG revenues built into 2018 Budget Projections:

Fiscal Plan - OPG Net Income

	2017-18	2018-19	2019-20	2020-21
OPG Net Income (OPG Business Plan)	1,195	795	1,053	877
GA Financing - OPG Trust Interest Revenue	10	80	150	225
OPG IFRS consolidation risk	(300)	(375)	(475)	(425)
OPG Income (IFRS basis)	905	500	728	677
~~ONFA~~Nuclear Funds Consolidation Adjustments	194	0	0	0
OPG Net Income (Reflected in Fiscal Plan)	**1,099**	**500**	**728**	**677**

Fiscal Plan - OPG PILs/Gross Revenue Charge (GRC)

	2017-18	2018-19	2019-20	2020-21
OPG Income Tax (PILs)	221	54	175	169
GRC: Payable to OEFC	206	209	212	212
Proxy Property Tax PILs to OEFC	13	14	14	13
Total OPG PILs / GRC	**440**	**277**	**401**	**394**

- Key Operational Metrics:
  - Annual Operations, Maintenance & Administration (OM&A) expenses from ongoing operations over the planning period 2018-2021 is targeting reductions of about $600M compared to last year's plan.
  - The cost of OPG generated electricity to customers is projected to remain ~45% below the average non-OPG cost of electricity to 2018, and over ~43% by 2021. Note: OPG provides

predominantly, lower-cost baseload generating capability, rather than more expensive peaking generating capability.

- Headcount Efficiencies – Headcount has fallen from 11,686 in 2010 to a forecasted 9,434 in 2018.

  Actual year-end 2017 headcount was about 590 lower than expected in the previous plan. This trend continues over the 2018-2021 planning period as forecast headcount is lower by about 410 employees, on average, in each year.

  OPG's plan reflects the addition of about 300 Term Employees, a new category of non-regular staff negotiated with the Power Workers' Union (PWU) through collective bargaining in 2015. OPG intends to add fewer regular staff in circumstances where they are likely to be laid off as a result of the end of Pickering commercial operations.

Commented [GH10]: Could additional details/information be provided on how the workforce numbers would be after the closure of Pickering?

- Key Projects:
  - The plan assumes ongoing operations at Pickering for about four years beyond 2020, and, as approved by Cabinet, the execution of the Darlington refurbishment consistent with an approved budget of $12.8 billion is now under way.
    - (OPG indicates it is approaching the midpoint in the schedule for refurbishment of Unit 2 and the project is tracking on time and on budget. First unit refurbishment, Unit 2, began in October 2016 and is assumed to be returned to service in February 2020, with the second unit refurbishment, Unit 3, commencing immediately thereafter in February 2020, and the third unit, Unit 1, refurbishment starting in July 2021, assuming necessary concurrence from the Province is obtained. (The Province recently agreed with OPG's assessment on Unit 2 progress and is not exercising and "off ramp" before Unit 3).
  - Total capital expenditures planned for the Darlington refurbishment, sustaining investments in existing assets, and organic development project $7.5B over the 2018-2021 planning period, this represents an increase of about $570M compared to the previous plan.

Commented [RK11]: ?

Commented [RK12]: State why.

- Rate Application to the OEB (Update from previous OPG Business Plan):
  - The OEB decision on revenue requirements was released December 28, 2017. OPG filed ists reply to a draft Payment Amounts Order on February 5, 2018 and includes a rate smoothing proposal that aims to make smoother customer bills as, for example, refurbished nuclear units at Darlington are brought back into production, triggering recovery of refurbishment costs from ratepayers.
  - Final revenues for OPG are still to be finalized (OEB decision expected in the first half of 2018)
  - OPG indicates the OEB decision disallowed a variety of revenue requirement items, and that it has taken proactive steps to mitigate a large portion of disallowances.

Key Risks:

Capital project completion – Led by Darlington Refurbishment, the plan includes extensive capital spending. Failure to meet project timelines and budgets reduces income due to lower production revenues and higher costs.

- OPG improved its project management planning in recent years.
- In the 2017-21 regulated payments Decision, the OEB stated it was satisfied with OPG's planning approach to Darlington and approved all project costs.
- OPG executive compensation is tied to milestone achievement on Darlington Refurbishment, and completion of other capital projects such as Ranney Falls and Nanticoke Solar.

Efficiency Improvements – The plan forecasts higher production and lower costs due to efficiency

improvements. Targets may not be achieved if these measures do not materialize as planned.

- Investments at Pickering contribute to efficiency targets. Some efficiency strategies have already been implemented.
- OPG is implementing its "OPG25" strategy aimed at preparing the organization for a post Pickering / post Refurbishment future where company operations and support functions are sized appropriately. Implementing strategies on staffing plans, use of non regular staff and use of "term" employees will help achieve efficiencies targeted in the plan and mitigate future staff downsizing costs associated with Pickering closure in the future.

Collective Bargaining – Many of OPG's strategies to reduce OM&A costs are dependent on successful outcomes of 2018 collective bargaining with PWU and Society.

- OPG hopes to build on successful 2015 agreement where it made progress on managing staff costs, reduced pension liability and introduced the use of term employees that carry reduced pension and severance obligations. .
- The Minister of Energy wrote to OPG in March 2018 signalling support for continued progress in managing costs through collective bargaining.

Pickering Licen~~s~~ce Extension – The plan assumes the federal ~~government~~regulator, the Canadian Nuclear Safety Commission (CNSC), will approve the extension of the Pickering Station's licen~~s~~ce without conditions in summer 2018. Production revenues and costs will be impacted if Pickering cannot operate beyond 2020.

- OPG has met filing requirements for the Pickering licen~~s~~ce extension.
- In its rate application, OEB approved costs for OPG to move forward with enabling work on Pickering.
- In March 2018 CNSC staff recommended a 10-year licen~~s~~ce extension.

Attracting talent & leadership – Inability to retain and attract leadership talent and qualified management employees could impact the execution of Darlington refurbishment, Pickering operations and other priorities.

- OPG plans to strengthen its leadership pipeline and increase diversity through the recruitment / selection process, and employee and leadership development programs.
- OPG's executive compensation program allow OPG to benchmark against private sector and international comparators, helping it to attract and retain executive talent

Performance risks: OPG's financial performance could be subjected to nuclear reliability issues such as unplanned outages and financial market risk on the performance of the nuclear funds, for which the Province consolidates on a realized [gains or losses] basis.

Accounting risks: A change in the basis of accounting used for consolidation of OPG results from U.S. GAAP to International Financial Reporting Standards (IFRS) on the Province's financial statements ~~is expected to~~ result~~s~~ in ~~potentially~~ significant fiscal impacts.

- OPG cites a risk of not extending Ontario Securities Commission exemption that Allows OPG to prepare consolidated financial statements under U.S. GAAP. Adoption of IFRS expected to cause significant net income volatility compared to U.S. GAAP.

Financing Costs: Higher cost public capital market borrowing (vs the Province's borrowing cost for OEFC to lend to OPG) would have a negative fiscal impact.

Regulatory Risk: [Should cite the Pension & OPEB risk.]

Commented [GH13]: What kind of (job) action can be taken by PWU or SEP (if any), should agreements not be reached. Furthermore what kind of (job) action could happen to affect the Darlington Refurbishment Project? Can any of these actions affect the timing, scope, deliverables and costs of the refurbishment? Can actions affect contracts with suppliers and also affect timing, scope, deliverables and costs of the refurbishment or is refurbishment insulated from collective agreements. Does OPG have a contingency plan?

Commented [GH14]: Although this was provided in the OPG BP Deck, the details of the compensation information are not included in the OPG Business Plan. Could OPG provide more details on the executive compensation package, including the methodology/comparison between private sector and international comparators?

In OEB's Dec 28th rate decision, it mentioned that OPG's compensation was still high. So how is OPG addressing those findings from OEB?

Name of analyst:	James Strang	**Phone number:**	7-2071
Date:	April 3, 2018	**Log number:**	
Branch / Division:	General Government, Planning and Resources Branch, PEM, TBS		

APPENDIX A: PROPOSED MINUTE

Note receipt of Ontario Power Generation's 2018-2021Business Plan.

In this regard,

i) Note the Minister of Energy will provide Ontario Power Generation (OPG) with a concurrence letter for its Business Plan.

ii) Direct the Ministry, in consultation with the Ministry of Finance / Ontario Financing Authority, to report back to the Board in early January each year with the approved or latest draft business plans for Ontario Power Generation for fiscal planning purposes.

FINANCIAL IMPACTS: CHANGES TO EXPENSE AND REVENUE					TABLE B1
		Fiscal Plan Basis			*Appropriations Basis*
$ Millions		**2014-15**	**2015-16**	**2016-17**	**2014-15**
Initiative cost recommended		0.0000	0.0000	0.0000	
Expense changes:					
Operating item	Oper	0.0000	0.0000	0.0000	0.0000
Capital item	Cap	0.0000	0.0000	0.0000	00000
Revenue changes:					
Revenue increase/offset		0.0000	0.0000	0.0000	
Revenue decrease		0.0000	0.0000	0.0000	
Total Fiscal Impact (draw from c-funds)		**0.0000**	**0.0000**	**0.0000**	**0.0000**

APPENDIX C: CONCURRENCE OVERVIEW

Under agreements between the Province (as sole shareholder) and OPG, the company is required to annually submit its multi-year business plan to the Minister of Energy for concurrence. Review of the business plan by Treasury Board prior to concurrence was stipulated as part of the 2013-14 Results-based Planning process (see below).

Concurrence is typically provided to OPG via a letter from the Minister of Energy. The letter will note key elements of the business plan, how these elements relate to the policy direction and priorities of the Province, and the government's expectation for the performance of the company. The letter may also indicate any elements of the business plan of which the government does not concur and/or provide additional guidance on expectations going forward.

The current submission looks at the multi-year business plan for OPG covering 2018~~6~~-2021~~8~~. Concurrence with the plan is still pending.

Below is the 2013-14 Results-based Plan Minute:

> Directed the Ministry of Energy and its agencies, Ontario Power Generation Inc. and Hydro One Inc., in consultation with the Ontario Financing Authority, to report back:
>
> - Annually each autumn with the respective multi-year business plans of the agencies as approved by the Boards of the companies, for review by Treasury Board/Management Board of Cabinet.
> - In this regard, the report should include the following, on a calendar and government fiscal year basis:
> - Multi-year financial and operational targets, including net income and earnings-before-tax.
> - Projected revenues and cash flows to the Province, including the Ontario Electricity Financial Corporation.
> - Planned financings from the Ontario Electricity Financial Corporation.
> - Quarterly with financial projection updates and progress reports on the agencies' respective business plan targets and any other new developments, initiatives or risks that may have a material fiscal impact on the Province including variance analysis of last quarter and year-to-date against the annual business plan reviewed by Treasury Board/Management Board of Cabinet.

APPENDIX D: SUMMARY OF KEY HIGHLIGHTS FROM OPG BUSINESS PLAN

Financials

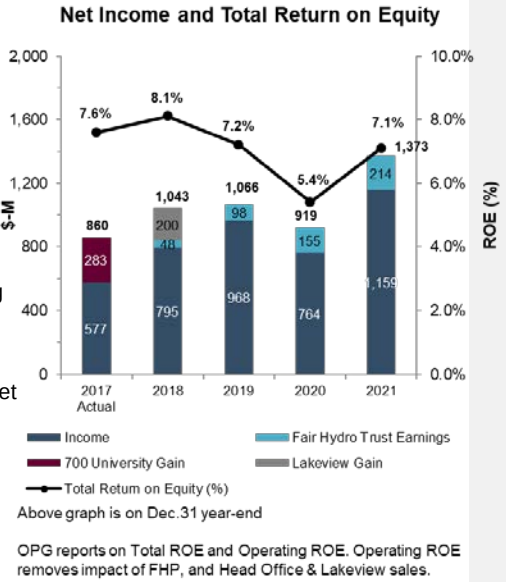
The 2018-2021 Plan forecasts total net income attributable to the Shareholder to reach $1.37B in 2021, from $860M in 2017.

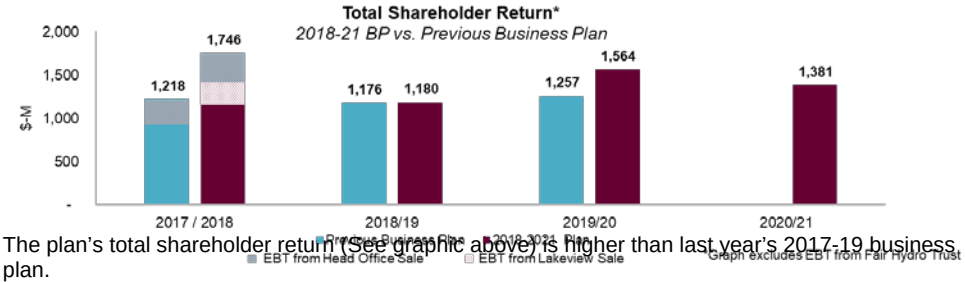
The plan reflects the OEB's December 2017 Decision on OPG's regulated rates through 2021, providing stability in the planning period.

The chart on the right shows Total Return on Equity (ROE). OPG also reports Operating ROE, which excludes impact of Fair Hydro Trust and one-time real estate gains. Operating ROE, a performance metric for executive compensation, is forecasted to increase from 5.3% in 2017 to 8.1% in 2021

Should OPG fail to meet targets for production, operating cost reductions or capital expenditures, net income improvements may not materialize.

Total net income in 2017/18 is impacted by one-time asset sales (Head Office and Lakeview), with net proceeds credited to the Trillium Trust.





The plan's total shareholder return (See graphic above) is higher than last year's 2017-19 business plan.

The financial performance reflects increased efficiency leading to revenue increases from higher production and lower operating costs. Head Office and Lakeview sales lead to higher than normal return in 2017/18:

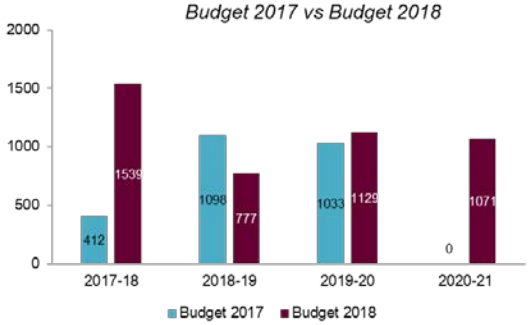
- Head Office sale generates $283M in net income and approximately $93M in PILS. The return is about $80M higher than assumed in previous business plan.
- Lakeview sale generates $200 million in net income and about $70M in PILS. The Lakeview sale was not included in the previous business plan.

The 2018 Ontario Budget reflects the impacts of OPG's 2018-2021 Business Plan.

When OPG's planning projections and financial results are consolidated into the Province's Budget and Public Accounts, some adjustments are required

- **IFRS:** OPG uses US GAAP accounting standards for financial reporting. The Province consolidates OPG's results adjusted to an International Financial Reporting Standards (IFRS) basis.
- **Nuclear Funds:** For the operating statement for Public Accounts, an adjustment is made to a realised gains basis, vs a fair value basis on OPG's statements.

Total OPG Revenues to the Province
Budget 2017 vs Budget 2018



2017/18 positive variance due to:
- $846M for real estate sales included as OPG revenue in Budget 2018. In Budget 2017, projected OPG real estate revenues were included in the Sales and Rentals line.
- Positive ONFA Adjustments included in Budget 2018 not in Budget 2017
- Lower IFRS adjustment in Budget 2018 than Budget 2017

2018/19 negative variance due to:
- Negative IFRS adjustment included in Budget 2018

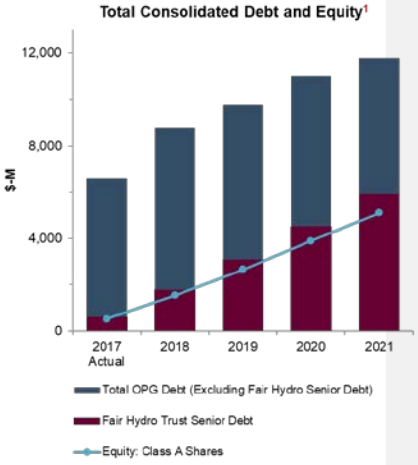
- **Fair Hydro Income:** While OPG separates out this income in its Business Plan, OPG's Financial Services Manger revenue is added to OPG net income when consolidated.

Ontario Fair Hydro Plan (OFHP)

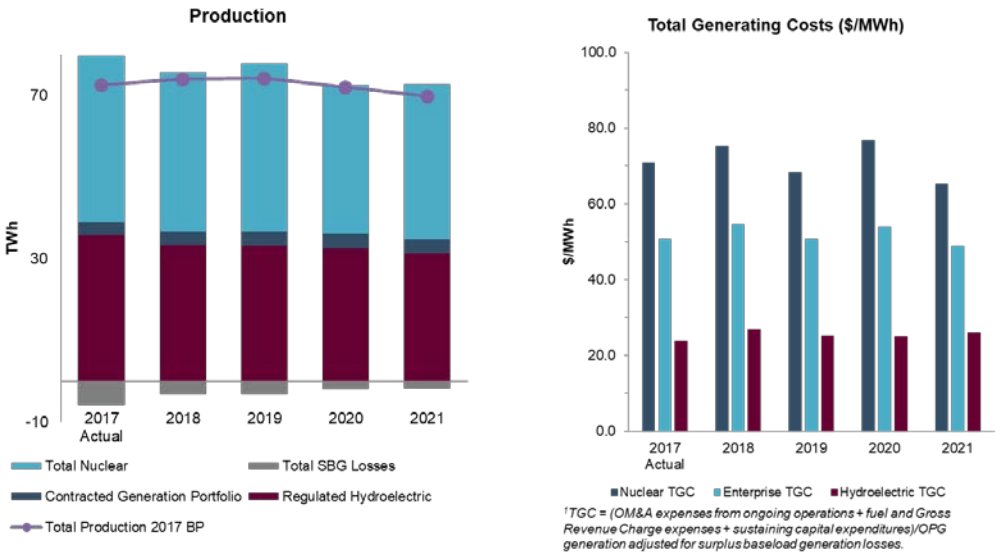
FHP is managing the deferral of a portion of Global Adjustment (GA) costs. OPG earns revenue and incurs debt; Provincial equity in OPG approximately doubles by 2021. While a new source of revenue for OPG, revenue is paid by Ontario ratepayers.

- In 2017, OPG began its role as OFHP Financial Services Manager (FSM).
- The Fair Hydro Trust contributes to increasing amounts of earnings before taxes, growing from $10M in 2018 to $225M in 2021 on a fiscal basis.
- This reflects the spread earned on the equity contributions from the Province to fund 44% of OPG's financing of the Trust.
- As the Province provides more funding to facilitate asset purchases in exchange for shares in the company, the government's equity increases, lowering ROE.
- The Fair Hydro Trust external senior debt is projected to increase to $5.9B by 2021.

Total Consolidated Debt and Equity[1]



Electricity Production and Total Cost of Generation



Production increases improve financial performance through increased revenue.

The 2018-2021 plan forecasts a total increase of 5.4 TWh compared to the last business plan.

Increases are driven by higher production at Pickering Generating Station.

- OPG will increase time between routine outages, allowing units to run longer.
- Other reliability improvements reduce Pickering's 'forced loss rate'- (i.e., losses from unplanned shutdowns.)

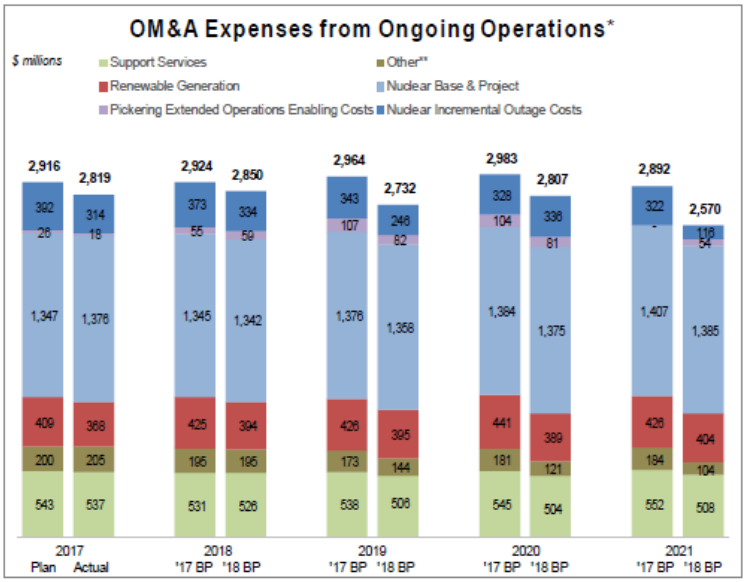
The forecasts assume Canadian Nuclear Safety Commission (CNSC) (federal regulator of nuclear power and materials in Canada) will grant Pickering license extension to 2024.

Production decreases in 2020 due to heavier cyclical outage work, including a station-wide outage at Pickering. This is also when Darlington Unit 2 returns to service and Unit 3 is taken offline (higher than normal forced loss rates assumed when units initially return to service).

The current Thunder Bay biomass energy supply agreement expires in January 2020.

Total generating cost forecasts fluctuate due to outages, water conditions and efficiency initiatives. Pickering's cost performance expected to improve relative to previous plan.

Operations, Maintenance and Administration (OM&A) Expenses



* Excludes Darlington refurbishment OM&A expenses and all OEB variance and deferrral account offsets

** Includes centrally held pension / OPEB costs, insurance and other corporate level costs

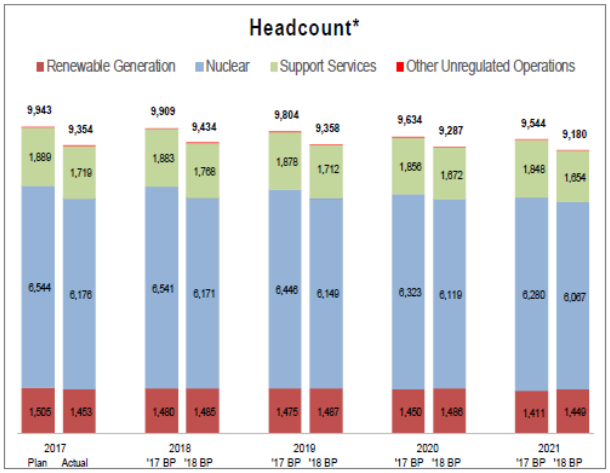
The plan targets a total decrease in OM&A expenditures of $600 million over four years compared to last year's business plan. Annual spending decreases by $280 million in 2021 compared to 2018.

The reductions will be achieved through new processes, technology upgrades and optimizing nuclear plant outages.

OPG25 Initiative

- OPG25 is a plan to restructure OPG due to the closure of Pickering in 2024.
- The objective of OPG25 is to ensure operations remain cost-effective and that OPG is positioned for growth.
- The long-term target for the plan is having Darlington operate in the top-quartile for total generating costs.
- The initiative includes a staffing transition work stream, making interaction with unions critical.
- The 2018-21 business plan's cost reductions will help move OPG towards achieving the total target reductions post Pickering operations.

Headcount



* 2017-2019 BP and 2017 Actuals have been restated for 2018 organizational changes. Includes PWU Term employees.

OPG indicates significant staffing reductions across the organization compared to the previous plan, supporting efforts to realign the corporate cost structure and drive productivity improvement and operational efficiencies. These efforts support the OPG25 initiative to ensure cost effectiveness of post-Pickering operations, and help to mitigate downsizing costs related to the Pickering closure.

Actual year-end 2017 headcount was about 590 lower than expected in the previous plan. This trend continues over the 2018-2021 period as forecast headcount is lower by about 410 employees, on average, in each year.

Compensation

Collective agreements expire in 2018. Results of collective bargaining will impact efficiency and cost-optimization initiatives.

Collective bargaining impacts OPG's ability to reduce OM&A. Most employees belong to either the Power Workers Union (PWU) or Society of Energy Professionals (Society).

Collective agreements with Society & PWU expire in 2018. Negotiated outcomes will impact OPG's ability to meet the plan's savings forecasts. Through collective bargaining, OPG hopes to:

- Manage wage increases
- Reduce future workforce costs including pension and benefits
- Ensure future staff capability
- Reduce downsizing costs resulting from Pickering closure

The plan identifies an accounting risk related to Pickering downsizing costs materializing prior to the next OEB rate application. This would affect net income in the year the costs were recognized.

Executive Compensation

Executive compensation program implemented in January 2017 that is focused performance based pay.

- The program is designed to provide compensation that is no more than the 50th percentile of the market and is compliant with the Broader Public Sector Executive Compensation Act.

- In 2017, TB/MBC approved exemptions allowing OPG to compare against private sector and international companies.
- Overall compensation for all management group staff increases at 2% based on assumed inflation each year in the plan.
- Short-term incentives are based on individual performance and the corporate scorecard. Strong performance on the scorecard led to increases in executive incentive payments in 2017.

OPG exceeded many of the measures in its Corporate Scorecard, impacting incentive payments.

- Scorecard is based on a predetermined scale of Threshold/Business Plan/Stretch targets (i.e., low/medium/high) and given a weighting. The scorecard is summarized below.

Category	Performance Measure	Threshold Target (0.5)	Business Plan Target (1.0)	Stretch Target (1.5)	2017 Results	Score (0 to 1.5)
Social Licence	All Injury rate (AIR)	0.49	0.37	0.31	0.48	0.54
	Addressing Safety Focus Areas	CEO assessed target			1.5	1.46
	No significant impacts to OPG's reputation					
Financial Strength	Earnings Before Taxes, ($M)	675	875	1075	1296	1.50
	OM&A Expenses ($M)	2675	2550	2425	2474	1.30
Operational Excellence	Production (TWh)	70.3	72.4	74.6	78.1	1.50
Project Excellence	Refurbishment Project Cost – 2017 actual expenditures ($M) as a percentage of approved 2017 budget [1]	100%	97.50%	95%	120%	0.00
	Refurbishment Unit 2 Critical Path Execution – Commencement of Feeder cabinet removal (Milestone	05-Aug-17	26-Jul-17	28-Jun-17	22-Jun-17	1.50
	Refurbishment Unit 2 Critical Path Execution: Progress of Critical path on Dec 31, 2017	All Bellows Severed	50% End Fitting Removed	400 Pressure Tubes Removed	45% of End Fittings Removed	0.95
	Pump Generating Station: In service	06-01-2017	04-01-2017	03-01-2017	02-04-2017	1.50
	Peter Sutherland Generating Station: Both Units in service	10-19-2017	06-30-2017	04-30-2017	03-31-2017	1.50
	Total In-service Capital -	$578 (+/- 10% to +/- to 15%)	$578 (+/- 3% to +/- 10%)	$578 (to +/- 3%)	$625 (+8%)	1.00
	Total Weighted Score					**1.19**

1. 2017 expenditures higher than budget due to change in schedule. Overall refurbishment remains on budget.
2. Table is part of OPG's Annual Information Form found here https://www.opg.com/about/finance/Documents/OPG_2017_AIF.pdf

Exceeded Stretch Target
Exceeded BP Target
Below BP Target
Below Threshold

Commented [GH15]: We would note that OPG achieved 'Exceeded Stretch Target' in five of the 11 performance measures while showing 'Exceeded BP Target' three additional performance measures.

Projects and Capital Expenditures

The plan includes $4.4 billion in capital expenditures for the Darlington Refurbishment project (DRP). Unit 2 is planned for return to service in early 2020.

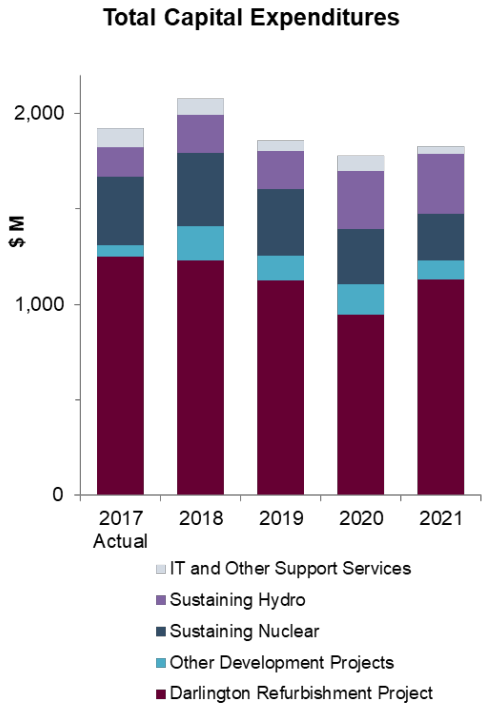
The plan includes $105 million in capital expenditures for the Heavy Water Storage(D2O) project, an enabling sub-project for the DRP that previously experienced delays and cost overruns (note: overall refurbishment has remained within budget and schedule).

In its rate decision, OEB confirmed it will take a holistic view to assessing DRP costs, evaluating overall project performance against approved budget rather than an individual sub-project basis.

Other capital expenditures include:

- Ranney Falls re-development (2019 completion)
- Nanticoke Solar (2019 completion)
- Beck canal rehabilitation (2022 completion)
- Other sustaining capital (Hydro unit overhauls; equipment upgrades)

The plan accelerates capital expenditures for OPG's digital transformation in support of improved efficiency.



From: Ronald Kwan
To: John Kim; Bruno Amara
Subject: RE: Outlook and PRRT
Date: Friday, February 23, 2018 7:00:27 AM
Attachments: Copy of Electricity Sector Outlook (2018 02 22)_v03_Markup.xlsm

---

Hi John, Bruno,

Some suggested text edits on some of the variance explanations.

Also, I thought that you were adding some other general revenue risks, such as the impact on OPG and Hydro One financial performance risk such as from higher OM&A costs (could include collective agreements risk).

I'd be also inclined to be lower on MEU PILs in 18-19 and out-years, unless we have good support for projecting a strong increase over a few years.

Ron

From: Bruno Amara
Sent: February-22-18 5:42 PM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>
Subject: Outlook and PRRT

Hi Ron, John

We revised the Electricity Outlook based on the updated IFRS impacts. Versus previous this revised IFRS increased OPG net income and ESDI by $100M, 100, 225, 325 starting in (Added a vs Previous panel to the Cover Sheet line 97). The explanation for OPG changes from Budget is also updated.

CQSD had also requested that we updated the PRRT note to be consistent with the electricity update. We had already sent a DRAFT to CQSD to review. This is also attached.

The only further update now would be NUGs. TBS/OB had asked for numbers (not just electricity) to be finalized as of tomorrow to prepare for weekend meetings.

Thanks
Bruno

Bruno Amara
Sr. Manager, Financial and Regulatory Analysis
Electricity Finance Branch
Corporate and Electricity Finance Division
Ontario Financing Authority

Tel: 416-325-1489
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Electricity Sector Outlook
February 2018

Disclosure:

All information contained in this workbook is confidential and commercially sensitive

All projected numbers are estimates and subjected to change

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Please consult with OFA before sharing of information.

Commercially Sensitive and Confidential Advice to Cabinet for Consideration of Options for Discussion Purposes Only

Commercially Sensitive and Confidential Advice to Cabinet for Consideration of Options for Discussion Purposes Only

Electricity Sector Outlook
Including Line Items for Consolidation

Electricity Summary - On Deck

February 2018

			MOF Expense Items (consolidated)	**Current Outlook**			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**38**	Power Supply Contract Costs	(182)	(183)	(134)	(103)
Expense	**MOF (OEFC)**	**40**	Demand Management Support Costs	(10)	-	-	-
Expense	**MOF (OEFC)**	**41**	Provision for Electricity Sector	797	449	736	711
Expense	**MOF**	**17**	Provision for Electricity Sector	(797)	(449)	(736)	(711)
Expense	**MOF (OEFC)**	**42**	Other (Finance)	(6)	(7)	(7)	(7)
			Total MOF Expense	**(198)**	**(190)**	**(141)**	**(110)**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**7**	OPG Income	905	500	728	677
Revenue	**ENE**	**8**	OPG - ONFA and other Fair Value Adjustments	194	-	-	-
Revenue	**ENE**	**10**	HOI Income	346	353	412	438
Revenue		**11**	Brampton Income	-	-	-	-
Revenue	**MOF (OEFC)**	**26**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	499	387	531	535
Revenue	**MOF (OEFC)**	**29**	Electricity Debt Retirement Charge	604	-	-	-
Revenue	**MOF (OEFC)**	**30**	Power Supply Contract Recoveries	182	183	134	103
Revenue	**MOF (OEFC)**	**31**	Net Reduction of Power Purchase Contracts	74	41	30	28
Revenue	**MOF (OEFC)**	**34**	Miscellaneous	-	-	-	-
			Total MOF Revenue	**2,804**	**1,463**	**1,835**	**1,781**
			OFA IOD Expense				
			Public Debt Interest - Electricity Sector	(454)	(404)	(404)	(404)
			Interest on Debt	(477)	(484)	(473)	(402)
			Total OFA IOD Expense	**(931)**	**(888)**	**(877)**	**(806)**
			Impact on Surplus/Deficit	**1,675**	**386**	**817**	**865**
			check	***(0)***	***(0)***	***(0)***	***(0)***

Electricity Summary - Budget 17

For Discussion			MOF Expense Items (consolidated)	Plan			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**38**	Power Supply Contract Costs	(292)	(325)	(301)	(273)
Expense	**MOF (OEFC)**	**40**	Demand Management Support Costs	(10)	0	0	0
Expense	**MOF (OEFC)**	**41**	Provision for Electricity Sector	125	0	0	0
Expense	**MOF**	**17**	Provision for Electricity Sector	(125)	0	0	0
Expense	**MOF (OEFC)**	**42**	Other (Finance)	(6)	(6)	(6)	(6)
			Total MOF Expense	**(308)**	**(331)**	**(307)**	**(279)**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**7**	OPG Income	97	732	625	1,066
Revenue	**ENE**	**8**	OPG - ONFA and other Fair Value Adjustments	0	0	0	0
Revenue	**ENE**	**10**	HOI Income	520	562	603	652
			Brampton Income				
Revenue	**MOF (OEFC)**	**25**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	405	476	538	679
Revenue	**MOF (OEFC)**	**29**	Electricity Debt Retirement Charge	623	0	0	0
Revenue	**MOF (OEFC)**	**30**	Power Supply Contract Recoveries	292	325	301	273
Revenue	**MOF (OEFC)**	**31**	Net Reduction of Power Purchase Contracts	74	41	30	28
Revenue	**MOF (OEFC)**	**34**	Miscellaneous	0	0	0	0
			Total MOF Revenue	**2,011**	**2,136**	**2,098**	**2,697**
			OFA IOD Expense				
		17	Public Debt Interest - Electricity Sector	(492)	(492)	(492)	(492)
		36	Interest on Debt	(422)	(374)	(342)	(250)
			Total OFA IOD Expense	**(914)**	**(866)**	**(834)**	**(742)**
			Impact on Surplus/Deficit	**789**	**939**	**957**	**1,676**
			check	**-**	**-**	**-**	**-**

Electricity Summary - Change

			MOF Expense Items (consolidated)	Variance from Plan			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**69**	Power Supply Contract Costs	110	142	167	170
Expense	**MOF (OEFC)**	**71**	Demand Management Support Costs	0	0	0	0
Expense	**MOF (OEFC)**	**72**	Provision for Electricity Sector	672	449	736	711
Expense	**MOF**	**48**	Provision for Electricity Sector	(672)	(449)	(736)	(711)
Expense	**MOF (OEFC)**	**73**	Other (Finance)	0	(1)	(1)	(1)
			Total MOF Expense	**110**	**141**	**166**	**169**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**38**	OPG Income	808	(232)	103	(389)
Revenue	**ENE**	**39**	OPG - ONFA and other Fair Value Adjustments	194	0	0	0
Revenue	**ENE**	**41**	HOI Income	(173)	(209)	(191)	(214)
			Brampton Income	0	0	0	0
Revenue	**MOF (OEFC)**	**25**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	93	(89)	(7)	(143)
Revenue	**MOF (OEFC)**	**60**	Electricity Debt Retirement Charge	(19)	0	0	0
Revenue	**MOF (OEFC)**	**61**	Power Supply Contract Recoveries	(110)	(142)	(167)	(170)
Revenue	**MOF (OEFC)**	**62**	Net Reduction of Power Purchase Contracts	(0)	(0)	(0)	(0)
Revenue	**MOF (OEFC)**	**65**	Miscellaneous	0	0	0	0
			Total MOF Revenue	**793**	**(672)**	**(262)**	**(916)**
			OFA IOD Expense				
		17	Public Debt Interest - Electricity Sector	38	88	88	88
		36	Interest on Debt	(55)	(110)	(131)	(152)
			Total OFA IOD Expense	**(17)**	**(22)**	**(43)**	**(64)**
			Impact on Surplus/Deficit	**886**	**(553)**	**(139)**	**(811)**
			check	***(0)***	***(0)***	***(0)***	***(0)***

Track Changes in Surplus/Deficit

Date	Change ID#	Source	Tab
5/1/2017	20170501-1	Link	ONFA
5/1/2017	20170501-2	Link	Hydro One
5/1/2017	20170501-3	Link	Hydro One
5/1/2017	20170501-4	Link	Other Data
5/2/2017	20170502-1	Link	OPG
5/9/2017	20170509-1	Link	OPG
5/10/2017	20170510-1	Link	Hydro One
5/10/2017	20170510-2	Link	Other Data
5/12/2017	20170512-1	Link	Hydro One
5/15/2017	20170515-1	Link?	
5/15/2017	20170515-2	Link	OPG
5/17/2017	20170517-1	Link	Hydro One
5/17/2017	20170517-2	Link	ONFA
5/17/2017	20170517-3		
5/18/2017	20170518-1	Link	OPG
5/18/2017	20170518-2	Link	OPG
5/18/2017	20170518-3		
6/15/2017	20170615-1	Link	OPG
6/22/2017	20170622-1	Link	Hydro One
6/22/2017	20170622-2	Link	Hydro One
6/26/2017	20170626-1		
6/29/2017	20170629-1		

7/6/2017	20170706-1		
7/11/2017	20170711-1		
7/13/2017	20170713-1	Link	Provision
7/17/2017	20170717-1	Link	Revenue (Risks)
7/24/2017	20170724-1	Link	Revenue (Risks)
7/25/2017	20170725-1	Link	Revenue (Risks)
7/26/2017	20170726-1	Link	Revenue (Risks)
7/27/2017	20170727-1	Link	Revenue (Risks)
7/27/2017	20170727-2	Link	Revenue (Risks)
7/31/2017	20170731-1		
7/31/2017	20170731-2	Link	Hydro One
7/31/2017	20170731-3	Link	Other Data
8/11/2017	20170811-1	Link	OPG
8/15/2017	20170815-1		
8/15/2017	20170815-2		
8/15/2017	20170815-3		
8/15/2017	20170815-4		
8/15/2017	20170815-5		Other Data
8/15/2017	20170815-6		Other Data
8/15/2017	20170815-7		Other Data
8/15/2017	20170815-8		Other Data
8/15/2017	20170815-9		Other Data
8/15/2017	20170815-10		Other Data
8/17/2017	20170817-1	Link	Provision
8/17/2017	20170817-2	Link	Hydro One
8/18/2017	20170818-1	Link	Revenue (Risks)
8/22/2017	20170822-1	Link	OPG
8/25/2017	20170825-1		Hydro One
8/29/2017	20170829-1		Revenue (Risks)
8/31/2017	20170831-1		Revenue (Risks)
9/5/2017	20170905-1		Other Data
9/5/2017	20170905-2		Other Data
9/5/2017	20170905-3	Link	OPG

9/6/2017	20170906-1	Link	Other Data
9/6/2017	20170906-2	Link	Revenue (Risks)
9/8/2017	20170908-1	Link	Hydro One
9/8/2017	20170908-2	Link	OPG
9/11/2017			
9/12/2017			
9/13/2017			
9/21/2017			
9/22/2017			
10/2/2017			Hydro One
10/2/2017			
10/2/2017			
10/2/2017			
10/4/2017	20171004-1		OPG
10/4/2017	20171004-2		OPG
10/4/2017			
10/4/2017			
10/5/2017			
10/6/2017			
10/7/2017			
10/8/2017			
10/10/2017	20171010-1		Hydro One
10/10/2017			
10/10/2017			
10/11/2017	20171011-1		OPG
10/11/2017			
10/11/2017			
10/12/2017			OPG
10/12/2017			
10/12/2017			
10/12/2017			
10/18/2017	20171018-1		Hydro One
10/18/2017	20171018-1		Hydro One
10/18/2017	20171018-1		Hydro One
10/19/2017	20171019-1		Revenue (Risks)
10/19/2017	20171019-2		Revenue (Risks)
10/20/2017	20171020-1		Revenue (Risks)
10/20/2017	20171020-2		
10/20/2017	20171020-2		
10/20/2017	20171020-2		
10/20/2017	20171020-3		Revenue (Risks)
10/20/2017	20171020-4		OPG
10/20/2017	20171020-4		OPG
10/20/2017	20171020-4		OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017	20171114-1		Hydro One

11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017		Hydro One
11/14/2017		Hydro One
11/14/2017		Hydro One
11/30/2017	20171130-1	Revenue (Risks)
12/8/2017		Hydro One
12/11/2017	20171211-1	Other Data
12/11/2017	20171211-1	Other Data
12/22/2017	20171222-1	OPG
1/2/2018		Hydro One
1/2/2018		Hydro One
1/2/2018		Hydro One
1/2/2018	20180102-1	OPG
1/2/2018	20180102-1	OPG
1/2/2018	20180102-1	OPG
1/2/2018	20180102-2	OPG
1/2/2018	20180102-3	OPG
1/2/2018	20180102-3	Revenue (Risks)
1/2/2018	20180102-4	Revenue (Risks)
1/2/2018	20180102-5	Revenue (Risks)
1/2/2018	20180102-6	Revenue (Risks)
1/2/2018	20180102-7	Revenue (Risks)
1/2/2018	20180102-8	Revenue (Risks)
1/2/2018	20180102-9	OPG
1/2/2018	20180102-9	OPG
1/2/2018	20180102-9	OPG
1/2/2018	20180102-9	OPG
1/3/2018		OPG
1/3/2018		OPG
1/3/2018		OPG
1/3/2018		OPG
1/3/2018		Hydro One
1/3/2018		Hydro One
1/3/2018		Hydro One
1/4/2018	20180104-1	OPG
1/4/2018	20180104-1	OPG
1/4/2018	20180104-1	OPG
1/4/2018	20180104-1	OPG
1/4/2018	20180104-2	Other Data
1/4/2018	20180104-2	Other Data
1/5/2018		
1/5/2018		
1/5/2018		
1/5/2018		
1/5/2018		
1/5/2018		
1/5/2018		
1/8/2018		
1/8/2018		
1/8/2018		
1/16/2018		Other Data

1/23/2018		OPG
2/2/2018	20180202-1	OPG
		OPG
		OPG
	20180202-1	OPG
	20180202-1	OPG
	20180202-1	OPG
	20180202-1	OPG
		OPG
		OPG
		OPG
		OPG
		OPG
		OPG
2/13/2018		
2/13/2018		
2/13/2018		
2/13/2018		
2/13/2018		
2/13/2018		
2/15/2018	20180215-1	Hydro One
2/15/2018		
2/15/2018		
2/22/2018	20180222-1	OPG
		OPG
		OPG

FOR EFB USE ONLY

Budget 2017 Outlook
Current Outlook
Change Since Budget

Description of Update
ONFA Update as of March 31 2017
s. 50.3 Update for 2016-17
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Debt Interest
OPG IFRS Risk in 2019-20
Revised OPG 2016-17 Net Income
Revised OPG 2016-17 Net Income
Revised OPG 2016-17 Net Income
tech change: slight update to assumed Prov share 70.05% from 70%
tech change: slight update to assumed Prov share 70.05% from 70%
tech change: slight update to assumed Prov share 70.05% from 70%
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
Updating H1 2016-17 Net Income for ESDI
Updating H1 2016-17 Net Income for ESDI
Updating H1 2016-17 Net Income for ESDI
Power Purchase Supply
H1 Model Forecasts - No Fiscal Update Resaving Data
Update Budget 2017 Tabs to reflect fiscal plan
Update OPG forecasted PILS to reflect sources
Update H1 2016-17 CIT
Re-inputting ONFA updates
Updating H1 Net Income to include Pref Shares in 16-17
Updating OPG Income Tax Expense for 2016-17
Updating OPG non-income tax PILs
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2017
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2018
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2019
Updating with actual OPG IFRS Adjustment 2016-17
Updating with actual OPG IFRS Adjustment 2016-17
Updating with actual OPG IFRS Adjustment 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
[NOT APPLIED] Updating H1 Brampton (Interim Adjustments)
Shifted H1 Brampton 2016-17 NI to the 2017-18
Removed H1 Brampton for 2016-17 (pending finals)
Removed H1 Brampton for 2016-17 (pending finals)
Removed H1 Brampton for 2016-17 (pending finals)

add prior-year adjustment for 2016-17

add prior-year adjustment for 2016-18
Reconfigured calculation of ESDI and MOF ESDI Expense
Reconfigured calculation of OPG 2017-18 Net Income
Backup for the Provincial Interest cost
Linking source for Revenue Risks Tab
New source for Revenue Risks Tab
Revenue Risks Tab - ROE Risks
Updating OEB Risk for OPG
OEB Staff Report - H1 Tx - Revenue Risks
OPG Pensions - Cash vs Accrual Deferral Accounts
Updating Links in Electricity Summary Change and OEFC Change
Preliminary estimate for Hydro One Brampton
Preliminary estimate for Hydro One Brampton
Preliminary estimate for Hydro One Brampton

Updating DRC for Actuals 2016-17 (Based on draft FS)
Updating PILs for 2016-17 Baced on Actuals
OPG: Non-ONFA Fair Value Adjustment
Round all Hydro One ownership assumptions to two decimal places
H1 Equity Adjustment rounding.
Round all Hydro One ownership assumptions to two decimal places
Round all Hydro One ownership assumptions to two decimal places
Revising source of ESDI, Dedicated Electricity Earnings
2016-17 - Update Power Supply Recoveries to actuals
2016-17 - Update Power Supply Recoveries to actuals
2016-17 - Updating Miscellaneous OEFC Revenue to Actuals
Adj: Exclude Bramton $15m add prior year adjustment +$3M
Adj: Exclude Bramton $15m add prior year adjustment +$3M
Public Accts: Updated IESO debt interest Interest On Debt, 2016-17
Public Accts: 2016-17 - Demand Management Support Costs Update
2017-18 - Demand Management Support Costs (no change)
Public Accts: 2016-17 - Updating Operating Expense in OEFC
Sourcing Provision for Electricity Sector from Actual Public Accounts
Revised 2016-17 Brampton Amount for Public Accounts
OPG Pensions - Cash vs Accrual Deferral Accounts (Revenue Risks Tab)
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
Reclassification
Reclassification
Reverting H1 Ownership change (undoing 20170518-3)
Reverting H1 Ownership change (undoing 20170518-3)
Reverting H1 Ownership change (undoing 20170518-3)
Updating Risks based on Hydro One Q2 Results Model
Avista Acquisition Risks
NUG Amortization Liability (sourcing amortization schedule)
2016-17 Actuals - Debt Guarantee Fee
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results

Interest Revenue for IESO and "Other"
OPG Revenue Risks from OEB Filings
Net income corrected for Preferred Shares
Net income corrected for Preferred Shares
Net income corrected for Preferred Shares
Made link edits to OPG sheet so that the "Net Income Before Tax" 2017-18 number is not a hardc
Updated PILs to include OPCD public accounts adjustment
Provision tab fix to pick up Hydro One preferred share net income
Provision tab fix to pick up Hydro One preferred share net income
FTD Update to OEFC Outlook (Sep 19, 2017) OPG Interest
FTD Update to OEFC Outlook (Sep 19, 2017) Other Interest
Update to Hydro One PILs from information in Transmission rate application material
OEB September 28, 2017 Hydro One decision and order impact - incl. rebasing
OEB September 28, 2017 Hydro One decision and order impact - incl. rebasing
OEB September 28, 2017 Hydro One decision and order impact - incl. rebasing
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Debenture Interest Costs - Removing from Revenue (Risks) and adding it ot H1 Model
Debenture Interest Costs - Removing from Revenue (Risks) and adding it ot H1 Model
Debenture Interest Costs - Removing from Revenue (Risks) and adding it ot H1 Model
Updated OPG Net Income and PILs based on monthly report (August 2017 results)
Updated OPG Net Income and PILs based on monthly report (August 2017 results)
Updated OPG Net Income and PILs based on monthly report (August 2017 results)
Correction to PILs on OPG sheet
Correction to PILs on OPG sheet
Correction to PILs on OPG sheet
Correction to PILs on OPG sheet
Switch to Direct from Model
Switch to Direct from Model
Switch to Direct from Model
Updating ROE Risks
Updating H1 Load Risks based on model output
Updating ONFA Risks for September 2017
Adjust OEB decision/rebasing to ~50% provincial ownership
Adjust OEB decision/rebasing to ~50% provincial ownership
Adjust OEB decision/rebasing to ~50% provincial ownership
Updating OPG
OPG IOD impact from GA Financing, FHP
OPG IOD impact from GA Financing, FHP
OPG IOD impact from GA Financing, FHP
Unpacking updated OPG Gain on sale (net income)
Unpacking updated OPG Gain on sale (net income)
Unpacking updated OPG Gain on sale (net income)
Unpack PILs related to HQ gain on sale
Updating IFRS Risk
Adjustment for lower Provincial share (from 70.1% to 50.9 2017-18 & 47.4% after)
Adjustment for lower Provincial share (from 70.1% to 50.9 2017-18 & 47.4% after)
Adjustment for lower Provincial share (from 70.1% to 50.9 2017-18 & 47.4% after)
November 1 and November 7 Hydro One model updates

November 1 and November 7 Hydro One model updates
November 1 and November 7 Hydro One model updates
Revise Hydro Model to reverse OEB tax decision ongoing annual impact
Revise Hydro Model to reverse OEB tax decision ongoing annual impact
Revise Hydro Model to reverse OEB tax decision ongoing annual impact
Undo allocation adjustment in H1 tab (now that provincial shares are updated)
Undo allocation adjustment in H1 tab (now that provincial shares are updated)
Undo allocation adjustment in H1 tab (now that provincial shares are updated)
Updating OPG Revenue Risks from rate application
Update Hydro One PILs (reverses update on line 119 whuich did not account fro Dx side)
Updating Debt Guarantee Fee
Updating OEFC Operating Expense
small changes - linking the net income numbers
Updated number of shares sold for First Nations (Dec 2017) sale
Updated number of shares sold for First Nations (Dec 2017) sale
Updated number of shares sold for First Nations (Dec 2017) sale
Implemented OEB's Dec 2017 payment amounts decision for OPG (CEFD Analysis)
Implemented OEB's Dec 2017 payment amounts decision for OPG (CEFD Analysis)
Implemented OEB's Dec 2017 payment amounts decision for OPG (CEFD Analysis)
Updated OPG Net Income (based on their Q3 update, Sep 30, 2017)
Updated OPG ONFA adjustment (up to Sep 30, 2017) in OPG tab (removed it from Risks table)
Removal of OPG ONFA Sep 2017 adjustment in Risks table
Included possible range (-50M to 50M) of impact for future OPG ONFA adjustment in the negative
Removal of negative regulatory risk: "OPG Switch from accrual based to cash based accounting f
Removal of negative regulatory risk: "Timing of OPG Rate Decision" from Risks table
Removal of negative regulatory risk: "OEB Staff Recommendations wrt OPG rate application(May
Removal of negative regulatory risk: "Nuclear Liabilities Cash vs. Accrual" from Risks table
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month
Updated estimates of NUG costs.
Updated estimates of NUG costs.
Unpacking OPG (Head Office sale)
Unpacking OPG (Head Office sale)
Unpacking OPG (Head Office sale)
Unpacking OPG (Head Office sale)
Unpacking Hydro One for AO (from 70.1% ownership to as of January 2018)
Unpacking Hydro One for AO (from 70.1% ownership to as of January 2018)
Unpacking Hydro One for AO (from 70.1% ownership to as of January 2018)
Update H1 allocations for additional shares (SIFB edits)
Update H1 allocations for additional shares (SIFB edits)
Update H1 allocations for additional shares (SIFB edits)
Updated (latest IOD) Debt Interest Expense line (OEFC on-deck tab) and OPG, IESO, and Other

ONFA consolidation adjustment for Dec 2017
OPG 2018-2021 BP preliminary net income update
OPG 2018-2021 BP preliminary net income update
OPG 2018-2021 BP preliminary net income update
OPG 2018-2021 BP preliminary Income Tax PILs
OPG 2018-2021 BP preliminary GRC payable to OEFC update
OPG 2018-21 BP preliminary Property Tax Payable to OEFC update
Removal of net income from estimated gain from Lakeview sale, as it has not been realized yet
Removal of PILs from estimated gain from Lakeview sale, as it has not been realized yet
Removal of net income from estimated gain from Lakeview sale, as it has not been realized yet
Removal of net income from estimated gain from Lakeview sale, as it has not been realized yet
Remove EFB OEB impact estimate
Remove EFB OEB impact estimate
Remove EFB OEB impact estimate
Update with Board-approved net income
Update with Board-approved net income
Update with Board-approved net income
Remove reversal of Lakeview proceeds on net income (now included)
Remove reversal of Lakeview proceeds on net income (now included)
Remove reversal of Lakeview proceeds on net income (now included)
Remove reversal of Lakeview proceeds on PILs (now included)
Update with Board-approved PILs
Update OPG Fair Hydro Plan amounts from OPG Busdiness Plan 2018-2021
Update OPG Fair Hydro Plan amounts from OPG Busdiness Plan 2018-2022
Update OPG Fair Hydro Plan amounts from OPG Busdiness Plan 2018-2023
Remove Hydro One Debenture Cost from Outlook (now in Model)
Remove Hydro One Debenture Cost from Outlook (now in Model)
Remove Hydro One Debenture Cost from Outlook (now in Model)
Annual Report 2017 Hydro One Net Income Updates
Annual Report 2017 Hydro One Net Income Updates
Annual Report 2017 Hydro One Net Income Updates
Adjustment from using quarterly actuals
Adjustment from using quarterly actuals
Adjustment from using quarterly actuals
Updating Hydro One debt interest Costs
Updating Hydro One debt interest Costs
February 15, 2018 FTD Update\
Update based on January 31, 2018 BSC material for OEFC YTD
Update from Hydro One Feb 16 (email to Gavin)
Update based on January 31, 2018 BSC material for OEFC YTD and Siva email
Updated OPG IFRS Impact
Updated OPG IFRS Impact
Updated OPG IFRS Impact
Rounding adjustment

This line show net impact of latest change. READ COMMENT

$ Millions

		2016-17	2017-18	2018-19	2019-20
		930	789	939	957
	File	915	1,675	386	817
		-15	886	-553	-139
	check	*0*	*0*	*0*	*0*
		Impacts by FY →			
Outlook line affected	**Expense / Rever**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
ONFA and other Fair Value Adjustments	Revenue	41.0	0.0	0.0	0.0
N/A		0.0	0.0	0.0	0.0
?		0.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		38.1		
Provision for Electricity Sector (MOF)	Expense		(38.1)		
Public Debt Interest - Electricity Sector	Expense	0.0	38.1	38.1	38.1
Interest on Debt	Expense	0.0	(69.1)	(79.1)	(75.1)
OPG Income	Expense	0.0	0.0	0.0	
OPG Income	Revenue	(2.0)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**(2.0)**			
Provision for Electricity Sector (MOF)	Expense	2.0			
HOI Income	Revenue	0.4			
Provision for Electricity Sector (OEFC)	Expense	0.4			
Provision for Electricity Sector (MOF)	Expense	(0.4)			
Public Debt Interest - Electricity Sector	Expense	1.7			
Provision for Electricity Sector (OEFC)	Expense	(1.7)			
Provision for Electricity Sector (MOF)	Expense	1.7			
Interest on Debt	Expense	(1.7)			
HOI Income	Revenue	(39.8)	0.0	0.0	(0.0)
Provision for Electricity Sector (OEFC)	Expense	**(39.8)**			
Provision for Electricity Sector (MOF)	Expense	39.8			
	Revenue	-	-	-	-
	Revenue	-	-	-	-
	n/a	-	-	-	-
		-	-	-	-
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	4.7	0.0	0.0	0.0
	Revenue	0.0	0.0	0.0	0.0
HOI Income	Revenue	18.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	7.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	8.0	9.0	12.0	3.5
HOI Income	Revenue	0.0	(141.5)	(181.4)	(194.9)
Provision for Electricity Sector (OEFC)	Expense		(141.5)		
Provision for Electricity Sector (MOF)	Expense		141.5		
OPG Income	Revenue	(3.0)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**(3.0)**			
Provision for Electricity Sector (MOF)	Expense	3.0			
HOI Income	Revenue	7.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**7.0**			
Provision for Electricity Sector (MOF)	Expense	(7.0)			
	Revenue	-	-	-	-
	Revenue	0.0	0.0	0.0	0.0
Brampton Income	Revenue	(14.7)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**(14.7)**			
Provision for Electricity Sector (MOF)	Expense	14.7			

Provision for Electricity Sector (OEFC)	Expense		3.2			
Provision for Electricity Sector (MOF)	Expense		(3.2)			
	Revenue	-	-	-	-	
		-	-	-	-	
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
Brampton Income	Revenue		15.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		**15.0**			
Provision for Electricity Sector (MOF)	Expense		(15.0)			
Provision for Electricity Sector (OEFC)	Expense		3.2			
Provision for Electricity Sector (MOF)	Expense		(3.2)			
Electricity Debt Retirement Charge	Revenue		(4.0)	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue		(29.0)	0.0	0.0	0.0
OPG Income	Revenue		(6.0)	0.0	0.0	0.0
HOI Income	Revenue		(0.0)	(0.0)	0.0	0.0
HOI Income	Revenue		(1.7)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense			(0.0)		
Provision for Electricity Sector (MOF)	Expense			0.0		
	Revenue		0.0	0.0	0.0	0.0
Power Supply Contract Recoveries	Revenue		99.0	0.0	0.0	0.0
Power Supply Contract Costs	Expense		(99.0)			
Miscellaneous	Revenue		14.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		(12.0)			
Provision for Electricity Sector (MOF)	Expense		12.0			
Interest on Debt	Expense		(3.0)	0.0	0.0	0.0
Demand Management Support Costs	Expense		1.8	0.0	0.0	0.0
			0.0	0.0	0.0	0.0
Other (Finance)	Expense		(1.0)	0.0	0.0	0.0
	Revenue	-	-	-	-	
Brampton Income	Revenue		3.0	0.0	0.0	0.0
			0.0	0.0	0.0	0.0
OPG Income	Revenue		0.0	85.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue			(6.0)		
Provision for Electricity Sector (OEFC)	Expense			**85.0**		
Provision for Electricity Sector (MOF)	Expense			(85.0)		
OPG Income	Revenue		6.0			
ONFA and other Fair Value Adjustments	Revenue		(6.0)			
HOI Income	Revenue		0.0	141.9	181.8	195.4
Provision for Electricity Sector (OEFC)	Expense			141.9		
Provision for Electricity Sector (MOF)	Expense			(141.9)		
	n/a		0.0	0.0	0.0	0.0
			0.0	0.0	0.0	0.0
Net Reduction of Power Purchase Contracts	Revenue		0.1	(0.1)	(0.1)	(0.1)
	Revenue		0.0	0.0	0.0	0.0
OPG Income	Revenue		0.0	16.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue			(1.0)		
Provision for Electricity Sector (OEFC)	Expense			**16.0**		
Provision for Electricity Sector (MOF)	Expense			(16.0)		

		0.0	0.0	0.0	0.0
	n/a	0.0	0.0	0.0	0.0
HOI Income	Revenue	0.0	5.3	5.3	5.3
Provision for Electricity Sector (OEFC)	Expense		(12.4)		
Provision for Electricity Sector (MOF)	Expense		12.4		
oded formula in the cell	n/a	0.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	(30.4)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		17.8		
Provision for Electricity Sector (MOF)	Expense		(17.8)		
Interest on Debt	Expense	(0.0)	1.0	(0.0)	1.0
Interest on Debt	Expense	0.0	15.0	15.0	5.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	0.0	(7.8)	(8.7)	(10.3)
HOI Income	Revenue	0.0	(47.4)	(54.0)	(54.0)
Provision for Electricity Sector (OEFC)	Expense	0.0	(47.4)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	47.4	0.0	0.0
OPG Income	Revenue	0.0	(61.0)	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	0.0	(21.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	(61.0)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	61.0	0.0	0.0
OPG Income	Revenue	0.0	(21.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	(21.0)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	21.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	0.0	21.0	0.0	0.0
HOI Income	Revenue	0.0	(23.6)	(27.4)	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	(23.6)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	23.6	0.0	0.0
OPG Income	Revenue	0.0	15.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	15.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	(15.0)	0.0	0.0
OPG Income	Revenue	0.0	21.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	0.0	(18.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	21.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	(21.0)	0.0	0.0
HOI Income	Revenue	0.0	(23.8)	(28.9)	(10.1)
Provision for Electricity Sector (OEFC)	Expense	0.0	(23.8)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	23.8	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
HOI Income	Revenue		16.1	26.7	20.6
Provision for Electricity Sector (OEFC)	Expense		16.1		
Provision for Electricity Sector (MOF)	Expense		(16.1)		
n/a	n/a	0.0	0.0	0.0	0.0
OPG Income	Revenue		(4.9)	(11.9)	(17.1)
Provision for Electricity Sector (OEFC)	Expense		(4.9)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		4.9	0.0	0.0
OPG Income	Revenue		283.0		
Provision for Electricity Sector (OEFC)	Expense		283.0		
Provision for Electricity Sector (MOF)	Expense		(283.0)		
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue		95.0		
OPG Income	Revenue		0.0	(475.0)	(500.0)
HOI Income	Revenue		(112.6)	(142.1)	(170.6)
Provision for Electricity Sector (OEFC)	Expense		(112.6)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		112.6	0.0	0.0
HOI Income	Revenue		(3.3)	(3.0)	(0.1)

Provision for Electricity Sector (OEFC)	Expense		(3.3)		
Provision for Electricity Sector (MOF)	Expense		3.3		
HOI Income	Revenue		14.7	14.4	12.9
Provision for Electricity Sector (OEFC)	Expense		14.7	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		(14.7)	0.0	0.0
HOI Income	Revenue		(16.1)	(26.7)	(20.6)
Provision for Electricity Sector (OEFC)	Expense		(16.1)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		16.1	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)		0.0	7.8	8.7	10.3
n/a	n/a	0.0	0.0	0.0	0.0
Other (Finance)			0.0	(1.0)	(1.0)
OPG Income	Revenue		0.0	0.0	0.0
HOI Income	Revenue		0.1	0.5	0.6
Provision for Electricity Sector (OEFC)	Expense		0.1	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		(0.1)	0.0	0.0
OPG Income	Revenue		(477.1)	(145.2)	(153.1)
Provision for Electricity Sector (OEFC)	Expense		(305.7)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		305.7	0.0	0.0
OPG Income	Revenue		39.0	0.0	0.0
OPG - ONFA and other Fair Value Adjustments	Revenue		171.5	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
OPG Income	Revenue		119.3	36.3	38.3
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue		(119.3)	(36.3)	(38.3)
Provision for Electricity Sector (OEFC)	Expense		0.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		0.0	0.0	0.0
OPG Income	Revenue		(283.0)	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue		(95.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		0.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		0.0	0.0	0.0
HOI Income	Revenue		116.8	147.1	176.1
Provision for Electricity Sector (OEFC)	Expense		0.0	0.0	80.3
Provision for Electricity Sector (MOF)	Expense		0.0	0.0	(80.3)
OPG Income	Revenue		37.5	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue		12.5	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		0.0	14.4	23.1
Provision for Electricity Sector (MOF)	Expense		0.0	(14.4)	(23.1)
Power Supply Contract Recoveries	Revenue		(109.9)	(142.1)	(166.7)
Power Supply Contract Costs	Expense		109.9	142.1	166.7
OPG Income	Revenue		283.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue		95.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		141.1	141.9	0.0
Provision for Electricity Sector (MOF)	Expense		(141.1)	(141.9)	0.0
HOI Income	Revenue		(116.8)	(147.1)	(176.1)
Provision for Electricity Sector (OEFC)	Expense		(116.8)	(147.1)	(103.4)
Provision for Electricity Sector (MOF)	Expense		116.8	147.1	103.4
HOI Income	Revenue		(0.0)	(0.2)	(0.2)
Provision for Electricity Sector (OEFC)	Expense		(0.0)	(0.2)	0.0
Provision for Electricity Sector (MOF)	Expense		0.0	0.2	0.0
Interest on Debt	Expense		(2.5)	8.0	(7.0)

OPG - ONFA and other Fair Value Adjustments	Revenue	22.5	0.0	0.0
OPG Income	Revenue	327.0	113.0	325.0
Provision for Electricity Sector (OEFC)	Expense	327.0	113.0	252.0
Provision for Electricity Sector (MOF)	Expense	(327.0)	(113.0)	(252.0)
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	54.0	(77.0)	7.0
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	(8.0)	(15.0)	(10.0)
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	(5.0)	(5.0)	(5.0)
OPG Income	Revenue	(185.0)	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	(65.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	(185.0)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	185.0	0.0	0.0
OPG Income	Revenue	427.1	145.2	153.1
Provision for Electricity Sector (OEFC)	Expense	427.1	145.2	153.1
Provision for Electricity Sector (MOF)	Expense	(427.1)	(145.2)	(153.1)
OPG Income	Revenue	11.0	4.0	2.0
Provision for Electricity Sector (OEFC)	Expense	11.0	4.0	2.0
Provision for Electricity Sector (MOF)	Expense	(11.0)	(4.0)	(2.0)
OPG Income	Revenue	185.0		
Provision for Electricity Sector (OEFC)	Expense	185.0		
Provision for Electricity Sector (MOF)	Expense	(185.0)		
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	65.0		
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	5.0	(4.0)	(2.0)
OPG Income	Revenue	(2.3)	37.5	67.7
Provision for Electricity Sector (OEFC)	Expense	(2.3)	37.5	67.7
Provision for Electricity Sector (MOF)	Expense	2.3	(37.5)	(67.7)
HOI Income	Revenue	17.1	18.6	0.0
Provision for Electricity Sector (OEFC)	Expense	17.1	18.6	0.0
Provision for Electricity Sector (MOF)	Expense	(17.1)	(18.6)	0.0
HOI Income	Revenue	8.4	7.7	24.4
Provision for Electricity Sector (OEFC)	Expense	8.4	7.7	24.4
Provision for Electricity Sector (MOF)	Expense	(8.4)	(7.7)	(24.4)
HOI Income	Revenue	(8.5)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	(8.5)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	8.5	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		50.4	50.4
Provision for Electricity Sector (MOF)	Expense		(50.4)	(50.4)
Interest on Debt	Expense	0.5	(4.0)	(5.0)
Electricity Debt Retirement Charge	Revenue	(19.0)	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	3.5	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	(35.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	100.0	100.0	225.0
Provision for Electricity Sector (MOF)	Expense	(100.0)	(100.0)	(225.0)
OPG Income	Revenue	100.0	100.0	225.0
		(0.0)	(0.0)	(0.0)
		0	***0***	***0***	***0***

2020-21
1,676
865
-811
0

2020-21	Further Explanation of Change and source of data
0.0	Regular quarterly ONFA Update
0.0	Benefit to OEFC under s.50.3: $411M gain, SIFB
0.0	Change to OEFC payment for interest costs of Debt for Equity Swap
38.1	Revised Provincial Debt Interest related to Hydro One Equity
(104.1)	From FTD, revised Debt Interest (net of revisions to Provincial and OPG debt interest)
0.0	Revised numbers from OEP with 2019-20 Risk
0.0	Updated numbers from OPG Q1 2017 FS
0.0	Updating H1 Net Income for actuals. Note does not update Brampton Income at this point. Will
-	No Change to numbers, just re-inputting data and saving sources
-	No Change to numbers, just re-inputting data and saving sources
-	No change to fiscal impact numbers. Deleting Budget 2016 and adding Budget 2017 fiscal imp
-	No Change to numbers, just re-inputting data and saving sources
0.0	Updated with CIT Numbers received from H1 as part of s.91.2 MB20 allocation from MOF
0.0	No Change to numbers, just re-inputting data and saving sources
0.0	Only included H1 Net Income - Common Shareholders before. Added preferred shareholder im
0.0	Updating OPG Income Tax Expense with info from OPG Monthly Presentation to Shareholder
1.8	Updating OPG GRC payable to OEFC and Proxy Property Tax from Answer back from OPG al
(210.6)	Based on H1 final offering and expected First Nations Sale by the end of 2017 (CY), with a wei
0.0	Based on EY analysis, and then applying fiscalization. Confirmation also received from OPCD.
0.0	Based on KPMG analysis, then fiscalization and other adjustments from OPCD.
-	**[NOT APPLIED, CALCULATIONS AND DATA LEFT ON THE FILE]** Used Brampton's Financ
0.0	Don't expect finalized 2016-17 data to become available in time for ESDI allocation. Will shift th
0.0	make decision on shifting when we know 2016-17 status.

-	No change to numbers. Just re-organizing spreadsheet. No backup data.
-	No change to numbers. Just re-organizing spreadsheet. No backup data.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided another scenario backup/source
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just updated the links to refer ot the delta between 2017 and On Deck
0.0	Adjustment to ESDI to include Hydro One Brampton
0.0	Finalizing 2016-17 DRC Based on Draft OEFC AR
0.0	Received actual PILs amounts from FTD with breakdown of source. Updated 2016-17 numbers
0.0	2016-17 - Non-ONFA Fair Value Adjustment
0.0	Round Hydro One ownership assumptions to 70.05% two decimal places to be consistent with
0.0	Revising Hydro One Amount for consistency with OPCD. Equity Adjustments
0.0	Updated Provision tab. Made two separate Provision amounts for ESDI in OEFC AR and Dedic
0.0	Updating Power Supply Recoveries to Public Accounts/OEFC AR actuals
0.0	Updating Miscellaneous to OEFC AR actuals
0.0	Updated 2016-17 Interest on Debt (IESO, OPG, Other (Net))
0.0	
0.0	2017-18 - Demand Management Support Costs (no change) - Linking correctly
0.0	2016-17 - Updating Operating Expense in OEFC and corresponding changes elsewhere and s
-	No change to numbers. Just re-organized spreadsheet
0.0	Revised H1 Brampton Net Income (for GBE Line only)
0.0	Revising for OPG's Q3 Finances
0.0	Revising OPG's Net Income for latest monthly report
211.1	Reverting ownership back to 70.05% from change 20170518-3. Will coordinate with other area
0.0	Updating Risks based on Hydro One Q2 Results Model
0.0	Updated two Risk components for the Avista Acquisition.
(0.0)	No significant changes, but used actual amortization liability schedule. Hence the rounding imp
0.0	Updating Debt Guarantee for actuals based on OEFC AR
0.0	Revising OPG's Net Income for latest monthly report

0.0	Linking interest revenue data for 2017-18 to 2020-21
0.0	OPG Revenue Risks from: OEB Staff Submission and OPG Updated Filings
5.3	Corrected Net income for 100% ownership in preferred shares and 70.05% in Commons Share
0.0	Updated the formula in the cell for 2017-18 Net Income Before Tax so that the numbers are no
0.0	Updated PILs to include OPCD public accounts adjustment
1.3	
5.0	
(12.2)	
(54.0)	
0.0	
0.0	
0.0	increase built into net income was $82m between NI and PILs
0.0	Remove $21m from PILs
0.0	expense impacts
0.0	expense impacts
0.0	need to also remove the $21m PILs built into OPG net incme
0.0	
0.0	
0.0	We removed $21m from PILs above, before having added it in (check is that lines 123 to 130 a
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
(13.0)	variances include: 2017-18 preferred vs common share fix, 2018-19 largely ROE change from
0.0	
0.0	
0.0	
0.0	
0.0	
21.6	
0.0	
(24.1)	
0.0	
0.0	**Distribution (October)**
(750.0)	
(185.3)	
0.0	
0.0	
(2.3)	

15.2	
0.0	
0.0	
(21.6)	
0.0	
0.0	
0.0	Updating OPG Rate application Revenue Risks based on revised calculations
12.2	
0.0	
(1.0)	Received Revised FTD Forecast
0.3	
0.7	
0.0	
0.0	
(180.7)	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	Removed based on Dec 2017 OEB decision
0.0	Removed based on Dec 2017 OEB decision
0.0	Removed based on Dec 2017 OEB decision
0.0	Removed based on Dec 2017 OEB decision
45.2	
(45.2)	
44.2	
(44.2)	
0.0	
0.0	
(44.2)	
44.2	
190.8	
311.7	
(311.7)	
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M
(170.7)	
170.7	
0.0	
0.0	
0.0	
0.0	
(190.8)	
(263.6)	
263.6	
(0.3)	
(0.5)	
0.5	**Distribution (January)**
0.4	

0.0
(39.3)
33.7
(33.7)
(127.3)
(10.0)
(6.0)
0.0
0.0
0.0
0.0
180.7
180.7
(180.7)
3.0
3.0
(3.0)

(2.0)
96.5
96.5
(96.5)
0.0
0.0
0.0
19.2
19.2
(19.2)
0.0
0.0
0.0
50.4
(50.4)
(4.4)
0.0
0.0
0.0
325.0
(325.0)
325.0
(0.0)

0

Data Validation:

Options
Revenue (F
OPG
Hydro One
Provision

ONFA
Other Data

update once revised numbers are received.

acts

ıpact as well.

bout the BP
ghted average ownership for 2017-18. Also adjusted future net income attributed to the province.

ial Statements to produce an estimate. May require additional calculations.
ıis to 2017-18.

(from 2016 and On Deck)

s to reflect this.

OPCD.

:ated Earnings in Public Accounts.

ources.

s to ensure broadening change and reduction in net income happens concurrently in forecasts.

acts/changes.

es

t hardcoded directly

dd up to -$82m gain that we wanted to remove.

9.09% to 8.78% not previously captured.

Risks)

Electricity Sector Outlook

$ Millions

	Actual 2015-16	Interim 2016-17	Plan 2017-18	2018-19	2019-20	2020-21
On Deck Outlook as of March 2017						
Income from Investment in Government Business Enterprises						
OPG Income[1]	291	304	97	732	625	1,066
OPG - ONFA and other Fair Value Adjustments[2]	172	8	-	-	-	-
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	-
HOI Income[3]	236	516	520	562	603	652
Brampton Income	20	15	-	-	-	-
Total OPG and HOI Income	**719**	**842**	**617**	**1,294**	**1,229**	**1,717**
Other Fees and Licences	**127**	**122**	**102**	**91**	**88**	**81**
Electricity Expenses of the Province						
Provision for Electricity Sector[4]	(3)	(342)	(125)		-	-
Public Debt Interest - Electricity Sector	(520)	(492)	(492)	(492)	(492)	(492)
Subtotal	(523)	(834)	(617)	(492)	(492)	(492)
Public Debt Interest - Impact of ONFA						
Amortization of Deferred Revenue re profit on sale of H1 notes						
Total Electricity Expenses of the Province	**(523)**	**(834)**	**(617)**	**(492)**	**(492)**	**(492)**
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	3,228	373	405	476	538	679
Other Revenue						
Electricity Debt Retirement Charge[5]	859	625	623	-	-	-
Power Supply Contract Recoveries	875	739	292	325	301	273
Net Reduction of Power Purchase Contracts	172	129	74	41	30	28
Other Fees and Licences	(127)	(122)	(102)	(91)	(88)	(81)
Miscellaneous	9	-	-	-	-	-
Expenses						
Interest on Debt	(596)	(532)	(422)	(374)	(342)	(250)
Power Supply Contract Costs	(875)	(739)	(292)	(325)	(301)	(273)
Electricity Consumer Price Protection Fund	-	-	-	-	-	-
Demand Management Support Costs[6]	(8)	(10)	(10)	-	-	-
Provision for Electricity Sector	3	342	125	-	-	-
Other (Finance)	(7)	(6)	(6)	(6)	(6)	(6)
Total OEFC Income	**3,533**	**800**	**687**	**46**	**132**	**370**
Impact on Surplus/(Deficit)	**3,856**	**930**	**789**	**939**	**957**	**1,676**

Notes: The Hydro One net income outlook above (2016-17 to 2020-21) reflects the Province's 70% ownership share after the initial IPO in 2015 and the secondary offering in April 2016. At the time of 2017 Budget, net estimated fiscal impacts from future Hydro One offerings are reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

Notes:

1.OPG's 2016-17 outlook reflected its reported earnings. 2017-18 to 2019-20 reflects OPG's preliminary 2017-2019 business plan (as fiscalized by OPG). 2020-21 estimates are based on OPG's calendar year-based business plan projections. OPG net income also reflects IFRS adjustments fiscal impact decisions that were made centrally.

2. Provincial consolidation adjustments for unrealized earnings on the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds, as of the end of December 2016.

3. Hydro One 2016-17 income reflects its reported net income, adjusted for Hydro One IPO impacts. 2017-18 to 2020-21 projections are based on CEFD projections using the latest public information. The Hydro One net income outlook above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering as of 2017 Budget were reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial ONFA consolidation adjustments, less the interest on the Province's OPG/Hydro One debt payable to OEFC. The provision is currently assumed to end once the DRC ends on a legislated fixed end date of April 1, 2018.

5. Reflects April 23, 2014 announcement that DRC will be eliminated for residential users, after December 31, 2015. The end date of DRC for remaining users is legislated to be on April 1, 2018. Estimates are subject to change based on actual consumption.

6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Electricity Sector Outlook

$ Millions

	Actual 2014-15	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
On Deck Outlook as of February 2018							
Income from Investment in Government Business Enterprises							
OPG Income[1]	574	291	299	905	500	728	677
OPG - ONFA and other Fair Value Adjustments[2]	239	172	43	194	-	-	-
Hydro One - Unrealized Gains Adjustment	(8)	-	-	-	-	-	-
HOI Income[3]	741	236	500	346	353	412	438
Brampton Income		20	18	-	-	-	-
Total OPG and HOI Income	**1,546**	**719**	**860**	**1,445**	**853**	**1,140**	**1,115**
Other Fees and Licences (Debt Guarantee fee)	**131**	**127**	**122**	**102**	**99**	**98**	**91**
Electricity Expenses of the Province							
Provision for Electricity Sector[4]	(795)	-	(290)	(797)	(449)	(736)	(711)
Public Debt Interest - Electricity Sector	(520)	(520)	(514)	(454)	(404)	(404)	(404)
Subtotal	(1,315)	(520)	(803)	(1,251)	(853)	(1,140)	(1,115)
Public Debt Interest - Impact of ONFA							
Amortization of Deferred Revenue re profit on sale of H1 notes							
Total Electricity Expenses of the Province	**(1,315)**	**(520)**	**(803)**	**(1,251)**	**(853)**	**(1,140)**	**(1,115)**
OEFC Income							
Taxation Revenue							
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	180	3,247	334	499	387	531	535
Other Revenue							
Electricity Debt Retirement Charge[5]	956	859	621	604	-	-	-
Power Supply Contract Recoveries	950	875	838	182	183	134	103
Net Reduction of Power Purchase Contracts	217	172	129	74	41	30	28
Other Fees and Licences	(131)	(127)	(122)	(102)	(99)	(98)	(91)
Miscellaneous	9	9	14	-	-	-	-
Expenses							
Interest on Debt	(658)	(596)	(513)	(477)	(484)	(473)	(402)
Power Supply Contract Costs	(950)	(875)	(838)	(182)	(183)	(134)	(103)
Electricity Consumer Price Protection Fund	-	-	-	-	-	-	-
Demand Management Support Costs[6]	(9)	(8)	(8)	(10)	-	-	-
Provision for Electricity Sector	795	-	290	797	449	736	711
Other (Finance)	(6)	(7)	(7)	(6)	(7)	(7)	(7)
Total OEFC Income	**1,353**	**3,549**	**737**	**1,379**	**287**	**719**	**774**
Impact on Surplus/(Deficit)	**1,715**	**3,876**	**915**	**1,675**	**386**	**817**	**865**
variance to OEFC check		*(156)*	*(454)*	*(531)*	-	-	-

Notes:

1.OPG's 2017-18 to 2020-21 outlook reflects OPG's 2018-2021 Business Plan and Includes OPG head office properties sale proceeds and Lakeview property sale proceeds. 2021-22 estimates are based on OPG's calendar year-based business plan projections for 2021 and a CEFD projection for 2022. OPG net income also reflect projected IFRS adjustments as provided by OPCD at the time of the 2017 Budget. Note: all Asset Optimization transactions are re-categorised from Sales and Rentals in this Outlook.

2. Provincial consolidation adjustments for unrealized earnings on the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds, as of the end of September 2017.

3. Hydro One 2017-18 is based on actual Hydro One results for 2017 and CEFD projection for 2018. Quarterly earnings are adjusted for the provincial ownership share during the quarter. 2018-19 and onwards are CEFD projections using the latest public information and reflects the Province's ownership share following the May 2017 share disposition and including the First Nations sale in December 2017. Note: all Asset Optimization transactions are re-categorised from Sales and Rentals in this Outlook.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial ONFA consolidation adjustments, minus the interest on debt payable to OEFC. The provision is now assumed to continue after 2017-18 based on TB/MBC approval of the PRRT submission to continue ESDI payments to OEFC beyond 2017-18.

5. Reflects that DRC eliminated for residential users, after December 31, 2015. The end date of DRC for remaining users is legislated to be on April 1, 2018. Estimates are subject to change based on actual consumption.

6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Electricity Sector Change Since Budget	$ Millions					
($million)	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Changes from Budget 2017 as of February 2018						
Income from Investment in Government Business Enterprises						
OPG Income	(5)	808	(232)	103	(389)	2016-17 small decrease due to IFRS adjustment revision and OPG Net Income revision. 2017-18 increase is largely due to the re-categorization from Sales and Rentals to OPG net income proceeds from the completed sale of OPG head office properties and prospective sale of Lakeview lands. This accounts for $483M of the increase. Note that while the re-categorization itself is fiscally-neutral, net income impacts of the proceeds from property sales are $206M higher than projected at the time of the 2017 Budget. 2017-18 results are also boosted by lower projected IFRS adjustment (by $100M) for 2017-18 and lower OPG expenses than estimated at the time of Budget 2017. 2018-19 to 2020-21 chnages reflect the negative impact of higher projeceted IFRS adjustment impacts over that period partially offset by higher OPG net income in 2018-19 and 2020-21 and more than offset by higher OPG net income in 2019-20.
ONFA and other Fair Value Adjustments	35	194	-	-	-	Largely revision to ONFA fair value as of December 31, 2017
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	
HOI Income	(16)	(173)	(209)	(191)	(214)	2016-17 slight decrease from Budget 2017 Interim projection. 2017-18 onwards mainly reflects i) re-categorization from Sales and Rentals to Hydro One net income of the impact of a lower Provincial share of Hydro One net income from Hydro One share sales ii) impact of OEB Sep. 2017 decision on Hydro One transmission rates and iii) interest expense on Avitsa debentures (in 2017-18 and 2018-19).
Brampton Income	3.3					
Total OPG and HOI Income	**17**	**828.5**	**(441)**	**(89)**	**(603)**	
Other Fees and Licences	**-**	**-**	**8**	**10**	**10**	
Electricity Expenses of the Province						
Provision for Electricity Sector	53	(672)	(449)	(736)	(711)	**[NOTE: A positive number on this line indicates a decrease in the provision, while a negative number means an increase in provision expense.]** Changes to the Provision (ESDI) expense in 2017-18 mainly reflect higher OPG net income due to recategorisation from Sales and Rentals (see above). Change in out-years reflects TB/MBC approval in 2017-18 PRRT approval to continue Provision for the Electricity Sector (i.e., Electricity Sector Dedicated Income to OEFC) beyond 2017-18. 2017 Budget assumed previous policy whereby ESDI ended after 2017-18.
Public Debt Interest - Electricity Sector	(22)	38	88	88	88	2016-17 PDI at ($514m) was slightly larger than ($492m) projected at Interim. 2017-18 and 2018-19 and onward change reflects revised projections for Provincial debt interest as a result of debt pay downs related to Hydro One's April 2016 and April 2017 offerings, repectively.
Total Electricity Expenses of the Province	**31**	**(635)**	**(361)**	**(648)**	**(623)**	

Electricity Sector Change Since Budget	$ Millions					
($million)	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs)	(40)	93	(89)	(7)	(143)	2016-17 decrease largely due to an OPCD Public Accounts PILs adjustment related to reconciling between OPCD and OEFC net opening assets. OPG PILs also slightly lower than projected. 2017-18 increase is largely due to inclusion of PILs related to disposition of OPG headquarters and Lakeview properties. 2018-19 onward lower mainly due to lower OPG income tax PILs. Property tax components are close to Budget 2017.
Other Revenue						
Electricity Debt Retirement Charge	(4)	(19)	-	-	-	
Power Supply Contract Recoveries	99	(110)	(142)	(167)	(170)	Variance in 16-17 is largely due to retroactive payments that the OEFC made to certain non-utility generators (NUGs) with former Ontario Hydro power purchase agreement (PPA) contracts with OEFC. OEFC was required to make these payment following the dismissal by the Supreme Court of Canada of OEFC's application for leave to appeal a judgment of the Court of Appeal of Ontario on a 2015 court decision. Going-forward, variance is largely due to suspension or early termination of some NUG PPAs in response to the IESO's NUG curtailment initiative.
Net Reduction of Power Purchase Contracts	0.1	(0)	(0)	(0)	(0)	
Other Fees and Licences	-	-	(8)	(10)	(10)	
Revenue Pool Residual	-	-	-		-	
Miscellaneous	14	-	-	-	-	
Expenses						
Interest on Debt	19	(55)	(110)	(131)	(152)	2017-18 and onward reflects revised debt interest outlook net of revisions to OEFC interest revenue from OPG, Hyro One IESO and Province.
Power Supply Contract Costs	(99)	110	142	167	170	Same as Power supply contract recoveries above. Power supply contract costs are fully recovered by power supply contract recoveries.
Electricity Consumer Price Protection Fund	-	-	-	-	-	
Demand Management Support Costs	1.8	-	-	-	-	
Provision for Electricity Sector	(53)	672	449	736	711	see explanation above for "Provision for Electriocty Sector" (line 17)
Other (Finance)	(1.0)	-	(1)	(1)	(1)	
Total OEFC Income	**(63)**	**692**	**241**	**587**	**404**	
Impact on Surplus/(Deficit)[1]	**-15**	**886**	**-553**	**-139**	**-811**	Note: A significant component of the changes above affecting this net is from a fiscally-neutral recategorisation of revenue impacts from the Asset Optimisation (AO) initiative previously shown in Sales and Rentals in Budget 2017 for commercial confidentiality. The pure changes to non-AO electricity sector changes is significantly fiscally negative. IN 2018-19 ONWARD. See summary table below for breakdown of total change between these components.
Information: Breakdown of change between revenue and expense						
Total Revenue Impact	87	793	(672)	(262)	(916)	
Total Expenditure impact	101	(93)	(119)	(123)	(105)	

Electricity Sector Outlook (PSAB)

Negative Revenue Risks	$ Millions				
($ millions)	Plan				
	2017-18	2018-19	2019-20	2020-21	2021-22
Generic					
OPG Generation Risk: Nuclear Output (-1.6 TWh)[1]	(120)	(120)	(120)	(120)	
1% decrease in Hydro One actual load[2]	(57)	(59)	(62)	(63)	
Lower OPG's Equity weighting & Return on Equity (ROE)[3]	(12)	(20)	(26)	(45)	
Lower Hydro One Return on Equity (ROE)[4]	(9)	(36)	(38)	(40)	
ONFA adjsutment risk		(400) to 0	(400) to 0	(400) to 0	(400) to 0
Regulatory					
Hydro One Distribution rate application[5]	(50)	(50)	(50)	(50)	
OPG Switch from accrual based to cash based accounting for pension and OPEB[6]	–	(600)			
Regulatory Risk - Timing of OPG Rate Decision[7]	–				
OEB Staff Recommendations wrt OPG rate application(May 2017)[8]	–				
Nuclear Liabilities Cash vs. Accrual[9]	–				
OEB decision on Hydro One tax recapture (if one-time write-down)[10]	(420)				
Accounting					
OPG IFRS Consolidation Risks[11]		—	—	—	
Other Risks					
ONFA adjustment decrease[12]	(100)				
Avista Acquisition - Termination fee		(49)			
PILs risk related to retirement of Stranded debt and potential wind down of OEFC[13]					(20)

Note: These risks do not reflect the impacts on electricity sector revenue and expense of reclassification of the Asset Optimization strate

1. OPG's market and generation risks related to nuclear reliability similar to the scenarios OPG developed for its sales margins to capture major market risk factors (e.g., natural gas prices, coal prices, foreign exchange, nuclear reliability) in its 2012 business plan. Currently, only the nuclear reliability risk is captured at the current regulated rate for OPG's nuclear generation.

2. Estimated revenue impact if Hydro One load for Transmission and Distribution is 1% lower than projected for all years in CEFD Hydro One Forecast. Based on the assumption a 1% increase in load is directly proportional to a 1% change in revenue requirements.

3. Risk range for Hydro One transmission and distribution reflects potential risk of lower ROE by 0.5% vs assumed ROEs in business plan along with reduced deemed debt to equity weighting of 55%/45% from the current 51%/49%.

4. Risk range for Hydro One transmission and distribution reflects potential risk of lower ROE by 0.5% vs assumed ROEs in CEFD Hydro One Forecast based on the most recent rate applications and forecasted ROE rates.

5. OEB is expected to make a decision on Hydro One's Distibution rate application for 2018 during the first half of 2018.

6. Previous risk removed shifted from 2017-18 to 2018-19. OEB's September 2017 Report, established accrual accounting method as default rate setting method to recover Pension and Other Pension Benefits (OPEBs) costs and recommended continuance of variance account tracking the difference between cash vs. accrual basis reporting for Pension and OPEB. This finding mitigates this risk. However, OEB December 28, OPG rate decision instructs OPG to submit request to dispose of Pension and OPEB deferral and variance account balances during 2018 for its 2019 payment application. OEB's final decision will be made at that time. Note, the impact of a decision could fall in 2019-20 depending on timing of the OEB decision.

7. **Previous risk removed with timing impact now reflected in OPG outlook.**. OEB December 28, decision and order provides an effective date for new rates of June 1, 2017. OPG's business plan assumed OEB decision would be effective as of January 1, 2017. OPG estimated an impact of -$60M for each month for which OEB decsion is not retroactive. The resulting $300M estimated impact has been included in the OPG outlook.

8. **Previous risk removed .** Estimated impact of OEB December 28the decision and order with respect to OPG rates is now reflected on the OPG Outlook.

9. **Previous risk removed.** Risk is related to potential switch to cash-basis accounting for regulated recovery of nuclear payment anmounts. OEB December 28, 2017 Decision and Order has deferred this issue to next OPG rate application in 2021 for 2022 to 2027 period.

10. The OEB's Sep. 28, 2017 ruling on Hydro One's Transmission rate application included direction on sharing, with ratepayers, tax savings related to the Hydro One IPO. Hydro One filed a Motion to Review this decision with the OEB and has also filed a court appeal. Hydro One's 2017 Q3 financial report notes that if the Motion to Review and appeal are unsuccesful the company would record a one-time write-down of $885 million (for transmission and distribution net income) reflecting the OEB decision. The risk above reflects this risk at the Province's current 47.4% average share allocation. Hydro One noted that timing for the Motion to Review and appeal is uncertain. It expects the OEB Review to start in Q1 but noted that it could run in to Q2. As a result the impact could occur in 2018-19.

11. **Previous risk figures removed.** OPCD provided IFRS impact estimates (largely related to OPG) at the time of Budget 2017. A portion of these were reflected in in OPG's and Hydro One's net income outlook at the time of the 2017. The current Electricity Outlook now reflects this additional IFRS risk. Table below outlines OPG IFRS Risks versus what is built into the 2017 Budget Fiscal Plan. The new IFRS adjustments figures are pending from OPG via Energy in the next few days.

	2017-18	2018-19	2019-20	2020-21
OPG IFRS Risk	(400)	(475)	(700)	(750)
Risks Built into Fiscal Plan at 2017 Budget	(400)	0	(200)	0
Additional Risks now picked up in this Electricity Outlook	0	(475)	(500)	(750)

Electricity Sector Outlook (PSAB)

Positive Revenue Risks ($ millions)	Plan 2017-18	2018-19	2019-20	2020-21
Generic				
OPG Generation Risk: Nuclear Output (+1.1 TWh)[1]	85	85	85	85
1% increase in Hydro One actual load[2]	57	59	61	63
Higher OPG Return on Equity (ROE)[3]	6	22	19	33
Higher Hydro One Return on Equity (ROE)[4]	19	69	50	50
ONFA adjsutment risk		0 to 400	0 to 400	0 to 400
Regulatory				
Accounting				
Other Risks				
ONFA adjustment increase[5]	100			

gy or updates to AO strategy.

1. OPG's market and generation risks related to nuclear reliability similar to the scenarios OPG developed for its sales margins to capture major market risk factors (e.g., natural gas prices, coal prices, foreign exchange, nuclear reliability) in its 2012 business plan. Currently, only the nuclear reliability risk is captured at the current regulated rate for OPG's nuclear generation.

2. Estimated revenue impact if Hydro One load for Transmission and Distribution is 1% higher than projected for all years in CEFD Hydro One Forecast. Based on the assumption a 1% increase in load is directly proportional to a 1% change in revenue requirements.

3. Risk range for OPG reflects potential risk of higher ROE in 2018-2021 (for nuclear base) vs assumed ROE in OPG's 2016 business plan and corresponding rate application. Assumed ROE is 9.85%, respresenting recent in 2010.

4. Risk range for Hydro One transmission and distribution reflects potential risk of higher ROE vs assumed ROEs in the Hydro One CEFD Forecast for 2018-2021. Assumed ROE is 9.85%, representing recent high in 2010.

5. Reflects risk around the consolidation adjustment to OPG net income, whereby the realized portion of gains or losses of OPG's nuclear funds are added or subtracted from OPG net income. Currently $194M positive adjustment reflecting valuations as of December 31, 2017 is included in the OPG outlook. Given current market volatility the ONFA adjustment could change significantly by the end of the Province's fiscal year, March 31, 2018. The net debt adjustment to be included in the fiscal plan consistent with the December 31, 2017 valuations/reports would also be subject to the same type of volatility.

ONTARIO ELECTRICITY FINANCIAL CORPORATION
On Deck Outlook as of March 2017

$ Millions

	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Revenue						
Revenue Pool Residual						
Debt Retirement Charge	859	625	623	-	-	-
Payments-in-lieu of tax:						
OPG	268	302	315	366	408	537
Legacy Hydro One (Including Brampton)	2,929	7	2	2	2	2
Hydro One CIT dedicated to OEFC	3	20	20	22	23	25
MEUs	27	44	68	86	105	114
Total PILs & CIT dedicated to OEFC[1]	3,228	373	405	476	538	679
Interest :						
OPG	173	179	168	153	135	135
H1						
IESO	2	3	3	3	3	3
Province	520	492	492	492	492	492
Other	28	10	5	5	5	5
Total Interest	723	684	668	653	635	635
Power Supply Contract Recoveries	875	739	292	325	301	273
Amortization of NUG liability	172	129	74	41	30	28
Electricity sector dedicated income	3	342	525	-	-	-
Gain to OEFC under s. 50.3	172	-	-	-	-	-
Miscellaneous	9	-	-	-	-	-
	6,041	2,893	2,587	1,495	1,504	1,615
Expense						
Debt interest	1,319	1,216	1,090	1,027	977	885
Interest on nuclear risk funding						
Demand Management Support Costs	8	10	10	-	-	-
Amortization of deferred debt costs	-	-	-			
Power Supply Contract Costs	875	739	292	325	301	273
Debt Guarantee fee	127	122	102	91	88	81
Operating	7	6	6	6	6	6
	2,336	2,093	1,500	1,449	1,372	1,245
Excess (Deficiency) of Revenue over Expense	**3,705**	**800**	**1,087**	**46**	**132**	**370**
Prior period adjustment	87					
Stranded Debt - Year End	**4,393**	**3,593**	**2,506**	**2,460**	**2,328**	**1,958**

Note: All the Hydro One ownership broadening impacts, other than the ownership change from the initial IPO in 2015 and the secondary offering in April 2016, were reflected in Sales and Rentals as of the 2017 Budget.

ONTARIO ELECTRICITY FINANCIAL CORPORATION
On Deck Outlook as of February 2018 **$ Millions**

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Revenue						
Revenue Pool Residual						
Debt Retirement Charge	859	621	604	0	0	0
Payments-in-lieu of tax:						
OPG	268	224	440	277	401	394
Legacy Hydro One (Including Brampton)	2,929	4	2	2	2	2
Hydro One CIT dedicated to OEFC	3	25	24	22	23	25
MEUs	27	112	33	86	105	114
Total PILs & CIT dedicated to OEFC[1]	3,228	364	499	387	531	535
Interest :						
OPG	173	167	155	166	158	131
H1						
IESO	2	2	3	3	3	3
Province	520	514	454	404	404	404
Other	28	20	20	20	10	10
Total Interest	723	703	632	593	575	548
Power Supply Contract Recoveries	875	838	182	183	134	103
Amortization of NUG liability	172	129	74	41	30	28
Electricity sector dedicated income	3	302	797	449	736	711
Gain to OEFC under s. 50.3[2]	172	411	531	0	0	0
Miscellaneous	9	14	0	0	0	0
	6,041	3,382	3,319	1,652	2,006	1,925
Expense						
Debt interest	1,319	1,216	1,109	1,077	1,048	950
Interest on nuclear risk funding						
Demand Management Support Costs	8	8	10	0	0	0
Amortization of deferred debt costs	0	0	0			
Power Supply Contract Costs	875	838	182	183	134	103
Debt Guarantee fee	127	122	102	99	98	91
Operating	7	7	6	7	7	7
	2,336	2,191	1,409	1,366	1,287	1,151
Excess (Deficiency) of Revenue over Expense	3,705	**1,191**	**1,911**	**287**	**719**	**774**
Prior period adjustment	87					
Stranded Debt - Year End	4,393	**3,202**	**1,292**	**1,005**	**286**	**(488)**

1

Payments-in-lieu of tax:	2015-16 Public Accounts
OPG	290
Legacy Hydro One (Including Brampton)	2,941
Hydro One CIT dedicated to OEFC	0
MEUs	15
	3,247

2 **2017-18 value preliminary estimate, subject to change.**

ONTARIO ELECTRICITY FINANCIAL CORPORATION

Changes from Budget 2017 as of February 2018 **$ Millions**

	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Revenue						
Debt Retirement Charge	(4)	(19)	-	-	-	
Payments-in-lieu of tax:						
OPG	(78)	125	(89)	(7)	(143)	2016-17 decrease largely due to an OPCD Public Accounts PILs adjustment related to reconciling between OPCD and OEFC net opening assets. OPG PILs also slightly lower than projected. 2017-18 increase is largely due to inclusion of PILs related to disposition of OPG headquarters and Lakeview properties. 2018-19 onward lower mainly due to lower OPG income tax PILs. Property tax componenst are close to Budget 2017. .
Legacy Hydro One (Including Brampton)	(3)	-	-	-	-	
Hydro One CIT dedicated to OEFC	5	3	-	-	-	Adjustment based on updated information in Hydro One rate application
MEUs	68	(35)	-	-	-	Large increase in 2016-17 from $80M payment during transfer of H01 Brampton to new consolidated MEU Alectra. Reduction in 17-18 based on YTD actual MEU PILs.
Total PILs	(9)	93	(89)	(7)	(143)	
Interest :						
OPG	(12)	(13)	13	23	(4)	Update to OPG interest outlook (wrt interest on OEFC loan).
H1	-	-	-	-	-	
IESO	(1)	-	-	-	-	
Province	22	(38)	(88)	(88)	(88)	2016-17 PDI at ($514m) was slightly larger than ($492m) projected at Interim. 2017-18 and 2018-19 and onward change reflects revised projections for Provincial debt interest as a result of debt pay downs related to Hydro One's April 2016 and May 2017 offerings, repectively.
Other	10	15	15	5	5	
Total Interest	19	(36)	(60)	(60)	(87)	
Power Supply Contract Recoveries	99	(110)	(142)	(167)	(170)	Variance in 16-17 is largely due to retroactive payments that the OEFC made to certain non-utility-generators (NUGs) with former Ontario Hydro power purchase agreement contracts with OEFC. OEFC was required to make these payment following the dismissal by the Supreme Court of Canada of OEFC's application for leave to appeal a judgment of the Court of Appeal of Ontario on a 2015 court decision. Going-forward, variance is largely due to suspension or early termination of some NUG PPAs in response to the IESO's NUG curtailment initiative.
Amortization of NUG liability	0	(0)	(0)	(0)	(0)	
Electricity sector dedicated income	(41)	272	449	736	711	The decrease in OEFC ESDI in 2017-18 reflects i) the IFRS adjustment of $400 million in 2017-18 that was not reflected in the OEFC ESDI projection at the time of the 2017 Budget (Note the IFRS adjustment was reflected in OPG net income for the 2017 Budget fiscal plan) and ii) the lower OPG and Hydro One net income due to OEB's 2017 rate decisions. Changes to the Provision (ESDI) expense in 2017-18 mainly reflect higher OPG net income due to recategorisation from Sales and Rentals of proceeds from the sale of OPG headquarters properties and Lakeview properties. Th eincrease in 2018-19 onward reflects TB/MBC approval in 2017-18 PRRT approval to continue Provision for the Electricity Sector (i.e., Electricity Sector Dedicated Income to OEFC) beyond 2017-18. 2017 Budget assumed previous policy whereby ESDI ended after 2017-18.
Gain to OEFC under s. 50.3	411	531	-	-	-	
Miscellaneous	14	-	-	-	-	
	489	732	157	502	310	
Expense						
Debt interest	-	19	50	71	65	Revised outlook for OEFC debt interest outlook
Interest on nuclear risk funding	-	-	-	-	-	
Demand Management Support Costs	(2)	-	-	-	-	
Amortization of deferred debt costs	-	-	-	-	-	
Power Supply Contract Costs	99	(110)	(142)	(167)	(170)	Same as Power supply contract recoveries above. Power supply contract costs are fully recovered by power supply contract recoveries.
Debt Guarantee fee	-	-	8	10	10	
Operating	1	-	1	1	1	
	98	(91)	(83)	(85)	(94)	
Excess (Deficiency) of Revenue over Expense	**391**	**823**	**241**	**587**	**404**	
Stranded Debt - Year End	**(391)**	**(1,214)**	**(1,455)**	**(2,042)**	**(2,446)**	

Provision for Electricity Sector (Dedicated Electricity Earnings/Electricity Sector Dedicated Earnings)

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Income from Investment in Government Business Enterprises						
OPG Income	291	299	905	500	728	677
Hydro One Income[1]	232	501	346	353	412	438
Hydro One Brampton (if applied separately)		15				
Total Income	**523**	**815**	**1,251**	**853**	**1,140**	**1,115**
Public Debt Interest - Electricity Sector						
OPG			(300)	(300)	(300)	(300)
Hydro One[1]			(154)	(104)	(104)	(104)
Public Debt Interest - Electricity Sector (OEFC Interest revenue)	**(520)**	**(514)**	**(454)**	**(404)**	**(404)**	**(404)**
MOF Provision Expense (before adjustments)	**3**	**302**	**797**	**449**	**736**	**711**
Other Adjustments						
Prior-year Adjustment[2]		3				
Exclude Brampton[3]		(15)				
MOF Provision Expense (after other adjustments)	**0**	**290**	**797**	**449**	**736**	**711**
Cumulative Shortfall Adjustment						
Opening Balance	0	0	0	0	0	0
Deduction / (Addition)	0	0	0	0	0	0
Ending Balance	0	0	0	0	0	0
Dedicated Electricity Earnings (all adjustments) (Public Accounts)	**0**	**290**	**797**	**449**	**736**	**711**
Electricity Sector Dedicated Income (OEFC Annual Report)	**3**	**302**	**797**	**449**	**736**	**711**

Notes:

1. The Hydro One financials above now reflects the Provincial share allocation as of January 2018.

2. 2016-17 Adjustment was due to the discrepancy between the numbers in MOF expense in PA 2015-16 and OEFC Financials in 2015-16 due to timing issues. $3M adjustment rectifies this discrepancy

3. Brampton was excluded from the Ministry of Finance's ESDI allocation.

Ontario Power Generation

OPG Income - Budget 2017

$ Millions

	Actual	Interim	Plan				
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22
OPG Net Income After Tax (Adjusted)	291	304	97	732	625	1,066	
OPG Net Income After Tax	*291*	*379*	*480*	*678*	*726*	*913*	
Extraordinary Gains	-	-	-	-	-	-	
GA - OPG Trust Interest Revenue			*17*	*54*	*99*	*153*	
OPG IFRS consolidation risk picked up in Fiscal Plan		(75)	(400)		(200)		
ONFA and other Fair Value Adjustments	(75)	8					
ONFA Adjustments	-	8					
Other Fair Value Adjustments	(75)						

OPG PIL - Budget 2017

$ Millions

	Actual	Interim		
	2015-16	2016-17	2017-18	2018-19
Net Income Before Tax	383	396	572	867
Net Income After Tax (Adjusted)	291	304	97	732
Income Taxes	92	92	92	135
GRC: Payable to OEFC	198	196	205	212
Proxy Property Tax	16	14	18	19
Ontario Capital Tax	0	0	0	0
Total	**306**	**302**	**315**	**366**

OPG Income - January 2018

$ Millions

	Actual	Actual	Current Outlook				
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22
OPG Net Income	291	377	1,195	795	1,053	877	1,070
GA Financing - OPG Trust Interest Revenue[2]			10	80	150	225	225
OPG IFRS consolidation risk[3]		(78.00)	(300)	(375)	(475)	(425)	(625)
OPG Net Income (Adjusted before ONFA)	**291**	**299**	**905**	**500**	**728**	**677**	**670**
ONFA Adjustments	247	49	194				
Other Fair Value Adjustments	(75)	(6)					
ONFA and other Fair Value Adjustments	**172**	**43**	**194**				
OPG Net Income	**463**	**342**	**1,099**	**500**	**728**	**677**	**670**

OPG PIL - January 2018

$ Millions

	Actual	Actual		Cu
	2015-16	2016-17	2017-18	2018-19
Income Before Tax	383	308	1,126	554
OPG Net Income (Adjusted before ONFA)	291	299	905	500
OPG Income Tax (PILs)	92	9	221	54
GRC: Payable to OEFC	198	201	206	209
Proxy Property Tax to OEFC	16	14	13	14
Ontario Capital Tax	0	0	0	0
Total OPG PILs	**306**	**224**	**440**	**277**

1. OPG's May 2017 head office facilities sale impacts are re-categorized from Sales and Rentals to OPG net income and PILs in the current Electricity Outlook update. This update now also includes 2017-18 proceeds from the Lakeview properties sale.

2. This reflects interest earnings on GA financing costs which are consolidated back to Province

3. IFRS risk provided by OPCD as of 2017 Budget

Hydro One Ownership Calculation:		SOURCE:
Total number of shares outstanding[1]	595,000,000	1. Hydro One Ltd Annual Report 2015, pg 94 of PDF, pg 92 of the Report.
Additional Common Shares Issued since IPO	386,711	
IPO November 2015		
Initial Public Offering(2015)[2]	81,100,000	2. From news release: http://hydroone.mediaroom.com/2015-11-05-Hydro-One-Limited-Announces-Closing-of-IPO
Over allotment option (2015)[3]	8,150,000	3. From news release: http://hydroone.mediaroom.com/2015-11-12-Hydro-One-Limited-Announces-Closing-of-IPO-Over-Allotment-Option
Sales to PWU/SEP Trusts	5,646,340	
Total	94,896,340	
Province's remaining ownership, Nov 2015 (# Shares)	**500,103,660**	
Province's remaining ownership, Nov 2015 (%)	**84.05%**	
Secondary Offering April 2016		
Secondary Offering (2016)	72,434,800	4. Hydro One Ltd. Q2 Report, pg 1 http://www.hydroone.com/InvestorRelations/FinancialReporting/Documents/Hydro%20One%20Ltd%20Second%20Quarter%20
Over allotment option (2016)	10,865,200	
Total	83,300,000	
Province's remaining ownership, Apr 2016 (# Shares)	**416,803,660**	
Province's remaining ownership, Apr 2016 (%)	**70.05%**	
Final Offering May 2017		
Final Offering (2017)	120,000,000	Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by-the-Provin
Over allotment option (2017)	-	Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by-the-Provin
Total	120,000,000	
Province's remaining ownership, May 8, 2017 (# Shares)	296,803,660	Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by-the-Provin
Province's remaining ownership, May 8, 2017 (%)	**49.88%**	
First Nations Sale, closed on December 29, 2017	14,391,012	Source: http://www.S:\Users\CEF\Hydro 2018\OEFC\RbP\Outlook\01. January\Backup\20180103-0 - H1 First Nations Sales\
	2.4170865%	Source: https://news.ontario.ca/mei/en/2017/05/ontario-raises-28-billion-from-final-hydro-one-share-offering.html
Province's remaining onwership - post First Nations Sale (#Shares)	282,412,648	
Province's remaining onwership - post First Nations Sale (%)	**47.43%**	
Avista Impact (projected closing date 2nd half of 2018)		
Contingent Convertible Debenture	$1,540,000,000	
Conversion Price	$21	
Potential Dilution (# Shares)	71,962,617	
Revised Total number of shares outstanding	**666,962,617**	
Province's remaining onwership - post Avista Acquisition (#Shares)	282,412,648	
Province's remaining onwership - post Avista Aquisition (%)	**42.34%**	

Ownership Percentage in 2017-18 Fiscal Year	Number of Months	Percentage of Year
70.05%	1	8.3%
49.88%	8	66.7%
47.43%	3	25.0%
	12	
Average 2017-18 FY Ownership:	**51.0%**	

Ownership Percentage in 2018-19 Fiscal Year (assume Avista closing end of September 2018)	Number of Months	Percentage of Year
47.43%	6	50.0%
42.34%	6	50.0%
	12	
Average 2018-19 FY Ownership:	**44.9%**	

Ownership Percentage in 2019-20 Fiscal Year Onwards
42.34%

Accretive to earnings per share and cash flow for Hydro One in the first full year post closing
above is from Hydro One transaction overview. Check what this means for timing of additional shares and /or earnings.

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Hydro One Net Income and PILs

Hydro One Income - Budget 2017
($ millions)

	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Hydro One Net Income After Tax	685	737	742	802	862	931
Hydro One - Unrealized Gains Adjustment						

2016-17 to 2020-21 from CEFD Hydro One 2016 model.

Hydro One PIL - Budget 2017
($ millions)

	2015-16	2016-17	2017-18	2018-19
Net Income After Tax	685	737	742	802
Income Taxes PILs	132	160	181	205
Proxy Property Tax	2	2	2	2
Ontario Capital Tax	0	0	0	0
Total	**134**	**162**	**183**	**207**

Hydro One Income - December 2017
($ millions) **$ Millions**

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21	2021-22
Hydro One Net Income After Tax			662	706	831	885	943
Hydro One Net Income After Tax - Including Adjustments	670	680	662	706	831	885	943
Hydro One - Net Income Attributable to Preferred Shareholders	15	18	18	18	18	18	18
Hydro One - Unrealized Gains Adjustment							

Hydro One (100% Ownership)
($ millions) **$ Millions**

	Actual 2015-16	Actual 2016-17	2017-18	Cu 2018-19
Net Income After Tax - Common Shares	670	680	662	706
Net Income After Tax - Preferred Shares	15	18		
Income Taxes PILs	132	160	181	205
Proxy Property Tax	2	2	2	2
Ontario Capital Tax	0	0	0	0

Public Debt Interest and Section 50.3 payments

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Hydro One Public Debt Interest and Section 50.3 payments						
Government Annual Interest Costs - Hydro One	220	220	220	220	220	220
Reduction in Interest Costs due to Broadening[1]		(29)	(66)	(116)	(116)	(116)
Province Annual Interest Costs - Hydro One Debt	**220**	**191**	**154**	**104**	**104**	**104**
Province Annual Interest Cost - OPG Debt	300	300	300	300	300	300
Total Public Debt Interest	**520**	**514**	**454**	**404**	**404**	**404**

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Gain to OEFC under s. 50.3	172	411	531	0	0	0

1. The Hydro One reduction in interest costs above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering are currently reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

2020-21							
220	ID# (Track Cha	Fiscal Year	alue (Hardcode	Value (Linked)	Description	Source Details	Source (Link)
-116	20170501-2	2016-17	411,152,733	411,152,733	s 50.3 Gain for	Calculation provided by SIFB	
104	20170501-3	2016-17	29	29	Reduction in Int	Internal Calculation	
	20170501-3	2017-18	66	-116	Reduction in Int	Internal Calculation	
	20170501-3	n/a	220	220	Annual Interest	Internal Calculation	
300							
404							

2020-21	ID# (Track Cha	Fiscal Year	alue (Hardcode	Value (Linked)	Description	Source Details	Source (Link)
0	n/a	n/a	5126		($M) Provinces	OEFC 1999-2000 FS, pg 24	
	n/a	n/a	5.85%		Annual Interest	OEFC 1999-2000 FS, pg 26	
			299.871				

	OPG's Annual Interest Costs:		300	
20170713-1	2016-17	-513,768,361	Provincial interest cost for equity investment in OPG, H1 in 2016-17 Monthly Balances Sheet (from FTD) S:\Users\CEF\Hydro 2017\OEFC\RbP\Outlook\07. July\Backup\20170713-1\interest fr	
s. 50.3	531	531	S:\Users\CEF\Hydro 2018\OEFC\RbP\Outlook\02. February\Back-up files	

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PROVINCIAL CONSOLIDATION ADJUSTMENTS
Ontario Nuclear Funds Agreement

Adjustment for Change in OPG Reported Net Income

Adjustment for DSF Unrealized Earnings

Unrealized Earnings as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Bruce Variance Account Adjustment
OPG Net Income Adjustment

Adjustment for UFSF Unrealized Earnings

Unrealized Earnings as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Bruce Variance Account Adjustment
OPG Net Income Adjustment

Unrealized Earnings -- Fiscal YTD

Adjustment for Change in Due to Province

Adjustment for DSF Due to Province
Due to Province (cost basis) as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Change in Due to Province -- Fiscal YTD

Adjustment for UFSF Due to Province

Due to Province (cost basis) as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Change in Due to Province -- Fiscal YTD

Provincial Consolidation Adjustment

Other Data

	Actual 2016-17	2017-18
Debt Retirement Charge	621	0

	2016-17	2017-18
Power Supply Contract Recoveries	838	182

	2016-17	2017-18
Interest		
OPG	167	155
IESO	2	3
Other (Net)	20	20
Expense		
Debt interest	1216	1109

	Actual 2016-17	2017-18
MEU - PIL Income Tax	109.8	
MEU - PIL Property Tax	0.6	
MEU - GRC	1.2	
TOTAL MEU PILs	111.6	

	Actual 2016-17	2017-18
Miscellaneous/Other (OEFC FS)	14	
Demand Management Support Costs (IEI)	8	10
Operating [Expense]	7	6
Interest on nuclear risk funding	-	-
Amortization of deferred debt costs	-	-
Amortization of NUG liability	129	74
Debt Guarantee Fee	122	102

Expense (Electrictiy Summary Tab)		
Other (Finance)	-7	-6
Demand Management Support Costs (IEI)	-8	-10
Debt Guarantee Fee	(122)	(102)

Plan 2018-19	2019-20	2020-21	2020-21
0	0	0	0

Plan 2018-19	2019-20	2020-21	2020-21
183	134	103	103

Plan 2018-19	2019-20	2020-21	2020-21	
166	158	131	119	updated Feb 15, FTD
3	3	3	3	updated Feb 15, FTD
20	10	10	10	updated Feb 15, FTD
1077	1048	950	818	updated Feb 15, FTD

Plan 2018-19	2019-20	2020-21	2020-21

Plan 2018-19	2019-20	2020-21	2020-21
7	7	7	7
-	-	-	-
-	-	-	-
41	30	28	28
99	98	91	91
-7	-7	-7	-7
(99)	(98)	(91)	-91

ID# (Track Changes	Fiscal Year	Value (Hardcoded)	Value (Linked)
20170510-2	2016-17	$ 739,216,115	
20170510-2	2017-18	$ 291,629,707	
20170510-2	2018-19	$ 324,906,017	
20170510-2	2019-20	$ 300,648,570	
20170510-2	2020-21	$ 273,240,858	
20170501-4	2016-17	179	179
20170501-4	2017-18	169	169
20170501-4	2018-19	179	179
20170501-4	2019-20	175	175
20170501-4	2020-21	148	148
20170501-5	2016-17	1216	1,216
20170501-5	2017-18	1121	1,121
20170501-5	2018-19	1094	1,094
20170501-5	2019-20	1053	1,053
20170501-5	2020-21	963	963
20170731-3	2016-17	621	
20170811-1	2016-17	109.8	
20170811-1	2016-17	0.6	
20170811-1	2016-17	1.2	
20170815-5	2016-17	$ 838,000,000	
20170815-6	2016-17	$ 14,000,000	
20170815-8	2016-17	8	
20170815-9	2017-18	10	
20170815-10	2016-17	7	
20171211-2	2017-18	6	6
20171211-2	2018-19	7	7
20171211-2	2019-20	7	7
20171211-2	2020-21	7	7
20170815-7	2016-17	167	
20170815-7	2016-17	2	
20170815-7	2016-17	20	
20170815-7			

ID# (Track Changes	Fiscal Year	Value (Hardcoded)	Value (Linked)
20170905-1	2016-17	129	129
20170905-1	2017-18	74	74

20170905-1	2018-19	41	41
20170905-1	2019-20	30	30
20170905-1	2020-21	28	28
20170905-2	2016-17	122	
20170906-1	2017-18	3	3
20170906-1	2018-19	3	3
20170906-1	2019-20	3	3
20170906-1	2020-21	3	3
20170906-1	2017-18	20	5
20170906-1	2018-19	20	5
20170906-1	2019-20	10	5
20170906-1	2020-21	10	5
20171211-0	2017-18	1115	
20171211-0	2018-19	1089	
20171211-0	2019-20	1060	
20171211-0	2020-21	963	
20171211-1	2017-18	102	102
20171211-1	2018-19	99	99
20171211-1	2019-20	98	98
20171211-1	2020-21	91	91
20171211-1			
20171211-1			
20171211-1			
20171211-1			
20171211-1			
20171211-1			
20171211-1			
20171211-1			
20171211-1			

ID# (Track Changes	Fiscal Year	Value (Hardcoded)	Value (Linked)
20180104-2	2017-18	$ 181,776,685	
20180104-2	2018-19	$ 182,785,215	
20180104-2	2019-20	$ 133,962,519	
20180104-2	2020-21	$ 102,554,665	

Description	Source Details	Source (Link)
The table below contains an updated preliminary N	SPFB Estimates, Email	
• The tables below provides both last year's submission for NUG costs by CEFD and this year's estimates (both of which exclude HST) based on the most recent NUG model.	SPFB Estimates, BN SPFB Estimates, BN SPFB Estimates, BN SPFB Estimates, BN	
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
Updating DRC from OEFC AR (Drafts)	2017 OEFC DRAFT FS	S:\Users\CEF\Hydro 2017\OEFC'
MEU - PIL Income Tax	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
MEU - PIL Property Tax	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
MEU - GRC	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
Updating to actuals	2017 OEFC AR	2017 OEFC Annual Report - Eng
Updating to actuals	2017 OEFC AR	2017 OEFC Annual Report - Eng
Updating to Actuals	2017 OEFC AR	S:\Users\CEF\Hydro 2017\OEFC'
OEFC 2017-18 IEI/Demand Management Suppor	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Operating Expense - Updating to Actuals	2017 OEFC AR	S:\Users\CEF\Hydro 2017\OEFC'
Revised Operating Expense from FTD Forecast	FTD - October PRRT	
OPG Interest Revenue - Actuals 2016-17	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
IESO Interest Revenue - Actuals 2016-17		
Other (Net) Interest Revenue - Actuals 2016-17		

Description	Source Details	Source (Link)
		S:\Users\CEF\Hydro 2017\OEFC'
	Amortization Schedule.	S:\Users\CEF\Hydro 2017\OEFC'

Sourcing the NUG liability amortization schedule.	Tab: Summary Fiscal Impact	S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Gurantee Fee - Updating to Actuals	2017 OEFC AR (pg 13 (	\\ofina.on.ca\ofadfs\Users\CEF\H
IESO Interest Revenue Plan	OEFC Revenue Forecast for Board - April 2017	\\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H
Other Interest Revenue Plan		\\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H
OEFC Debt Interest Expense (no change, just re-linking)	FTD - January 11	
OEFC Debt Guarantee Fee	FTD - October PRRT	S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC'

Description	Source Details	Source (Link)
Updated FY 2017-18 estimates of NUG costs	SPFB Estimates, BN	Power Purchases and Sales Fore
Updated FY 2017-18 estimates of NUG costs	SPFB Estimates, BN	Power Purchases and Sales Fore
Updated FY 2017-18 estimates of NUG costs	SPFB Estimates, BN	Power Purchases and Sales Fore
Updated FY 2017-18 estimates of NUG costs	SPFB Estimates, BN	Power Purchases and Sales Fore

\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board

\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board

\RbP\Outlook\07. July\Backup\20170731-3 - DRC Update\2017 OEFC Annual Report - English - DRAFT.PDF

\RbP\Outlook\08. August\Backup\20170811-1 - Updating PILs for 2016-17\OEFC 2016-17 Pils summary.pdf
\RbP\Outlook\08. August\Backup\20170811-1 - Updating PILs for 2016-17\OEFC 2016-17 Pils summary.pdf
\RbP\Outlook\08. August\Backup\20170811-1 - Updating PILs for 2016-17\OEFC 2016-17 Pils summary.pdf

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\RbP\Outlook\08. August\Backup\20170815-8 - 2016-17 Demand Management Support Costs (IEI)\2017 OEFC
\RbP\Outlook\08. August\Backup\20170815-9 - 2017-18 Demand Management Support Costs (IEI)\OEFC rever
\RbP\Outlook\08. August\Backup\20170815-10 - 2016-17 Operating (Expense)\2017 OEFC Annual Report - Enc

\RbP\Outlook\08. August\Backup\20170815-7 - 2016-17 Updated Interest on Debt Revenue\RE Revised OEFC

\RbP\Outlook\09. September\Backup\20170905-1 - Amortization of NUG Liability\NUG liability_estimated draw c
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ydro 2017\OEFC\RbP\Outlook\09. September\Backup\20170905-2 - 2016-17 Debt Guarantee Fee\2017 OEFC
ydro 2017\OEFC\RbP\Outlook\09. September\Backup\20170906-1 - OEFC Revenue Forecast for Board
ydro 2017\OEFC\RbP\Outlook\09. September\Backup\20170906-1 - OEFC Revenue Forecast for Board
ydro 2017\OEFC\RbP\Outlook\09. September\Backup\20170906-1 - OEFC Revenue Forecast for Board
ydro 2017\OEFC\RbP\Outlook\09. September\Backup\20170906-1 - OEFC Revenue Forecast for Board
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ydro 2017\OEFC\RbP\Outlook\09. September\Backup\20170906-1 - OEFC Revenue Forecast for Board
ydro 2017\OEFC\RbP\Outlook\09. September\Backup\20170906-1 - OEFC Revenue Forecast for Board

\RbP\Outlook\12. December\Backup\20171211-1 - Interest Numbers from FTD\OEFC forecast PRRT planning_
\RbP\Outlook\12. December\Backup\20171211-1 - Interest Numbers from FTD\OEFC forecast PRRT planning_
\RbP\Outlook\12. December\Backup\20171211-1 - Interest Numbers from FTD\OEFC forecast PRRT planning_
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Annual Report - English.pdf

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Colour Codes

Formulas are in black text

Hard coded numbers are in blue text

References elsewhere are in purple

Green bold text with or without highlights mean updates required

Policies to follow when making updates to the Outlook

*** To quickly jump to the source numbers for a link, press "**Ctrl + [**"

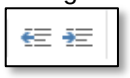
All new numbers must be fully sourced, and follow the colour codes above

Most numbers and text are Arial Size 10, unless it is a title

Add back up materials in a folder with the same numbers as in the 'Track Changes' tab

If there is a reason for italics, or other colours, or formatting make sure it is clear. Othe

Use indents to make things more clear to read



If numbers are taken from another tab they should ONLY be direct links, no calculation

Electricity Summary - (Budget17/On Deck) - Reflects Public Accounts/Financial Statem

OEFC - (Budget17/On Deck) - Reflects OEFC Annual Reports

*Due to slight discrepancies between Public Accounts reporting and OEFC Annual Rep

Outlook Updates Frequency

Frequency	Description	Tab
Monthly	OPG Net Income in-year forecast	OPG
Monthly	OPG PILs in-year forecast	OPG
Quarterly	ONFA Consolidation Adjustment	ONFA
Quarterly	OPG Cash vs Accrual Variance Account	Revenue (Risks)

ɔ.
rwise expect it to be cleared

ı, adjustment should be done. Even if its just making a negative to a positive. Perform all the calculations on the

ıents

ɔorts, the numbers may not be identical

source tab then bring the number into the next tab. (Eg. Formulas like this become hard to troubleshoot ='Hydro

One'!AR29+'Hydro One'!AR31+'Hydro One'!AR32), let's avoid them.

From: John Kim
To: Ronald Kwan
Cc: Gavin He
Subject: RE: Outlook
Date: Sunday, February 05, 2017 11:40:54 AM
Attachments: Electricity Sector Outlook- December 2016_84%_no IOD v5 OPG BP-Nov v16_OPG_H1TxRisks.xlsx

---

Hi Ron,

I'd propose 50m per year on the H1 Tx application. Also, reflected OPG operational efficiencies risk.

Thanks,

John.

From: Ronald Kwan
Sent: February-05-17 4:53 AM
To: John Kim <John.Kim@ofina.on.ca>
Cc: Gavin He <Gavin.He@ofina.on.ca>
Subject: RE: Outlook

Hi John,

Please add in the OPG BP risk that is from Energy's mitigation deck, as well as a factor for delayed implementation.

Also, what portion of the OEB staff report for H1's Tx application would be reasonable to add in as a risk?

Thanks,
Ron

From: John Kim
Sent: January-26-17 1:48 PM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Gavin He <Gavin.He@ofina.on.ca>
Subject: RE: Outlook

Hi Ron,

We did receive the latest monthly update and updated the Outlook to reflect the results. The second report arrived today with the fiscal update report coming yesterday.

Monthly report saved here:
\\ofina.on.ca\ofadfs\Users\CEF\Hydro 2017\OPG\Monthly Financial Updates\01-Jan

Thanks,

John.

From: Ronald Kwan
Sent: Saturday, January 21, 2017 12:18 PM
To: John Kim <John.Kim@ofina.on.ca>
Cc: Gavin He <Gavin.He@ofina.on.ca>
Subject: Re: Outlook

Thanks John.

For consistency, we'll need the OPG monthly update too. So please keep track with Kaitlin on timing of arrival.

And would you find out when OPG will share the draft year-end financials with us and Energy for review.

Thanks,
Ron

On Jan 21, 2017, at 9:10 AM, John Kim <John.Kim@ofina.on.ca> wrote:

> Hi Ron,
>
> Pls. see attached latest Outlook. We just got the ONFA reports yesterday, as well as updated NUG figures from SPFB.
>
> I have some queries about the ONFA reports but for the time being the consolidation amount has reversed to a small positive. On the DSF side, the earnings for both Cost and Market figures are exactly the same so I'm not sure I've seen that before, thus my queries to OPG.
>
> SPFB provided the NUGS forecast with the caveat that prior to the numbers lock, there may be further updates.
>
> Thanks,
>
> John.
>
> Y. John Kim
> Director(A), Electricity Finance Branch
> Corporate & Electricity Finance Division
> Ontario Financing Authority
> Ph: 416-212-6996

Email: john.kim@ofina.on.ca

<Electricity Sector Outlook- December 2016_84%_no IOD v5 OPG BP-Nov v15.xlsx>

Electricity Sector Outlook
November 2016

Disclosure:

All information contained in this workbook are confidential and commercially sensitive

All projected numbers are estimates and subjected to change, and the focus is on OPG and Hydro One projections

This workbook and all information or analysis contained in it is property of the Ontario Financing Authority,
any diclosure or share of information should be first consulted with the owner.

Commercially Sensitive and Confidential Advice to Cabinet for Consideration of Options for Discussion Purposes Only

Outlook Tracking Log

Date	Previous File Name	New File Name
Nov 2016 v2		
Dec 2016 v3		
Dec 2016 v4 OPG BP-July		
Dec 2016 v4 OPG BP-Nov		
Dec 2016 v4 OPG BP-Nov v2		
28-Dec-16	Electricity Sector Outlook-December 2016_84%_no IOD v4 OPG BP-Nov_v2.xlsx	Electricity Sector Outlook-December 2016_84%_no IOD v4 OPG BP-Nov_v3.xlsx
3-Jan-17	Electricity Sector Outlook-December 2016_84%_no IOD v5 OPG BP-Nov v4.xlsx	Electricity Sector Outlook-December 2016_84%_no IOD v5 OPG BP-Nov v5.xlsx
4-Jan-17	Electricity Sector Outlook-December 2016_84%_no IOD v5 OPG BP-Nov v5_Markup.xlsx	Electricity Sector Outlook-December 2016_84%_no IOD v5 OPG BP-Nov v6.xlsx
16-Jan-17	Electricity Sector Outlook-December 2016_84%_no IOD v5 OPG BP-Nov_v9.xlsx	Electricity Sector Outlook-December 2016_84%_no IOD v5 OPG BP-Nov_v10.xlsx
17-Jan-17	Electricity Sector Outlook-December 2016_84%_no IOD v5 OPG BP-Nov_v10.xlsx	Electricity Sector Outlook-December 2016_84%_no IOD v5 OPG BP-Nov_v11.xlsx
20-Jan-17	Electricity Sector Outlook-December 2016_84%_no IOD v5 OPG BP-Nov_v12.xlsx	Electricity Sector Outlook-December 2016_84%_no IOD v5 OPG BP-Nov_v13.xlsx
20-Jan-17	Electricity Sector Outlook-December 2016_84%_no IOD v5 OPG BP-Nov_v13.xlsx	Electricity Sector Outlook-December 2016_84%_no IOD v5 OPG BP-Nov_v14.xlsx

26-Jan-17	Electricity Sector Outlook-December 2016_84%_no IOD v5 OPG BP-Nov_v15.xlsx	Electricity Sector Outlook-December 2016_84%_no IOD v5 OPG BP-Nov_v16.xlsx

Summary of Changes
1) Price Mitigation Net Impact Tab - Flat-lined the tax base measures
2) Hydro One Tab - IPO Impacts, changed ownership to 70.1% from 84%
3) OPG Tab: Added 2017BP November 2016 NI and PILs numbers
Reverted Nov 2016 v2, #3 changes. Next version will insert H1 numbers from new EFB model and then will be split into 4 versions, 2 of which will incorporate the OPG Tab changes from Nov 2016 #3 changes.
New hydro one numbers have been inserted from the CEFD internal model. The 2020-21 number is the same as before.
Added in new OPG numbers from OPG BP November into OPG Tab
In OPG Tab, updated Income Tax for 2017-18 to reflect sale of HQ
Reverse the GRC amounts for OPG Nov 2016 BP to the previous forecast, since the breakdown information for GRC to OEFC information is not available in the new BP.
1) Addressed John's comments on various tabs, explaining the variances, and changed OPG's PIL revenues to $166M for 2017-18. 2) Updated the "Revenue (On Deck)" tab row 32 to include CIT impact. 3) Updated the variance explanation in the "Electricity Summary - Change" tab.
1) John linked the ONFA numbers on the "OPG" tab from the "ONFA" tab. 2) Updated the variance explanation on the "Electricity Summary - Change" tab.
1) Updated the positive and negative risks in the "Revenue (Risks)" tab for OPG and Hydro One, including the explanations. 2) ONFA Funds Return Risk on "Revenue (Risks)" tab - changed from -115.665 to -90 in 2016-17 3) OPG 2020-2021 numbers updated with business plan net income and income tax fiscalized.
1) Updated OPG Variance details on Electricity Summary - Change Tab 2) Added Note #4 on MEU PILs, confirming no change required on Revenue (On Deck) tab.
1) Updated Power Supply Contract Costs and Recoveries in OEFC tab with preliminary SFIB estimates, and explanations in the Electric Summary Change.
1) Revised ONFA Consolidation number for Dec 2016 update in the ONFA tab. 2) 2016-17 NUG lawsuit retroactive payment reflected in Power Supply Contract Costs and Recoveries. 3) Update NUG Forecast with 206-17 new forecast including the lawsuit.

1) OPG Net Income updated with latest monthly updated for 2016-2017.

Electricity Sector Outlook (PSAB)

($ millions)	Budget 2015-16	2016-17	2017-18	Plan 2018-19	2019-20	2020-21
Approved Revenue Outlook as of Budget 2016						
Electricity Revenues						
Income from Investment in Government Business Enterprises[1]	330	1,049	1,198	1,347	1,417	1,471
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes	3,232	515	480	532	481	565
Other Revenue						
Electricity Debt Retirement Charge	868	625	623	-	-	-
Power Supply Contract Recoveries	784	643	463	396	276	248
Net reduction of Power Purchase Contracts[2]	172	129	74	41	30	28
Miscellaneous	5	5	5	5	5	5
Total Electricity Revenue[3]	5,391	2,966	2,843	2,321	2,209	2,317

Notes:

1. Includes provincial consolidation adjustments for OPG's nuclear funds

2. Reflects the effective elimination of above-market NUG liability over a number of years starting January 1, 2005 (on a predetermined schedule).

3. Total reflects revenues from OPG, Hydro One, OEFC and PILS from MEUs, and excludes OPA and IESO and OEB.

Revenue Items On Deck - Changes Compared to Budget 2016

($ millions)	Budget 2015-16	2016-17	2017-18	Plan 2018-19	2019-20	2020-21
OPG November 2016 Financial Outlook[1]	21	(247)	(173)	(43)	86	301
ONFA and other Fair Value Accounting Adjustments[2]	(69)	8	0	0	0	0
Hydro One November 2016 Financial Outlook Update[3]	430	59	17	(1)	8	(9)
MEUs PILs[4]	2					
Other OEFC FS / Public Accounts Updates						
Electricity Debt Retirement Charge	(9)					
Miscellaneous	4	(5)	(5)	(5)	(5)	(5)
Power Supply Contract Recoveries[5]	91	96	(176)	(80)	21	17
Total Revenue Items On Deck	471	(90)	(337)	(129)	110	304

Notes:

1. OPG's 2015-16 outlook reflected its reported earnings. Out-years reflect OPG's 2017-19 business plan, November monthly update, and long-term outlook to 2019-20 (as fiscalized by OPG). 2020-21 estimates are based on OPG's calendar year-based long-term projections from the November business plan and fiscalized by CEFD staff. OPG Business Plan projections are also adjusted to remove amounts relared to asset optimisation amounts (for real estate sales, to avoid double-counting) that are reflected in the fiscal plan under sales and rentals ~~**[is this the case? -- CHECK. That's right]**~~

2. Reflects provincial adjustment as at December 31, 2016, for net unrealized earnings in the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decomissioning and used fuel segregated fund. Adjustment for 2014-15 also includes non-ONFA financial instruments.

3. Reflects CEFD forecasts based on latest available public information and modelling. Reflects an 84% Provincial share ownership, with impacts of future share sales incorporated into the asset optimisation projection in Other Non-Tax Revenues, Sales and Rentals

4. As of Nov 30, 2015, MEU PILs cash receipts were approx. 40% of actual MEU PILS receipts as of March 31, 2016. As of Nov 30, 2016, cash receipts also equal 40% of projected MEU PILS for 2016-17, confirming that MEU PILS projection for 2016-17 requires no update, with the assumption that the remaining 60% will be collected by March 31, 2016, similar to 2015-16. [TO DELETE THIS NOTE FOLLOWING REVIEW.]

5. Reflects retroactive payment to applicant NUGs under the Global Adjustment lawsuit, based on payment in October 2016. Reflect updated forecast from 2016-17 to 2020-21. [MAY BE UPDATED FURTHER PRIOR TO NUMBERS LOCK.]

On Deck Revenue Outlook as of November 2016	Budget 2015-16	2016-17	2017-18	Plan 2018-19	2019-20	2020-21
Electricity Revenues						
Income from Investment in Government Business Enterprises	719	1,006	1,043	1,359	1,455	1,650
Taxation Revenue	3,228	378	479	476	538	678
Electricity Payments-in-Lieu of Taxes						
Other Revenue						
Electricity Debt Retirement Charge	859	625	623	-	-	-
Power Supply Contract Recoveries	875	739	287	316	297	265
Net reduction of Power Purchase Contracts	172	129	74	41	30	28
Miscellaneous	9	-	-	-	-	-
Total Electricity Revenue	5,862	2,877	2,507	2,192	2,320	2,621
Check Calculation:						
Revenue	5,862	2,877	2,507	2,192	2,320	2,621
Expense	2,006	1,779	1,217	1,188	1,137	1,013
Net	3,856	1,098	1,290	1,004	1,183	1,608
Electricity Summary - On Deck	3,856	1,098	1,290	1,004	1,183	1,608
	ok	ok	ok	ok	ok	ok

($ millions)	2016-17 Changes		
Revenue Items On Deck - Changes Compared to Budget	**Net Income**	**PILs**	**Total**
OPG November 2016 Financial Outlook	(116)	(131)	(247)
ONFA and other Fair Value Accounting Adjustments	8		8
Hydro One November2016 Financial Outlook	65	(6)	59
Miscellaneous	(5)		(5)
Power Supply Contract Recoveries	96		96
	48	(137)	(90)

Electricity Sector Outlook (PSAB)

Expenditure Outlook as of Budget 2016						
($ millions)	Actual	Plan				
	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
Electricity Expenditures						
Finance - Own Account	7	6	6	6	6	6
Interest on Debt	1,248	1,178	1,159	1,127	1,149	1,109
Electricity Consumer Price Protection Fund	-	-	-	-	-	-
Power Supply Contract Costs	1,296	950	784	643	463	396
Total Electricity Expenditures	2,551	2,134	1,949	1,776	1,618	1,511

Details on Change in Expenditure Outlook						
($ millions)	Actual	Plan				
	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
Public Accounts 2010-11						
Finance - Own Account	-	-	(43)	(103)	(235)	(243)
Interest on Debt	-	-	-	-	-	-
Power Supply Contract Costs	-	-	91	96	(176)	(80)
Total Updates:	-	-	48	(7)	(411)	(323)

On Deck Expenditure Outlook as of November 2016						
($ millions)	Actual	Plan				
	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
Electricity Expenditures						
Finance - Own Account	7	6	7	6	6	6
Interest on Debt	1,248	1,178	1,116	1,024	914	866
Power Supply Contract Costs	1,296	950	875	739	287	316
Total Electricity Expenditures	2,551	2,134	1,998	1,769	1,207	1,188

Expense Items On Deck						
($ millions)	Actual	Plan				
	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
Finance - Own Account*	-	-	-	-	-	-
Interest on Debt*	-	-	-	-	-	-
Power Supply Contract Costs*	-	-	-	-	-	-
Total Expense Items "On Deck":	-	-	-	-	-	-

* Updated based on OEFC audited financial statements.

On Deck Expenditure Outlook as of November 2016						
($ millions)	Actual	Plan				
	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
Electricity Expenditures						
Finance - Own Account	7	6	7	6	6	6
Interest on Debt	1,248	1,178	1,116	1,024	914	866
Power Supply Contract Costs	1,296	950	875	739	287	316
Demand Management Support Costs	-	9	8	10	10	-
Total Electricity Expenditures	2,551	2,143	2,006	1,779	1,217	1,188

Additional Expenditure Risks						
($ millions)	Actual	Plan				
	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
Finance - Own Account						
Interest on Debt						
Power Supply Contract Costs						
Total Additional Risks:	-	-	-	-	-	-

Risk Based Expenditure Outlook						
($ millions)	Actual	Plan				
	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
Electricity Expenditures						
Finance - Own Account	7	6	7	6	6	6
Interest on Debt	1,248	1,178	1,116	1,024	914	866
Power Supply Contract Costs	1,296	950	875	739	287	316
Total Electricity Expenditures	2,551	2,134	1,998	1,769	1,207	1,188

Electricity Sector Outlook (PSAB)

($million)	Interim 2015-16	2016-17	2017-18	Plan 2018-19
Budget 2016 Outlook as of January 2016				
Income from Investment in Government Business Enterprises				
OPG Income[1]	257	471	586	673
OPG - ONFA and other Fair Value Adjustments[2]	241	-	-	-
Hydro One - Unrealized Gains Adjustment	-	-	-	-
HOI Income[3]	(168)	578	612	674
Total OPG and HOI Income	**330**	**1,049**	**1,198**	**1,347**
Other Fees and Licences	**127**	**127**	**125**	**123**
Electricity Expenses of the Province				
Provision for Electricity Sector[4]	-	(138)	(706)	-
Public Debt Interest - Electricity Sector	(508)	(492)	(492)	(492)
Subtotal	(508)	(630)	(1,198)	(492)
Public Debt Interest - Impact of ONFA				
Amortization of Deferred Revenue re profit on sale of H1 notes				
Total Electricity Expenses of the Province	**(508)**	**(630)**	**(1,198)**	**(492)**
OEFC Income				
Taxation Revenue				
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	3,232	515	480	532
Other Revenue				
Electricity Debt Retirement Charge[5]	868	625	623	-
Power Supply Contract Recoveries	784	643	463	396
Net Reduction of Power Purchase Contracts	172	129	74	41
Other Fees and Licences	(127)	(127)	(125)	(123)
Miscellaneous	5	5	5	5
Expenses				
Interest on Debt	(651)	(635)	(657)	(617)
Power Supply Contract Costs	(784)	(643)	(463)	(396)
Electricity Consumer Price Protection Fund	-	-	-	-
Demand Mangement Support Costs[6]	(9)	(10)	(10)	-
Provision for Electricity Sector	-	138	706	-
Other (Finance)	(6)	(6)	(6)	(6)
Total OEFC Income	**3,485**	**634**	**1,090**	**(168)**
Impact on Surplus/(Deficit)	**3,433**	**1,180**	**1,215**	**810**

Notes: All the Hydro One ownership broadening impacts, other than the initial IPO in 2015, are in the asset optimisation line (Sales and Rental) and not in the current Outlook file.

Notes:

1.Reflects OPG October 2015 report for 2015-16. Out-years reflect OPG's 2015 business plan and long-term outlook to 2018-19 (as fiscalized by OPG, received February 11, 2015). 2019-20 and 2020-21 estimates are preliminary and based on OPG's long-term model provided in 2015 and fiscalized by CEFD staff, to be updated.

2. Provincial consolidation adjustments for unrealized earnings on the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds, as of the end of December 2015.

3. Hydro One 2015-16 to 2020-21 projections are based on its 2015 Business plan, adjusted for latest information, including its 2015-17 distribution rate decsion, adjustments to forecast ROEs based on current interest rate outlook and estimated Hydro One IPO impacts.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial consolidation adjustments, minus the interest costs to OEFC. The provision is currently assumed to end once the DRC ends on a legislated fixed end date of April 1, 2018.

5. Reflects April 23, 2014 announcement announcement that DRC will be eliminated for residential users, after December 31, 2015. The end date of DRC for remaining users is legislated to be on April 1, 2018. Estimates are subject to change based on actual consumption.

6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Expenses	2015-16	2016-17	2017-18	2018-19
Power Supply Contract Costs	784	643	463	396
Demand Management Support Costs	9	10	10	-
Provision for Electricity Sector	-	(138)	(706)	-
Other (Finance)	6	6	6	6
SUBTOTAL - OEFC Consolidation	**799**	**521**	**(228)**	**402**
Provision for Electricity Sector (Dedicated Earnings)	**-**	**138**	**706**	**-**

2) DETAIL LINES

REVENUE	2015-16	2016-17	2017-18	2018-19
CONSOLIDATED OPG/HOI NET INCOME	**330**	**1,049**	**1,198**	**1,347**
Public Debt Interest - Electricity Sector exp	*508*	*492*	*492*	*492*
equals ampount above $520M (not incl ONFA)	*0*	*138*	*706*	*0*
*of which: ONFA Adjustments***	*241*	*0*	*0*	*0*
check total	*749*	*630*	*1,198*	*492*
CONSOLIDATED REVENUE - OEFC				
Other Fees and Licences				
Provision for Electricity Sector				
Electricity Payments-in-Lieu of Taxes (PILs)	3,232	515	480	532
Electricity Debt Retirement Charge	868	625	623	0
Power Supply Contract Recoveries	784	643	463	396
Net Reduction of Power Purchase Contracts	172	129	74	41
Other Fees and Licences				
Miscellaneous	5	5	5	5
SUBTOTAL	**5,391**	**2,966**	**2,843**	**2,321**
EXPENSE				
CONSOLIDATED OEFC EXPENSE				
Provision for Electricity Sector				
Power Supply Contract Costs	784	643	463	396
Demand Mangement Support Costs	9	10	10	0
less provision	0	(138)	(706)	0
Other OEFC Expenses	6	6	6	6
SUBTOTAL	**799**	**521**	**(228)**	**402**
FINANCE				
Provision for Electricity Sector	0	138	706	0
Public Debt Interest - Electricity Sector (Treasury Program)	508	492	492	492
SUBTOTAL	**508**	**630**	**1,198**	**492**
TREASURY PROGRAM - EXPENSE				
OEFC Debt interest	1,344	1,326	1,337	1,282
interest payments to OEFC from Other than Province	(185)	(199)	(188)	(173)
interest to OEFC from Province	(508)	(492)	(492)	(492)
SUBTOTAL	**651**	**635**	**657**	**617**
Impact on Surplus/(Deficit)	**3,433**	**1,180**	**1,215**	**810**

Electricity Sector Outlook (PSAB)

($million)	Actual 2014-15	Actual 2015-16	2016-17	2017-18	Plan 2018-19
On Deck Outlook as of November 2016					
Income from Investment in Government Business Enterprises					
OPG Income[1]	817	291	355	406	678
OPG - ONFA and other Fair Value Adjustments[2]	239	172	8	-	-
Hydro One - Unrealized Gains Adjustment	(8)	-	-	-	-
HOI Income[3]	741	236	629	623	667
Brampton Income		20	15	14	14
Total OPG and HOI Income	**1,789**	**719**	**1,006**	**1,043**	**1,359**
Other Fees and Licences	**131**	**127**	**122**	**102**	**91**
Electricity Expenses of the Province					
Provision for Electricity Sector[4]	(1,038)	(3)	(506)	(551)	-
Public Debt Interest - Electricity Sector	(520)	(520)	(492)	(492)	(492)
Subtotal	(1,558)	(523)	(998)	(1,043)	(492)
Public Debt Interest - Impact of ONFA					
Amortization of Deferred Revenue re profit on sale of H1 notes					
Total Electricity Expenses of the Province	**(1,558)**	**(523)**	**(998)**	**(1,043)**	**(492)**
OEFC Income					
Taxation Revenue					
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	180	3,228	378	479	476
Other Revenue					
Electricity Debt Retirement Charge[5]	956	859	625	623	-
Power Supply Contract Recoveries	950	875	739	287	316
Net Reduction of Power Purchase Contracts	217	172	129	74	41
Other Fees and Licences	(131)	(127)	(122)	(102)	(91)
Miscellaneous	9	9	-	-	-
Expenses					
Interest on Debt	(658)	(596)	(532)	(422)	(374)
Power Supply Contract Costs	(950)	(875)	(739)	(287)	(316)
Electricity Consumer Price Protection Fund	-	-	-	-	-
Demand Mangement Support Costs[6]	(9)	(8)	(10)	(10)	-
Provision for Electricity Sector	1,038	3	506	551	-
Other (Finance)	(6)	(7)	(6)	(6)	(6)
Total OEFC Income	**1,596**	**3,533**	**968**	**1,188**	**46**
Impact on Surplus/(Deficit)	**1,958**	**3,856**	**1,098**	**1,290**	**1,004**

Notes: All the Hydro One ownership broadening impacts, other than the initial IPO in2015 [and the secondary offering in April 2016], are in the asset optimisation line (Sales and Rental) and not in the current Outlook file.

Notes:

1.OPG's 2015-16 outlook reflected its reported earnings. 2016-17 outlook reflected OPG's November monthly update. Out-years reflect OPG's preliminary 2017-19 business plan and long-term outlook to 2019-20 (as fiscalized by OPG). 2020-21 estimates are based on OPG's calendar year-based business plan projections and as fiscalized by CEFD staff.

2. Provincial consolidation adjustments for unrealized earnings on the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds, as of the end of December 2016.

3. Hydro One 2015-16 income reflects its reported net income, adjusted for Hydro One IPO impacts. 2016-17 to 2020-21 projections are based on CEFD projections based on latest public information information and modelling, including its 2015-17 distribution rate decsion, adjustments to forecast ROEs based on current interest rate outlook and estimated Hydro One IPO impacts.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial consolidation adjustments, minus the interest costs to OEFC. The provision is currently assumed to end once the DRC ends on a legislated fixed end date of April 1, 2018.

5. Reflects April 23, 2014 announcement announcement that DRC will be eliminated for residential users, after December 31, 2015. The end date of DRC for remaining users is legislated to be on April 1, 2018. Estimates are subject to change based on actual consumption.

6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Expenses	2014-15	2015-16	2016-17	2017-18	2018-19
Power Supply Contract Costs	950	875	739	287	316
Demand Management Support Costs	9	8	10	10	-
Provision for Electricity Sector	(1,038)	(3)	(506)	(551)	-
Other (Finance)	6	7	6	6	6
SUBTOTAL - OEFC Consolidation	**(73)**	**887**	**249**	**(248)**	**322**
Provision for Electricity Sector (Dedicated Earnings)	**1,038**	**3**	**506**	**551**	**-**

2) DETAIL LINES

REVENUE	2014-15	2015-16	2016-17	2017-18	2018-19
CONSOLIDATED OPG/HOI NET INCOME	**1,789**	**719**	**1,006**	**1,043**	**1,359**
Public Debt Interest - Electricity Sector exp	*520*	*520*	*492*	*492*	*492*
equals ampount above $520M (not incl ONFA)	*1,038*	*3*	*506*	*551*	*0*
*of which: ONFA Adjustments***	*239*	*172*	*8*	*0*	*0*
check total	*1,797*	*695*	*1,006*	*1,043*	*492*
CONSOLIDATED REVENUE - OEFC					
Other Fees and Licences					
Provision for Electricity Sector					
Electricity Payments-in-Lieu of Taxes (PILs)	180	3,228	378	479	476
Electricity Debt Retirement Charge	956	859	625	623	0
Power Supply Contract Recoveries	950	875	739	287	316
Net Reduction of Power Purchase Contracts	217	172	129	74	41
Other Fees and Licences					
Miscellaneous	9	9	0	0	0
SUBTOTAL	**4,101**	**5,862**	**2,877**	**2,507**	**2,192**
EXPENSE					
CONSOLIDATED OEFC EXPENSE					
Provision for Electricity Sector					
Power Supply Contract Costs	950	875	739	287	316
Demand Mangement Support Costs	9	8	10	10	0
less provision	(1,038)	(3)	(506)	(551)	0
Other OEFC Expenses	6	7	6	6	6
SUBTOTAL	**(73)**	**887**	**249**	**(248)**	**322**
FINANCE					
Provision for Electricity Sector	1,038	3	506	551	0
Public Debt Interest - Electricity Sector (Treasury Program)	520	520	492	492	492
SUBTOTAL	**1,558**	**523**	**998**	**1,043**	**492**
TREASURY PROGRAM - EXPENSE					
OEFC Debt interest	1,385	1,319	1,216	1,090	1,027
interest payments to OEFC from Other than Province	(207)	(203)	(192)	(176)	(161)
interest to OEFC from Province	(520)	(520)	(492)	(492)	(492)
SUBTOTAL	**658**	**596**	**532**	**422**	**374**
Impact on Surplus/(Deficit)	**1,958**	**3,856**	**1,098**	**1,290**	**1,004**

Electricity Sector Outlook (PSAB)

($million)	Plan 2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Changes from Budget 2016 as of November 2016							
Income from Investment in Government Business Enterprises							
OPG Income	34	(116)	(180)	5	22	180	The explanation for the drop of OPG's Income are related to a number of OEB regulatory risks related to the pe application for the 5-year period starting in 2017. Budget 2016 figures were primarily based on OPG's 2015-17 Plan as its board-approved multi-year business plan had not yet been approved and provided when the 2016 B plan was locked. OPG's revenues are expected to improve as the regulated rate increases on the basis of a cu incentive regulation approach, and the first refurbished Darlington unit will return to service in February 2020.
ONFA and other Fair Value Adjustments	(69)	8	-	-	-	-	
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	-	
HOI Income	424	65	25	7	16	-	The variance primarily reflects impacts of new Hydro One net income and corporate income tax projections pro CEFD. Hydro One's net income increased due to the stronger than anticipated results for Q3 2016. Corporate i are also lower to reflect the corporate minimum cash taxes Hydro One will pay due to the benefit from the defe asset reducing cash taxes.
Total OPG and HOI Income	**389**	(43)	(155)	12	38	180	
Other Fees and Licences	**-**	(5)	(23)	(32)	(34)	(41)	
Electricity Expenses of the Province							
Provision for Electricity Sector	(3)	(368)	155	-	-	-	The variance is primarily due to the updated revenue figures from OPG and Hydro One. As well, at the time of 2016, the forecast was for a significant negative provision, which would have then be kept at zero to have the n balance clawed back from the subsequent year (2016-17). As a result of larger than anticipated deferred tax b reported by Hydro One and proportionate share attributed to the Province based on its ownership interest, the p 2015-16 came out to be $3 million [and not the large negative provision previously anticipated]. The variance i primarily explained by the reveral in the actual amount for 2015-16 versus the Budget 2016 forecast. The forec provision after 2017-18 fiscal is zero since the ESDI payments are assumed to discontinue after DRC ends on [CEFD will consider policy options on the continuation of ESDI in 2017.]
Public Debt Interest - Electricity Sector	(12)	-	-	-	-	-	
Subtotal	(15)	(368)	155	-	-	-	~~The variance is primarily due to the decreased revenue from OPG, and partially offset by the increased revenu One.~~
Public Debt Interest - Impact of ONFA	-	-	-	-		-	
Amortization of Deferred Revenue re profit on sale of H1 notes	-	-	-	-		-	
Total Electricity Expenses of the Province	**(15)**	(368)	155	-	-	-	~~The variance is primarily due to the decreased revenue from OPG, and partially offset by the increased revenu One.~~
OEFC Income							
Taxation Revenue							
Electricity Payments-in-Lieu of Taxes (PILs)	(4)	(137)	(1)	(56)	57	113	The variance is primarily due to updated OPG revenue figures in OPG's 2017-19 Business Plan, including lowe 2016-17, which impact its PIL payments as well.
Other Revenue							
Electricity Debt Retirement Charge	(9)	-	-	-	-	-	
Power Supply Contract Recoveries	91	96	(176)	(80)	21	17	The declines in payments in 2017-18 and 2018-19 are due to the expiry of several NUG PPAs (including those early due to curtailment agreements) and the suspension of several NUG PPAs due to curtailments. 2016-201 $181M lawsuit payment, partially offset by curtailed generation. The higer volume in 2019-20 and 2020-21 fron adjusted forecast for a NUG.
Net Reduction of Power Purchase Contracts	-	-	-	-	-	-	
Other Fees and Licences	-	5	23	32	34	41	
Revenue Pool Residual	-	-	-	-		-	
Miscellaneous	4	(5)	(5)	(5)	(5)	(5)	
Expenses							
Interest on Debt	55	103	235	243	291	377	
Power Supply Contract Costs	(91)	(96)	176	80	(21)	(17)	The declines in payments in 2017-18 and 2018-19 are due to the expiry of several NUG PPAs (including those early due to curtailment agreements) and the suspension of several NUG PPAs due to curtailments, partly offs curtailed generation. 2016-2017 reflects the $181M lawsuit payment. The higer volume in 2019-20 and 2020-2 adjusted forecast for a NUG.
Electricity Consumer Price Protection Fund	-	-	-	-	-	-	
Demand Mangement Support Costs	4	-	(2)	(2)		-	
Provision for Electricity Sector	3	368	(155)	-	-	-	
Other (Finance)	(1)	-	-	-	-	-	
Total OEFC Income	**49**	334	97	214	377	526	
Impact on Surplus/(Deficit)	**423**	(82)	74	194	380	664	
Total revenue Impact	**471**	**(89)**	**(337)**	**(129)**		**304**	
Total revenue Impact - less power supply contract recoveries	380	(185)	(161)	(49)		287	
Total Expenditure impact	**48**	**(7)**	**(411)**	**(323)**		**(360)**	

2) DETAIL LINES

REVENUE	2015-16	2016-17	2017-18	2018-19	2019-20
CONSOLIDATED OPG/HOI NET INCOME	**389**	**(43)**	**(155)**	**12**	**38**
Public Debt Interest - Electricity Sector exp	*12*	*0*	*0*	*0*	*0*
equals ampount above $520M (not incl ONFA)	*3*	*368*	*(155)*	*0*	*0*
of which: ONFA Adjustments	*(69)*	*8*	*0*	*0*	*0*
check total	*(54)*	*376*	*(155)*	*0*	*0*
CONSOLIDATED REVENUE - OEFC					
Other Fees and Licences					
Provision for Electricity Sector					
Electricity Payments-in-Lieu of Taxes (PILs)	(4)	(137)	(1)	(56)	57
Electricity Debt Retirement Charge	(9)	0	0	0	0
Power Supply Contract Recoveries	91	96	(176)	(80)	21
Net Reduction of Power Purchase Contracts	0	0	0	0	0
Other Fees and Licences					
Miscellaneous	4	(5)	(5)	(5)	(5)
SUBTOTAL	**471**	**(89)**	**(337)**	**(129)**	**111**
EXPENSE					
CONSOLIDATED OEFC EXPENSE					
Provision for Electricity Sector					
Power Supply Contract Costs	91	96	(176)	(80)	21
Demand Mangement Support Costs	(4)	-	2	2	-
less provision	(3)	(368)	155	0	0
Other OEFC Expenses	1	0	0	0	0
SUBTOTAL	**85**	**(272)**	**(19)**	**(78)**	**21**
FINANCE					
Provision for Electricity Sector	3	368	(155)	0	0
Public Debt Interest - Electricity Sector (Treasury Program)	12	0	0	0	0
SUBTOTAL	**15**	**368**	**(155)**	**0**	**0**
TREASURY PROGRAM - EXPENSE					
OEFC Debt interest	(25)	(110)	(247)	(255)	(303)
interest payments to OEFC from Other than Province	(18)	7	12	12	12
interest to OEFC from Province	(12)	0	0	0	0
SUBTOTAL	**(55)**	**(103)**	**(235)**	**(243)**	**(291)**

Impact on Surplus/(Deficit)	**426**	**(82)**	**72**	**192**	**380**

ONTARIO ELECTRICITY FINANCIAL CORPORATION
Budget 2016 Outlook as of January 2016

	Actual 2014-15	Interim 2015-16	2016-17	2017-18	Plan 2018-19
Revenue					
Revenue Pool Residual					
Debt Retirement Charge	956	868	625	623	-
Payments-in-lieu of tax:					
OPG	53	281	437	382	414
Legacy Hydro One (Inlucding Brampton)	95	2,913	7	7	7
Hydro One CIT dedicated to OEFC		13	26	28	30
MEUs	32	25	44	63	81
Total PILs & CIT dedicated to OEFC	180	3,232	515	480	532
Interest :					
OPG	191	177	191	180	165
H1					
IESO	3	3	3	3	3
Province	520	508	492	492	492
Other	13	5	5	5	5
Total Interest	727	693	691	680	665
Power Supply Contract Recoveries	950	784	643	463	396
Amortization of NUG liability	217	172	129	74	41
Electricity sector dedicated income	1,038	-	138	706	-
Gain to OEFC under s. 50.3	-	150	-	-	-
Miscellaneous	9	5	5	5	5
	4,077	5,904	2,746	3,031	1,639
Expense					
Debt interest	1,385	1,344	1,326	1,337	1,282
Interest on nuclear risk funding					
Demand Management Support Costs	9	9	10	10	-
Amortization of deferred debt costs	-	-	-	-	
Power Supply Contract Costs	950	784	643	463	396
Debt Guarantee fee	131	127	127	125	123
Operating	6	6	6	6	6
	2,481	2,270	2,112	1,941	1,807
Excess (Deficiency) of Revenue over Expense	**1,596**	**3,634**	**634**	**1,090**	**(168)**
Stranded Debt - Year End	**8,185**	**4,551**	**3,917**	**2,827**	**2,995**
	658	651	635	657	617

ONTARIO ELECTRICITY FINANCIAL CORPORATION
On Deck Outlook as of November 2016

	Actual 2014-15	Actual 2015-16	2016-17	2017-18	Plan 2018-19
Revenue					
Revenue Pool Residual					
Debt Retirement Charge	956	859	625	623	-
Payments-in-lieu of tax:					
OPG	53	268	306	389	366
Legacy Hydro One (Inlucding Brampton)	95	2,929	7	7	7
Hydro One CIT dedicated to OEFC		3	20	20	22
MEUs	32	27	44	63	81
Total PILs & CIT dedicated to OEFC[1]	180	3,228	378	479	476
Interest :					
OPG	191	173	179	168	153
H1					
IESO	3	2	3	3	3
Province	520	520	492	492	492
Other	13	28	10	5	5
Total Interest	727	723	684	668	653
Power Supply Contract Recoveries	950	875	739	287	316
Amortization of NUG liability	217	172	129	74	41
Electricity sector dedicated income	1,038	3	506	551	-
Gain to OEFC under s. 50.3	-	172	-	-	-
Miscellaneous	9	9	-	-	-
	4,077	6,041	3,061	2,683	1,486
Expense					
Debt interest	1,385	1,319	1,216	1,090	1,027
Interest on nuclear risk funding					
Demand Management Support Costs	9	8	10	10	-
Amortization of deferred debt costs	-	-	-	-	
Power Supply Contract Costs	950	875	739	287	316
Debt Guarantee fee	131	127	122	102	91
Operating	6	7	6	6	6
	2,481	2,336	2,093	1,495	1,440
Excess (Deficiency) of Revenue over Expense	**1,596**	**3,705**	**968**	**1,188**	**46**
Prior period adjustment		87			
Stranded Debt - Year End	**8,185**	**4,393**	**3,425**	**2,237**	**2,191**
	658	596	532	422	374

ONTARIO ELECTRICITY FINANCIAL CORPORATION

Changes from Budget 2016 as of November 2016

	Plan						
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Revenue							
Debt Retirement Charge	(9)	-	-	-	-	-	
Payments-in-lieu of tax:							
OPG	(13)	(131)	7	(48)	65	121	
Legacy Hydro One (Inlucding Brampton)	16	-	-	-	-	-	
Hydro One CIT dedicated to OEFC	(10)	(6)	(8)	(8)	(8)	(8)	
MEUs	2	-	-	-	-	-	
Total PILs	(4)	(137)	(1)	(56)	57	113	
Interest :							
OPG	(4)	(12)	(12)	(12)	(12)	(12)	
H1	-	-	-	-	-	-	
IESO	(1)	-	-	-	-	-	
Province	12	-	-	-	-	-	
Other	23	5	-	-	-	-	
Total Interest	30	(7)	(12)	(12)	(12)	(12)	
Power Supply Contract Recoveries	91	96	(176)	(80)	21	17	
Amortization of NUG liability	-	-	-	-	-	-	
Electricity sector dedicated income	3	368	(155)	-	-	-	
Gain to OEFC under s. 50.3	22	-	-	-	-	-	
Miscellaneous	4	(5)	(5)	(5)	(5)	(5)	
	137	315	(349)	(153)	61	113	
Expense							
Debt interest	(25)	(110)	(247)	(255)	(303)	(389)	
Interest on nuclear risk funding	-	-	-	-	-	-	
Demand Mangement Support Costs	(1)	-	-	-	-	-	
Amortization of deferred debt costs	-	-	-	-	-	-	
Power Supply Contract Costs	91	96	(176)	(80)	21	17	
Debt Guarantee fee	-	(5)	(23)	(32)	(34)	(41)	
Operating	1	-	-	-	-	-	
	66	(19)	(446)	(367)	(316)	(413)	
Excess (Deficiency) of Revenue over Expense	**71**	**334**	**97**	**214**			
Stranded Debt - Year End	**(158)**	**(492)**	**(590)**	**(803)**	**(1,180)**	**(1,706)**	

Electricity Sector Outlook (PSAB)

Negative Revenue Risks

($ millions)	Plan					
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
OPG Generation Risk: Nuclear Reliability (-1.6 TWh)[1]	-	(120)	(120)	(120)	(120)	(120)
ONFA Funds Return Risk[2]	-	(90)	(95)	(100)	(105)	(110)
Lower OPG's Equity weighting & Return on Equity (ROE)[3]		(2)	(12)	(20)	(25)	(43)
Ministry of Energy's price mitigation initiative - OPG operational efficiencies[9]		(60)	(240)	(240)	(240)	(180)
Lower Hydro One Return on Equity (ROE)[4]			(10)	(39)	(41)	(43)
Hydro One Tx rate application - OEB staff report[8]		(13)	(50)	(38)		
OPG Switch from accrual based to cash based accounting for pension and OPEB[5]		(475)				
OPG IFRS Consolidation Risks - Scenario 1: 15 year historical, update discount rate each year.[6] ~~, based on discussion at the time of 2014-15 Public Accounts and November 18, 2015 for the 2016-17 risk estimate[6] [TO BE UPDATED – Check with SIFB and info received under ONFA]~~	-	(75)	(425)	(525)	(675)	TBD
OPG IFRS Consolidation Risk - Scenario 2: 15 year historical + 5 forward, update every 5 year.[6]		(1,000)	(375)	(400)	(400)	TBD
~~OPG-OEFC-LNCSA Review – Outcome~~[7]	-					
Additional regulatory risk - Darlington Refurbishment Project and Others[7]		(300)				
Total - Scenario 1	-	(1,134)	(951)	(1,081)	(1,206)	(497)
Total - Scenario 2	-	(2,059)	(901)	(956)	(931)	(497)

Notes: The cumulative downside risk is presented as additive, which may overstate off-setting risks.

1. OPG's market and generation risks related to nuclear reliability similar to the scenarios OPG developed for its sales margins to capture major market risk factors (e.g., natural gas prices, coal prices, foreign exchange, nuclear reliability) in its 2012 business plan. Currently, only the nuclear reliability risk is captured at the current regulated rate for OPG's nuclear generation.

2. Under the Ontario Nuclear Funds Agreement (ONFA), OPG has established two segregated funds, the Decommissioning Segregated Fund (DSF) and for the Used Fuel Segregated Fund (UFSF). The risk shown is based on 1% decline on a realized basis in the DSF and UFSF, less the portion in the DSF assumed to be attributable to OPG's Bruce assets that is recoverable from consumers through the Bruce Variance Account.

3. Risk range for OPG reflects potential risk of lower ROE by 0.5% vs assumed ROEs in OPG's 2016 business plan and corresponding rate application. Also reflects how the proposed deemed equity of 49% might actuall revert to the prior approved 45% weighting.

4. Risk range for Hydro One transmission and distribution reflects potential risk of lower ROE by 0.5% vs assumed ROEs in CEFD Hydro One Forecast based on the most recent rate applications and forecasted ROE rates.

5. The OEB directed a switch to cash-based accounting for years 2014 and 2015. However, the OEB also directed OPG to track the difference between cash based and accrual based accounting in a deferral account, while a generic proceeding is underway for all OEB-regulated electric and gas utilities.

6. Province to consolidate OPG on IFRS basis. Estimated mpacts to the Province by OPG being consolidated on an IFRS basis with respect to its nuclear liabilities under two methodologies are summarized in Scenarios 1 and 2. (Following work on the next Reference Plan, the potential impact to the 2021-22 fiscal year and going forward would be known.) ~~Estimate of ($368 M) based on estimates provided by OPG and OPCD for transitional impacts on asset retirement obligations at the time of 2014-15 Public Accounts. In a meeting with OPCD and OPG on November 18, 2015, CEFD staff is aware of risk of $1.0 billion, representing ONFA reference plan revision. All numbers are preliminary and subjet to update. Volatility and exposure in out-years are also~~

~~7. OEFC engaged Navigant Consulting to review the payments under the Lambton and Nanticoke Contingency Support Agreement (LNCSA) for the 2009 to 2014 period. Current estimate for the claim is for $5.7M for the Nanticoke Unit 6 turbine damage cost incurred in 2009. **[TO BE UPDATED/DROPPED/HIDDEN]**~~

7. Additional regulatory risks related to the ~~planned~~ rate application in spring 2016, including risks related to a portion of costs-to-date of about $700-800M.

Electricity Sector Outlook (PSAB)

Positive Revenue Risks

($ millions)	Plan					
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
OPG Generation Risk: Nuclear Reliability (+1.1 TWh)[1]	-	85	85	85	85	85
Postive OPG regulatory risk - Motion to Review[2]	-	-	-	-	-	-
1% increase in Hydro One actual load[3]	-	15	15	15	15	15
Higher Hydro One Return on Equity (ROE)[4]		-	15	60	65	65
Higher OPG Return on Equity (ROE)[5]		-	6	25	30	55
	-	100	121	185	195	220

Notes: The cumulative upside risk is presented as additive, which may overstate off-setting risks.

1. OPG's market and generation risks related to nuclear reliability similar to the scenarios OPG developed for its sales margins to capture major market risk factors (e.g., natural gas prices, coal prices, foreign exchange, nuclear reliability) in its 2012 business plan. Currently, only the nuclear reliability risk is captured at the current regulated rate for OPG's nuclear generation.

2. Reflects OPG's Motion to Review application with the OEB for the Niagara Tunnel cost disallowance and the 2013 tax loss.

3. A 1% change in the forecast represents a change of approximately 206MW for Tx in peak demand based on 2015/2016revenue requirement.

4. Risk range for Hydro One transmission and distribution reflects potential risk of higher ROE by 1% vs assumed ROEs in the Hydro One CEFD Forecast. Rounded to the nearest $5M.

5. Risk range for OPG reflects potential risk of higher ROE by 1% (for nuclear base) vs assumed ROE in OPG's 2016 business plan and corresponding rate application. Rounded to the nearest $5M.

Ontario Electricity Financial Corporation

On Deck Revenue & Expense Outlook
($ millions)

		2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Revenue		4,077	6,041	3,061	2,683	1,486	1,500	1,606
less: interest income (to IOD)	1	727	723	684	668	653	635	635
less: Electricity Sector Dedicated Income from Prov	2	1,038	3	506	551	-	-	-
Adjustment to CRF revenue		2,312	5,315	1,871	1,463	833	865	971
Expense		2,481	2,336	2,093	1,495	1,440	1,368	1,237
less: Interest expense - With Province (to IOD)		1,385	1,319	1,216	1,090	1,027	977	885
less: Debt Guarantee Fee paid to Province	3	131	127	122	102	91	88	81
Adjustment to CRF expense		965	890	755	303	322	303	271
Surplus/(Deficit) Impact - without IOD Adj.		689	3,829	584	738	137	220	450
Surplus/(Deficit) Impact		1,347	4,425	1,116	1,160	511	562	700
In 2008-09 RBP - Surplus/(Deficit)		-	-	-	-	-	-	-
Adjustment required		1,347	4,425	1,116	1,160	511	562	700
Operating expense split		965	890	755	303	322	303	271
Capital expense split		-	-	-	-	-	-	-
Total		965	890	755	303	322	303	271
IOD		658	596	532	422	374	342	250

Notes:

1. OEFC interest income includes $520 million, or less (after H1 ownership broadening), annual interest payment from Province related to the Province's investment in OPG and Hydro One.

2. OEFC receives Electricity Sector Dedicated Income from the Province for the combined net income of OPG and Hydro One in excess of the Province's annual interest cost for its investment in these companies.

3. OEFC pays a Debt Guarantee Fee to the Province that is eliminated upon consolidation.

Ontario Power Generation

OPG Income - Budget 2016
($ millions)

	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
OPG Net Income After Tax	199	689	257	471	586	673	705	734
ONFA and other Fair Value Adjustments	475	122	241					
ONFA Adjustments	*367*	*122*	*241*					
Other Fair Value Adjustments	*108*							

OPG PIL - Budget 2016
($ millions)

	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
Net Income Before Tax	231	539	546	324	695	745	855
Net Income After Tax	244	334	689	257	471	586	673
Income Taxes	(12)	205	(143)	67	224	159	182
GRC	189	186	198	198	196	205	212
Proxy Property Tax	16	16	15	16	17	18	20
Ontario Capital Tax	0	0	0	0	0	0	0
Total	**193**	**407**	**70**	**281**	**437**	**382**	**414**

OPG Income - 2017-19 BP November 2016
($ millions)

	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
OPG Net Income After Tax (Adjusted)	334	817	291	355	406	678	726	913
OPG Net Income After Tax	*334*	*574*	*291*	*355*	*406*	*678*	*726*	*913*
Extraordinary Gains	*-*	*243*	*-*	*-*	*-*	*-*	*-*	*-*
ONFA and other Fair Value Adjustments	475	239	172	8				
ONFA Adjustments	*367*	*180*	*247*	*8*				
Other Fair Value Adjustments	*108*	*59*	(75)					

($ millions)

	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
Net Income Before Tax	232	539	659	383	450	572	813
Net Income After Tax (Adjusted)	244	334	817	291	355	406	678
Income Taxes	(12)	205	(158)	92	95	166	135
GRC	189	186	198	198	196	205	212
Proxy Property Tax	16	16	13	16	15	18	19
Ontario Capital Tax	0	0	0	0	0	0	0
Total	**193**	**407**	**53**	**306**	**306**	**389**	**366**

TO BE UPDATED - GRC to OEFC amounts not available in 2017-19 E

21.11% 29.02% 16.61%

OPG 2016-17 Net Income Calculation (USGAAP) ($M)			
	Q1 2016[1]	2016	Q1 2017[1]
Net Income Attributable to Shareholder	123	438	34

Hydro One

Hydro One Income - Budget 2016
($ millions)

	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Hydro One Net Income After Tax	786	741	703	772	831	908	952	995
Hydro One - Unrealized Gains Adjustment	10	-8						

Hydro One Income - November 2016
($ millions)

	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Hydro One Net Income After Tax	786	741	685	748	742	795	850	995
Hydro One - Unrealized Gains Adjustment	10	(8)						

2016-17 to 2019-20 from the Hydro One 2016 model.

Hydro One PIL - Budget 2016
($ millions)

	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
Net Income After Tax	786	754	703	772	831	908
Income Taxes	101	101	132	160	181	205
Proxy Property Tax	(3)	2	2	2	2	2
Ontario Capital Tax	0	0	0	0	0	0
Total	**98**	**103**	**134**	**162**	**183**	**207**

Hydro One (Before IPO Scenario - 100% Ownership)
($ millions)

	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
Net Income After Tax	786	741	685	748	742	795
Income Taxes PILs	101	92	132	160	181	205
Proxy Property Tax	(3)	3	2	2	2	2
Ontario Capital Tax	0	0	0	0	0	0
Total	**98**	**95**	**134**	**162**	**183**	**207**

Provision for Electricity Sector

	Actual	Plan						
	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Income from Investment in Government Business Enterprises								
OPG Income	334	817	291	355	406	678	726	913
Hydro One Income	786	741	232	643	637	681	729	737
Total Income	1,120	1,558	523	998	1,043	1,359	1,455	1,650
Public Debt Interest - Electricity Sector	(520)	(520)	(520)	(492)	(492)	(492)	(492)	(492)
Impact of OPG and Hydro One	600	1,038	3	506	551	867	963	1,158
Other Adjustments*								
Cumulative Shortfall								
Opening Balance	-	-	-	-	-	-	-	-
Deduction / (Addition)	-	-	-	-	-	-	-	-
Ending Balance	-	-	-	-	-	-	-	-
Provision for Electricity Sector (without adjusting for unrealized losses)	**599**	**1,038**	**3**	**506**	**551**	**867**	**963**	**1,158**

Notes:

1. Provision for the fiscal year 2018-19 is assumed 0 based on the expectation that stranded debt would be eliminated by then.

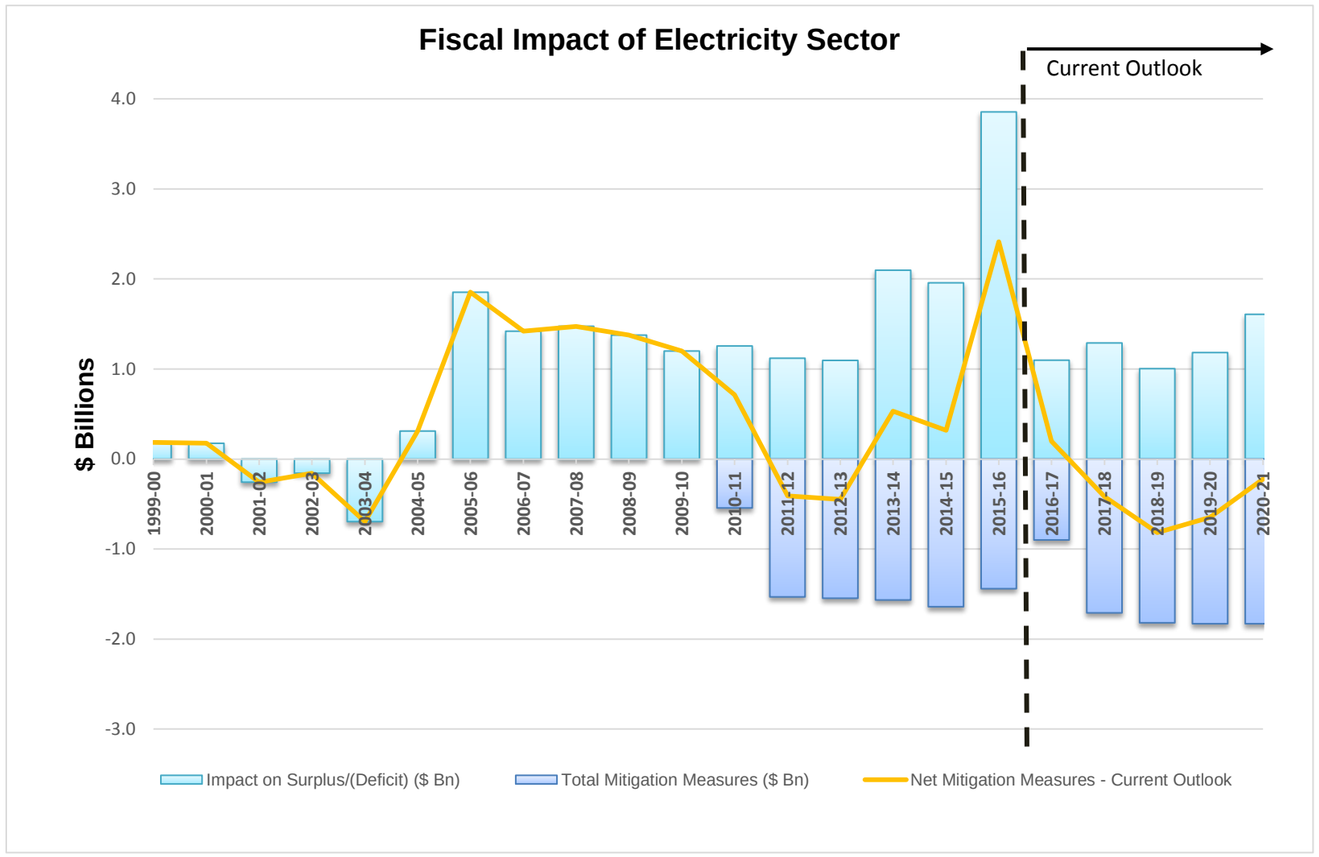
PROVINCIAL CONSOLIDATION ADJUSTMENTS
Ontario Nuclear Funds Agreement

	2011-12	2012-13	2013-14	2014-15
Adjustment for DSF Unrealized Earnings				
Unrealized Earnings as at beginning of year	0	0	0	0
Unrealized Earnings as at December 31, 2016	10	62	(244)	(21)
Bruce Variance Account Adjustment	5	29	(115)	(10)
Adjustment for UFSF Unrealized Earnings				
Unrealized Earnings as at beginning of year	0	0	0	0
Unrealized Earnings as at December 31, 2016	1	26	64	82
Bruce Variance Account Adjustment	1	14	34	43
Unrealized Earnings -- Fiscal YTD	**6**	**45**	**(99)**	**28**
Adjustment for UFSF Due to Province				
Due to Province (cost basis) as at beginning of year	(102)	(189)	(181)	87
Unrealized Earnings as at December 31, 2016	(189)	(181)	87	295
Change in Due to Province -- Fiscal YTD	**(87)**	**8**	**268**	**208**
Adjustment for DSF Due to Province				
Due to Province (cost basis) as at beginning of year				
Unrealized Earnings as at December 31, 2016				
Change in Due to Province -- Fiscal YTD				
Provincial Consolidation Adjustment	**(93)**	**(37)**	**367**	**180**

Fiscal Impact of Electricity Sector

Blue represents changed numbers from 2013
Maroon represents new information
Orange represents projections

	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	
Impact on Surplus/(Deficit)	1,256	1,120	1,096	2,098	1,958	3,856	1,098	1,290	1,004	1,183	1,608	
Impact on Surplus/(Deficit) ($ Bn)	*1.256*	*1.120*	*1.096*	*2.098*	*1.958*	*3.856*	*1.098*	*1.290*	*1.004*	*1.183*	*1.608*	
Electricity Price Mitigation Measures (Tax Base)												
Energy portion of the Ontario Energy and Property Tax Credit (OEPTC)**	113	354	406	418	429	444	450	460	470	480.5	480.5	OEP, Revenue Forecasting
Northern Ontario Energy Credit	24	23	24	25	24	26	27	27	27	27	27	Source for actuals
Ontario Emergency Energy Fund	2	2	2	2	2	2	2	2	2	2	2	
Northern Industrial Electricity Rate Program	105	120	120	115	108	108	120	120	120	120	120	Source for actuals
Ontario Clean Energy Benefit (OCEB)	300	1,033	994	1,006	1,078	860	-	-	-	-	-	
Ontario Rebate for Electricity Consumers							300	1100	1200	1200	1200	
Total Mitigation Measures ($ M)	**543**	**1,531**	**1,546**	**1,566**	**1,640**	**1,440**	**899**	**1,709**	**1,819**	**1,830**	**1,830**	
Total Mitigation Measures ($ Bn)	*(0.543)*	*(1.531)*	*(1.546)*	*(1.566)*	*(1.640)*	*(1.440)*	*(0.899)*	*(1.709)*	*(1.819)*	*(1.830)*	*(1.830)*	
Total Mitigation Measures excl. OCEB ($ M)	243	499	552	560	562	580	899	1,709	1,819	1,830	1,830	
Total Mitigation Measures excl. OCEB ($ Bn)	*0.243*	*0.499*	*0.552*	*0.560*	*0.562*	*0.580*	*0.899*	*1.709*	*1.819*	*1.830*	*1.830*	
Net Mitigation Measures - Current Outlook	0.71	(0.41)	(0.45)	0.53	0.32	2.42	0.20	(0.42)	(0.82)	(0.65)	(0.22)	



From:	John Kim
To:	Ronald Kwan; Gadi Mayman
Cc:	Usman Zahid; Anna Strathy; Mike Manning; Ken Kandeepan
Subject:	RE: Rating Agencies views on Fair Hydro
Date:	Thursday, April 19, 2018 1:37:15 PM

For sure. Do we have a sense of the remainder of the debt?

From: Ronald Kwan
Sent: Thursday, April 19, 2018 1:06 PM
To: Gadi Mayman <Gadi.Mayman@ofina.on.ca>
Cc: Usman Zahid <Usman.Zahid@ofina.on.ca>; Anna Strathy <Anna.Strathy@ofina.on.ca>; Mike Manning <Mike.Manning@ofina.on.ca>; Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>
Subject: Re: Rating Agencies views on Fair Hydro

Hi Gadi,

John was prepped to anticipate such a request!

Ron

From: Gadi Mayman
Sent: April 19, 2018 12:31 PM
To: Ronald Kwan
Cc: Usman Zahid; Anna Strathy; Mike Manning; Ken Kandeepan
Subject: FW: Rating Agencies views on Fair Hydro

Hi Ron. The deal ended up coming at 107, which is 32 back of us. We should update our interest calculation based on this.

Thanks,
Gadi

From: Caridia, Alex [mailto:alex.caridia@rbccm.com]
Sent: Thursday, April 19, 2018 9:35 AM
To: Gadi Mayman <Gadi.Mayman@ofina.on.ca>
Subject: RE: Rating Agencies views on Fair Hydro

Hi Gadi – jus called you for an update on this. As you will have seen books are open at 110 +/-3bps

See that as Ont +35 and Toronto +13bps

Happy to chat more at your convenience

Alex

From: Caridia, Alex
Sent: April 19, 18 7:59 AM
To: Gadi Mayman
Subject: Re: Rating Agencies views on Fair Hydro

Hi Gadi

In short, that's true. Moody's action on Ontario will have no immediate effect on the ratings of FHT. Moody's rates FHT in line with the Province's rating, and has stated that any move on Ontario will also move their ratings on the FH program. However, under securitization methodology, rating directions are not used, so there is no current change on FHT, but if the Province is downgraded, FHT will also be downgraded.

On: 18 April 2018 21:59,
"Gadi Mayman" <Gadi.Mayman@ofina.on.ca> wrote:
Thanks, Alex. I was told that structured finance ratings don't have negative outlooks; the rating is simply the rating, so Moody's putting us on negative outlook doesn't immediately affect their rating of the FHT. It's only if we were to get downgraded that they would also downgrade FHT. Seems weird to me, but that's what I was told, and given that you've proceeded with the FHT transaction, I assume it's true?

From: Caridia, Alex <alex.caridia@rbccm.com>
Sent: Wednesday, April 18, 2018 5:30:32 PM
To: Gadi Mayman
Subject: Fwd: Rating Agencies views on Fair Hydro

Hi Gadi - FYI

Begin Forwarded Message:
From: "Laham, Chris" <chris.laham@rbccm.com<mailto:chris.laham@rbccm.com>>
Subject: Rating Agencies views on Fair Hydro
Date: 18 April 2018 15:51
To: "+DS-GM-Bond Sales Desk" <DS-GM-BondSalesDesk@rbc.com<mailto:DS-GM-BondSalesDesk@rbc.com>>

Here are some bullet points outlining how each agency views Fair Hydro Trust in the context of the ratings of the Province.
The key point being, Moody's assumes at some point over the horizon of the program the Province will step in, thus linking the ratings. As a reminder, if this were to happen, the Province will assume the debt.

Here is Ian's outline for those that want a deeper dive:

DBRS

* Look at the transaction through a structured finance lens
* Change of law that could invoke a Protection Event is mitigated by the risk the FHT platform would become a liability of the Province, legislation took a long time to draft and pass, adverse change of law could bring into question other Provincial guarantee arrangements
* Significant enhancement (almost 100%) supports the senior notes, as does true-up mechanism, non-bypassability of recovery charge
* Amount of recovery charge is small as a percentage of the overall electricity user bill

Moody’s

* The program as structured and under current law and regulations is considered to be of similar credit quality to US utility cost recovery programs rated by Moody's
* However, the FHT program's 30-year term, combined with the pervasive role of the Province and its related entities in many aspects of this transaction, increase the risk that the Province could make future changes to the law or related regulations that could adversely affect the outstanding obligations under the FHT program
* The Provincial guarantee is a mitigant to this risk, but it is not as robust as the constitutional protection found in similar US programs. Accordingly, Moody’s has linked the provisional ratings of the notes to the Aa2 rating of the Province
* Future changes to the Province's rating will result in similar changes to the ratings of the notes.

Ian Benaiah | Director, Securitization Finance | RBC Capital Markets | TEL: 416.842.3820 | FAX: 416.842.3888 | ian.benaiah@rbccm.com<mailto:ian.benaiah@rbccm.com>

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From:	Gadi Mayman
To:	John Kim; Ronald Kwan
Cc:	Usman Zahid; Anna Strathy; Mike Manning; Ken Kandeepan
Subject:	RE: Rating Agencies views on Fair Hydro
Date:	Thursday, April 19, 2018 1:53:31 PM

Not that I'm aware of, but OPG is supposed to price the subordinated debt at the same time, so they should have those rates

Gadi

From: John Kim
Sent: Thursday, April 19, 2018 1:37 PM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; Gadi Mayman <Gadi.Mayman@ofina.on.ca>
Cc: Usman Zahid <Usman.Zahid@ofina.on.ca>; Anna Strathy <Anna.Strathy@ofina.on.ca>; Mike Manning <Mike.Manning@ofina.on.ca>; Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
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From:	Ronald Kwan
To:	Bruno Amara
Cc:	John Kim; Shajee Kathirgamanathan
Subject:	RE: Revised Electricity Outlook
Date:	Friday, October 20, 2017 4:21:26 PM

Thanks Bruno.

Please circulate it and get feedback from the various recipients / users.

Ron

From: Bruno Amara
Sent: October-20-17 16:10
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: John Kim <John.Kim@ofina.on.ca>; Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>
Subject: RE: Revised Electricity Outlook

Hi Ron

Thanks for your comments and please see the revised Outlook in response.

We have:

1. adjusted the Hydro One deferred tax benefit risk to reflect 50%. In the same vein we added an adjusted to Hydro One net income to reflect the OEB decision impacts at 50%. Footnotes added for both.
2. Added a positive risk for the H1 Motion to Review. The Motion challenge OEB ruling with the exception of the cap ex ruling.
2. added an estimate for 50.3 for 2017-18 to OEFC On Deck.
    - In regard to 50.3 amounts we are proposing discussing with our Frost colleagues adding in the offsetting expense entry to our Outlook for completeness. I suggested waiting until this discussion to avoid any confusion or changes to the cover sheet (and Summary-ON Deck tab) from what they last saw.
3. Revised the OEFC – Budget to correspond to what OEFC was assuming as of budget.
4. Added footnote as necessary where Hydro One proportionate numbers appear.
5. Updated OPG FHP Trust interest revenue based on revisions from FTD.

For any distribution outside of EFB, we would delete the "Track Changes" worksheet and the "H1 Provincial Allocations" worksheet.

Bruno

From: Ronald Kwan
Sent: Thursday, October 19, 2017 7:05 PM

To: Bruno Amara <Bruno.Amara@ofina.on.ca>
Cc: John Kim <John.Kim@ofina.on.ca>
Subject: Re: Revised Electricity Outlook

Hi Bruno,

I thought we discussed making an adjustment to the Hydro One deferred tax benefit upfront hit risk to be scaled at a proportionate 50%. It could be footnoted as done this way vs the 70% assumption used for H1 generally, pending the recategorisation from the AO sales and rentals outlook. (As an aside, would it be fair to say that the incremental risk is also less than what is shown because built into the update is the annual impact of the deferred tax benefit decision of the OEB? In that light, for symmetry, should there be a positive risk shown for H1 should it be successful in its OEB Motion to Review?

Also, why not put into the OEFC tab an estimated s.50.3 amount for 17-18?

Also, why does the Budget 2017 tab for OEFC show an excess of revenue over expense of about $0.7bn. I thought it was about $1.1 bn at the time of Budget. You may need to add to the ESDI formula to reverse the IFRS assumption in the OEFC Budget tab -- and then putting in the 50.3 amount in the OEFC on-deck tab would more than offset that (for now, pending other updates, such as for H1).

Also, for clarity, on each worksheet where Hydro One proportionate numbers appear, please add a footnote on that row, as some people may just go to one work sheet, or print one worksheet (and has each worksheet been formatted for easy printing -- can help multiple users and down the line). This includes the Provision worksheet, where I assume the financing cost for the Hydro One row is based on the 70%, but will go down to under 50% ultimately.

On the OPG FHP Trust interest revenue, is that scaled to the new equity injection projections supplied to FTD so it would match the IOD side? Are we aligned to match FTD's IOD assumptions for borrowing for the equity injection?

Thanks,
Ron

From: Bruno Amara
Sent: October 19, 2017 3:54 PM
To: Ronald Kwan
Cc: John Kim

Subject: Revised Electricity Outlook

Hi Ron

Attached is the revised Electricity Sector Outlook (document pw). I want to point out one change on the risk page in particular. In the version we walked you through, I had included an OPG risks reflecting head office sales (currently in Sales and rentals) and the in–year update. You had asked about Lakeview which could have a similar note. Hydro One unpacking could also be included and other reclassification impacts e.g., revenue impact related to IOD savings current in AO numbers. I think that all this may be better handled through the AO unpacking/updating analysis that we worked on with SIFB. When we send the Outlook to our Frost colleagues, we were planning to set up a staff level meeting between EFB, OB, OEP and TBS to review the Outlook and answer questions. We could as an option also use this meeting to review the AO unpacking/updating analysis at the same time if that makes sense. That isn't needed for FES, but may be worth getting people familiar with it now.

Also attached is a draft of some follow-up for OPG in regard to their September monthly report per our discussion.

Bruno

Bruno Amara
Sr. Manager, Financial and Regulatory Analysis
Electricity Finance Branch
Corporate and Electricity Finance Division
Ontario Financing Authority

Tel: 416-325-1489
Email: bruno.amara@ofina.on.ca

From: Bruno Amara
To: Ronald Kwan
Cc: John Kim; Shajee Kathirgamanathan
Subject: RE: Revised Electricity Outlook
Date: Friday, October 20, 2017 4:10:07 PM
Attachments: Electricity Sector Outlook (2017 10 20v3).xlsm

Hi Ron

Thanks for your comments and please see the revised Outlook in response.

We have:

1. adjusted the Hydro One deferred tax benefit risk to reflect 50%. In the same vein we added an adjusted to Hydro One net income to reflect the OEB decision impacts at 50%. Footnotes added for both.
2. Added a positive risk for the H1 Motion to Review. The Motion challenge OEB ruling with the exception of the cap ex ruling.
2. added an estimate for 50.3 for 2017-18 to OEFC On Deck.
    - In regard to 50.3 amounts we are proposing discussing with our Frost colleagues adding in the offsetting expense entry to our Outlook for completeness. I suggested waiting until this discussion to avoid any confusion or changes to the cover sheet (and Summary-ON Deck tab) from what they last saw.
3. Revised the OEFC – Budget to correspond to what OEFC was assuming as of budget.
4. Added footnote as necessary where Hydro One proportionate numbers appear.
5. Updated OPG FHP Trust interest revenue based on revisions from FTD.

For any distribution outside of EFB, we would delete the "Track Changes" worksheet and the "H1 Provincial Allocations" worksheet.
Bruno

From: Ronald Kwan
Sent: Thursday, October 19, 2017 7:05 PM
To: Bruno Amara <Bruno.Amara@ofina.on.ca>
Cc: John Kim <John.Kim@ofina.on.ca>
Subject: Re: Revised Electricity Outlook

Hi Bruno,

I thought we discussed making an adjustment to the Hydro One deferred tax benefit upfront hit risk to be scaled at a proportionate 50%. It could be footnoted as done this way vs the 70% assumption used for H1 generally, pending the recategorisation from the AO sales and rentals outlook. (As an aside, would it be fair to say that the incremental risk is also less than what is shown because built into the update is the annual impact of the deferred tax benefit decision of the OEB? In that light, for symmetry, should there be a positive risk shown for H1 should it

be successful in its OEB Motion to Review?

Also, why not put into the OEFC tab an estimated s.50.3 amount for 17-18?

Also, why does the Budget 2017 tab for OEFC show an excess of revenue over expense of about $0.7bn. I thought it was about $1.1 bn at the time of Budget. You may need to add to the ESDI formula to reverse the IFRS assumption in the OEFC Budget tab -- and then putting in the 50.3 amount in the OEFC on-deck tab would more than offset that (for now, pending other updates, such as for H1).

Also, for clarity, on each worksheet where Hydro One proportionate numbers appear, please add a footnote on that row, as some people may just go to one work sheet, or print one worksheet (and has each worksheet been formatted for easy printing -- can help multiple users and down the line). This includes the Provision worksheet, where I assume the financing cost for the Hydro One row is based on the 70%, but will go down to under 50% ultimately.

On the OPG FHP Trust interest revenue, is that scaled to the new equity injection projections supplied to FTD so it would match the IOD side? Are we aligned to match FTD's IOD assumptions for borrowing for the equity injection?

Thanks,
Ron

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Bruno

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Electricity Sector Outlook
October 2017

Disclosure:

All information contained in this workbook is confidential and commercially sensitive

All projected numbers are estimates and subjected to change

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Electricity Sector Outlook
Including Line Items for Consolidation

Electricity Summary - On Deck

			MOF Expense Items (consolidated)	Current Outlook			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**38**	Power Supply Contract Costs	(292)	(325)	(301)	(273)
Expense	**MOF (OEFC)**	**40**	Demand Management Support Costs	(10)	-	-	-
Expense	**MOF (OEFC)**	**41**	Provision for Electricity Sector	140	-	-	-
Expense	**MOF**	**17**	Provision for Electricity Sector	(140)	-	-	-
Expense	**MOF (OEFC)**	**42**	Other (Finance)	(6)	(6)	(6)	(6)
			Total MOF Expense	**(308)**	**(331)**	**(307)**	**(279)**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**7**	OPG Income	147	720	608	1,041
Revenue	**ENE**	**8**	OPG - ONFA and other Fair Value Adjustments	-	-	-	-
Revenue	**ENE**	**10**	HOI Income	447	484	566	612
Revenue		**11**	Brampton Income	-	-	-	-
Revenue	**MOF (OEFC)**	**26**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	381	479	531	668
Revenue	**MOF (OEFC)**	**29**	Electricity Debt Retirement Charge	623	-	-	-
Revenue	**MOF (OEFC)**	**30**	Power Supply Contract Recoveries	292	325	301	273
Revenue	**MOF (OEFC)**	**31**	Net Reduction of Power Purchase Contracts	74	41	30	28
Revenue	**MOF (OEFC)**	**34**	Miscellaneous	-	-	-	-
			Total MOF Revenue	**1,964**	**2,049**	**2,036**	**2,623**
			OFA IOD Expense				
			Public Debt Interest - Electricity Sector	(454)	(454)	(454)	(454)
			Interest on Debt	(475)	(438)	(411)	(348)
			Total OFA IOD Expense	**(929)**	**(892)**	**(865)**	**(802)**
			Impact on Surplus/Deficit	**727**	**826**	**864**	**1,542**
			check	**-**	**-**	**-**	**-**

Electricity Summary - Budget 17

	For Discussion		MOF Expense Items (consolidated)	Plan			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**38**	Power Supply Contract Costs	(292)	(325)	(301)	(273)
Expense	**MOF (OEFC)**	**40**	Demand Management Support Costs	(10)	0	0	0
Expense	**MOF (OEFC)**	**41**	Provision for Electricity Sector	125	0	0	0
Expense	**MOF**	**17**	Provision for Electricity Sector	(125)	0	0	0
Expense	**MOF (OEFC)**	**42**	Other (Finance)	(6)	(6)	(6)	(6)
			Total MOF Expense	**(308)**	**(331)**	**(307)**	**(279)**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**7**	OPG Income	97	732	625	1,066
Revenue	**ENE**	**8**	OPG - ONFA and other Fair Value Adjustments	0	0	0	0
Revenue	**ENE**	**10**	HOI Income	520	562	603	652
			Brampton Income				
Revenue	**MOF (OEFC)**	**25**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	405	476	538	679
Revenue	**MOF (OEFC)**	**29**	Electricity Debt Retirement Charge	623	0	0	0
Revenue	**MOF (OEFC)**	**30**	Power Supply Contract Recoveries	292	325	301	273
Revenue	**MOF (OEFC)**	**31**	Net Reduction of Power Purchase Contracts	74	41	30	28
Revenue	**MOF (OEFC)**	**34**	Miscellaneous	0	0	0	0
			Total MOF Revenue	**2,011**	**2,136**	**2,098**	**2,697**
			OFA IOD Expense				
		17	Public Debt Interest - Electricity Sector	(492)	(492)	(492)	(492)
		36	Interest on Debt	(422)	(374)	(342)	(250)
			Total OFA IOD Expense	**(914)**	**(866)**	**(834)**	**(742)**
			Impact on Surplus/Deficit	**789**	**939**	**957**	**1,676**
			check	**-**	**-**	**-**	**-**

Electricity Summary - Change

			MOF Expense Items (consolidated)	Variance from Plan			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**69**	Power Supply Contract Costs	0	0	0	(0)
Expense	**MOF (OEFC)**	**71**	Demand Management Support Costs	0	0	0	0
Expense	**MOF (OEFC)**	**72**	Provision for Electricity Sector	15	0	0	0
Expense	**MOF**	**48**	Provision for Electricity Sector	(15)	0	0	0
Expense	**MOF (OEFC)**	**73**	Other (Finance)	0	0	0	0
			Total MOF Expense	**0**	**0**	**0**	**(0)**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**38**	OPG Income	50	(12)	(17)	(24)
Revenue	**ENE**	**39**	OPG - ONFA and other Fair Value Adjustments	0	0	0	0
Revenue	**ENE**	**41**	HOI Income	(73)	(78)	(38)	(40)
			Brampton Income	0	0	0	0
Revenue	**MOF (OEFC)**	**25**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	(24)	3	(7)	(10)
Revenue	**MOF (OEFC)**	**60**	Electricity Debt Retirement Charge	0	0	0	0
Revenue	**MOF (OEFC)**	**61**	Power Supply Contract Recoveries	(0)	(0)	(0)	0
Revenue	**MOF (OEFC)**	**62**	Net Reduction of Power Purchase Contracts	(0)	(0)	(0)	(0)
Revenue	**MOF (OEFC)**	**65**	Miscellaneous	0	0	0	0
			Total MOF Revenue	**(47)**	**(87)**	**(62)**	**(74)**
			OFA IOD Expense				
		17	Public Debt Interest - Electricity Sector	38	38	38	38
		36	Interest on Debt	(53)	(64)	(69)	(98)
			Total OFA IOD Expense	**(15)**	**(26)**	**(31)**	**(60)**
			Impact on Surplus/Deficit	**(62)**	**(113)**	**(93)**	**(134)**
			check	***-***	***0***	***(0)***	***(0)***

Track Changes in Surplus/Deficit

Date	Change ID#	Source in File	Tab
5/1/2017	20170501-1	Link	ONFA
5/1/2017	20170501-2	Link	Hydro One
5/1/2017	20170501-3	Link	Hydro One
5/1/2017	20170501-4	Link	Other Data
5/2/2017	20170502-1	Link	OPG
5/9/2017	20170509-1	Link	OPG
5/10/2017	20170510-1	Link	Hydro One
5/10/2017	20170510-2	Link	Other Data
5/12/2017	20170512-1	Link	Hydro One
5/15/2017	20170515-1	Link?	
5/15/2017	20170515-2	Link	OPG
5/17/2017	20170517-1	Link	Hydro One
5/17/2017	20170517-2	Link	ONFA
5/17/2017	20170517-3		
5/18/2017	20170518-1	Link	OPG
5/18/2017	20170518-2	Link	OPG
5/18/2017	20170518-3		
6/15/2017	20170615-1	Link	OPG
6/22/2017	20170622-1	Link	Hydro One
6/22/2017	20170622-2	Link	Hydro One
6/26/2017	20170626-1		
6/29/2017	20170629-1		

7/6/2017	20170706-1		
7/11/2017	20170711-1		
7/13/2017	20170713-1	Link	Provision
7/17/2017	20170717-1	Link	Revenue (Risks)
7/24/2017	20170724-1	Link	Revenue (Risks)
7/25/2017	20170725-1	Link	Revenue (Risks)
7/26/2017	20170726-1	Link	Revenue (Risks)
7/27/2017	20170727-1	Link	Revenue (Risks)
7/27/2017	20170727-2	Link	Revenue (Risks)
7/31/2017	20170731-1		
7/31/2017	20170731-2	Link	Hydro One
7/31/2017	20170731-3	Link	Other Data
8/11/2017	20170811-1	Link	OPG
8/15/2017	20170815-1		
8/15/2017	20170815-2		
8/15/2017	20170815-3		
8/15/2017	20170815-4		
8/15/2017	20170815-5		Other Data
8/15/2017	20170815-6		Other Data
8/15/2017	20170815-7		Other Data
8/15/2017	20170815-8		Other Data
8/15/2017	20170815-9		Other Data
8/15/2017	20170815-10		Other Data
8/17/2017	20170817-1	Link	Provision
8/17/2017	20170817-2	Link	Hydro One
8/18/2017	20170818-1	Link	Revenue (Risks)
8/22/2017	20170822-1	Link	OPG
8/25/2017	20170825-1		Hydro One
8/29/2017	20170829-1		Revenue (Risks)
8/31/2017	20170831-1		Revenue (Risks)
9/5/2017	20170905-1		Other Data
9/5/2017	20170905-2		Other Data
9/5/2017	20170905-3	Link	OPG

9/6/2017	20170906-1	Link	Other Data
9/6/2017	20170906-2	Link	Revenue (Risks)
9/8/2017	20170908-1	Link	Hydro One
9/8/2017	20170908-2	Link	OPG
9/11/2017			
9/12/2017			
9/13/2017			
9/21/2017			
9/22/2017			
10/2/2017			Hydro One
10/2/2017			
10/2/2017			
10/2/2017			
10/4/2017	20171004-1		OPG
10/4/2017	20171004-2		OPG
10/4/2017			
10/4/2017			
10/5/2017			
10/6/2017			
10/7/2017			
10/8/2017			
10/10/2017	20171010-1		Hydro One
10/10/2017			
10/10/2017			
10/11/2017	20171011-1		OPG
10/11/2017			
10/11/2017			
10/12/2017			OPG
10/12/2017			
10/12/2017			
10/12/2017			
10/18/2017	20171018-1		Hydro One
10/18/2017	20171018-1		Hydro One
10/18/2017	20171018-1		Hydro One
10/19/2017	20171019-1		Revenue (Risks)
10/19/2017	20171019-2		Revenue (Risks)
10/20/2017	20171020-1		Revenue (Risks)
10/20/2017	20171020-2		
10/20/2017	20171020-2		
10/20/2017	20171020-2		
10/20/2017	20171020-3		Revenue (Risks)
10/20/2017	20171020-4		OPG
10/20/2017	20171020-4		
10/20/2017	20171020-4		

FOR EFB USE ONLY

Budget 2017 Outlook
Current Outlook
Change Since Budget

Description of Update
ONFA Update as of March 31 2017
s. 50.3 Update for 2016-17
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Debt Interest
OPG IFRS Risk in 2019-20
Revised OPG 2016-17 Net Income
Revised OPG 2016-17 Net Income
Revised OPG 2016-17 Net Income
tech change: slight update to assumed Prov share 70.05% from 70%
tech change: slight update to assumed Prov share 70.05% from 70%
tech change: slight update to assumed Prov share 70.05% from 70%
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
Updating H1 2016-17 Net Income for ESDI
Updating H1 2016-17 Net Income for ESDI
Updating H1 2016-17 Net Income for ESDI
Power Purchase Supply
H1 Model Forecasts - No Fiscal Update Resaving Data
Update Budget 2017 Tabs to reflect fiscal plan
Update OPG forecasted PILS to reflect sources
Update H1 2016-17 CIT
Re-inputting ONFA updates
Updating H1 Net Income to include Pref Shares in 16-17
Updating OPG Income Tax Expense for 2016-17
Updating OPG non-income tax PILs
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2017
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2018
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2019
Updating with actual OPG IFRS Adjustment 2016-17
Updating with actual OPG IFRS Adjustment 2016-17
Updating with actual OPG IFRS Adjustment 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
[NOT APPLIED] Updating H1 Brampton (Interim Adjustments)
Shifted H1 Brampton 2016-17 NI to the 2017-18
Removed H1 Brampton for 2016-17 (pending finals)
Removed H1 Brampton for 2016-17 (pending finals)
Removed H1 Brampton for 2016-17 (pending finals)

add prior-year adjustment for 2016-17

add prior-year adjustment for 2016-18
Reconfigured calculation of ESDI and MOF ESDI Expense
Reconfigured calculation of OPG 2017-18 Net Income
Backup for the Provincial Interest cost
Linking source for Revenue Risks Tab
New source for Revenue Risks Tab
Revenue Risks Tab - ROE Risks
Updating OEB Risk for OPG
OEB Staff Report - H1 Tx - Revenue Risks
OPG Pensions - Cash vs Accrual Deferral Accounts
Updating Links in Electricity Summary Change and OEFC Change
Preliminary estimate for Hydro One Brampton
Preliminary estimate for Hydro One Brampton
Preliminary estimate for Hydro One Brampton

Updating DRC for Actuals 2016-17 (Based on draft FS)
Updating PILs for 2016-17 Baced on Actuals
OPG: Non-ONFA Fair Value Adjustment
Round all Hydro One ownership assumptions to two decimal places
H1 Equity Adjustment rounding.
Round all Hydro One ownership assumptions to two decimal places
Round all Hydro One ownership assumptions to two decimal places
Revising source of ESDI, Dedicated Electricity Earnings
2016-17 - Update Power Supply Recoveries to actuals
2016-17 - Update Power Supply Recoveries to actuals
2016-17 - Updating Miscellaneous OEFC Revenue to Actuals
Adj: Exclude Bramton $15m add prior year adjustment +$3M
Adj: Exclude Bramton $15m add prior year adjustment +$3M
Public Accts: Updated IESO debt interest Interest On Debt, 2016-17
Public Accts: 2016-17 - Demand Management Support Costs Update
2017-18 - Demand Management Support Costs (no change)
Public Accts: 2016-17 - Updating Operating Expense in OEFC
Sourcing Provision for Electricity Sector from Actual Public Accounts
Revised 2016-17 Brampton Amount for Public Accounts
OPG Pensions - Cash vs Accrual Deferral Accounts (Revenue Risks Tab)
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
Reclassification
Reclassification
Reverting H1 Ownership change (undoing 20170518-3)
Reverting H1 Ownership change (undoing 20170518-3)
Reverting H1 Ownership change (undoing 20170518-3)
Updating Risks based on Hydro One Q2 Results Model
Avista Acquisition Risks
NUG Amortization Liability (sourcing amortization schedule)
2016-17 Actuals - Debt Guarantee Fee
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results

Interest Revenue for IESO and "Other"
OPG Revenue Risks from OEB Filings
Net income corrected for Preferred Shares
Net income corrected for Preferred Shares
Net income corrected for Preferred Shares
Made link edits to OPG sheet so that the "Net Income Before Tax" 2017-18 number is not a h
Updated PILs to include OPCD public accounts adjustment
Provision tab fix to pick up Hydro One preferred share net income
Provision tab fix to pick up Hydro One preferred share net income
FTD Update to OEFC Outlook (Sep 19, 2017) OPG Interest
FTD Update to OEFC Outlook (Sep 19, 2017) Other Interest
Update to Hydro One PILs from information in Tranmsission rate application material
OEB September 28, 2017 Hydro One decision and order impact - incl. rebasing
OEB September 28, 2017 Hydro One decision and order impact - incl. rebasing
OEB September 28, 2017 Hydro One decision and order impact - incl. rebasing
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Debenture Interest Costs - Removing from Revenue (Risks) and adding it ot H1 Model
Debenture Interest Costs - Removing from Revenue (Risks) and adding it ot H1 Model
Debenture Interest Costs - Removing from Revenue (Risks) and adding it ot H1 Model
Updated OPG Net Income and PILs based on monthly report (August 2017 results)
Updated OPG Net Income and PILs based on monthly report (August 2017 results)
Updated OPG Net Income and PILs based on monthly report (August 2017 results)
Correction to PILs on OPG sheet
Correction to PILs on OPG sheet
Correction to PILs on OPG sheet
Correction to PILs on OPG sheet
Switch to Direct from Model
Switch to Direct from Model
Switch to Direct from Model
Updating ROE Risks
Updating H1 Load Risks based on model output
Updating ONFA Risks for September 2017
  Adjust OEB decision/rebasing to ~50% provincial ownership
  Adjust OEB decision/rebasing to ~50% provincial ownership
  Adjust OEB decision/rebasing to ~50% provincial ownership
Updating OPG
OPG IOD impact from GA Financing, FHP
OPG IOD impact from GA Financing, FHP
OPG IOD impact from GA Financing, FHP

This line show net impact of latest change. READ COMMENT

Expense
Expense
Expense
Expense
Expense
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue

Expense
Expense
Expense
Expense
Expense
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue

		$ Millions	
		2016-17	**2017-18**
		930	789
	File	915	727
		-15	-62
	check	***0***	***0***

Outlook line affected	**Expense / Rever**	**Impacts by FY →**	
ONFA and other Fair Value Adjustments	Revenue	41.0	0.0
N/A		0.0	0.0
?		0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		38.1
Provision for Electricity Sector (MOF)	Expense		(38.1)
Public Debt Interest - Electricity Sector	Expense	0.0	38.1
Interest on Debt	Expense	0.0	(69.1)
OPG Income	Expense	0.0	0.0
OPG Income	Revenue	(2.0)	0.0
Provision for Electricity Sector (OEFC)	Expense	**(2.0)**	
Provision for Electricity Sector (MOF)	Expense	2.0	
HOI Income	Revenue	0.4	
Provision for Electricity Sector (OEFC)	Expense	0.4	
Provision for Electricity Sector (MOF)	Expense	(0.4)	
Public Debt Interest - Electricity Sector	Expense	1.7	
Provision for Electricity Sector (OEFC)	Expense	(1.7)	
Provision for Electricity Sector (MOF)	Expense	1.7	
Interest on Debt	Expense	(1.7)	
HOI Income	Revenue	(39.8)	0.0
Provision for Electricity Sector (OEFC)	Expense	**(39.8)**	
Provision for Electricity Sector (MOF)	Expense	39.8	
	Revenue	-	-
	Revenue	-	-
	n/a	-	-
		-	-
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	4.7	0.0
	Revenue	0.0	0.0
HOI Income	Revenue	18.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	7.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	8.0	9.0
HOI Income	Revenue	0.0	(141.5)
Provision for Electricity Sector (OEFC)	Expense		(141.5)
Provision for Electricity Sector (MOF)	Expense		141.5
OPG Income	Revenue	(3.0)	0.0
Provision for Electricity Sector (OEFC)	Expense	**(3.0)**	
Provision for Electricity Sector (MOF)	Expense	3.0	
HOI Income	Revenue	7.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**7.0**	
Provision for Electricity Sector (MOF)	Expense	(7.0)	
	Revenue	-	-
	Revenue	0.0	0.0
Brampton Income	Revenue	(14.7)	0.0
Provision for Electricity Sector (OEFC)	Expense	**(14.7)**	
Provision for Electricity Sector (MOF)	Expense	14.7	

Provision for Electricity Sector (OEFC)	Expense	3.2	
Provision for Electricity Sector (MOF)	Expense	(3.2)	
	Revenue	-	-
		-	-
	n/a	0.0	0.0
	n/a	0.0	0.0
	n/a	0.0	0.0
	n/a	0.0	0.0
	n/a	0.0	0.0
	n/a	0.0	0.0
	n/a	0.0	0.0
	n/a	0.0	0.0
Brampton Income	Revenue	15.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**15.0**	
Provision for Electricity Sector (MOF)	Expense	(15.0)	
Provision for Electricity Sector (OEFC)	Expense	3.2	
Provision for Electricity Sector (MOF)	Expense	(3.2)	
Electricity Debt Retirement Charge	Revenue	(4.0)	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	(29.0)	0.0
OPG Income	Revenue	(6.0)	0.0
HOI Income	Revenue	(0.0)	(0.0)
HOI Income	Revenue	(1.7)	0.0
Provision for Electricity Sector (OEFC)	Expense		(0.0)
Provision for Electricity Sector (MOF)	Expense		0.0
	Revenue	0.0	0.0
Power Supply Contract Recoveries	Revenue	99.0	0.0
Power Supply Contract Costs	Expense	(99.0)	
Miscellaneous	Revenue	14.0	0.0
Provision for Electricity Sector (OEFC)	Expense	(12.0)	
Provision for Electricity Sector (MOF)	Expense	12.0	
Interest on Debt	Expense	(3.0)	0.0
Demand Management Support Costs	Expense	1.8	0.0
		0.0	0.0
Other (Finance)	Expense	(1.0)	0.0
	Revenue	-	-
Brampton Income	Revenue	3.0	0.0
		0.0	0.0
OPG Income	Revenue	0.0	85.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue		(6.0)
Provision for Electricity Sector (OEFC)	Expense		**85.0**
Provision for Electricity Sector (MOF)	Expense		(85.0)
OPG Income	Revenue	6.0	
ONFA and other Fair Value Adjustments	Revenue	(6.0)	
HOI Income	Revenue	0.0	141.9
Provision for Electricity Sector (OEFC)	Expense		141.9
Provision for Electricity Sector (MOF)	Expense		(141.9)
	n/a	0.0	0.0
		0.0	0.0
Net Reduction of Power Purchase Contracts	Revenue	0.1	(0.1)
	Revenue	0.0	0.0
OPG Income	Revenue	0.0	16.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue		(1.0)
Provision for Electricity Sector (OEFC)	Expense		**16.0**
Provision for Electricity Sector (MOF)	Expense		(16.0)

		0.0	0.0
	n/a	0.0	0.0
HOI Income	Revenue	0.0	5.3
Provision for Electricity Sector (OEFC)	Expense		(12.4)
Provision for Electricity Sector (MOF)	Expense		12.4
ardcoded formula in the cell	n/a	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	(30.4)	0.0
Provision for Electricity Sector (OEFC)	Expense		17.8
Provision for Electricity Sector (MOF)	Expense		(17.8)
Interest on Debt	Expense	(0.0)	1.0
Interest on Debt	Expense	0.0	15.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	0.0	(7.8)
HOI Income	Revenue	0.0	(47.4)
Provision for Electricity Sector (OEFC)	Expense	0.0	(47.4)
Provision for Electricity Sector (MOF)	Expense	0.0	47.4
OPG Income	Revenue	0.0	(61.0)
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	0.0	(21.0)
Provision for Electricity Sector (OEFC)	Expense	0.0	(61.0)
Provision for Electricity Sector (MOF)	Expense	0.0	61.0
OPG Income	Revenue	0.0	(21.0)
Provision for Electricity Sector (OEFC)	Expense	0.0	(21.0)
Provision for Electricity Sector (MOF)	Expense	0.0	21.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	0.0	21.0
HOI Income	Revenue	0.0	(23.6)
Provision for Electricity Sector (OEFC)	Expense	0.0	(23.6)
Provision for Electricity Sector (MOF)	Expense	0.0	23.6
OPG Income	Revenue	0.0	15.0
Provision for Electricity Sector (OEFC)	Expense	0.0	15.0
Provision for Electricity Sector (MOF)	Expense	0.0	(15.0)
OPG Income	Revenue	0.0	21.0
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	0.0	(18.0)
Provision for Electricity Sector (OEFC)	Expense	0.0	21.0
Provision for Electricity Sector (MOF)	Expense	0.0	(21.0)
HOI Income	Revenue	0.0	(23.8)
Provision for Electricity Sector (OEFC)	Expense	0.0	(23.8)
Provision for Electricity Sector (MOF)	Expense	0.0	23.8
n/a	n/a	0.0	0.0
n/a	n/a	0.0	0.0
n/a	n/a	0.0	0.0
HOI Income	Revenue		16.1
Provision for Electricity Sector (OEFC)	Expense		16.1
Provision for Electricity Sector (MOF)	Expense		(16.1)
n/a	n/a	0.0	0.0
OPG Income	Revenue		(4.9)
Provision for Electricity Sector (OEFC)	Expense		(4.9)
Provision for Electricity Sector (MOF)	Expense		4.9
		0.0	***(0.00)***

Summary of Track Changes Above

Power Supply Contract Costs	(99.0)	0.0
Demand Management Support Costs	1.8	0.0
Provision for Electricity Sector OEFC)	(44.4)	4.0
Provision for Electricity Sector (MOF)	44.4	(4.0)
Other (Finance)	(1.0)	0.0
OPG Income	(5.0)	55.0
ONFA and other Fair Value Adjustments	35.0	0.0
HOI Income	(16.1)	(89.1)
Brampton Income	3.3	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	(39.7)	(23.8)
Electricity Debt Retirement Charge	(4.0)	0.0
Power Supply Contract Recoveries	99.0	0.0
Net Reduction of Power Purchase Contracts	0.1	(0.1)
Miscellaneous	14.0	0.0
Public Debt Interest - Electricity Sector	1.7	38.1
Interest on Debt	(4.7)	(53.1)
Impact on Surplus/Deficit	**(14.6)**	**(72.9)**
check	***0.0***	***(11.2)***

Check - Summary of Track Changes Above vs. Electricity Summary Change Worl

Power Supply Contract Costs	0.0	(0.4)
Demand Management Support Costs	(0.0)	0.0
Provision for Electricity Sector OEFC)	8.4	(11.1)
Provision for Electricity Sector (MOF)	(8.4)	11.1
Other (Finance)	0.0	0.0
OPG Income	0.0	4.9
ONFA and other Fair Value Adjustments	0.0	0.0
HOI Income	(0.0)	(16.1)
Brampton Income	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	(0.0)	0.0
Electricity Debt Retirement Charge	0.0	0.0
Power Supply Contract Recoveries	0.0	0.4
Net Reduction of Power Purchase Contracts	(0.0)	(0.0)
Miscellaneous	0.0	0.0
Public Debt Interest - Electricity Sector	23.4	0.1
Interest on Debt	(23.4)	(0.1)
Impact on Surplus/Deficit	**(0.0)**	**(11.2)**

2018-19	2019-20	2020-21
939	957	1,676
826	864	1,542
-113	-93	-134
0	***0***	***0***
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
38.1	38.1	38.1
(79.1)	(75.1)	(104.1)
0.0		0.0
0.0	0.0	0.0
0.0	(0.0)	0.0
-	-	-
-	-	-
-	-	-
-	-	-
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
12.0	3.5	1.8
(181.4)	(194.9)	(210.6)
0.0	0.0	0.0
0.0	0.0	0.0
-	-	-
0.0	0.0	0.0
0.0	0.0	0.0

-	-	-
-	-	-
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
-	-	-
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
181.8	195.4	211.1
0.0	0.0	0.0
0.0	0.0	0.0
(0.1)	(0.1)	(0.0)
0.0	0.0	0.0
0.0	0.0	0.0

0.0	0.0	0.0
0.0	0.0	0.0
5.3	5.3	5.3
0.0	0.0	0.0
0.0	0.0	0.0
(0.0)	1.0	1.3
15.0	5.0	5.0
(8.7)	(10.3)	(12.2)
(54.0)	(54.0)	(54.0)
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
(27.4)	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
(28.9)	(10.1)	(13.0)
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
26.7	20.6	21.6
0.0	0.0	0.0
(11.9)	(17.1)	(24.1)
0.0	0.0	0.0
0.0	0.0	0.0
0.00	***(0.00)***	***(0.00)***

0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
(104.6)	(58.3)	(61.2)
0.0	0.0	0.0
3.3	(6.8)	(10.5)
0.0	0.0	0.0
0.0	0.0	0.0
(0.1)	(0.1)	(0.0)
0.0	0.0	0.0
38.1	38.1	38.1
(64.1)	(69.1)	(97.8)
(127.4)	**(96.2)**	**(131.5)**
(14.8)	***(3.6)***	***2.5***

ksheet

(0.1)	(0.4)	0.2
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
11.9	17.1	24.1
0.0	0.0	0.0
(26.7)	(20.6)	(21.6)
0.0	0.0	0.0
0.0	0.0	(0.3)
0.0	0.0	0.0
0.1	0.4	(0.2)
(0.0)	(0.0)	0.0
0.0	0.0	0.0
0.1	0.1	0.1
(0.1)	(0.1)	0.1
(14.8)	**(3.6)**	**2.5**

Further Explanation of Change and source of data

Regular quarterly ONFA Update
Benefit to OEFC under s.50.3: $411M gain, SIFB
Change to OEFC payment for interest costs of Debt for Equity Swap

Revised Provincial Debt Interest related to Hydro One Equity
From FTD, revised Debt Interest (net of revisions to Provincial and OPG debt interest)
Revised numbers from OEP with 2019-20 Risk
Updated numbers from OPG Q1 2017 FS

Updating H1 Net Income for actuals. Note does not update Brampton Income at this point. Will update onc

No Change to numbers, just re-inputting data and saving sources
No Change to numbers, just re-inputting data and saving sources
No change to fiscal impact numbers. Deleting Budget 2016 and adding Budget 2017 fiscal impacts
No Change to numbers, just re-inputting data and saving sources
Updated with CIT Numbers received from H1 as part of s.91.2 MB20 allocation from MOF
No Change to numbers, just re-inputting data and saving sources
Only included H1 Net Income - Common Shareholders before. Added preferred shareholder impact as we
Updating OPG Income Tax Expense with info from OPG Monthly Presentation to Shareholder
Updating OPG GRC payable to OEFC and Proxy Property Tax from Answer back from OPG about the BP
Based on H1 final offering and expected First Nations Sale by the end of 2017 (CY), with a weighted avera

Based on EY analysis, and then applying fiscalization. Confirmation also received from OPCD.

Based on KPMG analysis, then fiscalization and other adjustments from OPCD.

[NOT APPLIED, CALCULATIONS AND DATA LEFT ON THE FILE] Used Brampton's Financial Stateme
Don't expect finalized 2016-17 data to become available in time for ESDI allocation. Will shift this to 2017-
make decision on shifting when we know 2016-17 status.

No change to numbers. Just re-organizing spreadsheet. No backup data.
No change to numbers. Just re-organizing spreadsheet. No backup data.
No change to numbers. Just provided actual backup/source.
No change to numbers. Just provided actual backup/source.
No change to numbers. Just provided another scenario backup/source
No change to numbers. Just provided actual backup/source.
No change to numbers. Just provided actual backup/source.
No change to numbers. Just provided actual backup/source.
No change to numbers. Just provided actual backup/source.
No change to numbers. Just updated the links to refer ot the delta between 2017 and On Deck (from 2016
Adjustment to ESDI to include Hydro One Brampton

Finalizing 2016-17 DRC Based on Draft OEFC AR
Received actual PILs amounts from FTD with breakdown of source. Updated 2016-17 numbers to reflect t
2016-17 - Non-ONFA Fair Value Adjustment
Round Hydro One ownership assumptions to 70.05% two decimal places to be consistent with OPCD.
Revising Hydro One Amount for consistency with OPCD. Equity Adjustments

Updated Provision tab. Made two separate Provision amounts for ESDI in OEFC AR and Dedicated Earnir
Updating Power Supply Recoveries to Public Accounts/OEFC AR actuals

Updating Miscellaneous to OEFC AR actuals

Updated 2016-17 Interest on Debt (IESO, OPG, Other (Net))

2017-18 - Demand Management Support Costs (no change) - Linking correctly
2016-17 - Updating Operating Expense in OEFC and corresponding changes elsewhere and sources.
No change to numbers. Just re-organized spreadsheet
Revised H1 Brampton Net Income (for GBE Line only)
Revising for OPG's Q3 Finances
Revising OPG's Net Income for latest monthly report

Reverting ownership back to 70.05% from change 20170518-3. Will coordinate with other areas to ensure

Updating Risks based on Hydro One Q2 Results Model
Updated two Risk components for the Avista Acquisition.
No significant changes, but used actual amortization liability schedule. Hence the rounding impacts/change
Updating Debt Guarantee for actuals based on OEFC AR
Revising OPG's Net Income for latest monthly report

Linking interest revenue data for 2017-18 to 2020-21
OPG Revenue Risks from: OEB Staff Submission and OPG Updated Filings
Corrected Net income for 100% ownership in preferred shares and 70.05% in Commons Shares

Updated the formula in the cell for 2017-18 Net Income Before Tax so that the numbers are not hardcodec
Updated PILs to include OPCD public accounts adjustment

increase built into net income was $82m between NI and PILs
Remove $21m from PILs
expense impacts
expense impacts
need to also remove the $21m PILs built into OPG net incme

We removed $21m from PILs above, before having added it in (check is that lines 123 to 130 add up to -$

varinaces include: 2017-18 preferred vs common share fix, 2018-19 largely ROE change from 9.09% to 8.

Data Validation:

Options
Revenue (Risks)
OPG
Hydro One
Provision

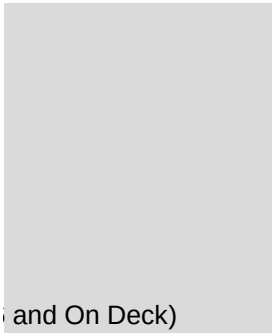
ONFA
Other Data

:e revised numbers are received.

ll.

ıge ownership for 2017-18. Also adjusted future net income attributed to the province.

nts to produce an estimate. May require additional calculations.
18.



and On Deck)

his.

gs in Public Accounts.

broadening change and reduction in net income happens concurrently in forecasts.

es.

ɪ directly

82m gain that we wanted to remove.

78% not previously captured.

Electricity Sector Outlook

$ Millions

	Actual 2015-16	Interim 2016-17	Plan 2017-18	2018-19	2019-20	2020-21
On Deck Outlook as of March 2017						
Income from Investment in Government Business Enterprises						
OPG Income[1]	291	304	97	732	625	1,066
OPG - ONFA and other Fair Value Adjustments[2]	172	8	-	-	-	-
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	-
HOI Income[3]	236	516	520	562	603	652
Brampton Income	20	15	-	-	-	-
Total OPG and HOI Income	**719**	**842**	**617**	**1,294**	**1,229**	**1,717**
Other Fees and Licences	**127**	**122**	**102**	**91**	**88**	**81**
Electricity Expenses of the Province						
Provision for Electricity Sector[4]	(3)	(342)	(125)		-	-
Public Debt Interest - Electricity Sector	(520)	(492)	(492)	(492)	(492)	(492)
Subtotal	(523)	(834)	(617)	(492)	(492)	(492)
Public Debt Interest - Impact of ONFA						
Amortization of Deferred Revenue re profit on sale of H1 notes						
Total Electricity Expenses of the Province	**(523)**	**(834)**	**(617)**	**(492)**	**(492)**	**(492)**
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	3,228	373	405	476	538	679
Other Revenue						
Electricity Debt Retirement Charge[5]	859	625	623	-	-	-
Power Supply Contract Recoveries	875	739	292	325	301	273
Net Reduction of Power Purchase Contracts	172	129	74	41	30	28
Other Fees and Licences	(127)	(122)	(102)	(91)	(88)	(81)
Miscellaneous	9	-	-	-	-	-
Expenses						
Interest on Debt	(596)	(532)	(422)	(374)	(342)	(250)
Power Supply Contract Costs	(875)	(739)	(292)	(325)	(301)	(273)
Electricity Consumer Price Protection Fund	-	-	-	-	-	-
Demand Management Support Costs[6]	(8)	(10)	(10)	-	-	-
Provision for Electricity Sector	3	342	125	-	-	-
Other (Finance)	(7)	(6)	(6)	(6)	(6)	(6)
Total OEFC Income	**3,533**	**800**	**687**	**46**	**132**	**370**
Impact on Surplus/(Deficit)	**3,856**	**930**	**789**	**939**	**957**	**1,676**

Notes: The Hydro One net income outlook above (2016-17 to 2020-21) reflects the Province's current 70% ownership share, after the initial IPO in 2015 [and the secondary offering in April 2016]. Net estimated fiscal impacts from future Hydro One offerings are reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

Notes:

1.OPG's 2016-17 outlook reflected its reported earnings. 2017-18 outlook reflects OPG's latest monthly update. Out-years reflect OPG's preliminary 2017-19 business plan and long-term outlook to 2019-20 (as fiscalized by OPG). 2020-21 estimates are based on OPG's calendar year-based business plan projections and as fiscalized by CEFD staff.

2. Provincial consolidation adjustments for unrealized earnings on the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds, as of the end of December 2016.

3. Hydro One 2016-17 income reflects its reported net income, adjusted for Hydro One IPO impacts. 2017-18 to 2020-21 projections are based on CEFD projections using the latest public information. The Hydro One net income outlook above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering are currently reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial ONFA consolidation adjustments, minus the interest on debt payable to OEFC. The provision is currently assumed to end once the DRC ends on a legislated fixed end date of April 1, 2018.

5. Reflects April 23, 2014 announcement that DRC will be eliminated for residential users, after December 31, 2015. The end date of DRC for remaining users is legislated to be on April 1, 2018. Estimates are subject to change based on actual consumption.

6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Electricity Sector Outlook

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
On Deck Outlook as of October 2017						
Income from Investment in Government Business Enterprises						
OPG Income[1]	291	299	147	720	608	1,041
OPG - ONFA and other Fair Value Adjustments[2]	172	43	-	-	-	-
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	-
HOI Income[3]	236	500	447	484	566	612
Brampton Income	20	18	-	-	-	-
Total OPG and HOI Income	**719**	**860**	**594**	**1,204**	**1,174**	**1,654**
Other Fees and Licences (Debt Guarantee fee)	**127**	**122**	**102**	**91**	**88**	**81**
Electricity Expenses of the Province						
Provision for Electricity Sector[4]	-	(290)	(140)			
Public Debt Interest - Electricity Sector	(520)	(514)	(454)	(454)	(454)	(454)
Subtotal	(520)	(803)	(594)	(454)	(454)	(454)
Public Debt Interest - Impact of ONFA						
Amortization of Deferred Revenue re profit on sale of H1 notes						
Total Electricity Expenses of the Province	**(520)**	**(803)**	**(594)**	**(454)**	**(454)**	**(454)**
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	3,247	334	381	479	531	668
Other Revenue						
Electricity Debt Retirement Charge[5]	859	621	623	-	-	-
Power Supply Contract Recoveries	875	838	292	325	301	273
Net Reduction of Power Purchase Contracts	172	129	74	41	30	28
Other Fees and Licences	(127)	(122)	(102)	(91)	(88)	(81)
Miscellaneous	9	14	-	-	-	-
Expenses						
Interest on Debt	(596)	(513)	(475)	(438)	(411)	(348)
Power Supply Contract Costs	(875)	(838)	(292)	(325)	(301)	(273)
Electricity Consumer Price Protection Fund	-	-	-	-	-	-
Demand Management Support Costs[6]	(8)	(8)	(10)	-	-	-
Provision for Electricity Sector	-	290	140	-	-	-
Other (Finance)	(7)	(7)	(6)	(6)	(6)	(6)
Total OEFC Income	**3,549**	**737**	**625**	**(15)**	**56**	**261**
Impact on Surplus/(Deficit)	**3,876**	**915**	**727**	**826**	**864**	**1,542**
variance to OEFC check	*(156)*	*(454)*	*(550)*	*-*	*0*	*-*

Notes:

1.OPG's 2016-17 outlook reflected its reported earnings. 2017-18 outlook reflects OPG's latest monthly update. Out-years reflect OPG's preliminary 2017-19 business plan and long-term outlook to 2019-20 (as fiscalized by OPG). 2020-21 estimates are based on OPG's calendar year-based business plan projections and as fiscalized by CEFD staff.

2. Provincial consolidation adjustments for unrealized earnings on the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds, as of the end of December 2016.

3. Hydro One 2016-17 income reflects its reported net income, adjusted for Hydro One IPO impacts. 2017-18 to 2020-21 projections are based on CEFD projections using the latest public information. The Hydro One net income outlook above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering are currently reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial ONFA consolidation adjustments, minus the interest on debt payable to OEFC. The provision is currently assumed to end once the DRC ends on a legislated fixed end date of April 1, 2018.

5. Reflects April 23, 2014 announcement that DRC will be eliminated for residential users, after December 31, 2015. The end date of DRC for remaining users is legislated to be on April 1, 2018. Estimates are subject to change based on actual consumption.

6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Electricity Sector Change Since Budget

$ Millions

($million)	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Changes from Budget 2017 as of October 2017						
Income from Investment in Government Business Enterprises						
OPG Income	(5)	50	(12)	(17)	(24)	2016-17 small decrease due to IFRS adjustment revision and OPG Net Income revision. 2017-18 increase mainly due to deferral of Pickering Unit 6 planned outage to Jan 18, deferral of sale of land at Hearn site from Q1 2017 to later in 2017, partially offsdet by lower gropss margin.
ONFA and other Fair Value Adjustments	35	-	-	-	-	Largely revision to ONFA fair value as of March 31, 2017
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	
HOI Income	(16)	(73)	(78)	(38)	(40)	2016-17 slight decrease from Budget 2017 Interim projection. 2017-18 onwards reflects impacts of OEB decision on Hydro One rates, interest expense on Avitsa debentures (in 2017-18 and 2018-19) and update to Hydro One model update based on Hydro One Q2 results.
Brampton Income	3.3					
Total OPG and HOI Income	**17**	**(22.9)**	**(90)**	**(55)**	**(64)**	
Other Fees and Licences	**-**	**-**	**-**	**-**	**-**	
Electricity Expenses of the Province						
Provision for Electricity Sector	53	(15)	-	-	-	Changes in the Proviision (ESDI) expense reflect net changes in the outlook for Public Debt Interest, and OPG and HOI net income (excludinging ONFA adjustments).
Public Debt Interest - Electricity Sector	(22)	38	38	38	38	2016-17 PDI at ($514m) was slightly larger than ($492m) projected at Interim. 2017-18 change reflects revised projections for Provincial debt interest related to Hydro equity.
Total Electricity Expenses of the Province	**31**	**23**	**38**	**38**	**38**	
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs)	(40)	(24)	3	(7)	(10)	2016-17 decrease largely due to an OPCD Public Accounts PILs adjustment related to reconciling between OPCD and OEFC net opening assets. OPG PILs also slightly lower than projected.
Other Revenue						
Electricity Debt Retirement Charge	(4)	-	-	-	-	
Power Supply Contract Recoveries	99	(0)	(0)	(0)	0	Variance is largely due to retroactive payments that the OEFC made to certain non-utility-generators (NUGs) with former Ontario Hydro power purchase agreement contracts with OEFC. OEFC was required to make these payment following the dismissal by the Supreme Court of Canada of OEFC's application for leave to appeal a judgment of the Court of Appeal of Ontario on a 2015 court decision.
Net Reduction of Power Purchase Contracts	0.1	(0)	(0)	(0)	(0)	
Other Fees and Licences	-	-	-	-	-	
Revenue Pool Residual	-	-	-		-	
Miscellaneous	14	-	-	-	-	Higher than projected at Interim.
Expenses						
Interest on Debt	19	(53)	(64)	(69)	(98)	2016-17 higher than projected at Interim. 2017-18 reflects revised debt interest outlook net of revisions to OEFC interest revenue from OPG and Province.
Power Supply Contract Costs	(99)	0	0	0	(0)	Same as Power supply contract recoveries above. Power supply contract costs are fully recovered by power supply contract recoveries.
Electricity Consumer Price Protection Fund	-	-	-	-	-	
Demand Management Support Costs	1.8	-	-	-	-	
Provision for Electricity Sector	(53)	15	-	-	-	Changes in the Proviision (ESDI) expense (negative expense or revenue to OEFC) reflect net changes in the outlook for Public Debt Interest, and OPG and HOI net income (excludinging ONFA adjustments).
Other (Finance)	(1.0)	-	-	-	-	
Total OEFC Income	**(63)**	**(62)**	**(61)**	**(76)**	**(108)**	
Impact on Surplus/(Deficit)	**(14.6)**	**(62)**	**(113)**	**(93)**	**(134)**	

Information: Breakdown of change between revenue and expense

Total Revenue Impact	87	(47)	(87)	(62)	(74)	
Total Expenditure impact	101	15	26	31	60	

Electricity Sector Outlook (PSAB)

Negative Revenue Risks	$ Millions			
($ millions)	**Plan**			
	2017-18	**2018-19**	**2019-20**	**2020-21**
Generic				
OPG Generation Risk: Nuclear Reliability (-1.6 TWh)[1]	(120)	(120)	(120)	(120)
1% decrease in Hydro One actual load[2]	(57)	(59)	(62)	(63)
Lower OPG's Equity weighting & Return on Equity (ROE)[3]	(12)	(20)	(26)	(45)
Lower Hydro One Return on Equity (ROE)[4]	(9)	(36)	(38)	(40)
Regulatory				
Hydro One Distribution rate application[5]	(50)	(50)	(50)	(50)
OPG Switch from accrual based to cash based accounting for pension and OPEB[6]	(600)			
Regulatory Risk - Timing of Rate Decision[7]	(540)			
OEB Staff Recommendations wrt OPG rate application(May 2017)[8]	(175)	(143)	(151)	(175)
Nuclear Liabilities Cash vs. Accrual[9]	(450)	(450)	(450)	(450)
OEB decision on Hydro One tax recapture (if one-time write-down)[10]	(251)			
Accounting				
Net OPG IFRS Consolidation Risks - Scenario 1b: 15 year historical, update discount rate each year.[11]	-	(475)	(500)	(750)
Other Risks				
Avista Acquisition - Termination fee		(103)		

Note: These risks do not reflect the impacts on electricity sector revenue and expense of reclassification of the Asset Optimiza

1. OPG's market and generation risks related to nuclear reliability similar to the scenarios OPG developed for its sales margins to capture major market risk factors (e.g., natural gas prices, coal prices, foreign exchange, nuclear reliability) in its 2012 business plan. Currently, only the nuclear reliability risk is captured at the current regulated rate for OPG's nuclear generation.

2. Estimated revenue impact if Hydro One load for Transmission and Distribution is 1% lower than projected for all years in CEFD Hydro One Forecast. Based on the assumption a 1% increase in load is directly proportional to a 1% change in revenue requirements.

3. Risk range for Hydro One transmission and distribution reflects potential risk of lower ROE by 0.5% vs assumed ROEs in business plan along with reduced deemed debt to equity weighting of 55%/45% from the current 51%/49%.

4. Risk range for Hydro One transmission and distribution reflects potential risk of lower ROE by 0.5% vs assumed ROEs in CEFD Hydro One Forecast based on the most recent rate applications and forecasted ROE rates.

5. OEB is expected to make a decision on Hydro One's Distibution rate application for 2018 during the first half of 2018.

6. The OEB directed a switch to cash-based accounting for years 2014 and 2015. However, the OEB also directed OPG to track the difference between cash based and accrual based accounting in a deferral account, while a generic proceeding is underway for all OEB-regulated electric and gas utilities. OEB September 2017 Report, recommends continuance of variance account which would mitigate this risk. However, the final decision (expected in Fall 2017) will be with the OEB Board.

7. Risk refelects OPG impact if the OEB rate rulings are applied as of the final decision date rather than retroactive to January 1, 2017. OPG's business plan assumed OEB decision would be effective as of January 1, 2017. OPG estimated an impact of -$60M for each month for which OEB decsion is not retroactive.

8. Reflects OEB staff report (May 2017) reccomendations with respect to OPG's rate application. (Inlcudes OPG rate application updates).

9. Risk refelects impact of OEB decision that OPG switch to cash-basis accounting for regulated recovery of nuclear payment anmounts. OEB staff report (May 2017) appears to mitigate this risk as it makes no decision and recommends revisiting this issue in 5 years at next OEB application.

10. The OEB's Sep. 28, 2017 ruling on Hydro One's Transmission rate application included direction on sharing, with ratepayers, tax savings related to the Hydro One IPO. The estimated annual ongoing impact of this is factored into the current outlook. This risk reflects the impact if a decision is made by Hydro One that the impact of the ruling has to be accounted for as an immediate one-time write-down.
Note: Corresponding Positive Revenue Risks would also need to be incorporated for 2018-19 to 2020-21 if this risk is to be recognized. The risk reflect ther roughly 50% proncial ownership pending recategorization from teh AO Sales and Rentals outlook.

11. OPCD provided IFRS impact estimates at the time of Budget 2017. A portion of these were reflected in in OPG's and Hydro One's net inc0me outlook. The Risk above reflect the impacts iof IFRS not refelcted in the Budget 2017 fiscal plan.
Table below outlines OPG IFRS Risks versus what is built into the Fiscal Plan.

	2017-18	2018-19	2019-20	2020-21
OPG IFRS Risk	(400)	(475)	(700)	(750)
Risks Built into Fiscal Plan	(400)	0	(200)	0
Additional Risks to be picked up	0	(475)	(500)	(750)

Electricity Sector Outlook (PSAB)

Positive Revenue Risks				
($ millions)	**Plan**			
	2017-18	**2018-19**	**2019-20**	**2020-21**
Generic				
OPG Generation Risk: Nuclear Reliability (+1.1 TWh)[1]	85	85	85	85
1% increase in Hydro One actual load[2]	57	59	61	63
Higher OPG Return on Equity (ROE)[3]	6	22	19	33
Higher Hydro One Return on Equity (ROE)[4]	19	69	50	50
Regulatory				
Hydro One Motion to Review OEB Transmission ruling[5]	40	54	41	43
OEB decision on Hydro One tax recapture (if one-time write-down)[6]		6	7	10
Other Risks				
ONFA adjustment increase (as of September 2017 Q3)[7]	171			

ation strategy or updates to AO strategy.

1. OPG's market and generation risks related to nuclear reliability similar to the scenarios OPG developed for its sales margins to capture major market risk factors (e.g., natural gas prices, coal prices, foreign exchange, nuclear reliability) in its 2012 business plan. Currently, only the nuclear reliability risk is captured at the current regulated rate for OPG's nuclear generation.

2. Estimated revenue impact if Hydro One load for Transmission and Distribution is 1% higher than projected for all years in CEFD Hydro One Forecast. Based on the assumption a 1% increase in load is directly proportional to a 1% change in revenue requirements.

3. Risk range for OPG reflects potential risk of higher ROE in 2018-2021 (for nuclear base) vs assumed ROE in OPG's 2016 business plan and corresponding rate application. Assumed ROE is 9.85%, respresenting recent in 2010.

4. Risk range for Hydro One transmission and distribution reflects potential risk of higher ROE vs assumed ROEs in the Hydro One CEFD Forecast for 2018-2021. Assumed ROE is 9.85%, representing recent high in 2010.

5. On October 18, 2017, Hydro One filed a Notice of Motion to Review and vary the Decision and Order dated September 28, 2017. Upside risks based on Hydro One's motions to vary the OEB decision.

6. The OEB's Sep. 28, 2017 ruling on Hydro One's Transmission rate application included direction on sharing, with ratepayers, tax savings related to the Hydro One IPO. The estimated annual ongoing impact of this is factored into the current outlook. This risk reflects the impact if a decision is made by Hydro One that the impact of the ruling has to be accounted for as an immediate one-time write-down.
Note: Corresponding Negative Revenue Risks would also need to be incorporated for 2017-18 if this risk is to be recognized

7. Reflects consolidation adjustment to OPG net income, whereby the realized portion of gains or losses of OPG's nuclear funds are added or subtracted from OPG net income.

ONTARIO ELECTRICITY FINANCIAL CORPORATION
On Deck Outlook as of March 2017

$ Millions

	Actual 2015-16	Interim 2016-17	Plan 2017-18	2018-19	2019-20	2020-21
Revenue						
Revenue Pool Residual						
Debt Retirement Charge	859	625	623	-	-	-
Payments-in-lieu of tax:						
OPG	268	302	315	366	408	537
Legacy Hydro One (Including Brampton)	2,929	7	2	2	2	2
Hydro One CIT dedicated to OEFC	3	20	20	22	23	25
MEUs	27	44	68	86	105	114
Total PILs & CIT dedicated to OEFC[1]	3,228	373	405	476	538	679
Interest :						
OPG	173	179	168	153	135	135
H1						
IESO	2	3	3	3	3	3
Province	520	492	492	492	492	492
Other	28	10	5	5	5	5
Total Interest	723	684	668	653	635	635
Power Supply Contract Recoveries	875	739	292	325	301	273
Amortization of NUG liability	172	129	74	41	30	28
Electricity sector dedicated income	3	342	525	-	-	-
Gain to OEFC under s. 50.3	172	-	-	-	-	-
Miscellaneous	9	-	-	-	-	-
	6,041	2,893	2,587	1,495	1,504	1,615
Expense						
Debt interest	1,319	1,216	1,090	1,027	977	885
Interest on nuclear risk funding						
Demand Management Support Costs	8	10	10	-	-	-
Amortization of deferred debt costs	-	-	-			
Power Supply Contract Costs	875	739	292	325	301	273
Debt Guarantee fee	127	122	102	91	88	81
Operating	7	6	6	6	6	6
	2,336	2,093	1,500	1,449	1,372	1,245
Excess (Deficiency) of Revenue over Expense	**3,705**	**800**	**1,087**	**46**	**132**	**370**
Prior period adjustment	87					
Stranded Debt - Year End	**4,393**	**3,593**	**2,506**	**2,460**	**2,328**	**1,958**

Note: All the Hydro One ownership broadening impacts, other than the ownership change from the initial IPO in 2015 [and the secondary offering in April 2016], are in the asset optimisation line (Sales and Rentals) and not in the current Outlook file.

ONTARIO ELECTRICITY FINANCIAL CORPORATION

On Deck Outlook as of October 2017 **$ Millions**

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Revenue						
Revenue Pool Residual						
Debt Retirement Charge	859	621	623	0	0	0
Payments-in-lieu of tax:						
OPG	268	224	299	378	411	539
Legacy Hydro One (Including Brampton)	2,929	4	2	2	2	2
Hydro One CIT dedicated to OEFC	3	25	12	13	13	13
MEUs	27	112	68	86	105	114
Total PILs & CIT dedicated to OEFC[1]	3,228	364	381	479	531	668
Interest :						
OPG	173	167	169	179	175	148
H1						
IESO	2	2	3	3	3	3
Province	520	514	454	454	454	454
Other	28	20	20	20	10	10
Total Interest	723	703	646	656	642	615
Power Supply Contract Recoveries	875	838	292	325	301	273
Amortization of NUG liability	172	129	74	41	30	28
Electricity sector dedicated income	3	302	140	0	0	0
Gain to OEFC under s. 50.3[2]	172	411	550	0	0	0
Miscellaneous	9	14	0	0	0	0
	6,041	3,382	2,706	1,501	1,504	1,585
Expense						
Debt interest	1,319	1,216	1,121	1,094	1,053	963
Interest on nuclear risk funding						
Demand Management Support Costs	8	8	10	0	0	0
Amortization of deferred debt costs	0	0	0			
Power Supply Contract Costs	875	838	292	325	301	273
Debt Guarantee fee	127	122	102	91	88	81
Operating	7	7	6	6	6	6
	2,336	2,191	1,531	1,516	1,448	1,323
Excess (Deficiency) of Revenue over Expense	3,705	**1,191**	**1,175**	**(15)**	**56**	**261**
Prior period adjustment	87					
Stranded Debt - Year End	4,393	**3,202**	**2,027**	**2,042**	**1,985**	**1,724**

1

Payments-in-lieu of tax:	2015-16 Public Accounts
OPG	290
Legacy Hydro One (Including Brampton)	2,941
Hydro One CIT dedicated to OEFC	0
MEUs	15
	3,247

2 **2017-18 currently does not include the transfer to OEFC, under s. 50.3 of FAA, related to the last Hydro One disposition. This will be included later this fiscal year, and will as a result increase the Exess of Revenue over Expense for 2017-18.**

ONTARIO ELECTRICITY FINANCIAL CORPORATION

Changes from Budget 2017 as of October 2017 **$ Millions**

	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Revenue						
Debt Retirement Charge	(4)	-	-	-	-	
Payments-in-lieu of tax:						
OPG	(78)	(16)	12	4	2	2016-17 variance is largely due to method of reporting OPG PILs by OEFC and OPG.
Legacy Hydro One (Including Brampton)	(3)	-	-	-	-	
Hydro One CIT dedicated to OEFC	5	(8)	(9)	(10)	(12)	Adjustment based on updated information in Hydro One rate application
MEUs	68	-	-	-	-	Large increase in 2016-17 from $80M payment during transfer of H01 Brampton to new consolidated MEU Alectra.
Total PILs	(9)	(24)	3	(7)	(10)	
Interest :						
OPG	(12)	1	26	40	13	Update to OPG interest outlook (wrt interest on OEFC loan).
H1	-	-	-	-	-	
IESO	(1)	-	-	-	-	
Province	22	(38)	(38)	(38)	(38)	2016-17 PDI at ($514m) was slightly larger than ($492m) projected at Interim. 2017-18 change reflects revised projections for Provincial debt interest related to Hydro equity.
Other	10	15	15	5	5	
Total Interest	19	(22)	3	7	(20)	
Power Supply Contract Recoveries	99	(0)	(0)	(0)	0	Variance is largely due to retroactive payments that the OEFC made to certain non-utility-generators (NUGs) with former Ontario Hydro power purchase agreement contracts with OEFC. OEFC was required to make these payment following the dismissal by the Supreme Court of Canada of OEFC's application for leave to appeal a judgment of the Court of Appeal of Ontario on a 2015 court decision.
Amortization of NUG liability	0	(0)	(0)	(0)	(0)	
Electricity sector dedicated income	(41)	(385)	-	-	-	Changes to ESDI (offset ny MoF Provision expense) largely reflect combined revisions to OPG and Hydro One net income and revisions to public debt intetest.
Gain to OEFC under s. 50.3	411	550	-	-	-	
Miscellaneous	14	-	-	-	-	
	489	119	6	(0)	(30)	
Expense						
Debt interest	-	31	67	76	78	Revised outlook for OEFC debt interest outlook
Interest on nuclear risk funding	-	-	-	-	-	
Demand Management Support Costs	(2)	-	-	-	-	
Amortization of deferred debt costs	-	-	-	-	-	
Power Supply Contract Costs	99	(0)	(0)	(0)	0	Same as Power supply contract recoveries above. Power supply contract costs are fully recovered by power supply contract recoveries.
Debt Guarantee fee	-	-	-	-	-	
Operating	1	-	-	-	-	
	98	31	67	76	78	
Excess (Deficiency) of Revenue over Expense	**391**	**88**	**(61)**			
Stranded Debt - Year End	**3,202**	**2,027**	**2,042**	**1,985**	**1,724**	

Provision for Electricity Sector (Dedicated Electricity Earnings/Electricity Sector Dedicated Earnings)

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Income from Investment in Government Business Enterprises						
OPG Income	291	299	147	720	608	1,041
Hydro One Income[1]	232	501	447	484	566	612
Hydro One Brampton (if applied separately)		15				
Total Income	**523**	**815**	**594**	**1,204**	**1,174**	**1,654**
Public Debt Interest - Electricity Sector						
OPG			(300)	(300)	(300)	(300)
Hydro One[1]			(154)	(154)	(154)	(154)
Public Debt Interest - Electricity Sector (OEFC Interest revenue)	**(520)**	**(514)**	**(454)**	**(454)**	**(454)**	**(454)**
MOF Provision Expense (before adjustments)	**3**	**302**	**140**	**750**	**720**	**1,199**
Other Adjustments						
Prior-year Adjustment[2]		3				
Exclude Brampton[3]		(15)				
MOF Provision Expense (after other adjustments)	**0**	**290**	**140**	**750**	**720**	**1,199**
Cumulative Shortfall Adjustment						
Opening Balance	0	0	0	0	0	0
Deduction / (Addition)	0	0	0	0	0	0
Ending Balance	0	0	0	0	0	0
Dedicated Electricity Earnings (all adjustments) (Public Accounts)	**0**	**290**	**140**	**750**	**720**	**1,199**
Electricity Sector Dedicated Income (OEFC Annual Report)	**3**	**302**	**140**			

Notes:

1. The Hydro One financials above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering are currently reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

2. 2016-17 Adjustment was due to the discrepancy between the numbers in MOF expense in PA 2015-16 and OEFC Financials in 2015-16 due to timing issues. $3M adjustment rectifies this discrepancy

3. Brampton was excluded from the Ministry of Finance's ESDI allocation.

Ontario Power Generation

OPG Income - Budget 2017

$ Millions

	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
OPG Net Income After Tax (Adjusted)	291	304	97	732	625	1,066
OPG Net Income After Tax	*291*	*379*	*480*	*678*	*726*	*913*
Extraordinary Gains	-	-	-	-	-	-
GA - OPG Trust Interest Revenue			*17*	*54*	*99*	*153*
OPG IFRS consolidation risk picked up in Fiscal Plan		(75)	(400)		(200)	
ONFA and other Fair Value Adjustments	(75)	8				
ONFA Adjustments	-	8				
Other Fair Value Adjustments	(75)					

OPG PIL - Budget 2017

$ Millions

	Actual	Interim		Pl
	2015-16	2016-17	2017-18	2018-19
Net Income Before Tax	383	396	572	867
Net Income After Tax (Adjusted)	291	304	97	732
Income Taxes	92	92	92	135
GRC: Payable to OEFC	198	196	205	212
Proxy Property Tax	16	14	18	19
Ontario Capital Tax	0	0	0	0
Total	**306**	**302**	**315**	**366**

OPG Income - October 2017

$ Millions

	Actual	Actual	Current Outlook			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
OPG Net Income	291	377	818	678	726	913
Adjustment for OPG HQ gain on sale[1]			(283)			
Extraordinary Gains	0	0	0	0	0	0
GA Financing - OPG Trust Interest Revenue[2]			12	42	82	128
OPG IFRS consolidation risk reflected in Fiscal Plan[3]		(78.00)	(400)		(200)	
OPG Net Income (Adjusted before ONFA)	**291**	**299**	**147**	**720**	**608**	**1,041**
ONFA Adjustments	247	49				
Other Fair Value Adjustments	(75)	(6)				
ONFA and other Fair Value Adjustments	**172**	**43**				
OPG Net Income	**463**	**342**	**147**	**720**	**608**	**1,041**

1. As part of Asset Optimization Plan the projected proceeds are currently reported in OEP/MoF Sales and Rentals line. To be re-categorized after the transaction is completed and in coordination with OEP and SIFB.
2. This reflects interest earnings on GA financing costs which are consolidated back to Province
3. See Risks tab for IFRS impacts that were not reflected in Fiscal Plan, and table below.

	2017-18	2018-19	2019-20	2020-21
OPG IFRS Risk	(400)	(475)	(700)	(750)

OPG PIL - August 2017

$ Millions

	Actual	Actual		Current
	2015-16	2016-17	2017-18	2018-19
Income Before Tax	383	308	684	855
OPG Net Income (Adjusted before ONFA)	291	299	147	720
OPG Income Tax (PILs)	92	9	162	135
Tax adjustment for OPG HQ gain on sale[1]			(95)	
GRC: Payable to OEFC	198	201	214	224
Proxy Property Tax to OEFC	16	14	18	19
Ontario Capital Tax	0	0	0	0
Total OPG PILs	**306**	**224**	**299**	**378**

Hydro One Net Income and PILs

Hydro One Income - Budget 2017
($ millions)

	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Hydro One Net Income After Tax	685	737	742	802	862	931
Hydro One - Unrealized Gains Adjustment						

2016-17 to 2020-21 from CEFD Hydro One 2016 model.

Hydro One PIL - Budget 2017
($ millions)

	2015-16	2016-17	2017-18	2018-19
Net Income After Tax	685	737	742	802
Income Taxes PILs	132	160	181	205
Proxy Property Tax	2	2	2	2
Ontario Capital Tax	0	0	0	0
Total	**134**	**162**	**183**	**207**

Hydro One Income - October 2017
($ millions) **$ Millions**

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Hydro One Net Income After Tax			623	666	753	818
Debenture Costs Impacts (After Tax)			(34)	(39)		
Hydro One Net Income After Tax - Including Adjustments	670	680	589	627	753	818
Hydro One - Net Income Attributable to Preferred Shareholders	15	18				
Hydro One - Unrealized Gains Adjustment						

Hydro One (100% Ownership)
($ millions) **$ Millions**

	Actual 2015-16	Actual 2016-17	Current 2017-18	2018-19
Net Income After Tax - Common Shares	670	680	589	627
Net Income After Tax - Preferred Shares	15	18		
Income Taxes PILs	132	160	181	205
Proxy Property Tax	2	2	2	2
Ontario Capital Tax	0	0	0	0

Hydro One Ownership Calculation:		SOURCE:
Total number of shares outstanding[1]	595,000,000	1. Hydro One Ltd Annual Report 2015, pg 94 of PDF, pg 92 of the Report.
IPO November 2015		
Initial Public Offering(2015)[2]	81,100,000	2. From news release: http://hydroone.mediaroom.com/2015-11-05-Hydro-One-Limited-Announces-Closing-of-IPO
Over allotment option (2015)[3]	8,150,000	3. From news release: http://hydroone.mediaroom.com/2015-11-12-Hydro-One-Limited-Announces-Closing-of-IPO-Over-Allotment-Option
Sales to PWU/SEP Trusts	5,646,340	
Total	94,896,340	
Province's remaining ownership, Nov 2015 (# Shares)	**500,103,660**	
Province's remaining ownership, Nov 2015 (%)	**84.05%**	
Secondary Offering April 2016		
Secondary Offering (2016)	72,434,800	4. Hydro One Ltd. Q2 Report, pg 1 http://www.hydroone.com/InvestorRelations/FinancialReporting/Documents/Hydro%20One%20Ltd%20Second%20Qu
Over allotment option (2016)	10,865,200	
Total	83,300,000	
Province's remaining ownership, Apr 2016 (# Shares)	**416,803,660**	
Province's remaining ownership, Apr 2016 (%)	**70.05%**	
Final Offering May 2017		
Final Offering (2017)	120,000,000	Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by
Over allotment option (2017)	-	Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by
Total	120,000,000	
Province's remaining ownership, May 8, 2017 (# Shares)	296,803,660	Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by
Province's remaining ownership, May 8, 2017 (%)	**49.88%**	
First Nations Sale, Assumed closing for December 31, 2017	14,875,000	
	2.5%	Source: https://news.ontario.ca/mei/en/2017/05/ontario-raises-28-billion-from-final-hydro-one-share-offering.html
Province's remaining onwership - post First Nations Sale (#Shares)	281,928,660	
Province's remaining onwership - post First Nations Sale (%)	**47.38%**	
Avista Impact (projected closing date 2nd half of 2018)		
Contingent Convertible Debenture	$1,540,000,000	
Conversion Price	$21	
Potential Dilution (# Shares)	71,962,617	
Revised Total number of shares outstanding	**666,962,617**	
Province's remaining onwership - post Avista Acquisition (#Shares)	281,928,660	
Province's remaining onwership - post Avista Aquisition (%)	**42.27%**	

Ownership Percentage in 2017-18 Fiscal Year	Number of Months	Percentage of Year
70.05%	1	8.3%
49.88%	8	66.7%
47.38%	3	25.0%
	12	
Average 2017-18 FY Ownership:	**50.9%**	

Ownership Percentage in 2018-19 Fiscal Year (assume Avista closing end of September 2018)	Number of Months	Percentage of Year
47.38%	6	50.0%
42.27%	6	50.0%
	12	
Average 2018-19 FY Ownership:	**44.8%**	

Ownership Percentage in 2019-20 Fiscal Year Onwards
42.27%

Accretive to earnings per share and cash flow for Hydro One in the first full year post closing
above is from Hydro One transaction overview. Check what this means for timing of additional shares and /or earnings.

ıarter%202016%20Results.pdf

-the-Province-of-Ontario
-the-Province-of-Ontario

-the-Province-of-Ontario

Public Debt Interest and Section 50.3 payments

$ Millions	Actual 2015-16	Actual 2016-17	2017-18
Hydro One Public Debt Interest and Section 50.3 payments			
Government Annual Interest Costs - Hydro One	220	220	220
Reduction in Interest Costs due to Broadening[1]		(29)	(66)
Province Annual Interest Costs - Hydro One Debt	**220**	**191**	**154**
Province Annual Interest Cost - OPG Debt	300	300	300
Total Public Debt Interest	**520**	**514**	**454**

$ Millions	Actual 2015-16	Actual 2016-17	2017-18
Gain to OEFC under s. 50.3	172	411	550

1. The Hydro One reduction in interest costs above currently reflects a 70.5% Provincial share allocation as of the secondary offering in Apr
the last Hydro One offering are currently reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the P

Current Outlook		
2018-19	2019-20	2020-21
220	220	220
(66)	(66)	(66)
154	**154**	**154**
300	300	300
454	**454**	**454**

ID# (Track Cha	Fiscal Year	alue (Hardcode
20170501-2	2016-17	411,152,733
20170501-3	2016-17	29
20170501-3	2017-18	66
20170501-3	n/a	220

Current Outlook		
2018-19	2019-20	2020-21
0	0	0

ID# (Track Cha	Fiscal Year	alue (Hardcode
n/a	n/a	5126
n/a	n/a	5.85%
		299.871

ril 2016. Net estimated fiscal impacts related to
Provinces Revenue outlook.

OPG's Annual Interest Costs:

20170713-1	2016-17	-513,768,361

Value (Linked)	Description	Source Details	Source (Link)
411,152,733	s 50.3 Gain for	Calculation provided by SIFB	
29	Reduction in Int	Internal Calculation	
66	Reduction in Int	Internal Calculation	
220	Annual Interest	Internal Calculation	

Value (Linked)	Description	Source Details	Source (Link)
	($M) Provinces	OEFC 1999-2000 FS, pg 24	
	Annual Interest	OEFC 1999-2000 FS, pg 26	

300

Provincial interest cost for equity investment in OPG, H1 in 2016-17
Monthly Balances Sheet (from FTD)
S:\Users\CEF\Hydro 2017\OEFC\RbP\Outlook\07. July\Backup\20170713-1\interest from Province.pdf

PROVINCIAL CONSOLIDATION ADJUSTMENTS
Ontario Nuclear Funds Agreement

Adjustment for Change in OPG Reported Net Income

Adjustment for DSF Unrealized Earnings

Unrealized Earnings as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Bruce Variance Account Adjustment
OPG Net Income Adjustment

Adjustment for UFSF Unrealized Earnings

Unrealized Earnings as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Bruce Variance Account Adjustment
OPG Net Income Adjustment

Unrealized Earnings -- Fiscal YTD

Adjustment for Change in Due to Province

Adjustment for DSF Due to Province
Due to Province (cost basis) as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Change in Due to Province -- Fiscal YTD

Adjustment for UFSF Due to Province

Due to Province (cost basis) as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Change in Due to Province -- Fiscal YTD

Provincial Consolidation Adjustment

Other Data

	Actual 2016-17	2017-18
Debt Retirement Charge	621	0

	2016-17	2017-18
Power Supply Contract Recoveries	838	292

	2016-17	2017-18
Interest		
OPG	167	169
IESO	2	3
Other (Net)	20	20
Expense		
Debt interest	1216	1121

	Actual 2016-17	2017-18
MEU - PIL Income Tax	109.8	
MEU - PIL Property Tax	0.6	
MEU - GRC	1.2	
TOTAL MEU PILs	111.6	

	Actual 2016-17	2017-18
Miscellaneous/Other (OEFC FS)	14	
Demand Management Support Costs (IEI)	8	10
Operating [Expense]	7	6
Interest on nuclear risk funding	-	-
Amortization of deferred debt costs	-	-
Amortization of NUG liability	129	74
Debt Guarantee Fee	122	

Expense (Electrictiy Summary Tab)		
Other (Finance)	-7	-6
Demand Management Support Costs (IEI)	-8	-10
Debt Guarantee Fee	(122)	

Plan		
2018-19	2019-20	2020-21
0	0	0

Plan		
2018-19	2019-20	2020-21
325	301	273

Plan		
2018-19	2019-20	2020-21
179	175	148
3	3	3
20	10	10
1094	1053	963

Plan		
2018-19	2019-20	2020-21

Plan		
2018-19	2019-20	2020-21
6	6	6
-	-	-
-	-	-
41	30	28
-6	-6	-6

ID# (Track Changes	Fiscal Year	Value (Hardcoded)	Value (Linked)
20170510-2	2016-17	$ 739,216,115	
20170510-2	2017-18	$ 291,629,707	
20170510-2	2018-19	$ 324,906,017	
20170510-2	2019-20	$ 300,648,570	
20170510-2	2020-21	$ 273,240,858	
20170501-4	2016-17	179	179
20170501-4	2017-18	169	169
20170501-4	2018-19	179	179
20170501-4	2019-20	175	175
20170501-4	2020-21	148	148
20170501-5	2016-17	1216	1,216
20170501-5	2017-18	1121	1,121
20170501-5	2018-19	1094	1,094
20170501-5	2019-20	1053	1,053
20170501-5	2020-21	963	963
20170731-3	2016-17	621	
20170811-1	2016-17	109.8	
20170811-1	2016-17	0.6	
20170811-1	2016-17	1.2	
20170815-5	2016-17	$ 838,000,000	
20170815-6	2016-17	$ 14,000,000	
20170815-8	2016-17	8	
20170815-9	2017-18	10	
20170815-10	2016-17	7	
20170815-10	2017-18	6	
20170815-10	2018-19	6	
20170815-10	2019-20	6	
20170815-10	2020-21	6	
20170815-7	2016-17	167	
20170815-7	2016-17	2	
20170815-7	2016-17	20	
20170815-7			

ID# (Track Changes	Fiscal Year	Value (Hardcoded)	Value (Linked)
20170905-1	2016-17	129	129
20170905-1	2017-18	74	74

20170905-1	2018-19	41	41
20170905-1	2019-20	30	30
20170905-1	2020-21	28	28
20170905-2	2016-17	122	
20170906-1	2017-18	3	3
20170906-1	2018-19	3	3
20170906-1	2019-20	3	3
20170906-1	2020-21	3	3
20170906-1	2017-18	20	5
20170906-1	2018-19	20	5
20170906-1	2019-20	10	5
20170906-1	2020-21	10	5

Description	Source Details	Source (Link)
The table below contains an updated preliminary N	SPFB Estimates, Email	
• The tables below provides both last year's submission for NUG costs by CEFD and this year's estimates (both of which exclude HST) based on the most recent NUG model.	SPFB Estimates, BN SPFB Estimates, BN SPFB Estimates, BN SPFB Estimates, BN	
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
Updating DRC from OEFC AR (Drafts)	2017 OEFC DRAFT FS	S:\Users\CEF\Hydro 2017\OEFC'
MEU - PIL Income Tax	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
MEU - PIL Property Tax	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
MEU - GRC	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
Updating to actuals	2017 OEFC AR	2017 OEFC Annual Report - Eng
Updating to actuals	2017 OEFC AR	2017 OEFC Annual Report - Eng
Updating to Actuals	2017 OEFC AR	S:\Users\CEF\Hydro 2017\OEFC'
OEFC 2017-18 IEI/Demand Management Suppor	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Operating Expense - Updating to Actuals	2017 OEFC AR	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Operating Expense - No source available. Just brought the information to this tab.		
OPG Interest Revenue - Actuals 2016-17	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
IESO Interest Revenue - Actuals 2016-17		
Other (Net) Interest Revenue - Actuals 2016-17		

Description	Source Details	Source (Link)
		S:\Users\CEF\Hydro 2017\OEFC'
	Amortization Schedule.	S:\Users\CEF\Hydro 2017\OEFC'

Sourcing the NUG liability amortization schedule.	Tab: Summary Fiscal Impact	S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Gurantee Fee - Updating to Actuals	2017 OEFC AR (pg 13 (	\\ofina.on.ca\ofadfs\Users\CEF\H
IESO Interest Revenue Plan	OEFC Revenue Forecast for Board - April 2017	\\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H
Other Interest Revenue Plan		\\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H

\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
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\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board

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\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board

\RbP\Outlook\07. July\Backup\20170731-3 - DRC Update\2017 OEFC Annual Report - English - DRAFT.PDF

\RbP\Outlook\08. August\Backup\20170811-1 - Updating PILs for 2016-17\OEFC 2016-17 Pils summary.pdf
\RbP\Outlook\08. August\Backup\20170811-1 - Updating PILs for 2016-17\OEFC 2016-17 Pils summary.pdf
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\RbP\Outlook\08. August\Backup\20170815-8 - 2016-17 Demand Management Support Costs (IEI)\2017 OEFC
\RbP\Outlook\08. August\Backup\20170815-9 - 2017-18 Demand Management Support Costs (IEI)\OEFC rever
\RbP\Outlook\08. August\Backup\20170815-10 - 2016-17 Operating (Expense)\2017 OEFC Annual Report - Enc

\RbP\Outlook\08. August\Backup\20170815-7 - 2016-17 Updated Interest on Debt Revenue\RE Revised OEFC

\RbP\Outlook\09. September\Backup\20170905-1 - Amortization of NUG Liability\NUG liability_estimated draw c
\RbP\Outlook\09. September\Backup\20170905-1 - Amortization of NUG Liability\NUG liability_estimated draw c

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\RbP\Outlook\09. September\Backup\20170905-1 - Amortization of NUG Liability\NUG liability_estimated draw c
\RbP\Outlook\09. September\Backup\20170905-1 - Amortization of NUG Liability\NUG liability_estimated draw c

ydro 2017\OEFC\RbP\Outlook\09. September\Backup\20170905-2 - 2016-17 Debt Guarantee Fee\2017 OEFC
ydro 2017\OEFC\RbP\Outlook\09. September\Backup\20170906-1 - OEFC Revenue Forecast for Board
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Debt Interest Cost.msg

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down_Mar15_if apply Jan1_Apr21.xls

down_Mar15_if apply Jan1_Apr21.xls
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down_Mar15_if apply Jan1_Apr21.xls

Annual Report - English.pdf

Colour Codes

Formulas are in black text

Hard coded numbers are in blue text

References elsewhere are in purple

Green bold text with or without highlights mean updates required

Policies to follow when making updates to the Outlook

*** To quickly jump to the source numbers for a link, press "**Ctrl + [**"

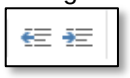
All new numbers must be fully sourced, and follow the colour codes above

Most numbers and text are Arial Size 10, unless it is a title

Add back up materials in a folder with the same numbers as in the 'Track Changes' tab

If there is a reason for italics, or other colours, or formatting make sure it is clear. Othe

Use indents to make things more clear to read



If numbers are taken from another tab they should ONLY be direct links, no calculation

Electricity Summary - (Budget17/On Deck) - Reflects Public Accounts/Financial Statem

OEFC - (Budget17/On Deck) - Reflects OEFC Annual Reports

*Due to slight discrepancies between Public Accounts reporting and OEFC Annual Rep

Outlook Updates Frequency

Frequency	Description	Tab
Monthly	OPG Net Income in-year forecast	OPG
Monthly	OPG PILs in-year forecast	OPG
Quarterly	ONFA Consolidation Adjustment	ONFA
Quarterly	OPG Cash vs Accrual Variance Account	Revenue (Risks)

ɔ.
rwise expect it to be cleared

ı, adjustment should be done. Even if its just making a negative to a positive. Perform all the calculations on the

ıents

ɔorts, the numbers may not be identical

source tab then bring the number into the next tab. (Eg. Formulas like this become hard to troubleshoot ='Hydro

One'!AR29+'Hydro One'!AR31+'Hydro One'!AR32), let's avoid them.

From:	Bruno Amara
To:	Ronald Kwan
Cc:	John Kim; Shajee Kathirgamanathan
Subject:	RE: Revised Electricity Outlook
Date:	Friday, October 20, 2017 4:25:10 PM

OK Thanks

From: Ronald Kwan
Sent: Friday, October 20, 2017 4:21 PM
To: Bruno Amara <Bruno.Amara@ofina.on.ca>
Cc: John Kim <John.Kim@ofina.on.ca>; Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>
Subject: RE: Revised Electricity Outlook

Thanks Bruno.

Please circulate it and get feedback from the various recipients / users.

Ron

From: Bruno Amara
Sent: October-20-17 16:10
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: John Kim <John.Kim@ofina.on.ca>; Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>
Subject: RE: Revised Electricity Outlook

Hi Ron

Thanks for your comments and please see the revised Outlook in response.

We have:

1. adjusted the Hydro One deferred tax benefit risk to reflect 50%. In the same vein we added an adjusted to Hydro One net income to reflect the OEB decision impacts at 50%. Footnotes added for both.
2. Added a positive risk for the H1 Motion to Review. The Motion challenge OEB ruling with the exception of the cap ex ruling.
2. added an estimate for 50.3 for 2017-18 to OEFC On Deck.
    - In regard to 50.3 amounts we are proposing discussing with our Frost colleagues adding in the offsetting expense entry to our Outlook for completeness. I suggested waiting until this discussion to avoid any confusion or changes to the cover sheet (and Summary-ON Deck tab) from what they last saw.
3. Revised the OEFC – Budget to correspond to what OEFC was assuming as of budget.
4. Added footnote as necessary where Hydro One proportionate numbers appear.

5. Updated OPG FHP Trust interest revenue based on revisions from FTD.

For any distribution outside of EFB, we would delete the “Track Changes” worksheet and the “H1 Provincial Allocations” worksheet.

Bruno

From: Ronald Kwan
Sent: Thursday, October 19, 2017 7:05 PM
To: Bruno Amara <Bruno.Amara@ofina.on.ca>
Cc: John Kim <John.Kim@ofina.on.ca>
Subject: Re: Revised Electricity Outlook

Hi Bruno,

I thought we discussed making an adjustment to the Hydro One deferred tax benefit upfront hit risk to be scaled at a proportionate 50%. It could be footnoted as done this way vs the 70% assumption used for H1 generally, pending the recategorisation from the AO sales and rentals outlook. (As an aside, would it be fair to say that the incremental risk is also less than what is shown because built into the update is the annual impact of the deferred tax benefit decision of the OEB? In that light, for symmetry, should there be a positive risk shown for H1 should it be successful in its OEB Motion to Review?

Also, why not put into the OEFC tab an estimated s.50.3 amount for 17-18?

Also, why does the Budget 2017 tab for OEFC show an excess of revenue over expense of about $0.7bn. I thought it was about $1.1 bn at the time of Budget. You may need to add to the ESDI formula to reverse the IFRS assumption in the OEFC Budget tab -- and then putting in the 50.3 amount in the OEFC on-deck tab would more than offset that (for now, pending other updates, such as for H1).

Also, for clarity, on each worksheet where Hydro One proportionate numbers appear, please add a footnote on that row, as some people may just go to one work sheet, or print one worksheet (and has each worksheet been formatted for easy printing -- can help multiple users and down the line). This includes the Provision worksheet, where I assume the financing cost for the Hydro One row is based on the 70%, but will go down to under 50% ultimately.

On the OPG FHP Trust interest revenue, is that scaled to the new equity injection projections supplied to FTD so it would match the IOD side? Are we aligned to match FTD's IOD assumptions for borrowing for the equity injection?

Thanks,

Ron

From: Bruno Amara
Sent: October 19, 2017 3:54 PM
To: Ronald Kwan
Cc: John Kim
Subject: Revised Electricity Outlook

Hi Ron

Attached is the revised Electricity Sector Outlook (document pw). I want to point out one change on the risk page in particular. In the version we walked you through, I had included an OPG risks reflecting head office sales (currently in Sales and rentals) and the in–year update. You had asked about Lakeview which could have a similar note. Hydro One unpacking could also be included and other reclassification impacts e.g., revenue impact related to IOD savings current in AO numbers. I think that all this may be better handled through the AO unpacking/updating analysis that we worked on with SIFB. When we send the Outlook to our Frost colleagues, we were planning to set up a staff level meeting between EFB, OB, OEP and TBS to review the Outlook and answer questions. We could as an option also use this meeting to review the AO unpacking/updating analysis at the same time if that makes sense. That isn't needed for FES, but may be worth getting people familiar with it now.

Also attached is a draft of some follow-up for OPG in regard to their September monthly report per our discussion.

Bruno

Bruno Amara
Sr. Manager, Financial and Regulatory Analysis
Electricity Finance Branch
Corporate and Electricity Finance Division
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Tel: 416-325-1489
Email: bruno.amara@ofina.on.ca

From:	Ronald Kwan
To:	John Kim
Subject:	RE: Revised Outlook
Date:	Thursday, January 04, 2018 4:22:13 PM
Attachments:	Electricity Sector Outlook (2018 01 04)_reverse unpacking_Markup.xlsm

Hi John,

Some comments and edits, primarily to the footnotes on various tabs. It might also be good to add some of the key footnotes to the cover sheet.

One key query is if all the OPG OEB decision impact is shown on the net income line. Does that overstate the impact on ESDI and what the PRRT request would be? Should we be more cautious, and show, say a split of the OEB impact between net income and PILs at a statutory rate? And should we note that the OPG 2018 multi-year business plan has not yet been received, so estimated impacts are preliminary and expected to be updated.

Ron

From: John Kim
Sent: January-04-18 3:59 PM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Subject: RE: Revised Outlook

Hi Ron,

It usually gets well into February when they are able to provide the NUG line. I can ask them but I believe next week's FPC is the first cut at updating so it would be good to submit today even without updated NUGs.

Thanks,

John

From: Ronald Kwan
Sent: Thursday, January 04, 2018 3:56 PM
To: John Kim <John.Kim@ofina.on.ca>
Subject: RE: Revised Outlook

Hi John,

Hasn't SPFB been working on updating the NUG expense and recovery lines?

Ron

From: John Kim
Sent: January-04-18 3:08 PM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Subject: RE: Revised Outlook

Hi Ron,

Sure, we can note that in the covering email….would you be okay if we send?

Thanks,

John

From: Ronald Kwan
Sent: Thursday, January 04, 2018 3:03 PM
To: John Kim <John.Kim@ofina.on.ca>
Subject: Re: Revised Outlook

Hi,

On the covering email, should the pension and OPEB risk be shifted to the future, pending a future OEB decision on that?

Ron

On Jan 4, 2018, at 1:58 PM, John Kim <John.Kim@ofina.on.ca> wrote:

> Hi Ron,
>
> Pls. let me know if you have any comments.
>
> Thanks,
>
> John
>
> ---
>
> **From:** Bruno Amara
> **Sent:** Thursday, January 04, 2018 1:52 PM
> **To:** John Kim <John.Kim@ofina.on.ca>
> **Subject:** Revised Outlook
>
> John
>
> Please see attached. We are formatting the version to send out.
>
> Bruno

Attached is our Electricity update as of January 4, 2018. **Key changes** in the electricity outlook since our previous update include the following.

- The full projected IFRS adjustments are reflected in OPG's net income outlook lowering OPG net income by $475M in 2018-19, $500M in 2019-20 and $750M in 2020-21
- The estimated impact of OEB's Dec. 28, 2017 decision on OPG's rate application is reflected in the Outlook
- Other OPG updates for 2017-18 include moving the positive projected ONFA adjustment (+$171m) into the OPG forecast rather than reflecting as "risk" and reflecting Other positive in-year updates.
- Eliminating some material OPG "reporting" risks (pension and nuclear liability) as a result of OEB's December decision.
- Based on PRRT approval in principal, current update assumes ESDI continues beyond 2017-18. No bottom line impact, but does affect
- The negative impact of the OEB tax decision (about $15M per year) with respect to Hydro One's transmission rate application, which was reflected in the previous electricity outlook has been reversed pending decision on Hydro One's motion to review and appeal. In addition, Hydro One clarified that if the OEB decision is upheld it would be reflected as a one-time write-down rather than an ongoing annual impact. This risk is reflected in the Risk table in the "Revenue (Risks)" tab.
- Other minor updates.

Note. This Electricity Outlook does not reflect re-categorization of Asset Optimization impacts. CEFD will work with OB and OEP to re-categorize these impacts. Re-categorization ~~will be largely~~ is fiscally-neutral.

There is still **information to come** that could change the outlook before the Document. Key information to come includes the following

- OPG's 2018-2020 Business Plan (expected in February) could change OPG's outlook.
- OEB decision on Hydro One's distribution rate application (expected 1st half of 2018)
- Year-end results for OPG and Hydro One
- Monthly results for OPG
- Final ONFA adjustment result for 2017 (late January or February)
- Final Decision on PRRT submission to continue ESDI payments to OEFC beyond 2017-18 (currently approved in principle)
- Final net proceeds from the sale of the Lakeview lands (expected close in March 2018)

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<Electricity Sector Outlook (2018 01 04)_reverse unpacking.xlsm>

Electricity Sector Outlook
October 2017

Disclosure:

All information contained in this workbook is confidential and commercially sensitive

All projected numbers are estimates and subjected to change

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Electricity Sector Outlook
Including Line Items for Consolidation

Electricity Summary - On Deck

			MOF Expense Items (consolidated)	Current Outlook			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**38**	Power Supply Contract Costs	(292)	(325)	(301)	(273)
Expense	**MOF (OEFC)**	**40**	Demand Management Support Costs	(10)	-	-	-
Expense	**MOF (OEFC)**	**41**	Provision for Electricity Sector	-	14	103	312
Expense	**MOF**	**17**	Provision for Electricity Sector	-	(14)	(103)	(312)
Expense	**MOF (OEFC)**	**42**	Other (Finance)	(6)	(7)	(7)	(7)
			Total MOF Expense	**(308)**	**(332)**	**(308)**	**(280)**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**7**	OPG Income	(134)	137	(7)	156
Revenue	**ENE**	**8**	OPG - ONFA and other Fair Value Adjustments	171	-	-	-
Revenue	**ENE**	**10**	HOI Income	446	474	564	610
Revenue		**11**	Brampton Income	-	-	-	-
Revenue	**MOF (OEFC)**	**26**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	282	452	503	635
Revenue	**MOF (OEFC)**	**29**	Electricity Debt Retirement Charge	623	-	-	-
Revenue	**MOF (OEFC)**	**30**	Power Supply Contract Recoveries	292	325	301	273
Revenue	**MOF (OEFC)**	**31**	Net Reduction of Power Purchase Contracts	74	41	30	28
Revenue	**MOF (OEFC)**	**34**	Miscellaneous	-	-	-	-
			Total MOF Revenue	**1,755**	**1,428**	**1,391**	**1,702**
			OFA IOD Expense				
			Public Debt Interest - Electricity Sector	(454)	(454)	(454)	(454)
			Interest on Debt	(475)	(438)	(411)	(348)
			Total OFA IOD Expense	**(929)**	**(892)**	**(865)**	**(802)**
			Impact on Surplus/Deficit	**518**	**204**	**219**	**620**
			check	**-**	**-**	**-**	**-**

Electricity Summary - Budget 17

	For Discussion		MOF Expense Items (consolidated)	Plan			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**38**	Power Supply Contract Costs	(292)	(325)	(301)	(273)
Expense	**MOF (OEFC)**	**40**	Demand Management Support Costs	(10)	0	0	0
Expense	**MOF (OEFC)**	**41**	Provision for Electricity Sector	125	0	0	0
Expense	**MOF**	**17**	Provision for Electricity Sector	(125)	0	0	0
Expense	**MOF (OEFC)**	**42**	Other (Finance)	(6)	(6)	(6)	(6)
			Total MOF Expense	**(308)**	**(331)**	**(307)**	**(279)**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**7**	OPG Income	97	732	625	1,066
Revenue	**ENE**	**8**	OPG - ONFA and other Fair Value Adjustments	0	0	0	0
Revenue	**ENE**	**10**	HOI Income	520	562	603	652
			Brampton Income				
Revenue	**MOF (OEFC)**	**25**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	405	476	538	679
Revenue	**MOF (OEFC)**	**29**	Electricity Debt Retirement Charge	623	0	0	0
Revenue	**MOF (OEFC)**	**30**	Power Supply Contract Recoveries	292	325	301	273
Revenue	**MOF (OEFC)**	**31**	Net Reduction of Power Purchase Contracts	74	41	30	28
Revenue	**MOF (OEFC)**	**34**	Miscellaneous	0	0	0	0
			Total MOF Revenue	**2,011**	**2,136**	**2,098**	**2,697**
			OFA IOD Expense				
		17	Public Debt Interest - Electricity Sector	(492)	(492)	(492)	(492)
		36	Interest on Debt	(422)	(374)	(342)	(250)
			Total OFA IOD Expense	**(914)**	**(866)**	**(834)**	**(742)**
			Impact on Surplus/Deficit	**789**	**939**	**957**	**1,676**
			check	**-**	**-**	**-**	**-**

Electricity Summary - Change

			MOF Expense Items (consolidated)	Variance from Plan			
Type	**Ministry Pickup**	**Line**	**Item**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
Expense	**MOF (OEFC)**	**69**	Power Supply Contract Costs	0	0	0	(0)
Expense	**MOF (OEFC)**	**71**	Demand Management Support Costs	0	0	0	0
Expense	**MOF (OEFC)**	**72**	Provision for Electricity Sector	(125)	14	103	312
Expense	**MOF**	**48**	Provision for Electricity Sector	125	(14)	(103)	(312)
Expense	**MOF (OEFC)**	**73**	Other (Finance)	0	(1)	(1)	(1)
			Total MOF Expense	**0**	**(1)**	**(1)**	**(1)**
			MOF Revenue Items (consolidated)				
Revenue	**ENE**	**38**	OPG Income	(231)	(596)	(632)	(909)
Revenue	**ENE**	**39**	OPG - ONFA and other Fair Value Adjustments	171	0	0	0
Revenue	**ENE**	**41**	HOI Income	(73)	(88)	(39)	(42)
			Brampton Income	0	0	0	0
Revenue	**MOF (OEFC)**	**25**	Electricity Payments-in-Lieu of Taxes (PILs), including CIT	(123)	(24)	(35)	(43)
Revenue	**MOF (OEFC)**	**60**	Electricity Debt Retirement Charge	0	0	0	0
Revenue	**MOF (OEFC)**	**61**	Power Supply Contract Recoveries	(0)	(0)	(0)	0
Revenue	**MOF (OEFC)**	**62**	Net Reduction of Power Purchase Contracts	(0)	(0)	(0)	(0)
Revenue	**MOF (OEFC)**	**65**	Miscellaneous	0	0	0	0
			Total MOF Revenue	**(256)**	**(708)**	**(706)**	**(994)**
			OFA IOD Expense				
		17	Public Debt Interest - Electricity Sector	38	38	38	38
		36	Interest on Debt	(53)	(64)	(69)	(98)
			Total OFA IOD Expense	**(15)**	**(26)**	**(31)**	**(60)**
			Impact on Surplus/Deficit	**(271)**	**(735)**	**(738)**	**(1,056)**
			check	**-**	**-**	**-**	**-**

Track Changes in Surplus/Deficit

Date	Change ID#	Source	Tab
5/1/2017	20170501-1	Link	ONFA
5/1/2017	20170501-2	Link	Hydro One
5/1/2017	20170501-3	Link	Hydro One
5/1/2017	20170501-4	Link	Other Data
5/2/2017	20170502-1	Link	OPG
5/9/2017	20170509-1	Link	OPG
5/10/2017	20170510-1	Link	Hydro One
5/10/2017	20170510-2	Link	Other Data
5/12/2017	20170512-1	Link	Hydro One
5/15/2017	20170515-1	Link?	
5/15/2017	20170515-2	Link	OPG
5/17/2017	20170517-1	Link	Hydro One
5/17/2017	20170517-2	Link	ONFA
5/17/2017	20170517-3		
5/18/2017	20170518-1	Link	OPG
5/18/2017	20170518-2	Link	OPG
5/18/2017	20170518-3		
6/15/2017	20170615-1	Link	OPG
6/22/2017	20170622-1	Link	Hydro One
6/22/2017	20170622-2	Link	Hydro One
6/26/2017	20170626-1		
6/29/2017	20170629-1		

7/6/2017	20170706-1		
7/11/2017	20170711-1		
7/13/2017	20170713-1	Link	Provision
7/17/2017	20170717-1	Link	Revenue (Risks)
7/24/2017	20170724-1	Link	Revenue (Risks)
7/25/2017	20170725-1	Link	Revenue (Risks)
7/26/2017	20170726-1	Link	Revenue (Risks)
7/27/2017	20170727-1	Link	Revenue (Risks)
7/27/2017	20170727-2	Link	Revenue (Risks)
7/31/2017	20170731-1		
7/31/2017	20170731-2	Link	Hydro One
7/31/2017	20170731-3	Link	Other Data
8/11/2017	20170811-1	Link	OPG
8/15/2017	20170815-1		
8/15/2017	20170815-2		
8/15/2017	20170815-3		
8/15/2017	20170815-4		
8/15/2017	20170815-5		Other Data
8/15/2017	20170815-6		Other Data
8/15/2017	20170815-7		Other Data
8/15/2017	20170815-8		Other Data
8/15/2017	20170815-9		Other Data
8/15/2017	20170815-10		Other Data
8/17/2017	20170817-1	Link	Provision
8/17/2017	20170817-2	Link	Hydro One
8/18/2017	20170818-1	Link	Revenue (Risks)
8/22/2017	20170822-1	Link	OPG
8/25/2017	20170825-1		Hydro One
8/29/2017	20170829-1		Revenue (Risks)
8/31/2017	20170831-1		Revenue (Risks)
9/5/2017	20170905-1		Other Data
9/5/2017	20170905-2		Other Data
9/5/2017	20170905-3	Link	OPG

9/6/2017	20170906-1	Link	Other Data
9/6/2017	20170906-2	Link	Revenue (Risks)
9/8/2017	20170908-1	Link	Hydro One
9/8/2017	20170908-2	Link	OPG
9/11/2017			
9/12/2017			
9/13/2017			
9/21/2017			
9/22/2017			
10/2/2017			Hydro One
10/2/2017			
10/2/2017			
10/2/2017			
10/4/2017	20171004-1		OPG
10/4/2017	20171004-2		OPG
10/4/2017			
10/4/2017			
10/5/2017			
10/6/2017			
10/7/2017			
10/8/2017			
10/10/2017	20171010-1		Hydro One
10/10/2017			
10/10/2017			
10/11/2017	20171011-1		OPG
10/11/2017			
10/11/2017			
10/12/2017			OPG
10/12/2017			
10/12/2017			
10/12/2017			
10/18/2017	20171018-1		Hydro One
10/18/2017	20171018-1		Hydro One
10/18/2017	20171018-1		Hydro One
10/19/2017	20171019-1		Revenue (Risks)
10/19/2017	20171019-2		Revenue (Risks)
10/20/2017	20171020-1		Revenue (Risks)
10/20/2017	20171020-2		
10/20/2017	20171020-2		
10/20/2017	20171020-2		
10/20/2017	20171020-3		Revenue (Risks)
10/20/2017	20171020-4		OPG
10/20/2017	20171020-4		OPG
10/20/2017	20171020-4		OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017			OPG
11/14/2017	20171114-1		Hydro One

11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017	20171114-1	Hydro One
11/14/2017		Hydro One
11/14/2017		Hydro One
11/14/2017		Hydro One
11/30/2017	20171130-1	Revenue (Risks)
12/8/2017		Hydro One
12/11/2017	20171211-1	Other Data
12/11/2017	20171211-1	Other Data
12/22/2017	20171222-1	OPG
1/2/2018		Hydro One
1/2/2018		Hydro One
1/2/2018		Hydro One
1/2/2018	20180102-1	OPG
1/2/2018	20180102-1	OPG
1/2/2018	20180102-1	OPG
1/2/2018	20180102-2	OPG
1/2/2018	20180102-3	OPG
1/2/2018	20180102-3	Revenue (Risks)
1/2/2018	20180102-4	Revenue (Risks)
1/2/2018	20180102-5	Revenue (Risks)
1/2/2018	20180102-6	Revenue (Risks)
1/2/2018	20180102-7	Revenue (Risks)
1/2/2018	20180102-8	Revenue (Risks)
1/2/2018	20180102-9	OPG
1/2/2018	20180102-9	OPG
1/2/2018	20180102-9	OPG
1/2/2018	20180102-9	OPG
1/3/2018		OPG
1/3/2018		OPG
1/3/2018		OPG
1/3/2018		OPG
1/3/2018		Hydro One
1/3/2018		Hydro One
1/3/2018		Hydro One
1/4/2018	20180104-1	OPG
1/4/2018	20180104-1	OPG
1/4/2018	20180104-1	OPG
1/4/2018	20180104-1	OPG

FOR EFB USE ONLY

Budget 2017 Outlook
Current Outlook
Change Since Budget

Description of Update
ONFA Update as of March 31 2017
s. 50.3 Update for 2016-17
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Debt Interest
OPG IFRS Risk in 2019-20
Revised OPG 2016-17 Net Income
Revised OPG 2016-17 Net Income
Revised OPG 2016-17 Net Income
tech change: slight update to assumed Prov share 70.05% from 70%
tech change: slight update to assumed Prov share 70.05% from 70%
tech change: slight update to assumed Prov share 70.05% from 70%
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
Updating H1 2016-17 Net Income for ESDI
Updating H1 2016-17 Net Income for ESDI
Updating H1 2016-17 Net Income for ESDI
Power Purchase Supply
H1 Model Forecasts - No Fiscal Update Resaving Data
Update Budget 2017 Tabs to reflect fiscal plan
Update OPG forecasted PILS to reflect sources
Update H1 2016-17 CIT
Re-inputting ONFA updates
Updating H1 Net Income to include Pref Shares in 16-17
Updating OPG Income Tax Expense for 2016-17
Updating OPG non-income tax PILs
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2017
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2018
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2019
Updating with actual OPG IFRS Adjustment 2016-17
Updating with actual OPG IFRS Adjustment 2016-17
Updating with actual OPG IFRS Adjustment 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
[NOT APPLIED] Updating H1 Brampton (Interim Adjustments)
Shifted H1 Brampton 2016-17 NI to the 2017-18
Removed H1 Brampton for 2016-17 (pending finals)
Removed H1 Brampton for 2016-17 (pending finals)
Removed H1 Brampton for 2016-17 (pending finals)

add prior-year adjustment for 2016-17

add prior-year adjustment for 2016-18
Reconfigured calculation of ESDI and MOF ESDI Expense
Reconfigured calculation of OPG 2017-18 Net Income
Backup for the Provincial Interest cost
Linking source for Revenue Risks Tab
New source for Revenue Risks Tab
Revenue Risks Tab - ROE Risks
Updating OEB Risk for OPG
OEB Staff Report - H1 Tx - Revenue Risks
OPG Pensions - Cash vs Accrual Deferral Accounts
Updating Links in Electricity Summary Change and OEFC Change
Preliminary estimate for Hydro One Brampton
Preliminary estimate for Hydro One Brampton
Preliminary estimate for Hydro One Brampton

Updating DRC for Actuals 2016-17 (Based on draft FS)
Updating PILs for 2016-17 Baced on Actuals
OPG: Non-ONFA Fair Value Adjustment
Round all Hydro One ownership assumptions to two decimal places
H1 Equity Adjustment rounding.
Round all Hydro One ownership assumptions to two decimal places
Round all Hydro One ownership assumptions to two decimal places
Revising source of ESDI, Dedicated Electricity Earnings
2016-17 - Update Power Supply Recoveries to actuals
2016-17 - Update Power Supply Recoveries to actuals
2016-17 - Updating Miscellaneous OEFC Revenue to Actuals
Adj: Exclude Bramton $15m add prior year adjustment +$3M
Adj: Exclude Bramton $15m add prior year adjustment +$3M
Public Accts: Updated IESO debt interest Interest On Debt, 2016-17
Public Accts: 2016-17 - Demand Management Support Costs Update
2017-18 - Demand Management Support Costs (no change)
Public Accts: 2016-17 - Updating Operating Expense in OEFC
Sourcing Provision for Electricity Sector from Actual Public Accounts
Revised 2016-17 Brampton Amount for Public Accounts
OPG Pensions - Cash vs Accrual Deferral Accounts (Revenue Risks Tab)
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
Reclassification
Reclassification
Reverting H1 Ownership change (undoing 20170518-3)
Reverting H1 Ownership change (undoing 20170518-3)
Reverting H1 Ownership change (undoing 20170518-3)
Updating Risks based on Hydro One Q2 Results Model
Avista Acquisition Risks
NUG Amortization Liability (sourcing amortization schedule)
2016-17 Actuals - Debt Guarantee Fee
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results

Interest Revenue for IESO and "Other"
OPG Revenue Risks from OEB Filings
Net income corrected for Preferred Shares
Net income corrected for Preferred Shares
Net income corrected for Preferred Shares
Made link edits to OPG sheet so that the "Net Income Before Tax" 2017-18 number is not a hardc
Updated PILs to include OPCD public accounts adjustment
Provision tab fix to pick up Hydro One preferred share net income
Provision tab fix to pick up Hydro One preferred share net income
FTD Update to OEFC Outlook (Sep 19, 2017) OPG Interest
FTD Update to OEFC Outlook (Sep 19, 2017) Other Interest
Update to Hydro One PILs from information in Transmission rate application material
OEB September 28, 2017 Hydro One decision and order impact - incl. rebasing
OEB September 28, 2017 Hydro One decision and order impact - incl. rebasing
OEB September 28, 2017 Hydro One decision and order impact - incl. rebasing
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Remove update of gain on sale of head office(assume in Sales and Rentals)
Debenture Interest Costs - Removing from Revenue (Risks) and adding it ot H1 Model
Debenture Interest Costs - Removing from Revenue (Risks) and adding it ot H1 Model
Debenture Interest Costs - Removing from Revenue (Risks) and adding it ot H1 Model
Updated OPG Net Income and PILs based on monthly report (August 2017 results)
Updated OPG Net Income and PILs based on monthly report (August 2017 results)
Updated OPG Net Income and PILs based on monthly report (August 2017 results)
Correction to PILs on OPG sheet
Correction to PILs on OPG sheet
Correction to PILs on OPG sheet
Correction to PILs on OPG sheet
Switch to Direct from Model
Switch to Direct from Model
Switch to Direct from Model
Updating ROE Risks
Updating H1 Load Risks based on model output
Updating ONFA Risks for September 2017
Adjust OEB decision/rebasing to ~50% provincial ownership
Adjust OEB decision/rebasing to ~50% provincial ownership
Adjust OEB decision/rebasing to ~50% provincial ownership
Updating OPG
OPG IOD impact from GA Financing, FHP
OPG IOD impact from GA Financing, FHP
OPG IOD impact from GA Financing, FHP
Unpacking updated OPG Gain on sale (net income)
Unpacking updated OPG Gain on sale (net income)
Unpacking updated OPG Gain on sale (net income)
Unpack PILs related to HQ gain on sale
Updating IFRS Risk
Adjustment for lower Provincial share (from 70.1% to 50.9 2017-18 & 47.4% after)
Adjustment for lower Provincial share (from 70.1% to 50.9 2017-18 & 47.4% after)
Adjustment for lower Provincial share (from 70.1% to 50.9 2017-18 & 47.4% after)
November 1 and November 7 Hydro One model updates

November 1 and November 7 Hydro One model updates
November 1 and November 7 Hydro One model updates
Revise Hydro Model to reverse OEB tax decision ongoing annual impact
Revise Hydro Model to reverse OEB tax decision ongoing annual impact
Revise Hydro Model to reverse OEB tax decision ongoing annual impact
Undo allocation adjustment in H1 tab (now that provincial shares are updated)
Undo allocation adjustment in H1 tab (now that provincial shares are updated)
Undo allocation adjustment in H1 tab (now that provincial shares are updated)
Updating OPG Revenue Risks from rate application
Update Hydro One PILs (reverses update on line 119 whuich did not account fro Dx side)
Updating Debt Guarantee Fee
Updating OEFC Operating Expense
small changes - linking the net income numbers

Updated number of shares sold for First Nations (Dec 2017) sale
Updated number of shares sold for First Nations (Dec 2017) sale
Updated number of shares sold for First Nations (Dec 2017) sale
Implemented OEB's Dec 2017 payment amounts decision for OPG (CEFD Analysis)
Implemented OEB's Dec 2017 payment amounts decision for OPG (CEFD Analysis)
Implemented OEB's Dec 2017 payment amounts decision for OPG (CEFD Analysis)
Updated OPG Net Income (based on their Q3 update, Sep 30, 2017)
Updated OPG ONFA adjustment (up to Sep 30, 2017) in OPG tab (removed it from Risks table)
Removal of OPG ONFA Sep 2017 adjustment in Risks table
Included possible range (-50M to 50M) of impact for future OPG ONFA adjustment in the negative
Removal of negative regulatory risk: "OPG Switch from accrual based to cash based accounting f
Removal of negative regulatory risk: "Timing of OPG Rate Decision" from Risks table
Removal of negative regulatory risk: "OEB Staff Recommendations wrt OPG rate application(May
Removal of negative regulatory risk: "Nuclear Liabilities Cash vs. Accrual" from Risks table
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Allocated 75% of Dec 2017 OEB payment amounts decision (CEFD Analysis) impact to Net Incon
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Reverse AO unpacking for the Interim January distribution
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month
Updated the 2017-18 monthly "OEB Risk - Delay in Effective Date of OPG Rates" to $50M/month

This line show net impact of latest change. READ COMMENT

Expense

Expense
Expense
Expense
Expense
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue

Expense
Expense
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Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue

$ Millions

		2016-17	2017-18	2018-19	2019-20
		930	789	939	957
	File	915	518	204	219
		-15	-271	-735	-738
	check	*0*	*0*	*0*	*0*
		Impacts by FY →			
Outlook line affected	**Expense / Rever**	**2016-17**	**2017-18**	**2018-19**	**2019-20**
ONFA and other Fair Value Adjustments	Revenue	41.0	0.0	0.0	0.0
N/A		0.0	0.0	0.0	0.0
?		0.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		38.1		
Provision for Electricity Sector (MOF)	Expense		(38.1)		
Public Debt Interest - Electricity Sector	Expense	0.0	38.1	38.1	38.1
Interest on Debt	Expense	0.0	(69.1)	(79.1)	(75.1)
OPG Income	Expense	0.0	0.0	0.0	
OPG Income	Revenue	(2.0)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**(2.0)**			
Provision for Electricity Sector (MOF)	Expense	2.0			
HOI Income	Revenue	0.4			
Provision for Electricity Sector (OEFC)	Expense	0.4			
Provision for Electricity Sector (MOF)	Expense	(0.4)			
Public Debt Interest - Electricity Sector	Expense	1.7			
Provision for Electricity Sector (OEFC)	Expense	(1.7)			
Provision for Electricity Sector (MOF)	Expense	1.7			
Interest on Debt	Expense	(1.7)			
HOI Income	Revenue	(39.8)	0.0	0.0	(0.0)
Provision for Electricity Sector (OEFC)	Expense	**(39.8)**			
Provision for Electricity Sector (MOF)	Expense	39.8			
	Revenue	-	-	-	-
	Revenue	-	-	-	-
	n/a	-	-	-	-
		-	-	-	-
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	4.7	0.0	0.0	0.0
	Revenue	0.0	0.0	0.0	0.0
HOI Income	Revenue	18.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	7.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	8.0	9.0	12.0	3.5
HOI Income	Revenue	0.0	(141.5)	(181.4)	(194.9)
Provision for Electricity Sector (OEFC)	Expense		(141.5)		
Provision for Electricity Sector (MOF)	Expense		141.5		
OPG Income	Revenue	(3.0)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**(3.0)**			
Provision for Electricity Sector (MOF)	Expense	3.0			
HOI Income	Revenue	7.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**7.0**			
Provision for Electricity Sector (MOF)	Expense	(7.0)			
	Revenue	-	-	-	-
	Revenue	0.0	0.0	0.0	0.0
Brampton Income	Revenue	(14.7)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**(14.7)**			
Provision for Electricity Sector (MOF)	Expense	14.7			

Provision for Electricity Sector (OEFC)	Expense		3.2			
Provision for Electricity Sector (MOF)	Expense		(3.2)			
	Revenue	-	-	-	-	
		-	-	-	-	
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
	n/a		0.0	0.0	0.0	0.0
Brampton Income	Revenue		15.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		**15.0**			
Provision for Electricity Sector (MOF)	Expense		(15.0)			
Provision for Electricity Sector (OEFC)	Expense		3.2			
Provision for Electricity Sector (MOF)	Expense		(3.2)			
Electricity Debt Retirement Charge	Revenue		(4.0)	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue		(29.0)	0.0	0.0	0.0
OPG Income	Revenue		(6.0)	0.0	0.0	0.0
HOI Income	Revenue		(0.0)	(0.0)	0.0	0.0
HOI Income	Revenue		(1.7)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense			(0.0)		
Provision for Electricity Sector (MOF)	Expense			0.0		
	Revenue		0.0	0.0	0.0	0.0
Power Supply Contract Recoveries	Revenue		99.0	0.0	0.0	0.0
Power Supply Contract Costs	Expense		(99.0)			
Miscellaneous	Revenue		14.0	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		(12.0)			
Provision for Electricity Sector (MOF)	Expense		12.0			
Interest on Debt	Expense		(3.0)	0.0	0.0	0.0
Demand Management Support Costs	Expense		1.8	0.0	0.0	0.0
			0.0	0.0	0.0	0.0
Other (Finance)	Expense		(1.0)	0.0	0.0	0.0
	Revenue	-	-	-	-	
Brampton Income	Revenue		3.0	0.0	0.0	0.0
			0.0	0.0	0.0	0.0
OPG Income	Revenue		0.0	85.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue			(6.0)		
Provision for Electricity Sector (OEFC)	Expense			**85.0**		
Provision for Electricity Sector (MOF)	Expense			(85.0)		
OPG Income	Revenue		6.0			
ONFA and other Fair Value Adjustments	Revenue		(6.0)			
HOI Income	Revenue		0.0	141.9	181.8	195.4
Provision for Electricity Sector (OEFC)	Expense			141.9		
Provision for Electricity Sector (MOF)	Expense			(141.9)		
	n/a		0.0	0.0	0.0	0.0
			0.0	0.0	0.0	0.0
Net Reduction of Power Purchase Contracts	Revenue		0.1	(0.1)	(0.1)	(0.1)
	Revenue		0.0	0.0	0.0	0.0
OPG Income	Revenue		0.0	16.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue			(1.0)		
Provision for Electricity Sector (OEFC)	Expense			**16.0**		
Provision for Electricity Sector (MOF)	Expense			(16.0)		

		0.0	0.0	0.0	0.0
	n/a	0.0	0.0	0.0	0.0
HOI Income	Revenue	0.0	5.3	5.3	5.3
Provision for Electricity Sector (OEFC)	Expense		(12.4)		
Provision for Electricity Sector (MOF)	Expense		12.4		
oded formula in the cell	n/a	0.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	(30.4)	0.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		17.8		
Provision for Electricity Sector (MOF)	Expense		(17.8)		
Interest on Debt	Expense	(0.0)	1.0	(0.0)	1.0
Interest on Debt	Expense	0.0	15.0	15.0	5.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	0.0	(7.8)	(8.7)	(10.3)
HOI Income	Revenue	0.0	(47.4)	(54.0)	(54.0)
Provision for Electricity Sector (OEFC)	Expense	0.0	(47.4)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	47.4	0.0	0.0
OPG Income	Revenue	0.0	(61.0)	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	0.0	(21.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	(61.0)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	61.0	0.0	0.0
OPG Income	Revenue	0.0	(21.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	(21.0)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	21.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	0.0	21.0	0.0	0.0
HOI Income	Revenue	0.0	(23.6)	(27.4)	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	(23.6)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	23.6	0.0	0.0
OPG Income	Revenue	0.0	15.0	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	15.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	(15.0)	0.0	0.0
OPG Income	Revenue	0.0	21.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue	0.0	(18.0)	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense	0.0	21.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	(21.0)	0.0	0.0
HOI Income	Revenue	0.0	(23.8)	(28.9)	(10.1)
Provision for Electricity Sector (OEFC)	Expense	0.0	(23.8)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense	0.0	23.8	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
HOI Income	Revenue		16.1	26.7	20.6
Provision for Electricity Sector (OEFC)	Expense		16.1		
Provision for Electricity Sector (MOF)	Expense		(16.1)		
n/a	n/a	0.0	0.0	0.0	0.0
OPG Income	Revenue		(4.9)	(11.9)	(17.1)
Provision for Electricity Sector (OEFC)	Expense		(4.9)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		4.9	0.0	0.0
OPG Income	Revenue		283.0		
Provision for Electricity Sector (OEFC)	Expense		283.0		
Provision for Electricity Sector (MOF)	Expense		(283.0)		
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue		95.0		
OPG Income	Revenue		0.0	(475.0)	(500.0)
HOI Income	Revenue		(112.6)	(142.1)	(170.6)
Provision for Electricity Sector (OEFC)	Expense		(112.6)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		112.6	0.0	0.0
HOI Income	Revenue		(3.3)	(3.0)	(0.1)

Provision for Electricity Sector (OEFC)	Expense		(3.3)		
Provision for Electricity Sector (MOF)	Expense		3.3		
HOI Income	Revenue		14.7	14.4	12.9
Provision for Electricity Sector (OEFC)	Expense		14.7	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		(14.7)	0.0	0.0
HOI Income	Revenue		(16.1)	(26.7)	(20.6)
Provision for Electricity Sector (OEFC)	Expense		(16.1)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		16.1	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)		0.0	7.8	8.7	10.3
n/a	n/a	0.0	0.0	0.0	0.0
Other (Finance)			0.0	(1.0)	(1.0)
OPG Income	Revenue		0.0	0.0	0.0
HOI Income	Revenue		0.1	0.5	0.6
Provision for Electricity Sector (OEFC)	Expense		0.1	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		(0.1)	0.0	0.0
OPG Income	Revenue		(477.1)	(145.2)	(153.1)
Provision for Electricity Sector (OEFC)	Expense		(305.7)	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		305.7	0.0	0.0
OPG Income	Revenue		39.0	0.0	0.0
OPG - ONFA and other Fair Value Adjustments	Revenue		171.5	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
n/a	n/a	0.0	0.0	0.0	0.0
OPG Income	Revenue		119.3	36.3	38.3
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue		(119.3)	(36.3)	(38.3)
Provision for Electricity Sector (OEFC)	Expense		0.0	0.0	0.0
Provision for Electricity Sector (MOF)	Expense		0.0	0.0	0.0
OPG Income			(283.0)	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs), including CIT			(95.0)	0.0	0.0
Provision for Electricity Sector (OEFC)			0.0	0.0	0.0
Provision for Electricity Sector (MOF)			0.0	0.0	0.0
HOI Income	Revenue		116.8	147.1	176.1
Provision for Electricity Sector (OEFC)	Expense		0.0	0.0	80.3
Provision for Electricity Sector (MOF)	Expense		0.0	0.0	(80.3)
OPG Income	Revenue		37.5	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs), inc	Revenue		12.5	0.0	0.0
Provision for Electricity Sector (OEFC)	Expense		0.0	14.4	23.1
Provision for Electricity Sector (MOF)	Expense		0.0	(14.4)	(23.1)
		0	***0***	***0***	***0***

Summary of Track Changes Above

Power Supply Contract Costs	(99.0)	0.0	0.0	0.0

Demand Management Support Costs	1.8	0.0	0.0	0.0
Provision for Electricity Sector OEFC)	(44.4)	180.9	0.0	0.0
Provision for Electricity Sector (MOF)	44.4	(180.9)	0.0	0.0
Other (Finance)	(1.0)	0.0	(1.0)	(1.0)
OPG Income	(5.0)	333.1	(486.9)	(517.1)
ONFA and other Fair Value Adjustments	35.0	0.0	0.0	0.0
HOI Income	(16.1)	(190.4)	(235.3)	(216.1)
Brampton Income	3.3	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	(39.7)	79.0	12.0	3.5
Electricity Debt Retirement Charge	(4.0)	0.0	0.0	0.0
Power Supply Contract Recoveries	99.0	0.0	0.0	0.0
Net Reduction of Power Purchase Contracts	0.1	(0.1)	(0.1)	(0.1)
Miscellaneous	14.0	0.0	0.0	0.0
Public Debt Interest - Electricity Sector	1.7	38.1	38.1	38.1
Interest on Debt	(4.7)	(53.1)	(64.1)	(69.1)
Impact on Surplus/Deficit	**(14.6)**	**206.7**	**(737.3)**	**(761.7)**
check	***0.0***	***477.7***	***(2.4)***	***(23.7)***

Check - Summary of Track Changes Above vs. Electricity Summary Change Worksheet

Power Supply Contract Costs	0.0	(0.4)	(0.1)	(0.4)
Demand Management Support Costs	(0.0)	0.0	0.0	0.0
Provision for Electricity Sector OEFC)	8.4	305.7	(14.4)	(103.4)
Provision for Electricity Sector (MOF)	(8.4)	(305.7)	14.4	103.4
Other (Finance)	0.0	0.0	0.0	0.0
OPG Income	0.0	564.3	108.9	114.8
ONFA and other Fair Value Adjustments	0.0	(171.5)	0.0	0.0
HOI Income	(0.0)	(116.9)	(147.6)	(176.8)
Brampton Income	0.0	0.0	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	(0.0)	201.8	36.3	38.3
Electricity Debt Retirement Charge	0.0	0.0	0.0	0.0
Power Supply Contract Recoveries	0.0	0.4	0.1	0.4
Net Reduction of Power Purchase Contracts	(0.0)	(0.0)	(0.0)	(0.0)
Miscellaneous	0.0	0.0	0.0	0.0
Public Debt Interest - Electricity Sector	23.4	0.1	0.1	0.1
Interest on Debt	(23.4)	(0.1)	(0.1)	(0.1)
Impact on Surplus/Deficit	**(0.0)**	**477.7**	**(2.4)**	**(23.7)**

2020-21	
1,676	
620	
-1,056	
0	

2020-21	Further Explanation of Change and source of data
0.0	Regular quarterly ONFA Update
0.0	Benefit to OEFC under s.50.3: $411M gain, SIFB
0.0	Change to OEFC payment for interest costs of Debt for Equity Swap
38.1	Revised Provincial Debt Interest related to Hydro One Equity
(104.1)	From FTD, revised Debt Interest (net of revisions to Provincial and OPG debt interest)
0.0	Revised numbers from OEP with 2019-20 Risk
0.0	Updated numbers from OPG Q1 2017 FS
0.0	Updating H1 Net Income for actuals. Note does not update Brampton Income at this point. Will
-	No Change to numbers, just re-inputting data and saving sources
-	No Change to numbers, just re-inputting data and saving sources
-	No change to fiscal impact numbers. Deleting Budget 2016 and adding Budget 2017 fiscal imp
-	No Change to numbers, just re-inputting data and saving sources
0.0	Updated with CIT Numbers received from H1 as part of s.91.2 MB20 allocation from MOF
0.0	No Change to numbers, just re-inputting data and saving sources
0.0	Only included H1 Net Income - Common Shareholders before. Added preferred shareholder im
0.0	Updating OPG Income Tax Expense with info from OPG Monthly Presentation to Shareholder
1.8	Updating OPG GRC payable to OEFC and Proxy Property Tax from Answer back from OPG al
(210.6)	Based on H1 final offering and expected First Nations Sale by the end of 2017 (CY), with a wei
0.0	Based on EY analysis, and then applying fiscalization. Confirmation also received from OPCD.
0.0	Based on KPMG analysis, then fiscalization and other adjustments from OPCD.
-	**[NOT APPLIED, CALCULATIONS AND DATA LEFT ON THE FILE]** Used Brampton's Financ
0.0	Don't expect finalized 2016-17 data to become available in time for ESDI allocation. Will shift th
0.0	make decision on shifting when we know 2016-17 status.

-	No change to numbers. Just re-organizing spreadsheet. No backup data.
-	No change to numbers. Just re-organizing spreadsheet. No backup data.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided another scenario backup/source
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just provided actual backup/source.
0.0	No change to numbers. Just updated the links to refer ot the delta between 2017 and On Deck
0.0	Adjustment to ESDI to include Hydro One Brampton
0.0	Finalizing 2016-17 DRC Based on Draft OEFC AR
0.0	Received actual PILs amounts from FTD with breakdown of source. Updated 2016-17 numbers
0.0	2016-17 - Non-ONFA Fair Value Adjustment
0.0	Round Hydro One ownership assumptions to 70.05% two decimal places to be consistent with
0.0	Revising Hydro One Amount for consistency with OPCD. Equity Adjustments
0.0	Updated Provision tab. Made two separate Provision amounts for ESDI in OEFC AR and Dedic
0.0	Updating Power Supply Recoveries to Public Accounts/OEFC AR actuals
0.0	Updating Miscellaneous to OEFC AR actuals
0.0	Updated 2016-17 Interest on Debt (IESO, OPG, Other (Net))
0.0	
0.0	2017-18 - Demand Management Support Costs (no change) - Linking correctly
0.0	2016-17 - Updating Operating Expense in OEFC and corresponding changes elsewhere and s
-	No change to numbers. Just re-organized spreadsheet
0.0	Revised H1 Brampton Net Income (for GBE Line only)
0.0	Revising for OPG's Q3 Finances
0.0	Revising OPG's Net Income for latest monthly report
211.1	Reverting ownership back to 70.05% from change 20170518-3. Will coordinate with other area
0.0	Updating Risks based on Hydro One Q2 Results Model
0.0	Updated two Risk components for the Avista Acquisition.
(0.0)	No significant changes, but used actual amortization liability schedule. Hence the rounding imp
0.0	Updating Debt Guarantee for actuals based on OEFC AR
0.0	Revising OPG's Net Income for latest monthly report

0.0	Linking interest revenue data for 2017-18 to 2020-21
0.0	OPG Revenue Risks from: OEB Staff Submission and OPG Updated Filings
5.3	Corrected Net income for 100% ownership in preferred shares and 70.05% in Commons Share
0.0	Updated the formula in the cell for 2017-18 Net Income Before Tax so that the numbers are no
0.0	Updated PILs to include OPCD public accounts adjustment
1.3	
5.0	
(12.2)	
(54.0)	
0.0	
0.0	
0.0	increase built into net income was $82m between NI and PILs
0.0	Remove $21m from PILs
0.0	expense impacts
0.0	expense impacts
0.0	need to also remove the $21m PILs built into OPG net incme
0.0	
0.0	
0.0	We removed $21m from PILs above, before having added it in (check is that lines 123 to 130 a
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
(13.0)	variances include: 2017-18 preferred vs common share fix, 2018-19 largely ROE change from
0.0	
0.0	
0.0	
0.0	
0.0	
21.6	
0.0	
(24.1)	
0.0	
0.0	**Distribution (October)**
(750.0)	
(185.3)	
0.0	
0.0	
(2.3)	

15.2	
0.0	
0.0	
(21.6)	
0.0	
0.0	
0.0	Updating OPG Rate application Revenue Risks based on revised calculations
12.2	
0.0	
(1.0)	Received Revised FTD Forecast
0.3	
0.7	
0.0	
0.0	
(180.7)	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	
0.0	Removed based on Dec 2017 OEB decision
0.0	Removed based on Dec 2017 OEB decision
0.0	Removed based on Dec 2017 OEB decision
0.0	Removed based on Dec 2017 OEB decision
45.2	
(45.2)	
44.2	
(44.2)	
0.0	
0.0	
(44.2)	
44.2	
190.8	
311.7	
(311.7)	
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M
0.0	Total difference in using $50M/month vs $60M/month for period of 5 months is $50M

0

0.0

0.0
0.0
0.0
(1.0)
(774.1)
0.0
(233.7)
0.0
1.8
0.0
0.0
(0.0)
0.0
38.1
(97.8)
(1,067)
(11.1)

t

0.2
0.0
(311.7)
311.7
0.0
135.3
0.0
(191.5)
0.0
44.9
0.0
(0.2)
0.0
0.0
0.1
0.1
(11.1)

Data Validation:

Options
Revenue (F
OPG
Hydro One
Provision

ONFA
Other Data

update once revised numbers are received.

acts

ıpact as well.

bout the BP
ghted average ownership for 2017-18. Also adjusted future net income attributed to the province.

ial Statements to produce an estimate. May require additional calculations.
ıis to 2017-18.

(from 2016 and On Deck)

s to reflect this.

OPCD.

:ated Earnings in Public Accounts.

ources.

s to ensure broadening change and reduction in net income happens concurrently in forecasts.

acts/changes.

es

t hardcoded directly

dd up to -$82m gain that we wanted to remove.

9.09% to 8.78% not previously captured.

Risks)

Electricity Sector Outlook

$ Millions

	Actual 2015-16	Interim 2016-17	Plan 2017-18	2018-19	2019-20	2020-21
On Deck Outlook as of March 2017						
Income from Investment in Government Business Enterprises						
OPG Income[1]	291	304	97	732	625	1,066
OPG - ONFA and other Fair Value Adjustments[2]	172	8	-	-	-	-
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	-
HOI Income[3]	236	516	520	562	603	652
Brampton Income	20	15	-	-	-	-
Total OPG and HOI Income	**719**	**842**	**617**	**1,294**	**1,229**	**1,717**
Other Fees and Licences	**127**	**122**	**102**	**91**	**88**	**81**
Electricity Expenses of the Province						
Provision for Electricity Sector[4]	(3)	(342)	(125)		-	-
Public Debt Interest - Electricity Sector	(520)	(492)	(492)	(492)	(492)	(492)
Subtotal	(523)	(834)	(617)	(492)	(492)	(492)
Public Debt Interest - Impact of ONFA						
Amortization of Deferred Revenue re profit on sale of H1 notes						
Total Electricity Expenses of the Province	**(523)**	**(834)**	**(617)**	**(492)**	**(492)**	**(492)**
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	3,228	373	405	476	538	679
Other Revenue						
Electricity Debt Retirement Charge[5]	859	625	623	-	-	-
Power Supply Contract Recoveries	875	739	292	325	301	273
Net Reduction of Power Purchase Contracts	172	129	74	41	30	28
Other Fees and Licences	(127)	(122)	(102)	(91)	(88)	(81)
Miscellaneous	9	-	-	-	-	-
Expenses						
Interest on Debt	(596)	(532)	(422)	(374)	(342)	(250)
Power Supply Contract Costs	(875)	(739)	(292)	(325)	(301)	(273)
Electricity Consumer Price Protection Fund	-	-	-	-	-	-
Demand Management Support Costs[6]	(8)	(10)	(10)	-	-	-
Provision for Electricity Sector	3	342	125	-	-	-
Other (Finance)	(7)	(6)	(6)	(6)	(6)	(6)
Total OEFC Income	**3,533**	**800**	**687**	**46**	**132**	**370**
Impact on Surplus/(Deficit)	**3,856**	**930**	**789**	**939**	**957**	**1,676**

Notes: The Hydro One net income outlook above (2016-17 to 2020-21) reflects the Province's 70% ownership share after the initial IPO in 2015 and the secondary offering in April 2016. At the time of 2017 Budget, net estimated fiscal impacts from future Hydro One offerings are reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

Notes:

1.OPG's 2016-17 outlook reflected its reported earnings. 2017-18 to 2019-20 reflects OPG's preliminary 2017-2019 business plan (as fiscalized by OPG). 2020-21 estimates are based on OPG's calendar year-based business plan projections. OPG net income also reflects IFRS adjustments fiscal impact decisions that were made centrally.

2. Provincial consolidation adjustments for unrealized earnings on the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds, as of the end of December 2016.

3. Hydro One 2016-17 income reflects its reported net income, adjusted for Hydro One IPO impacts. 2017-18 to 2020-21 projections are based on CEFD projections using the latest public information. The Hydro One net income outlook above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering as of 2017 Budget were reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial ONFA consolidation adjustments, less the interest on the Province's OPG/Hydro One debt payable to OEFC. The provision is currently assumed to end once the DRC ends on a legislated fixed end date of April 1, 2018.

5. Reflects April 23, 2014 announcement that DRC will be eliminated for residential users, after December 31, 2015. The end date of DRC for remaining users is legislated to be on April 1, 2018. Estimates are subject to change based on actual consumption.

6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Electricity Sector Outlook

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
On Deck Outlook as of October 2017						
Income from Investment in Government Business Enterprises						
OPG Income[1]	291	299	(134)	137	(7)	156
OPG - ONFA and other Fair Value Adjustments[2]	172	43	171	-	-	-
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	-
HOI Income[3]	236	500	446	474	564	610
Brampton Income	20	18	-	-	-	-
Total OPG and HOI Income	**719**	**860**	**484**	**610**	**557**	**766**
Other Fees and Licences (Debt Guarantee fee)	**127**	**122**	**102**	**99**	**98**	**91**
Electricity Expenses of the Province						
Provision for Electricity Sector[4]	-	(290)	-	(14)	(103)	(312)
Public Debt Interest - Electricity Sector	(520)	(514)	(454)	(454)	(454)	(454)
Subtotal	(520)	(803)	(454)	(469)	(557)	(766)
Public Debt Interest - Impact of ONFA						
Amortization of Deferred Revenue re profit on sale of H1 notes						
Total Electricity Expenses of the Province	**(520)**	**(803)**	**(454)**	**(469)**	**(557)**	**(766)**
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	3,247	334	282	452	503	635
Other Revenue						
Electricity Debt Retirement Charge[5]	859	621	623	-	-	-
Power Supply Contract Recoveries	875	838	292	325	301	273
Net Reduction of Power Purchase Contracts	172	129	74	41	30	28
Other Fees and Licences	(127)	(122)	(102)	(99)	(98)	(91)
Miscellaneous	9	14	-	-	-	-
Expenses						
Interest on Debt	(596)	(513)	(475)	(438)	(411)	(348)
Power Supply Contract Costs	(875)	(838)	(292)	(325)	(301)	(273)
Electricity Consumer Price Protection Fund	-	-	-	-	-	-
Demand Management Support Costs[6]	(8)	(8)	(10)	-	-	-
Provision for Electricity Sector	-	290	-	14	103	312
Other (Finance)	(7)	(7)	(6)	(7)	(7)	(7)
Total OEFC Income	**3,549**	**737**	**386**	**(37)**	**121**	**529**
Impact on Surplus/(Deficit)	**3,876**	**915**	**518**	**204**	**219**	**620**
variance to OEFC check	*(156)*	*(454)*	*(550)*	*0*	*0*	*-*

Notes:

1.OPG's 2016-17 outlook reflected its reported earnings. 2017-18 reflects OPG's lates monthly update. 2018 to 2019-20 reflects OPG's preliminary **[NTD: Still preliminary?]** 2017-2019 business plan (as fiscalized by OPG). 2020-21 estimates are based on OPG's calendar year-based business plan projections. OPG net income also reflect projected IFRS adjustments as provided by OPCD at the time of the 2017 Budget.

2. Provincial consolidation adjustments for unrealized earnings on the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds, as of the end of **September 2017**.

3. Hydro One 2016-17 income reflects its projected net income adjusted for the Province's ownership share in Hydro One following the final offering in May 2017 and including the ~~**planned**~~ First Nations sale in December 2017. 2017-18 to 2020-21 projections are based on CEFD projections using the latest public information.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial ONFA consolidation adjustments, minus the interest on debt payable to OEFC. The provision is ~~**currently**~~ now assumed to continue ~~end once the DRC ends on a legislated fixed end date of April 1, 2018~~. There is currently a PRRT submission to continue ESDI payments to OEFC beyond 2017-18.

5. Reflects ~~April 23, 2014 announcement~~ that DRC ~~will be~~ eliminated for residential users, after December 31, 2015. The end date of DRC for remaining users is legislated to be on April 1, 2018. Estimates are subject to change based on actual consumption.

6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Electricity Sector Change Since Budget	$ Millions					
($million)	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Changes from Budget 2017 as of October 2017						
Income from Investment in Government Business Enterprises						
OPG Income	(5)	(231)	(596)	(632)	(909)	2016-17 small decrease due to IFRS adjustment revision and OPG Net Income revision. 2017-18 due largely to OEB Dec. 28, 2017 rate decision including effective date of June 1, 2017 rather than jan. 1, 2017. Decrease in 2018-19 onward is due mainly to taking on projeceted IFRS adjustment impacts in those years as well as OEB Dec. 28, 2017 rate decision. The OEB rate decision impacts are all shown in the OPG net income line. Actual impacts are likely to be spread out between net income & PILs.
ONFA and other Fair Value Adjustments	35	171	-	-	-	Largely revision to ONFA fair value as of September 30, 2017
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	
HOI Income	(16)	(73)	(88)	(39)	(42)	2016-17 slight decrease from Budget 2017 Interim projection. 2017-18 onwards reflects i) impact of OEB Sep. 2017 decision on Hydro One transmission rates and ii) interest expense on Avitsa debentures (in 2017-18 and 2018-19).
Brampton Income	3.3					
Total OPG and HOI Income	**17**	**(133.2)**	**(684)**	**(671)**	**(951)**	
Other Fees and Licences	**-**	**-**	**8**	**10**	**10**	
Electricity Expenses of the Province						
Provision for Electricity Sector	53	125	(14)	(103)	(312)	Changes to the Proviision (ESDI) expense in 2017-18 mainly reflect lower OPG net income due to OEB's Dec. 28, 2017 rate decision and lower Hydro One net income due to OEB's Sep. 2017 transmission rate decision. The projected change in 2019-20 and 2020-21 is due to the continuation of ESDI beyond 2017-18 (approved in principle in the current PRRT). In the 2017 Budget outlook, ESDI was assumed to end after 2017-18. ESDI estimates for 2018-19 and 2018-19 are reduced due to negative balances in 2017-18 and 2018-19,
Public Debt Interest - Electricity Sector	(22)	38	38	38	38	2016-17 PDI at ($514m) was slightly larger than ($492m) projected at Interim. 2017-18 change reflects revised projections for Provincial debt interest related to HydroOne's April 2016 offering. Note the impact of the final offering will be refelected in PDI during 2018.
Total Electricity Expenses of the Province	**31**	**163**	**24**	**(65)**	**(274)**	

Electricity Sector Change Since Budget	$ Millions					
($million)	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs)	(40)	(123)	(24)	(35)	(43)	2016-17 decrease largely due to an OPCD Public Accounts PILs adjustment related to reconciling between OPCD and OEFC net opening assets. OPG PILs also slightly lower than projected. ~~2017-18 increase is due mainly to recategorization of the PILs impact of the OPG head office sale from Sales and Rentals.~~
Other Revenue						
Electricity Debt Retirement Charge	(4)	-	-	-	-	
Power Supply Contract Recoveries	99	(0)	(0)	(0)	0	Variance is largely due to retroactive payments that the OEFC made to certain non-utility-generators (NUGs) with former Ontario Hydro power purchase agreement contracts with OEFC. OEFC was required to make these payment following the dismissal by the Supreme Court of Canada of OEFC's application for leave to appeal a judgment of the Court of Appeal of Ontario on a 2015 court decision.
Net Reduction of Power Purchase Contracts	0.1	(0)	(0)	(0)	(0)	
Other Fees and Licences	-	-	(8)	(10)	(10)	
Revenue Pool Residual	-	-	-		-	
Miscellaneous	14	-	-	-	-	
Expenses						
Interest on Debt	19	(53)	(64)	(69)	(98)	2017-18 reflects revised debt interest outlook net of revisions to OEFC interest revenue from OPG and Province.
Power Supply Contract Costs	(99)	0	0	0	(0)	Same as Power supply contract recoveries above. Power supply contract costs are fully recovered by power supply contract recoveries.
Electricity Consumer Price Protection Fund	-	-	-	-	-	
Demand Management Support Costs	1.8	-	-	-	-	
Provision for Electricity Sector	(53)	(125)	14	103	312	see explanation above for "Provision for Electriocty Sector" (line 17)
Other (Finance)	(1.0)	-	(1)	(1)	(1)	
Total OEFC Income	**(63)**	**(301)**	**(83)**	**(11)**	**160**	
Impact on Surplus/(Deficit)	**(14.6)**	**(271)**	**(735)**	**(738)**	**(1,056)**	
Information: Breakdown of change between revenue and expense						
Total Revenue Impact	87	(256)	(708)	(706)	(994)	
Total Expenditure impact	101	15	27	32	61	

Electricity Sector Outlook (PSAB)

Negative Revenue Risks	$ Millions			
($ millions)	**Plan**			
	2017-18	**2018-19**	**2019-20**	**2020-21**
Generic				
OPG Generation Risk: Nuclear Reliability (-1.6 TWh)[1]	(120)	(120)	(120)	(120)
1% decrease in Hydro One actual load[2]	(57)	(59)	(62)	(63)
Lower OPG's Equity weighting & Return on Equity (ROE)[3]	(12)	(20)	(26)	(45)
Lower Hydro One Return on Equity (ROE)[4]	(9)	(36)	(38)	(40)
Regulatory				
Hydro One Distribution rate application[5]	(50)	(50)	(50)	(50)
OPG Switch from accrual based to cash based accounting for pension and OPEB[6]	—	TBD	TBD	TBD
Regulatory Risk - Timing of OPG Rate Decision[7]	—			
OEB Staff Recommendations wrt OPG rate application(May 2017)[8]	—			
Nuclear Liabilities Cash vs. Accrual[9]	—			
OEB decision on Hydro One tax recapture (if one-time write-down)[10]	(440)			
Accounting				
OPG IFRS Consolidation Risks[11]		—	—	—
Other Risks				
ONFA adjustment decrease[12]	(50)			
Avista Acquisition - Termination fee		(49)		

Note: These risks do not reflect the impacts on electricity sector revenue and expense of reclassification of the Asset Optimizat

1. OPG's market and generation risks related to nuclear reliability similar to the scenarios OPG developed for its sales margins to capture major market risk factors (e.g., natural gas prices, coal prices, foreign exchange, nuclear reliability) in its 2012 business plan. Currently, only the nuclear reliability risk is captured at the current regulated rate for OPG's nuclear generation.

2. Estimated revenue impact if Hydro One load for Transmission and Distribution is 1% lower than projected for all years in CEFD Hydro One Forecast. Based on the assumption a 1% increase in load is directly proportional to a 1% change in revenue requirements.

3. Risk range for Hydro One transmission and distribution reflects potential risk of lower ROE by 0.5% vs assumed ROEs in business plan along with reduced deemed debt to equity weighting of 55%/45% from the current 51%/49%.

4. Risk range for Hydro One transmission and distribution reflects potential risk of lower ROE by 0.5% vs assumed ROEs in CEFD Hydro One Forecast based on the most recent rate applications and forecasted ROE rates.

5. OEB is expected to make a decision on Hydro One's Distibution rate application for 2018 during the first half of 2018.

6. **Previous risk removed** **from 17-18**. OEB September 2017 Report, established accrual method as default rate setting method to recover Pension and Other Pension Benefits (OPEBs) costs and recommended continuance of variance account tracking the difference between cash vs. accrual basis reporting for Pension and OPEB. OEB December 28, decision and order instructs OPG to submit request to dispose of Pension and OPEB deferral and variance account balances during 2018 for its 2019 payment application.

7. **Previous risk removed** **with timing impact now reflected in OPG outlook**. OEB December 28, decision and order provides an effective date for new rates of June 1, 2017. OPG's business plan assumed OEB decision would be effective as of January 1, 2017. OPG estimated an impact of -$60M for each month for which OEB decsion is not retroactive. The resulting $300M estimated impact has been included in the OPG outlook.

8. **Previous risk removed.** Estimated impact of OEB December 28the decision and order with respect to OPG rates is now reflected on the OPG Outlook.

9. **Previous risk removed.** Risk is related to potential switch to cash-basis accounting for regulated recovery of nuclear payment anmounts. OEB December 28, 2017 Decision and Order has deferred this issue to next OPG rate application in 2021 for 2022 to 2027 period.

10. The OEB's Sep. 28, 2017 ruling on Hydro One's Transmission rate application included direction on sharing, with ratepayers, tax savings related to the Hydro One IPO. Hydro One filed a Motion to Review this decision with the OEB and has also filed a court appeal. Hydro One's 2017 Q3 financial report notes that if the Motion to Review and appeal are unsuccesful teh company would record a one-time write-down of $885 million reflecting the OEB decision. The risk above reflects this risk at teh Province's 49.9% average share allocation for 2017-18. Hydro One noted that timing for the Motion to Review and appeal is uncertain. It expects the OEB Review to start in Q1 but noted that it could run in to Q2.

11. **Previous risk removed.** OPCD provided IFRS impact estimates (largely related to OPG) at the time of Budget 2017. A portion of these were reflected in in OPG's and Hydro One's net income outlook at the time of the 2017. The current Electricity Outlook now reflects this additional IFRS risk. Table below outlines OPG IFRS Risks versus what is built into the 2017 Budget Fiscal Plan.

	2017-18	**2018-19**	**2019-20**	**2020-21**
OPG IFRS Risk	(400)	(475)	(700)	(750)
Risks Built into Fiscal Plan at 2017 Budget	(400)	0	(200)	0
Additional Risks now picked up in this Electricity Outlook	0	(475)	(500)	(750)

Electricity Sector Outlook (PSAB)

Positive Revenue Risks				
($ millions)	**Plan**			
	2017-18	**2018-19**	**2019-20**	**2020-21**
Generic				
OPG Generation Risk: Nuclear Reliability (+1.1 TWh)[1]	85	85	85	85
1% increase in Hydro One actual load[2]	57	59	61	63
Higher OPG Return on Equity (ROE)[3]	6	22	19	33
Higher Hydro One Return on Equity (ROE)[4]	19	69	50	50
Regulatory				
Accounting				
Other Risks				
ONFA adjustment increase[5]	50			

ion strategy or updates to AO strategy.

1. OPG's market and generation risks related to nuclear reliability similar to the scenarios OPG developed for its sales margins to capture major market risk factors (e.g., natural gas prices, coal prices, foreign exchange, nuclear reliability) in its 2012 business plan. Currently, only the nuclear reliability risk is captured at the current regulated rate for OPG's nuclear generation.

2. Estimated revenue impact if Hydro One load for Transmission and Distribution is 1% higher than projected for all years in CEFD Hydro One Forecast. Based on the assumption a 1% increase in load is directly proportional to a 1% change in revenue requirements.

3. Risk range for OPG reflects potential risk of higher ROE in 2018-2021 (for nuclear base) vs assumed ROE in OPG's 2016 business plan and corresponding rate application. Assumed ROE is 9.85%, respresenting recent in 2010.

4. Risk range for Hydro One transmission and distribution reflects potential risk of higher ROE vs assumed ROEs in the Hydro One CEFD Forecast for 2018-2021. Assumed ROE is 9.85%, representing recent high in 2010.

5. Reflects risk around the consolidation adjustment to OPG net income, whereby the realized portion of gains or losses of OPG's nuclear funds are added or subtracted from OPG net income. Currently $171M positive adjustment is included in the OPG outlook. The ONFA adjustment is expected to be finalized in February 2018.

ONTARIO ELECTRICITY FINANCIAL CORPORATION
On Deck Outlook as of March 2017

$ Millions

	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Revenue						
Revenue Pool Residual						
Debt Retirement Charge	859	625	623	-	-	-
Payments-in-lieu of tax:						
OPG	268	302	315	366	408	537
Legacy Hydro One (Including Brampton)	2,929	7	2	2	2	2
Hydro One CIT dedicated to OEFC	3	20	20	22	23	25
MEUs	27	44	68	86	105	114
Total PILs & CIT dedicated to OEFC[1]	3,228	373	405	476	538	679
Interest :						
OPG	173	179	168	153	135	135
H1						
IESO	2	3	3	3	3	3
Province	520	492	492	492	492	492
Other	28	10	5	5	5	5
Total Interest	723	684	668	653	635	635
Power Supply Contract Recoveries	875	739	292	325	301	273
Amortization of NUG liability	172	129	74	41	30	28
Electricity sector dedicated income	3	342	525	-	-	-
Gain to OEFC under s. 50.3	172	-	-	-	-	-
Miscellaneous	9	-	-	-	-	-
	6,041	2,893	2,587	1,495	1,504	1,615
Expense						
Debt interest	1,319	1,216	1,090	1,027	977	885
Interest on nuclear risk funding						
Demand Management Support Costs	8	10	10	-	-	-
Amortization of deferred debt costs	-	-	-			
Power Supply Contract Costs	875	739	292	325	301	273
Debt Guarantee fee	127	122	102	91	88	81
Operating	7	6	6	6	6	6
	2,336	2,093	1,500	1,449	1,372	1,245
Excess (Deficiency) of Revenue over Expense	**3,705**	**800**	**1,087**	**46**	**132**	**370**
Prior period adjustment	87					
Stranded Debt - Year End	**4,393**	**3,593**	**2,506**	**2,460**	**2,328**	**1,958**

Note: All the Hydro One ownership broadening impacts, other than the ownership change from the initial IPO in 2015 and the secondary offering in April 2016, were reflected in Sales and Rentals as of the 2017 Budget.

ONTARIO ELECTRICITY FINANCIAL CORPORATION
On Deck Outlook as of October 2017

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Revenue						
Revenue Pool Residual						
Debt Retirement Charge	859	621	623	0	0	0
Payments-in-lieu of tax:						
OPG	268	224	192	342	373	494
Legacy Hydro One (Including Brampton)	2,929	4	2	2	2	2
Hydro One CIT dedicated to OEFC	3	25	20	22	23	25
MEUs	27	112	68	86	105	114
Total PILs & CIT dedicated to OEFC[1]	3,228	364	282	452	503	635
Interest :						
OPG	173	167	169	179	175	148
H1						
IESO	2	2	3	3	3	3
Province	520	514	454	454	454	454
Other	28	20	20	20	10	10
Total Interest	723	703	646	656	642	615
Power Supply Contract Recoveries	875	838	292	325	301	273
Amortization of NUG liability	172	129	74	41	30	28
Electricity sector dedicated income	3	302	0	14	103	312
Gain to OEFC under s. 50.3[2]	172	411	550	0	0	0
Miscellaneous	9	14	0	0	0	0
	6,041	3,382	2,467	1,488	1,579	1,863
Expense						
Debt interest	1,319	1,216	1,121	1,094	1,053	963
Interest on nuclear risk funding						
Demand Management Support Costs	8	8	10	0	0	0
Amortization of deferred debt costs	0	0	0			
Power Supply Contract Costs	875	838	292	325	301	273
Debt Guarantee fee	127	122	102	99	98	91
Operating	7	7	6	7	7	7
	2,336	2,191	1,531	1,525	1,459	1,334
Excess (Deficiency) of Revenue over Expense	3,705	**1,191**	**936**	**(37)**	**121**	**529**
Prior period adjustment	87					
Stranded Debt - Year End	4,393	**3,202**	**2,266**	**2,303**	**2,182**	**1,653**

1

Payments-in-lieu of tax:	**2015-16 Public Accounts**
OPG	290
Legacy Hydro One (Including Brampton)	2,941
Hydro One CIT dedicated to OEFC	0
MEUs	15
	3,247

2 2017-18 value preliminary estimate, subject to change.

ONTARIO ELECTRICITY FINANCIAL CORPORATION

Changes from Budget 2017 as of October 2017 **$ Millions**

	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Revenue						
Debt Retirement Charge	(4)	-	-	-	-	
Payments-in-lieu of tax:						
OPG	(78)	(123)	(24)	(35)	(43)	2016-17 decrease largely due to reconciling between OPCD and OEFC net opening assets. OPG PILs also slightly lower than projected. 2017-18 and onward decrease is due to estimated impact of OEB Dec. 29=8, 2017 rate decision.
Legacy Hydro One (Including Brampton)	(3)	-	-	-	-	
Hydro One CIT dedicated to OEFC	5	-	-	-	-	Adjustment based on updated information in Hydro One rate application
MEUs	68	-	-	-	-	Large increase in 2016-17 from $80M payment during transfer of H01 Brampton to new consolidated MEU Alectra.
Total PILs	(9)	(123)	(24)	(35)	(43)	
Interest :						
OPG	(12)	1	26	40	13	Update to OPG interest outlook (wrt interest on OEFC loan).
H1	-	-	-	-	-	
IESO	(1)	-	-	-	-	
Province	22	(38)	(38)	(38)	(38)	2016-17 PDI at ($514m) was slightly larger than ($492m) projected at Interim. 2017-18 change reflects revised projections for Provincial debt interest related to Hydro equity.
Other	10	15	15	5	5	
Total Interest	19	(22)	3	7	(20)	
Power Supply Contract Recoveries	99	(0)	(0)	(0)	0	Variance is largely due to retroactive payments that the OEFC made to certain non-utility-generators (NUGs) with former Ontario Hydro power purchase agreement contracts with OEFC. OEFC was required to make these payment following the dismissal by the Supreme Court of Canada of OEFC's application for leave to appeal a judgment of the Court of Appeal of Ontario on a 2015 court decision.
Amortization of NUG liability	0	(0)	(0)	(0)	(0)	
Electricity sector dedicated income	(41)	(525)	14	103	312	The decrease in OEFC ESDI in 2017-18 reflects i) the IFRS adjustment of $400 million in 2017-18 that was not reflected in the OEFC ESDI projection at the time of the 2017 Budget (Note the IFRS adjustment was reflected in OPG net income for the 2017 Budget fiscal plan) and ii) the lower OPG and Hydro One net income due to OEB's 2017 rate decisions. The projected change in 2019-20 and 2020-21 is due to the continuation of ESDI beyond 2017-18 (approved in principle in the current PRRT). In the 2017 Budget outlook, ESDI was assumed to end after 2017-18. ESDI estimates for 2018-19 and 2018-19 are reduced due to negative balances in 2017-18 and 2018-19,
Gain to OEFC under s. 50.3	411	550	-	-	-	
Miscellaneous	14	-	-	-	-	
	489	(120)	(7)	75	249	
Expense						
Debt interest	-	31	67	76	78	Revised outlook for OEFC debt interest outlook
Interest on nuclear risk funding	-	-	-	-	-	
Demand Management Support Costs	(2)	-	-	-	-	
Amortization of deferred debt costs	-	-	-	-	-	
Power Supply Contract Costs	99	(0)	(0)	(0)	0	Same as Power supply contract recoveries above. Power supply contract costs are fully recovered by power supply contract recoveries.
Debt Guarantee fee	-	-	8	10	10	
Operating	1	-	1	1	1	
	98	31	76	87	89	
Excess (Deficiency) of Revenue over Expense	**391**	**(151)**	**(83)**			
Stranded Debt - Year End	**3,202**	**2,266**	**2,303**	**2,182**	**1,653**	

Provision for Electricity Sector (Dedicated Electricity Earnings/Electricity Sector Dedicated Earnings)

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Income from Investment in Government Business Enterprises						
OPG Income	291	299	(134)	137	(7)	156
Hydro One Income[1]	232	501	446	474	564	610
Hydro One Brampton (if applied separately)		15				
Total Income	**523**	**815**	**312**	**610**	**557**	**766**
Public Debt Interest - Electricity Sector						
OPG			(300)	(300)	(300)	(300)
Hydro One[1]			(154)	(154)	(154)	(154)
Public Debt Interest - Electricity Sector (OEFC Interest revenue)	**(520)**	**(514)**	**(454)**	**(454)**	**(454)**	**(454)**
MOF Provision Expense (before adjustments)	**3**	**302**	**(142)**	**156**	**103**	**312**
Other Adjustments						
Prior-year Adjustment[2]		3				
Exclude Brampton[3]		(15)				
MOF Provision Expense (after other adjustments)	**0**	**290**	**(142)**	**156**	**103**	**312**
Cumulative Shortfall Adjustment						
Opening Balance	0	0	0	(142)	0	0
Deduction / (Addition)	0	0	(142)	142	0	0
Ending Balance	0	0	(142)	0	0	0
Dedicated Electricity Earnings (all adjustments) (Public Accounts)	**0**	**290**	**0**	**14**	**103**	**312**
Electricity Sector Dedicated Income (OEFC Annual Report)	**3**	**302**	**0**	**14**	**103**	**312**

Notes:

1. The Hydro One financials above currently reflects the Provincial share allocation as the May 2017 final offering.

2. 2016-17 Adjustment was due to the discrepancy between the numbers in MOF expense in PA 2015-16 and OEFC Financials in 2015-16 due to timing issues. $3M adjustment rectifies this discrepancy

3. Brampton was excluded from the Ministry of Finance's ESDI allocation.

Ontario Power Generation

OPG Income - Budget 2017

$ Millions

	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
OPG Net Income After Tax (Adjusted)	291	304	97	732	625	1,066
OPG Net Income After Tax	*291*	*379*	*480*	*678*	*726*	*913*
Extraordinary Gains	-	-	-	-	-	-
GA - OPG Trust Interest Revenue			*17*	*54*	*99*	*153*
OPG IFRS consolidation risk picked up in Fiscal Plan		(75)	(400)		(200)	
ONFA and other Fair Value Adjustments	(75)	8				
ONFA Adjustments	-	8				
Other Fair Value Adjustments	(75)					

OPG PIL - Budget 2017

$ Millions

	Actual	Interim		Pl
	2015-16	2016-17	2017-18	2018-19
Net Income Before Tax	383	396	572	867
Net Income After Tax (Adjusted)	291	304	97	732
Income Taxes	92	92	92	135
GRC: Payable to OEFC	198	196	205	212
Proxy Property Tax	16	14	18	19
Ontario Capital Tax	0	0	0	0
Total	**306**	**302**	**315**	**366**

OPG Income - January 2018

$ Millions

	Actual	Actual	Current Outlook			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
OPG Net Income	291	377	857	678	726	913
Adjustment for OPG HQ gain on sale[1]			(283)			
Unpacking updated OPG Gain on sale (net income)						
OEB December 28, 2017 Rate Decision Impact[2]			(320)	(109)	(115)	(136)
Extraordinary Gains	0	0	0	0	0	0
GA Financing - OPG Trust Interest Revenue[3]			12	42	82	128
OPG IFRS consolidation risk reflected in Fiscal Plan[4]		(78.00)	(400)		(200)	
Update IFRS Risk			0	(475)	(500)	(750)
OPG Net Income (Adjusted before ONFA)	**291**	**299**	**(134)**	**137**	**(7)**	**156**
ONFA Adjustments	247	49	171			
Other Fair Value Adjustments	(75)	(6)				
ONFA and other Fair Value Adjustments	**172**	**43**	**171**			
OPG Net Income	**463**	**342**	**37**	**137**	**(7)**	**156**

OPG PIL - January 2018

$ Millions

	Actual	Actual		Current
	2015-16	2016-17	2017-18	2018-19
Income Before Tax	383	308	723	235
OPG Net Income (Adjusted before ONFA)	291	299	(134)	137
OPG Income Tax (PILs)	92	9	162	135
OEB December 28, 2017 Rate Decision Impact[2]			(107)	(36)
Tax adjustment for OPG HQ gain on sale[1]			(95)	
Unpack PILs related to HQ gain on sale				
GRC: Payable to OEFC	198	201	214	224
Proxy Property Tax to OEFC	16	14	18	19
Ontario Capital Tax	0	0	0	0
Total OPG PILs	**306**	**224**	**192**	**342**

1. OPG's May 2017 head office facilities sale impacts are re-categorized from Sales and Rentals to OPG net income and PILs in the current Electricity Outlook update.
2. OEB December 28, 2017 estimated rate decision impacts are split between net income and PILs and a 75%/25% basis.
3. This reflects interest earnings on GA financing costs which are consolidated back to Province
4. See Risks tab for IFRS impacts that were not reflected in Fiscal Plan, and table below.

	2017-18	2018-19	2019-20	2020-21
OPG IFRS Risk	(400)	(475)	(700)	(750)

Hydro One Ownership Calculation:	
Total number of shares outstanding[1]	595,000,000
IPO November 2015	
Initial Public Offering(2015)[2]	81,100,000
Over allotment option (2015)[3]	8,150,000
Sales to PWU/SEP Trusts	5,646,340
Total	94,896,340
Province's remaining ownership, Nov 2015 (# Shares)	**500,103,660**
Province's remaining ownership, Nov 2015 (%)	**84.05%**
Secondary Offering April 2016	
Secondary Offering (2016)	72,434,800
Over allotment option (2016)	10,865,200
Total	83,300,000
Province's remaining ownership, Apr 2016 (# Shares)	**416,803,660**
Province's remaining ownership, Apr 2016 (%)	**70.05%**
Final Offering May 2017	
Final Offering (2017)	120,000,000
Over allotment option (2017)	-
Total	120,000,000
Province's remaining ownership, May 8, 2017 (# Shares)	296,803,660
Province's remaining ownership, May 8, 2017 (%)	**49.88%**
First Nations Sale, closed on December 29, 2017	14,391,012
	2.4%
Province's remaining onwership - post First Nations Sale (#Shares)	282,412,648
Province's remaining onwership - post First Nations Sale (%)	**47.46%**
Avista Impact (projected closing date 2nd half of 2018)	
Contingent Convertible Debenture	$1,540,000,000
Conversion Price	$21
Potential Dilution (# Shares)	71,962,617
Revised Total number of shares outstanding	**666,962,617**
Province's remaining onwership - post Avista Acquisition (#Shares)	282,412,648
Province's remaining onwership - post Avista Aquisition (%)	**42.34%**

SOURCE:

1. Hydro One Ltd Annual Report 2015, pg 94 of PDF, pg 92 of the Report.

2. From news release: http://hydroone.mediaroom.com/2015-11-05-Hydro-One-Limited-Announces-Closing-of-IPO

3. From news release: http://hydroone.mediaroom.com/2015-11-12-Hydro-One-Limited-Announces-Closing-of-IPO-Over-Allotment-Option

4. Hydro One Ltd. Q2 Report, pg 1 http://www.hydroone.com/InvestorRelations/FinancialReporting/Documents/Hydro%20One%20Ltd%20Second%20Qu

Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by

Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by

Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by

Source: http://www.r S:\Users\CEF\Hydro 2018\OEFC\RbP\Outlook\01. January\Backup\20180103-0 - H1 First Nations Sales\

Source: https://news.ontario.ca/mei/en/2017/05/ontario-raises-28-billion-from-final-hydro-one-share-offering.html

Ownership Percentage in 2017-18 Fiscal Year	Number of Months	Percentage of Year
70.05%	1	8.3%
49.88%	8	66.7%
47.46%	3	25.0%
	12	
Average 2017-18 FY Ownership:	**51.0%**	

Ownership Percentage in 2018-19 Fiscal Year (assume Avista closing end of September 2018)	Number of Months	Percentage of Year
47.46%	6	50.0%
42.34%	6	50.0%
	12	
Average 2018-19 FY Ownership:	**44.9%**	

Ownership Percentage in 2019-20 Fiscal Year Onwards
42.34%

Accretive to earnings per share and cash flow for Hydro One in the first full year post closing

above is from Hydro One transaction overview. Check what this means for timing of additional shares and /or earnings.

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-the-Province-of-Ontario
-the-Province-of-Ontario

-the-Province-of-Ontario

Hydro One Net Income and PILs

Hydro One Income - Budget 2017
($ millions)

	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Hydro One Net Income After Tax	685	737	742	802	862	931
Hydro One - Unrealized Gains Adjustment						

2016-17 to 2020-21 from CEFD Hydro One 2016 model.

Hydro One PIL - Budget 2017
($ millions)

	2015-16	2016-17	2017-18	2018-19
Net Income After Tax	685	737	742	802
Income Taxes PILs	132	160	181	205
Proxy Property Tax	2	2	2	2
Ontario Capital Tax	0	0	0	0
Total	**134**	**162**	**183**	**207**

Hydro One Income - December 2017
($ millions) **$ Millions**

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Hydro One Net Income After Tax			645	690	780	845
Debenture Costs Impacts (After Tax)			(34)	(39)		
Hydro One Net Income After Tax - Including Adjustments	670	680	612	651	780	845
Hydro One - Net Income Attributable to Preferred Shareholders	15	18				
Hydro One - Unrealized Gains Adjustment						

Hydro One (100% Ownership)
($ millions) **$ Millions**

	Actual 2015-16	Actual 2016-17	2017-18	Current 2018-19
Net Income After Tax - Common Shares	670	680	612	651
Net Income After Tax - Preferred Shares	15	18		
Income Taxes PILs	132	160	181	205
Proxy Property Tax	2	2	2	2
Ontario Capital Tax	0	0	0	0

Public Debt Interest and Section 50.3 payments

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Hydro One Public Debt Interest and Section 50.3 payments						
Government Annual Interest Costs - Hydro One	220	220	220	220	220	220
Reduction in Interest Costs due to Broadening[1]		(29)	(66)	(66)	(66)	(66)
Province Annual Interest Costs - Hydro One Debt	**220**	**191**	**154**	**154**	**154**	**154**
Province Annual Interest Cost - OPG Debt	300	300	300	300	300	300
Total Public Debt Interest	**520**	**514**	**454**	**454**	**454**	**454**

$ Millions

	Actual 2015-16	Actual 2016-17	Current Outlook 2017-18	2018-19	2019-20	2020-21
Gain to OEFC under s. 50.3	172	411	550	0	0	0

1. The Hydro One reduction in interest costs above currently reflects a 70.5% Provincial share allocation as of the secondary offering in April 2016. Net estimated fiscal impacts related to the last Hydro One offering are currently reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

ID# (Track Cha	Fiscal Year	alue (Hardcode	Value (Linked)	Description	Source Details	Source (Link)
20170501-2	2016-17	411,152,733	411,152,733	s 50.3 Gain for	Calculation provided by SIFB	
20170501-3	2016-17	29	29	Reduction in Int	Internal Calculation	
20170501-3	2017-18	66	66	Reduction in Int	Internal Calculation	
20170501-3	n/a	220	220	Annual Interest	Internal Calculation	

ID# (Track Cha	Fiscal Year	alue (Hardcode	Value (Linked)	Description	Source Details	Source (Link)
n/a	n/a	5126		($M) Provinces	OEFC 1999-2000 FS, pg 24	
n/a	n/a	5.85%		Annual Interest	OEFC 1999-2000 FS, pg 26	
		299.871				

OPG's Annual Interest Costs: 300

20170713-1	2016-17	-513,768,361	Provincial interest cost for equity investment in OPG, H1 in 2016-17 Monthly Balances Sheet (from FTD) S:\Users\CEF\Hydro 2017\OEFC\RbP\Outlook\07. July\Backup\20170713-1\interest fr

om Province.pdf

PROVINCIAL CONSOLIDATION ADJUSTMENTS
Ontario Nuclear Funds Agreement

Adjustment for Change in OPG Reported Net Income

Adjustment for DSF Unrealized Earnings

Unrealized Earnings as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Bruce Variance Account Adjustment
OPG Net Income Adjustment

Adjustment for UFSF Unrealized Earnings

Unrealized Earnings as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Bruce Variance Account Adjustment
OPG Net Income Adjustment

Unrealized Earnings -- Fiscal YTD

Adjustment for Change in Due to Province

Adjustment for DSF Due to Province
Due to Province (cost basis) as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Change in Due to Province -- Fiscal YTD

Adjustment for UFSF Due to Province

Due to Province (cost basis) as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Change in Due to Province -- Fiscal YTD

Provincial Consolidation Adjustment

Other Data

	Actual 2016-17	2017-18
Debt Retirement Charge	621	0

	2016-17	2017-18
Power Supply Contract Recoveries	838	292

	2016-17	2017-18
Interest		
OPG	167	169
IESO	2	3
Other (Net)	20	20
Expense		
Debt interest	1216	1121

	Actual 2016-17	2017-18
MEU - PIL Income Tax	109.8	
MEU - PIL Property Tax	0.6	
MEU - GRC	1.2	
TOTAL MEU PILs	111.6	

	Actual 2016-17	2017-18
Miscellaneous/Other (OEFC FS)	14	
Demand Management Support Costs (IEI)	8	10
Operating [Expense]	7	6
Interest on nuclear risk funding	-	-
Amortization of deferred debt costs	-	-
Amortization of NUG liability	129	74
Debt Guarantee Fee	122	102

Expense (Electrictiy Summary Tab)		
Other (Finance)	-7	-6
Demand Management Support Costs (IEI)	-8	-10
Debt Guarantee Fee	(122)	(102)

Plan		
2018-19	2019-20	2020-21
0	0	0

Plan		
2018-19	2019-20	2020-21
325	301	273

Plan		
2018-19	2019-20	2020-21
179	175	148
3	3	3
20	10	10
1094	1053	963

Plan		
2018-19	2019-20	2020-21

Plan		
2018-19	2019-20	2020-21
7	7	7
-	-	-
-	-	-
41	30	28
99	98	91
-7	-7	-7
(99)	(98)	(91)

ID# (Track Changes	Fiscal Year	Value (Hardcoded)	Value (Linked)
20170510-2	2016-17	$ 739,216,115	
20170510-2	2017-18	$ 291,629,707	
20170510-2	2018-19	$ 324,906,017	
20170510-2	2019-20	$ 300,648,570	
20170510-2	2020-21	$ 273,240,858	
20170501-4	2016-17	179	179
20170501-4	2017-18	169	169
20170501-4	2018-19	179	179
20170501-4	2019-20	175	175
20170501-4	2020-21	148	148
20170501-5	2016-17	1216	1,216
20170501-5	2017-18	1121	1,121
20170501-5	2018-19	1094	1,094
20170501-5	2019-20	1053	1,053
20170501-5	2020-21	963	963
20170731-3	2016-17	621	
20170811-1	2016-17	109.8	
20170811-1	2016-17	0.6	
20170811-1	2016-17	1.2	
20170815-5	2016-17	$ 838,000,000	
20170815-6	2016-17	$ 14,000,000	
20170815-8	2016-17	8	
20170815-9	2017-18	10	
20170815-10	2016-17	7	
20171211-2	2017-18	6	6
20171211-2	2018-19	7	7
20171211-2	2019-20	7	7
20171211-2	2020-21	7	7
20170815-7	2016-17	167	
20170815-7	2016-17	2	
20170815-7	2016-17	20	
20170815-7			

ID# (Track Changes	Fiscal Year	Value (Hardcoded)	Value (Linked)
20170905-1	2016-17	129	129
20170905-1	2017-18	74	74

20170905-1	2018-19	41	41
20170905-1	2019-20	30	30
20170905-1	2020-21	28	28
20170905-2	2016-17	122	
20170906-1	2017-18	3	3
20170906-1	2018-19	3	3
20170906-1	2019-20	3	3
20170906-1	2020-21	3	3
20170906-1	2017-18	20	5
20170906-1	2018-19	20	5
20170906-1	2019-20	10	5
20170906-1	2020-21	10	5
20171211-0	2017-18	1121	1,121
20171211-0	2018-19	1094	1,094
20171211-0	2019-20	1053	1,053
20171211-0	2020-21	963	963
20171211-1	2017-18	102	102
20171211-1	2018-19	99	99
20171211-1	2019-20	98	98
20171211-1	2020-21	91	91
20171211-1			
20171211-1			
20171211-1			
20171211-1			
20171211-1			
20171211-1			
20171211-1			
20171211-1			
20171211-1			

Description	Source Details	Source (Link)
The table below contains an updated preliminary N	SPFB Estimates, Email	
• The tables below provides both last year's submission for NUG costs by CEFD and this year's estimates (both of which exclude HST) based on the most recent NUG model.	SPFB Estimates, BN SPFB Estimates, BN SPFB Estimates, BN SPFB Estimates, BN	
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
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MEU - PIL Income Tax	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
MEU - PIL Property Tax	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
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OEFC Operating Expense - Updating to Actuals	2017 OEFC AR	S:\Users\CEF\Hydro 2017\OEFC'
Revised Operating Expense from FTD Forecast	FTD - October PRRT	
OPG Interest Revenue - Actuals 2016-17	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
IESO Interest Revenue - Actuals 2016-17		
Other (Net) Interest Revenue - Actuals 2016-17		

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		S:\Users\CEF\Hydro 2017\OEFC'
	Amortization Schedule.	S:\Users\CEF\Hydro 2017\OEFC'

Sourcing the NUG liability amortization schedule.	Tab: Summary Fiscal Impact	S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC'
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Colour Codes

Formulas are in black text

Hard coded numbers are in blue text

References elsewhere are in purple

Green bold text with or without highlights mean updates required

Policies to follow when making updates to the Outlook

*** To quickly jump to the source numbers for a link, press "**Ctrl + [**"

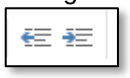
All new numbers must be fully sourced, and follow the colour codes above

Most numbers and text are Arial Size 10, unless it is a title

Add back up materials in a folder with the same numbers as in the 'Track Changes' tab

If there is a reason for italics, or other colours, or formatting make sure it is clear. Othe

Use indents to make things more clear to read



If numbers are taken from another tab they should ONLY be direct links, no calculation

Electricity Summary - (Budget17/On Deck) - Reflects Public Accounts/Financial Statem

OEFC - (Budget17/On Deck) - Reflects OEFC Annual Reports

*Due to slight discrepancies between Public Accounts reporting and OEFC Annual Rep

Outlook Updates Frequency

Frequency	Description	Tab
Monthly	OPG Net Income in-year forecast	OPG
Monthly	OPG PILs in-year forecast	OPG
Quarterly	ONFA Consolidation Adjustment	ONFA
Quarterly	OPG Cash vs Accrual Variance Account	Revenue (Risks)

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rwise expect it to be cleared

ı, adjustment should be done. Even if its just making a negative to a positive. Perform all the calculations on the

ıents

ɔorts, the numbers may not be identical

source tab then bring the number into the next tab. (Eg. Formulas like this become hard to troubleshoot ='Hydro

One'!AR29+'Hydro One'!AR31+'Hydro One'!AR32), let's avoid them.

From:	Lewis, Brian (MOF)
To:	Ronald Kwan
Subject:	RE: Statement from Minister Thibeault on the Ontario Energy Board"s New Regulated Price Plan Electricity Rate Announcement
Date:	Thursday, June 22, 2017 5:05:09 PM

Thanks Ron. Good to know.

From: Ronald Kwan [mailto:Ronald.Kwan@ofina.on.ca]
Sent: June 22, 2017 5:00 PM
To: Lewis, Brian (MOF)
Subject: RE: Statement from Minister Thibeault on the Ontario Energy Board's New Regulated Price Plan Electricity Rate Announcement

Hi Brian,

This is the next step in the implementation of the Fair Hydro Plan announced in March and incorporated into the Budget 2017 Fiscal Plan. As such, there is no incremental change to the OPG outlook in the plan associated with the OEB announcement today.

Ron

From: Lewis, Brian (MOF) [mailto:Brian.Lewis@Ontario.ca]
Sent: June-22-17 16:23
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Subject: FW: Statement from Minister Thibeault on the Ontario Energy Board's New Regulated Price Plan Electricity Rate Announcement

Hi Ron,

Does this have an impact on the OPG net income outlook?

Brian

From: Ontario News [mailto:newsroom@ontario.ca]
Sent: June 22, 2017 12:26 PM
To: Lewis, Brian (MOF)
Subject: Statement from Minister Thibeault on the Ontario Energy Board's New Regulated Price Plan Electricity Rate Announcement

Ontario Newsroom

Statement

Statement from Minister Thibeault on the Ontario Energy Board's New Regulated Price Plan Electricity Rate Announcement[news.ontario.ca]

June 22, 2017

Today, Glenn Thibeault, Minister of Energy, issued the following statement in response to the Ontario Energy Board's (OEB) announcement to lower electricity prices for residential and small business customers on the Regulated Price Plan (RPP):

“Premier Wynne committed to reducing electricity bills by 25 per cent on average for households across the province, and today represents the next stage in the implementation of Ontario’s Fair Hydro Plan.

The Ontario Energy Board Regulated Price Plan announcement means that the average 25 per cent reduction will be in place effective July 1 for all households in Ontario, providing real and significant relief on hydro costs. As many as half a million small businesses and farms will also benefit. The 25 per cent includes the eight per cent rebate, equal to the provincial portion of the HST that took effect on January 1, 2017. Our plan also holds any increases in electricity bills to the rate of inflation for four years.

Low-income Ontarians and those living in eligible rural or remote communities will receive even greater reductions, as much as 40 to 50 per cent on their bills through the already expanded Ontario Electricity Support Program and the broadening of the Rural or Remote Rate Protection program, while the delivery charge portion of residential electricity bills will be removed for on-reserve First Nations communities.

The OEB will continue to serve in its important role, which includes establishing reasonable rates and protecting energy consumers, while also ensuring proper investments are made to maintain long-term system reliability. Ontario’s 2017 Long-Term Energy Plan, to be released later this summer, will focus on taking additional costs out of the system, and address long-term affordability.

Our government committed to providing significant and real relief on hydro bills for people across Ontario, and we have delivered on this pledge.”

CONTACTS

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416-325-2690

Colin.Nekolaichuk@ontario.ca

Natasha Demetriades
Communications Branch
416 327-3855
Natasha.Demetriades@ontario.ca

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From:	Ken Kandeepan
To:	John Kim
Cc:	Carlos Yep; John Psinas; James Devine; Anna Strathy; Ronald Kwan
Subject:	RE: Summary of the OFHP
Date:	Friday, October 27, 2017 10:36:44 AM

Thanks John, for the FE to present earnings there has to be some sort of a revenue stream, not sure how that is possible in the first four years given the structure of the OFHP, much appreciated if you can share the details of the revenue mechanism as soon as it becomes available.

I am cc'ing Ron as well in case he can shed additional light.

Thanks

Ken k

From: John Kim
Sent: Friday, October 27, 2017 10:26 AM
To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
Cc: Carlos Yep <Carlos.Yep@ofina.on.ca>; John Psinas <John.Psinas@ofina.on.ca>; James Devine <James.Devine@ofina.on.ca>; Anna Strathy <Anna.Strathy@ofina.on.ca>
Subject: RE: Summary of the OFHP

Hi Ken,

I meant to come up to chat but got tied up preparing for the LMSo this morning.

The details are not yet clear to me but my understanding is that FE will continue to earn even in the first 4 yrs. The mechanism to do that is still under discussion and potentially will involve some sort of a deferral account. This was the reason for Energy's delay in providing us the numbers for the borrowing requirement last week.

Thanks,

John

From: Ken Kandeepan
Sent: Thursday, October 26, 2017 5:10 PM
To: John Kim <John.Kim@ofina.on.ca>
Cc: Carlos Yep <Carlos.Yep@ofina.on.ca>; John Psinas <John.Psinas@ofina.on.ca>; James Devine <James.Devine@ofina.on.ca>; Anna Strathy <Anna.Strathy@ofina.on.ca>
Subject: Summary of the OFHP

Hi john

The way I understand the operations of the OFHP at least for the first 4 years is as follows:

IESO pays 100% to the generators and charges ratepayers approximately 83%, with the difference set up as a regulatory asset funded vi a credit facility of $2 billion form the Province. On a quarterly basis the regulatory asset will be purchased by the Financing Entity with debt issued to OPG (49%) and the capital markets (51%).

Over the first four years the Financing Entity has no revenue sources hence interest on this debt will be paid via additional borrowings issued in the same proportion. Once the CEA kicks in, it will be used to pay interest and draw down debt as appropriate.

Happy to discuss, I am relatively free in the AM tomorrow.

Thanks

Ken k

From:	Nelms, Scott (MOF)
To:	Veinot, Cindy (TBS); Ronald Kwan
Subject:	RE: What amounts if any have been provided to the budget process for GA refinancing re OPG?
Date:	Monday, April 17, 2017 1:19:35 PM

I'm copying Ron, in case he has more insight. I understand that OFA assumed incremental IOD using the ~$1.25B /yr equity infusion from the Province (consistent with the announced curve) and OFA's typical borrowing rate. On the other side OFA assumed equivalent incremental earnings from OPG to ensure the initiative is fiscally neutral. I don't have visibility into the specific numbers, but this is, in concept, what I understand was included.

From: Veinot, Cindy (TBS)
Sent: April-17-17 1:18 PM
To: Nelms, Scott (MOF)
Subject: What amounts if any have been provided to the budget process for GA refinancing re OPG?

Sent from my BlackBerry 10 smartphone on the Rogers network.

From: Nelms, Scott (MOF)
To: Veinot, Cindy (TBS); Ronald Kwan
Subject: RE: What amounts if any have been provided to the budget process for GA refinancing re OPG?
Date: Monday, April 17, 2017 3:38:49 PM

Not to my knowledge. I asked OPG whether they had yet made any assumptions around borrowing requirements, but they were not ready to prepare this forecast, given uncertainties. For now I would think of it as a plug to get to a $0 fiscal impact.

-----Original Message-----
From: Veinot, Cindy (TBS)
Sent: April-17-17 3:35 PM
To: Kwan, Ronald (OFA)
Cc: Nelms, Scott (MOF)
Subject: Re: What amounts if any have been provided to the budget process for GA refinancing re OPG?

Thanks. Was that assumption validated with OPG?

Sent from my BlackBerry 10 smartphone on the Rogers network.
Original Message
From: Ronald Kwan
Sent: Monday, April 17, 2017 2:56 PM
To: Veinot, Cindy (TBS)
Cc: Nelms, Scott (MOF)
Subject: Re: What amounts if any have been provided to the budget process for GA refinancing re OPG?

Hi,

Staff used Ken's estimated UOD impact and added the same amount to OPG results to have no net impact, by assumption.

Ron

> On Apr 17, 2017, at 1:23 PM, Veinot, Cindy (TBS) <Cindy.Veinot@ontario.ca> wrote:
>
> Thanks. I confirmed with Ken re what OFA included re IOD, but don't have any visibility into what was included for OPG's role.
>
> Cindy
>
> Sent from my BlackBerry 10 smartphone on the Rogers network.
> From: Nelms, Scott (MOF)
> Sent: Monday, April 17, 2017 1:19 PM
> To: Veinot, Cindy (TBS); Kwan, Ronald (OFA)
> Subject: RE: What amounts if any have been provided to the budget process for GA refinancing re OPG?
>
>
> I'm copying Ron, in case he has more insight. I understand that OFA assumed incremental IOD using the ~$1.25B /yr equity infusion from the Province (consistent with the announced curve) and OFA's typical borrowing rate. On the other side OFA assumed equivalent incremental earnings from OPG to ensure the initiative is fiscally neutral. I don't have visibility into the specific numbers, but this is, in concept, what I understand was included.
>
> From: Veinot, Cindy (TBS)
> Sent: April-17-17 1:18 PM

> To: Nelms, Scott (MOF)
> Subject: What amounts if any have been provided to the budget process for GA refinancing re OPG?
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> Sent from my BlackBerry 10 smartphone on the Rogers network.

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From: John Kim
To: Ronald Kwan; Usman Zahid
Subject: RE: sensitive Fair Hydro Trust question
Date: Friday, April 27, 2018 4:22:55 PM

Hi Usman,

Adding to Ron's comments, we have debt costs related to the equity injection that needs to be accounted for.

We have OPG's insight into what the income attributed to FHT would be in their business plan.

We can produce this, yes, and in fact working towards it for ESDI reasons but we would need numbers from Risk.

Thanks,

John

From: Ronald Kwan
Sent: Friday, April 27, 2018 3:37 PM
To: Usman Zahid <Usman.Zahid@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>
Subject: Re: sensitive Fair Hydro Trust question

Hi,

While Lubna may not want OPG to get into it, I think we have to cite the borrowing cost on the equity injection. It would be good to know what sub-debt rates OPG assumed on its interest revenues over the life of the Trust.

Ron

From: Usman Zahid
Sent: April 27, 2018 3:25 PM
To: John Kim
Cc: Ronald Kwan
Subject: FW: sensitive Fair Hydro Trust question

Hi John,

Please see question from Energy below.

Regards,
Usman

From: Pichette, Marc (MOF) [mailto:Marc.Pichette@ontario.ca]
Sent: Friday, April 27, 2018 1:32 PM
To: Usman Zahid <Usman.Zahid@ofina.on.ca>
Subject: FW: sensitive Fair Hydro Trust question

Hi Usman, please see question below from the Ministry of Energy that was sent to my director.

From: Whytock, John (ENERGY) <John.Whytock@ontario.ca>
Date: Thursday, Apr 26, 2018, 4:45 PM
To: LeBlanc, Jenna (MOF) <Jenna.LeBlanc@ontario.ca>
Subject: FW: sensitive Fair Hydro Trust question

Hi Jenna. I've got a sensitive question for you. Our MO asked what the revenue implications of the Fair Hydro Trust were for OPG, and how much we estimated would return to the provincial coffers.

As you'll see below, OPG has put a number on their own expected revenues, but my policy folks were not in a position to say what it could mean for returns to government.

Is this a number that Finance can produce? More importantly, are you willing to share?

Thanks much

jw

From: ROWE Jennifer -CORPAFFAIRS [mailto:jennifer.rowe@opg.com]
Sent: April-23-18 10:19 AM
To: Whytock, John (ENERGY)
Cc: KELLY Neal -CORPCOMM
Subject: RE: EXTERNAL – Fair Hydro Trust question

John,

Here's a simplified version of what I just sent you:

The total amount of income that OPG expects to earn over the life of the Fair Hydro Plan is in the range of **$4.5 Billion to $4.9 Billion.** The actual amount will vary based on the actual debt issued and interest rates.

This is over a period of 30 years (2017 to 2047). The income will be earned gradually, and will peak around 2029/2030.

Since the Province owns OPG, and consolidates OPG into their books, the net income flows back to

the Province.

Jennifer

From: LADAK Lubna -TREASURY
Sent: Monday, April 23, 2018 10:14 AM
To: ROWE Jennifer -CORPAFFAIRS <jennifer.rowe@opg.com>; KELLY Neal -CORPCOMM <neal.kelly@opg.com>; HARTWICK Ken -FINANCE <ken.hartwick@opg.com>
Cc: LEE John -TREASURY <john.s.lee@opg.com>; LIU Sheen -TREASURY <sheen.liu@opg.com>; LAURETA LAPIRA May -TREASURY <may.lapira@opg.com>
Subject: RE: EXTERNAL – Fair Hydro Trust question

The total amount of income that OPG expects to earn over the life of the Fair Hydro Plan is in the range of $4.5 Billion to $4.9 Billion.
It is comprised of about $200 M for management fees and $4.3 Billion to $4.7 Billion of interest income.

The actual amount will vary based on the actual debt issued and interest rates.

This is over a period of 30 years (2017 to 2047). The income will be earned gradually, and will peak around 2029/2030.

Since the Province owns OPG, and consolidates OPG into their books, the net income flows back to the Province.

FYI – I don't know how the Province funds the equity injections. If they borrow the funds, the overall net income impact in their books could be lower. I wouldn't get into this though.

Lubna Ladak | VP Treasury - FHP| Ontario Power Generation
700 University Avenue, Toronto, Ontario M5G 1X6 | 416-592-5984 | Cell 416-578-0219 | Fax 416-592-4189
lubna.ladak@opg.com

From: Ronald Kwan
To: John Kim
Subject: Re: Draft Fees Regulation
Date: Wednesday, September 27, 2017 4:18:41 PM

Hi John,

Could you get me back on the e-mail chain.

Thanks,
Ron

From: John Kim
Sent: September 27, 2017 3:50 PM
To: Ronald Kwan
Subject: FW: Draft Fees Regulation

Fyi, went back with some minor comments.

From: John Kim
Sent: Wednesday, September 27, 2017 3:43 PM
To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>; Mike Manning <Mike.Manning@ofina.on.ca>; James Devine <James.Devine@ofina.on.ca>
Cc: Carlos Yep <Carlos.Yep@ofina.on.ca>
Subject: RE: Draft Fees Regulation

Some minor comments. All under Base Fee section.

I'd convey that the compromise of 5bps is still generous more explicitly. I think that was Jim's comment. The rest of the comments imply it but could be useful. "10bps is high. We would recommend a compromise of 5bps to start, which we feel is still generous and to be reviewed in a year."

Where it says "This is consistent with the actual fees paid by OPG and the Province…", consider adding "also" to imply that it is referring to the 1-2bps for passive fixed income funds.

"From a significant economics of the financing entity,…" I wasn't quite sure what this is trying to say. Could be just me.

From: Ken Kandeepan
Sent: Wednesday, September 27, 2017 2:54 PM
To: Mike Manning <Mike.Manning@ofina.on.ca>; James Devine <James.Devine@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>

Cc: Carlos Yep <Carlos.Yep@ofina.on.ca>
Subject: RE: Draft Fees Regulation

Hi Mike at al

Pls see the draft email back to Scott Nelms, all credit to Carlos. Mike you may want to send it to Scott with cc's to the usual suspects, if you have any logistical issues, I am happy to do so, I will wait until 4.30 and if I don't hear from you will send it out.

Thanks

Ken k

From: Carlos Yep
Sent: Wednesday, September 27, 2017 2:43 PM
To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
Subject: FW: Draft Fees Regulation
Importance: High

Ken
Here are some thoughts …

Base Fee: 10bps is high. We recommend a compromise of 5bps to be reviewed in a year.
As background, market investment manager fees are 1-2bps for passive fixed income funds.
This is consistent with the actual fees paid by OPG and Province to co-manage the nuclear fund's index fixed income funds. The index funds require constant rebalancing by the investment manager.

From a significant economics of the financing entity, OPG is getting 44% equity investment from the Province at 0% cost and lending the funds as subordinated debt at a forecasted yield of around 5%. Ie. For each $2.5B of Global Asset X 44% equity injection would contribute $55million net revenue to OPG for each of 10 years and would be a reduced amounts for the following 30 years as the Global Asset is paid down.

Variable Fee: We recommend going back to the original proposal of "… not more than plus/minus 1% … on the net annual funding obligation …"
That means deleting column 1 and item 2 of the table.

Pass through costs: Pass through costs as outlined in the draft regulations appear reasonable. As suggested in Scott's email including tighter language that prevents any OPG costs from being passed through makes sense. As further due diligence it may be advisable for the for the Financing Entity as part of its annual audit or a separate assurance audit to have the external auditors opine whether the actual pass through costs of the Financing Entity in each fiscal year is in accordance with the regulations.

From: Mike Manning
Sent: Tuesday, September 26, 2017 1:53 PM
To: James Devine <James.Devine@ofina.on.ca>; Carlos Yep <Carlos.Yep@ofina.on.ca>
Cc: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
Subject: FW: Draft Fees Regulation
Importance: High

I was talking to Ken Kandeepan, and he was talking about arranging a meeting for as early as tomorrow.

Mike

From: Nelms, Scott (MOF) [mailto:Scott.Nelms@ontario.ca]
Sent: Tuesday, September 26, 2017 12:18 PM
To: Gadi Mayman <Gadi.Mayman@ofina.on.ca>
Cc: Steen Hume (CAB) <Steen.Hume@ontario.ca>; Mike Manning <Mike.Manning@ofina.on.ca>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Subject: Draft Fees Regulation
Importance: High

Hi Gadi,

I hope NYC is going well and you are finding air conditioning.

We have been working with Steen's team and Energy legal on a draft of the fees regulation for OPG Trust and OFHP. As we progress through this, there are some elements of the regulation that we were hoping you and the OFA team might be able to consider (please see attached a black line for your reference):

- The draft reg outlines a base fee as well as a variable fee.
  - The base fee is provided monthly at an annual rate of 10-basis points for the first two years (we had this initially set at one year but Torys' markup changes this to two years). After 2019, the base fee is provided at an annual rate of 8 basis points should the funding obligations exceed $10B. Does this seem reasonable?
  - The variable fee structure seems consistent with previous discussions (5 basis point fee provided on the spread). Do you think this makes sense?
  - It would also be helpful if the OFA could let us know if the method for calculating the monthly funding obligation is reasonable.
- With respect to costs, our understanding is that these sorts of costs are typically a pass through; can the OFA confirm? The Torys markup removes OEB oversight on costs but we are wondering if there should be a role for the OFA in reviewing / providing oversight in this regard?
  - Also, do the costs they've outlined seem reasonable? In particular, LSB is wondering whether this leaves the door open for OPG to pass through any overhead costs (i.e. should we be

explicit about excluding them)?

- On timing, the draft reg currently contemplates a fee application by OPG every two years regardless of what interest rates are in the market. Do we think this is fair or should the application occur annually? (Note that until new fees are established, the old fees are still in effect).

In terms of next steps, OPG would like to get a draft to their Board in time for the meeting on Friday. ENERGY LSB is hoping for comments by tomorrow. I don't think we need anything too detailed or formal, but a quick sniff test would be useful to ensure we are on the right track.

Thanks for your help,
Scott

From: Gadi Mayman
To: Scott Nelms (ENERGY)
Cc: Steen Hume (CAB); Mike Manning; Ronald Kwan; Ken Kandeepan
Subject: Re: Draft Fees Regulation
Date: Tuesday, September 26, 2017 2:15:30 PM

Thanks, Scott. I understand that there are a few items in here that are a little different than what we'd expected, so we'll get back to you with our consolidated OFA response tomorrow.

Regards,
Gadi

On Sep 26, 2017, at 12:18 PM, Nelms, Scott (MOF) <Scott.Nelms@ontario.ca> wrote:

> Hi Gadi,
>
> I hope NYC is going well and you are finding air conditioning.
>
> We have been working with Steen's team and Energy legal on a draft of the fees regulation for OPG Trust and OFHP. As we progress through this, there are some elements of the regulation that we were hoping you and the OFA team might be able to consider (please see attached a black line for your reference):
>
> - The draft reg outlines a base fee as well as a variable fee.
>   - The base fee is provided monthly at an annual rate of 10-basis points for the first two years (we had this initially set at one year but Torys' markup changes this to two years). After 2019, the base fee is provided at an annual rate of 8 basis points should the funding obligations exceed $10B. Does this seem reasonable?
>   - The variable fee structure seems consistent with previous discussions (5 basis point fee provided on the spread). Do you think this makes sense?
>   - It would also be helpful if the OFA could let us know if the method for calculating the monthly funding obligation is reasonable.
> - With respect to costs, our understanding is that these sorts of costs are typically a pass through; can the OFA confirm? The Torys markup removes OEB oversight on costs but we are wondering if there should be a role for the OFA in reviewing / providing oversight in this regard?
>   - Also, do the costs they've outlined seem reasonable? In particular, LSB is wondering whether this leaves the door open for OPG to pass through any overhead costs (i.e. should we be explicit about excluding them)?

<!--[if !supportLists]-->• <!--[endif]-->On timing, the draft reg currently contemplates a fee application by OPG every two years regardless of what interest rates are in the market. Do we think this is fair or should the application occur annually? (Note that until new fees are established, the old fees are still in effect).

In terms of next steps, OPG would like to get a draft to their Board in time for the meeting on Friday. ENERGY LSB is hoping for comments by tomorrow. I don't think we need anything too detailed or formal, but a quick sniff test would be useful to ensure we are on the right track.

Thanks for your help,
Scott

<Blackline_24180663v1 - 24180663v3.pdf>

From: John Kim
To: Ken Kandeepan; Mike Manning; James Devine
Cc: Carlos Yep; Ronald Kwan
Subject: Re: Draft Fees Regulation
Date: Wednesday, September 27, 2017 4:20:15 PM

Looping Ron in the email chain.

Sent from my iPhone

On Sep 27, 2017, at 3:42 PM, John Kim <John.Kim@ofina.on.ca> wrote:

> Some minor comments. All under Base Fee section.
>
> I'd convey that the compromise of 5bps is still generous more explicitly. I think that was Jim's comment. The rest of the comments imply it but could be useful. "10bps is high. We would recommend a compromise of 5bps to start, which we feel is still generous and to be reviewed in a year."
>
> Where it says "This is consistent with the actual fees paid by OPG and the Province…", consider adding "also" to imply that it is referring to the 1-2bps for passive fixed income funds.
>
> "From a significant economics of the financing entity,…" I wasn't quite sure what this is trying to say. Could be just me.
>
> ---
>
> **From:** Ken Kandeepan
> **Sent:** Wednesday, September 27, 2017 2:54 PM
> **To:** Mike Manning <Mike.Manning@ofina.on.ca>; James Devine <James.Devine@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>
> **Cc:** Carlos Yep <Carlos.Yep@ofina.on.ca>
> **Subject:** RE: Draft Fees Regulation
>
> Hi Mike at al
>
> Pls see the draft email back to Scott Nelms, all credit to Carlos. Mike you may want to send it to Scott with cc's to the usual suspects, if you have any logistical issues, I am happy to do so, I will wait until 4.30 and if I don't hear from you will send it out.
>
> Thanks
>
> Ken k
>
> ---
>
> **From:** Carlos Yep
> **Sent:** Wednesday, September 27, 2017 2:43 PM
> **To:** Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>

Subject: FW: Draft Fees Regulation
Importance: High

Ken
Here are some thoughts …

Base Fee: 10bps is high. We recommend a compromise of 5bps to be reviewed in a year.
As background, market investment manager fees are 1-2bps for passive fixed income funds.
This is consistent with the actual fees paid by OPG and Province to co-manage the nuclear fund's index fixed income funds. The index funds require constant rebalancing by the investment manager.
From a significant economics of the financing entity, OPG is getting 44% equity investment from the Province at 0% cost and lending the funds as subordinated debt at a forecasted yield of around 5%.
Ie. For each $2.5B of Global Asset X 44% equity injection would contribute $55million net revenue to OPG for each of 10 years and would be a reduced amounts for the following 30 years as the Global Asset is paid down.

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That means deleting column 1 and item 2 of the table.

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From: Mike Manning
Sent: Tuesday, September 26, 2017 1:53 PM
To: James Devine <James.Devine@ofina.on.ca>; Carlos Yep <Carlos.Yep@ofina.on.ca>
Cc: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
Subject: FW: Draft Fees Regulation
Importance: High

I was talking to Ken Kandeepan, and he was talking about arranging a meeting for as early as tomorrow.

Mike

From: Nelms, Scott (MOF) [mailto:Scott.Nelms@ontario.ca]
Sent: Tuesday, September 26, 2017 12:18 PM
To: Gadi Mayman <Gadi.Mayman@ofina.on.ca>
Cc: Steen Hume (CAB) <Steen.Hume@ontario.ca>; Mike Manning <Mike.Manning@ofina.on.ca>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Subject: Draft Fees Regulation
Importance: High

Hi Gadi,

I hope NYC is going well and you are finding air conditioning.

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application occur annually? (Note that until new fees are established, the old fees are still in effect).

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Thanks for your help,
Scott

From: Ken Kandeepan
To: Ronald Kwan
Cc: Gadi Mayman; Lynsey Wynberg; Mike Manning; Gavin He
Subject: Re: EXTERNAL – RE: OEFC Funding of the Global Adjustment Deferral
Date: Wednesday, February 15, 2017 10:36:30 PM

That's my understanding as well.

Thanks

Ken k

On Feb 15, 2017, at 10:34 PM, Ronald Kwan <Ronald.Kwan@ofina.on.ca> wrote:

> Hi. Ken, emails crossed. I agree, but it would mean OPG is not being regulated by the OEB on this.
>
> Ron
>
> On Feb 15, 2017, at 10:32 PM, Ken Kandeepan <Ken.Kandeepan@ofina.on.ca> wrote:
>
> > No, I was informed by OPCD that IESO will set up the reg asset as you point out but will promptly sell same to the Trust. So the expectation is that at the end of each fiscal year the reg asset set up in that year would be sold to the OPG Trust.
> >
> > Thanks
> >
> > Ken k
> >
> > On Feb 15, 2017, at 10:27 PM, Ronald Kwan <Ronald.Kwan@ofina.on.ca> wrote:
> >
> > > Hi,
> > >
> > > I may be wrong on this, so correct me if so, as I have not been at the accounting meetings on this structure.
> > >
> > > But, based on the Energy submission, I took it as IESO would have the regulatory asset. As such, I took it that the Trust would be outside of OPG's OEB regulated entity.
> > >
> > > Ron
> > >
> > > On Feb 15, 2017, at 10:21 PM, Gadi Mayman <Gadi.Mayman@ofina.on.ca> wrote:

First getting it past their auditors will be a challenge, as you've said, and secondly getting the OEB to accept that OPG should be earning the extra $750 million per year that we'd need at the peak of the debt accumulation will be even more challenging. It would have to be a hit to ratepayers. That would be even harder to explain than a hit to them from an ROE to the Province, which, as you've seen, I've had trouble wrapping my mind around in earlier emails.

On Feb 15, 2017, at 10:11 PM, Ken Kandeepan <Ken.Kandeepan@ofina.on.ca> wrote:

> Not entirely, though the underlying concept is similar. This is just logical speculation on my part but what John is probably driving at is the Trust pays OPG the interest but instead of expensing same it's capitalized.
>
> As such when the Trust is consolidated with OPG the interest income remains in OPG's books since there is no expense to offset it in the books of the Trust.
>
> Ergo, OPG has a net interest income which all else being equal increases its net income, which in turn when consolidated with Province, provides the required fiscal offset to the increase in the Province's IOD.
>
> The problem here would be how willing OPG's auditors will be in recognizing an interest income on OPG books that will be paid in about 15 years time and that too on a piecemeal basis.

Having said all of this let me repeat I may be quite mistaken and John may have a more feasible solution in mind.

Thanks

Ken k

On Feb 15, 2017, at 9:36 PM, Gadi Mayman <Gadi.Mayman@ofina.on.ca> wrote:

> Sounds to me that they're going where Scott Nelms alluded to in his email with an ROE for the Province that would offset our borrowing cost?
>
> Adding Ron and Mike so that all of us at the OFA are aware of the same facts, as this is moving quickly, and any of us may be asked at any time about it, including on Friday when you and I are away,
> Ken.
>
> Gadi
>
> ---
>
> **From:** Ken Kandeepan

Sent: Wednesday, February 15, 2017 9:19 PM
To: Gadi Mayman
Cc: Lynsey Wynberg
Subject: Fwd: EXTERNAL – RE: OEFC Funding of the Global Adjustment Deferral

Hi Gadi

My exchange with John, as you can see little short on the details.

Thanks

Ken k

Begin forwarded message:

From: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>

Date: February 15, 2017 at 6:36:48 PM EST
To: LEE John - TREASURY <john.s.lee@opg.com>

Cc: "Veinot, Cindy (TBS)" <Cindy.Veinot@ontario.ca>, "Nadine Petsche

(MOF)"
<Nadine.Petsche@ontario.ca>,
RYFA
Ken -
TREASURY
<ken.ryfa@opg.com>,
CHENG
Alec -
FIN &
C
CTRL
<alec.cheng@opg.com>

Subject:
Re:
EXTERNAL
â€“
RE:
OEFC
Funding
of the
Global
Adjustment
Deferral

Thanks
John, it
seems
that
what
you are
saying
is
OPG's
net
income
will
increase,
all else
being
equal,
by the
amount
of the
interest
relating
to the
equity

injection.

In
which
case
upon
consolidation
there
will be
no
fiscal
impact
to the
Province.

As you
work
through
the
options
this
needs
to be
fleshed
out
since
the
Trust
will be
consolidated
with
OPG
we
need to
understand
how
OPG
will
show a
net
interest
income.

Thanks

Ken k

On Feb 15, 2017, at 6:28 PM, LEE John - TREASURY <john.s.lee@opg.com> wrote:

Ken:

To clarify the expectation is that equity injected into OPG which is on-lend to the Trust would result in net interest income that would roll up to the Province

and
this
would
cover
the
interest
expense
for
the
associated
debt
at
the
Province.
The
dividend
comment
was
meant
to
describe
mechanism
on
how
to
get
cash
to
the
province.

John

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-
Original
Message-
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-

From:
Ken
Kandeepan
[mailto:Ken.Kandeepan@ofina.on.ca]

Sent:
Wednesday,
February
15,
2017
5:51
PM

To:
LEE
John
-
TREASURY;
'Veinot,
Cindy
(TBS)'

Cc:
Nadine
Petsche
(MOF)

Subject:
RE:
EXTERNAL
–
RE:
OEFC
Funding
of
the
Global
Adjustment
Deferral

Hi
John
and

Cindy

I
just
realized
that
in
the
event
of
an
equity
injection
by
the
Province
to
OPG
for
a
maximum
of
49%,
will
as
we
discussed,
have
no
impact
on
the
Province's
net
debt.

Unfortunately
there
will
be
an
IOD
impact.
John,

I remember you mentioning that OPG will increase the dividends it pays to the Province by an amount equivalent to the interest on the equity injection to date, however, that will only provide a cash and not a fiscal offset.

The only way a fiscal offset

can
be
provided
is
if
OPG's
net
income
increases
by
an
amount
equal
to
the
increase
in
the
Province's
IOD
(
all
else
being
equal).
In
which
case
the
Province
will
be
fiscally
whole
upon
consolidation.

But
I
am
not
sure
that
going
to
happen
since

the Trust will not contribute to OPG's bottom line, or at least that's my understanding.

As such the potential fiscal impact from the increased IOD may be an issue for the Province re this option. In any event I will check with Gadi and circle back.

Thanks

Ken
k

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-
-
Original
Message-
-
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-
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From:
HAHN
PARKER
Janet
-
TREASURY
[mailto:j.hahnparker@opg.com]

Sent:
Wednesday,
February
15,
2017
4:50
PM

To:
Ken
Kandeepan
<Ken.Kandeepan@ofina.on.ca>

Cc:
LEE
John
-
TREASURY
<john.s.lee@opg.com>;
'Veinot,
Cindy
(TBS)'
<Cindy.Veinot@ontario.ca>

Subject:
RE:
EXTERNAL
–
RE:
OEFC
Funding
of
the
Global
Adjustment
Deferral

Thank
you.
Will
do.

-
-
-
-
-
Original
Message-
-
-
-
-

From:
Ken

Kandeepan
[mailto:Ken.Kandeepan@ofina.on.ca]

Sent:
Wednesday,
February
15,
2017
4:49
PM

To:
HAHN
PARKER
Janet
-
TREASURY

Cc:
LEE
John
-
TREASURY;
'Veinot,
Cindy
(TBS)'

Subject:
RE:
EXTERNAL
–
RE:
OEFC
Funding
of
the
Global
Adjustment
Deferral

Cindy
is
free
now

if
you
can
set
up
the
call.

Thanks

Ken
k

-
-
-
-
-
Original
Message-
-
-
-
-

From:
HAHN
PARKER
Janet
-
TREASURY
[mailto:j.hahnparker@opg.com]

Sent:
Wednesday,
February
15,
2017
3:43
PM

To:
Ken
Kandeepan
<Ken.Kandeepan@ofina.on.ca>

Cc:
LEE
John
-
TREASURY
<john.s.lee@opg.com>

Subject:
RE:
EXTERNAL
–
RE:
OEFC
Funding
of
the
Global
Adjustment
Deferral

Thank
you.

This
is
of
utmost
importance.
Please
advise
soonest.

Janet

-

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-
-
Original
Message-
-
-
-
-

From:
Ken
Kandeepan
[mailto:Ken.Kandeepan@ofina.on.ca]

Sent:
Wednesday,
February
15,
2017
3:37
PM

To:
HAHN
PARKER
Janet
-
TREASURY

Cc:
LEE
John
-
TREASURY

Subject:
RE:
EXTERNAL
–
RE:
OEFC
Funding
of
the

Global
Adjustment
Deferral

My
apologies
for
the
delay,
unfortunately
I
am
yet
to
hear
back
from
Cindy,
will
let
you
know
as
soon
as
I
do.

Thanks

Ken
K

-
-
-
-
-
Original

Message-
-
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-
-

From:
HAHN
PARKER
Janet
-
TREASURY
[mailto:j.hahnparker@opg.com]

Sent:
Wednesday,
February
15,
2017
1:57
PM

To:
Ken
Kandeepan
<Ken.Kandeepan@ofina.on.ca>

Cc:
LEE
John
-
TREASURY
<john.s.lee@opg.com>

Subject:
RE:
EXTERNAL
–
RE:
OEFC
Funding
of
the
Global
Adjustment
Deferral

Ken,

Please advise on this call. Timing is important.

A prompt response would be most appreciated,

Thank you,

Janet Hahn Parker

416 592-6749

j.hahnparker@opg.com

-

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-
-
-
Original
Message-
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-
-

From:
Ken
Kandeepan
[mailto:Ken.Kandeepan@ofina.on.ca]

Sent:
Wednesday,
February
15,
2017
9:30
AM

To:
LEE
John
-
TREASURY

Cc:
CHENG
Alec
-
FIN
&
C
CTRL;
RYFA
Ken
-
TREASURY;
LIU
Sheen
-
TREASURY;
HAHN

PARKER
Janet
-
TREASURY

Subject:
EXTERNAL
–
RE:
OEFC
Funding
of
the
Global
Adjustment
Deferral

***
Exercise
caution.
This
is
an
EXTERNAL
email.
DO
NOT
open
attachments
or
click
links
from
unknown
senders
or
unexpected
email.
***

Thanks
John
for
the

quick response, I have forwarded your email to Cindy, since her presence and/or Nadine's is essential if we are having a conference call, will get back to you as soon as I hear from her.

Ken
K

-
-
-
-

-
Original
Message-
-
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-
-

From:
LEE
John
-
TREASURY
[mailto:john.s.lee@opg.com]

Sent:
Wednesday,
February
15,
2017
9:09
AM

To:
Ken
Kandeepan
<Ken.Kandeepan@ofina.on.ca>

Cc:
CHENG
Alec
-
FIN
&
C
CTRL
<alec.cheng@opg.com>;
RYFA
Ken
-
TREASURY
<ken.ryfa@opg.com>;
LIU
Sheen
-
TREASURY
<sheen.liu@opg.com>;

HAHN
PARKER
Janet
-
TREASURY
<j.hahnparker@opg.com>

Subject:
RE:
OEFC
Funding
of
the
Global
Adjustment
Deferral

Ken:

Got
your
voice
message
with
respect
to
your
proposal
to
have
OEFC
fund
the
Global
Adjustment
deferral
indirectly
by
lending
to
OPG
and
having
OPG

subsequently lend to a Financing Trust. I agree that this would be the simplest funding mechanism. However since the key objective for the Province to avoid having to recognize the debt and writeoff the Global Adjustment deferral OPG must maintain Government Business Entity (GBE) status. In order to remain a

GBE, we must be able to "in the normal course of its operations, maintain its operations and meet its liabilities from revenue received from sources outside of the government reporting entity." I understanding from Alec Cheng (OPG accounting) who was on yesterday accounting call with Nadine (Controllers Office) that OPG

GBE status would be put at high risk under the proposed scheme due to the proposed quantum of lending from the OEFC.

Our accounting group along with Treasury will be performing some further assessment on this but it may be worth arranging another call with you and your accounting group

to
layout
the
issues
since
the
Province
seems
to
be
driven
by
very
tight
and
uncertain
timelines
and
I
want
everyone
to
be
up
to
speed.

We
can
make
ourselves
available
for
a
call
this
morning.
Please
advise.

John

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From: Ken Kandeepan
To: Ronald Kwan
Cc: Gadi Mayman; Lynsey Wynberg; Mike Manning; Gavin He
Subject: Re: EXTERNAL – RE: OEFC Funding of the Global Adjustment Deferral
Date: Wednesday, February 15, 2017 10:32:21 PM

No, I was informed by OPCD that IESO will set up the reg asset as you point out but will promptly sell same to the Trust. So the expectation is that at the end of each fiscal year the reg asset set up in that year would be sold to the OPG Trust.

Thanks

Ken k

On Feb 15, 2017, at 10:27 PM, Ronald Kwan <Ronald.Kwan@ofina.on.ca> wrote:

> Hi,
>
> I may be wrong on this, so correct me if so, as I have not been at the accounting meetings on this structure.
>
> But, based on the Energy submission, I took it as IESO would have the regulatory asset. As such, I took it that the Trust would be outside of OPG's OEB regulated entity.
>
> Ron
>
> On Feb 15, 2017, at 10:21 PM, Gadi Mayman <Gadi.Mayman@ofina.on.ca> wrote:
>
> > First getting it past their auditors will be a challenge, as you've said, and secondly getting the OEB to accept that OPG should be earning the extra $750 million per year that we'd need at the peak of the debt accumulation will be even more challenging. It would have to be a hit to ratepayers. That would be even harder to explain than a hit to them from an ROE to the Province, which, as you've seen, I've had trouble wrapping my mind around in earlier emails.
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> >
> > > Not entirely, though the underlying concept is similar. This is just logical speculation on my part but what John is probably driving at is the Trust pays OPG the interest but instead of expensing same it's capitalized.
> > >
> > > As such when the Trust is consolidated with OPG the interest income remains in OPG's books since there is no

expense to offset it in the books of the Trust.

Ergo, OPG has a net interest income which all else being equal increases its net income, which in turn when consolidated with Province, provides the required fiscal offset to the increase in the Province's IOD.

The problem here would be how willing OPG's auditors will be in recognizing an interest income on OPG books that will be paid in about 15 years time and that too on a piecemeal basis.

Having said all of this let me repeat I may be quite mistaken and John may have a more feasible solution in mind.

Thanks

Ken k

On Feb 15, 2017, at 9:36 PM, Gadi Mayman <Gadi.Mayman@ofina.on.ca> wrote:

> Sounds to me that they're going where Scott Nelms alluded to in his email with an ROE for the Province that would offset our borrowing cost?
>
> Adding Ron and Mike so that all of us at the OFA are aware of the same facts, as this is moving quickly, and any of us may be asked at any time about it, including on Friday when you and I are away, Ken.
>
> Gadi
>
> **From:** Ken Kandeepan
> **Sent:** Wednesday, February 15, 2017 9:19 PM
> **To:** Gadi Mayman
> **Cc:** Lynsey Wynberg
> **Subject:** Fwd: EXTERNAL – RE: OEFC Funding of the Global Adjustment Deferral
>
> Hi Gadi

My exchange with John, as you can see little short on the details.

Thanks

Ken k

Begin forwarded message:

From: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
Date: February 15, 2017 at 6:36:48 PM EST
To: LEE John -TREASURY <john.s.lee@opg.com>
Cc: "Veinot, Cindy (TBS)" <Cindy.Veinot@ontario.ca>, "Nadine Petsche (MOF)" <Nadine.Petsche@ontario.ca>, RYFA Ken -TREASURY <ken.ryfa@opg.com>, CHENG Alec -FIN & C CTRL <alec.cheng@opg.com>
Subject: Re: EXTERNAL â€“ RE: OEFC Funding of the Global Adjustment Deferral

Thanks John, it seems that what you are saying is OPG's net income will increase, all else being equal, by the amount of the interest relating to the equity injection.

In which case upon consolidation there will be no fiscal impact to the Province.

As you work through the options this needs to be fleshed out since the Trust will be consolidated with OPG we need to understand how OPG will show a net interest income.

Thanks

Ken k

On Feb 15, 2017, at 6:28 PM, LEE John -TREASURY <john.s.lee@opg.com> wrote:

Ken:

To clarify the expectation is that equity injected into OPG which is on-lend to the Trust would result in net interest income that would roll up to the Province and this would cover the interest expense for the associated debt at the Province. The dividend comment was meant to describe mechanism on how to get cash to the province.

John

-----Original Message-----

From: Ken Kandeepan [mailto:Ken.Kandeepan@ofina.on.ca]

Sent: Wednesday, February 15, 2017 5:51 PM

To: LEE John - TREASURY; 'Veinot, Cindy (TBS)'

Cc: Nadine Petsche (MOF)

Subject: RE: EXTERNAL – RE: OEFC Funding of the Global Adjustment Deferral

Hi John and Cindy

I just realized that in the event of an equity injection by the Province to OPG for a maximum of 49%, will as we discussed, have no impact on the Province's net debt.

Unfortunately there will be an IOD impact. John, I remember you mentioning that OPG will increase the dividends it pays to the Province by an amount equivalent to the interest on the equity injection to date, however, that will only provide a cash and not a fiscal offset.

The only way a fiscal offset can be provided is if OPG's net income increases by an amount equal to the increase in the Province's IOD (all else being equal). In which case the Province will be fiscally whole upon consolidation.

But I am not sure that going to happen since the Trust will not contribute to OPG's bottom line, or at least that's my understanding.

As such the potential fiscal impact from the increased IOD may be an issue for the Province re this option. In any event I will check with Gadi and circle back.

Thanks

Ken k

-----Original

Message-----

From: HAHN PARKER Janet - TREASURY [mailto:j.hahnparker@opg.com]

Sent: Wednesday, February 15, 2017 4:50 PM

To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>

Cc: LEE John - TREASURY <john.s.lee@opg.com>; 'Veinot, Cindy (TBS)' <Cindy.Veinot@ontario.ca>

Subject: RE: EXTERNAL – RE: OEFC Funding of the Global Adjustment Deferral

Thank you. Will do.

-----Original Message-----

From: Ken Kandeepan [mailto:Ken.Kandeepan@ofina.on.ca]

Sent: Wednesday, February 15, 2017 4:49 PM

To: HAHN

PARKER Janet - TREASURY

Cc: LEE John - TREASURY; 'Veinot, Cindy (TBS)'

Subject: RE: EXTERNAL – RE: OEFC Funding of the Global Adjustment Deferral

Cindy is free now if you can set up the call.

Thanks

Ken k

-----Original Message-----

From: HAHN PARKER Janet - TREASURY [mailto:j.hahnparker@opg.com]

Sent: Wednesday, February 15, 2017 3:43 PM

To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>

Cc: LEE John - TREASURY <john.s.lee@opg.com>

Subject: RE: EXTERNAL – RE: OEFC Funding of the Global Adjustment Deferral

Thank you.

This is of utmost importance. Please advise soonest.

Janet

-----Original Message-----

From: Ken Kandeepan [mailto:Ken.Kandeepan@ofina.on.ca]

Sent: Wednesday, February 15, 2017 3:37 PM

To: HAHN PARKER Janet - TREASURY

Cc: LEE John - TREASURY

Subject: RE: EXTERNAL – RE: OEFC Funding of the Global Adjustment Deferral

My apologies for the delay, unfortunately I am

yet to hear back
from Cindy, will let
you know as soon
as I do.

Thanks

Ken K

-----Original
Message-----

From: HAHN
PARKER Janet -
TREASURY
[mailto:j.hahnparker@opg.com]

Sent: Wednesday,
February 15, 2017
1:57 PM

To: Ken
Kandeepan
<Ken.Kandeepan@ofina.on.ca>

Cc: LEE John -
TREASURY
<john.s.lee@opg.com>

Subject: RE:
EXTERNAL – RE:
OEFC Funding of
the Global
Adjustment
Deferral

Ken,

Please advise on

this call. Timing is important.

A prompt response would be most appreciated,

Thank you,

Janet Hahn Parker

416 592-6749

j.hahnparker@opg.com

-----Original Message-----

From: Ken Kandeepan [mailto:Ken.Kandeepan@ofina.on.ca]

Sent: Wednesday, February 15, 2017 9:30 AM

To: LEE John - TREASURY

Cc: CHENG Alec - FIN & C CTRL; RYFA Ken - TREASURY; LIU Sheen - TREASURY; HAHN PARKER Janet -TREASURY

Subject: EXTERNAL – RE: OEFC Funding of the Global Adjustment Deferral

*** Exercise caution. This is an EXTERNAL email. DO NOT open attachments or click links from unknown senders or unexpected email. ***

Thanks John for the quick response, I have forwarded your email to Cindy, since her presence and/or Nadine's is essential if we are having a conference call, will get back to you as soon as I hear from her.

Ken K

-----Original Message-----

From: LEE John - TREASURY [mailto:john.s.lee@opg.com]

Sent: Wednesday, February 15, 2017 9:09 AM

To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>

Cc: CHENG Alec - FIN & C CTRL <alec.cheng@opg.com>; RYFA Ken - TREASURY <ken.ryfa@opg.com>; LIU Sheen - TREASURY <sheen.liu@opg.com>; HAHN PARKER Janet -TREASURY <j.hahnparker@opg.com>

Subject: RE: OEFC Funding of the Global Adjustment Deferral

Ken:

Got your voice message with respect to your proposal to have OEFC fund the Global Adjustment deferral indirectly by lending to OPG and having OPG subsequently lend to a Financing Trust. I agree that this would be the simplest funding mechanism. However since the key objective for the Province to avoid having to recognize the debt and writeoff the Global Adjustment deferral OPG must maintain

Government Business Entity (GBE) status. In order to remain a GBE, we must be able to “in the normal course of its operations, maintain its operations and meet its liabilities from revenue received from sources outside of the government reporting entity.” I understanding from Alec Cheng (OPG accounting) who was on yesterday accounting call with Nadine (Controllers Office) that OPG GBE status would be put at high risk under the proposed scheme due to the proposed quantum of lending from the OEFC. Our accounting group along with Treasury will be performing some further assessment on this but it may be worth arranging another call with you and your accounting group to layout the issues since the Province seems to be driven by very tight and uncertain timelines and I want everyone to be up to speed.

We can make ourselves available for a call this morning. Please advise.

John

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From:	Gadi Mayman
To:	Ken Kandeepan
Cc:	Lynsey Wynberg; Ronald Kwan; Mike Manning; Gavin He
Subject:	Re: EXTERNAL – RE: OEFC Funding of the Global Adjustment Deferral
Date:	Wednesday, February 15, 2017 10:21:28 PM

First getting it past their auditors will be a challenge, as you've said, and secondly getting the OEB to accept that OPG should be earning the extra $750 million per year that we'd need at the peak of the debt accumulation will be even more challenging. It would have to be a hit to ratepayers. That would be even harder to explain than a hit to them from an ROE to the Province, which, as you've seen, I've had trouble wrapping my mind around in earlier emails.

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> >
> > Adding Ron and Mike so that all of us at the OFA are aware of the same facts, as this is moving quickly, and any of us may be asked at

any time about it, including on Friday when you and I are away, Ken.

Gadi

From: Ken Kandeepan
Sent: Wednesday, February 15, 2017 9:19 PM
To: Gadi Mayman
Cc: Lynsey Wynberg
Subject: Fwd: EXTERNAL – RE: OEFC Funding of the Global Adjustment Deferral

---

Hi Gadi

My exchange with John, as you can see little short on the details.

Thanks

Ken k

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> **From:** Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
> **Date:** February 15, 2017 at 6:36:48 PM EST
> **To:** LEE John -TREASURY <john.s.lee@opg.com>
> **Cc:** "Veinot, Cindy (TBS)" <Cindy.Veinot@ontario.ca>, "Nadine Petsche (MOF)" <Nadine.Petsche@ontario.ca>, RYFA Ken -TREASURY <ken.ryfa@opg.com>, CHENG Alec -FIN & C CTRL <alec.cheng@opg.com>
> **Subject: Re: EXTERNAL â€“ RE: OEFC Funding of the Global Adjustment Deferral**
>
> Thanks John, it seems that what you are saying is OPG's net income will increase, all else being equal, by the amount of the interest relating to the equity injection.
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Sent: Wednesday, February 15, 2017 5:51 PM

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Cc: Nadine Petsche (MOF)

Subject: RE: EXTERNAL – RE: OEFC Funding of the Global Adjustment Deferral

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To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>

Cc: LEE John -TREASURY

<john.s.lee@opg.com>; 'Veinot, Cindy (TBS)' <Cindy.Veinot@ontario.ca>

Subject: RE: EXTERNAL – RE: OEFC Funding of the Global Adjustment Deferral

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Sent: Wednesday, February 15, 2017 4:49 PM

To: HAHN PARKER Janet -TREASURY

Cc: LEE John -TREASURY; 'Veinot, Cindy (TBS)'

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Subject: RE: EXTERNAL – RE: OEFC
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Janet

-----Original Message-----

From: Ken Kandeepan
[mailto:Ken.Kandeepan@ofina.on.ca]

Sent: Wednesday, February 15, 2017 3:37 PM

To: HAHN PARKER Janet -TREASURY

Cc: LEE John -TREASURY

Subject: RE: EXTERNAL – RE: OEFC
Funding of the Global Adjustment Deferral

My apologies for the delay, unfortunately I am yet to hear back from Cindy, will let you know as soon as I do.

Thanks

Ken K

-----Original Message-----

From: HAHN PARKER Janet -TREASURY
[mailto:j.hahnparker@opg.com]

Sent: Wednesday, February 15, 2017 1:57 PM

To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>

Cc: LEE John -TREASURY <john.s.lee@opg.com>

Subject: RE: EXTERNAL – RE: OEFC Funding of the Global Adjustment Deferral

Ken,

Please advise on this call. Timing is important.

A prompt response would be most appreciated,

Thank you,

Janet Hahn Parker

416 592-6749

j.hahnparker@opg.com

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From: Ken Kandeepan [mailto:Ken.Kandeepan@ofina.on.ca]

Sent: Wednesday, February 15, 2017 9:30 AM

To: LEE John -TREASURY

Cc: CHENG Alec -FIN & C CTRL; RYFA Ken -TREASURY; LIU Sheen -TREASURY; HAHN PARKER Janet -TREASURY

Subject: EXTERNAL – RE: OEFC Funding of the Global Adjustment Deferral

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Thanks John for the quick response, I have forwarded your email to Cindy, since her presence and/or Nadine's is essential if we are having a conference call, will get back to you as soon as I hear from her.

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From: LEE John -TREASURY [mailto:john.s.lee@opg.com]

Sent: Wednesday, February 15, 2017 9:09 AM

To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>

Cc: CHENG Alec -FIN & C CTRL <alec.cheng@opg.com>; RYFA Ken -TREASURY <ken.ryfa@opg.com>; LIU Sheen -TREASURY <sheen.liu@opg.com>; HAHN PARKER Janet -TREASURY <j.hahnparker@opg.com>

Subject: RE: OEFC Funding of the Global Adjustment Deferral

Ken:

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We can make ourselves available for a call this morning. Please advise.

John

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From: Ken Kandeepan
To: Gadi Mayman
Cc: Lynsey Wynberg; Ronald Kwan; Mike Manning; Gavin He
Subject: Re: EXTERNAL – RE: OEFC Funding of the Global Adjustment Deferral
Date: Wednesday, February 15, 2017 10:11:47 PM

Not entirely, though the underlying concept is similar. This is just logical speculation on my part but what John is probably driving at is the Trust pays OPG the interest but instead of expensing same it's capitalized.

As such when the Trust is consolidated with OPG the interest income remains in OPG's books since there is no expense to offset it in the books of the Trust.

Ergo, OPG has a net interest income which all else being equal increases its net income, which in turn when consolidated with Province, provides the required fiscal offset to the increase in the Province's IOD.

The problem here would be how willing OPG's auditors will be in recognizing an interest income on OPG books that will be paid in about 15 years time and that too on a piecemeal basis.

Having said all of this let me repeat I may be quite mistaken and John may have a more feasible solution in mind.

Thanks

Ken k

On Feb 15, 2017, at 9:36 PM, Gadi Mayman <Gadi.Mayman@ofina.on.ca> wrote:

> Sounds to me that they're going where Scott Nelms alluded to in his email with an ROE for the Province that would offset our borrowing cost?
>
> Adding Ron and Mike so that all of us at the OFA are aware of the same facts, as this is moving quickly, and any of us may be asked at any time about it, including on Friday when you and I are away, Ken.
>
> Gadi
>
> ---
>
> **From:** Ken Kandeepan
> **Sent:** Wednesday, February 15, 2017 9:19 PM
> **To:** Gadi Mayman
> **Cc:** Lynsey Wynberg
> **Subject:** Fwd: EXTERNAL – RE: OEFC Funding of the Global Adjustment Deferral
>
> Hi Gadi

My exchange with John, as you can see little short on the details.

Thanks

Ken k

Begin forwarded message:

> **From:** Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
> **Date:** February 15, 2017 at 6:36:48 PM EST
> **To:** LEE John -TREASURY <john.s.lee@opg.com>
> **Cc:** "Veinot, Cindy (TBS)" <Cindy.Veinot@ontario.ca>, "Nadine Petsche (MOF)" <Nadine.Petsche@ontario.ca>, RYFA Ken -TREASURY <ken.ryfa@opg.com>, CHENG Alec -FIN & C CTRL <alec.cheng@opg.com>
> **Subject: Re: EXTERNAL â€“ RE: OEFC Funding of the Global Adjustment Deferral**
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> In which case upon consolidation there will be no fiscal impact to the Province.
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> As you work through the options this needs to be fleshed out since the Trust will be consolidated with OPG we need to understand how OPG will show a net interest income.
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> > On Feb 15, 2017, at 6:28 PM, LEE John -TREASURY <john.s.lee@opg.com> wrote:
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> > Ken:
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> > To clarify the expectation is that equity injected into OPG which is on-lend to the Trust would result in net interest income that would roll up to the Province and this would cover the interest expense for the associated debt at the Province. The dividend comment was meant to describe mechanism on how to get cash to the province.

John

-----Original Message-----

From: Ken Kandeepan
[mailto:Ken.Kandeepan@ofina.on.ca]

Sent: Wednesday, February 15, 2017 5:51 PM

To: LEE John -TREASURY; 'Veinot, Cindy (TBS)'

Cc: Nadine Petsche (MOF)

Subject: RE: EXTERNAL – RE: OEFC Funding of the Global Adjustment Deferral

Hi John and Cindy

I just realized that in the event of an equity injection by the Province to OPG for a maximum of 49%, will as we discussed, have no impact on the Province's net debt.

Unfortunately there will be an IOD impact. John, I remember you mentioning that OPG will increase the dividends it pays to the Province by an amount equivalent to the interest on the equity injection to date, however, that will only provide a cash and not a fiscal offset.

The only way a fiscal offset can be provided is if OPG's net income increases by an amount equal to the increase in the Province's IOD (all else being equal). In which case the Province will be fiscally whole upon consolidation.

But I am not sure that going to happen since the Trust will not contribute to OPG's bottom line, or at least that's

my understanding.

As such the potential fiscal impact from the increased IOD may be an issue for the Province re this option. In any event I will check with Gadi and circle back.

Thanks

Ken k

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From: HAHN PARKER Janet -TREASURY [mailto:j.hahnparker@opg.com]

Sent: Wednesday, February 15, 2017 4:50 PM

To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>

Cc: LEE John -TREASURY <john.s.lee@opg.com>; 'Veinot, Cindy (TBS)' <Cindy.Veinot@ontario.ca>

Subject: RE: EXTERNAL – RE: OEFC Funding of the Global Adjustment Deferral

Thank you. Will do.

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Subject: RE: EXTERNAL – RE: OEFC Funding of the Global Adjustment Deferral

Cindy is free now if you can set up the call.

Thanks

Ken k

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Sent: Wednesday, February 15, 2017 3:43 PM

To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>

Cc: LEE John -TREASURY <john.s.lee@opg.com>

Subject: RE: EXTERNAL – RE: OEFC Funding of the Global Adjustment Deferral

Thank you.

This is of utmost importance. Please advise soonest.

Janet

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Sent: Wednesday, February 15, 2017 3:37 PM

To: HAHN PARKER Janet -TREASURY

Cc: LEE John -TREASURY

Subject: RE: EXTERNAL – RE: OEFC Funding of the Global Adjustment Deferral

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We can make ourselves available for a call this morning. Please advise.

John

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Inc.

From: Gadi Mayman
To: Ronald Kwan
Cc: Ken Kandeepan; Lynsey Wynberg; Mike Manning; Gavin He
Subject: Re: EXTERNAL – RE: OEFC Funding of the Global Adjustment Deferral
Date: Wednesday, February 15, 2017 10:07:28 PM

It'd be a very interesting intellectual challenge if billions of dollars didn't rest on the outcome.

On Feb 15, 2017, at 9:58 PM, Ronald Kwan <Ronald.Kwan@ofina.on.ca> wrote:

> Thanks Gadi.
>
> I feel some sympathy for Scott N, and Cindy as they try to have viable options on the table, when it's such a challenging task.
>
> Ron
>
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me by return e-mail and delete this message from your system. Ontario Power Generation Inc.

From: Gadi Mayman
To: Ken Kandeepan
Cc: Lynsey Wynberg; Ronald Kwan; Mike Manning; Gavin He
Subject: Re: EXTERNAL – RE: OEFC Funding of the Global Adjustment Deferral
Date: Wednesday, February 15, 2017 9:36:08 PM

Sounds to me that they're going where Scott Nelms alluded to in his email with an ROE for the Province that would offset our borrowing cost?

Adding Ron and Mike so that all of us at the OFA are aware of the same facts, as this is moving quickly, and any of us may be asked at any time about it, including on Friday when you and I are away, Ken.

Gadi

From: Ken Kandeepan
Sent: Wednesday, February 15, 2017 9:19 PM
To: Gadi Mayman
Cc: Lynsey Wynberg
Subject: Fwd: EXTERNAL – RE: OEFC Funding of the Global Adjustment Deferral

Hi Gadi

My exchange with John, as you can see little short on the details.

Thanks

Ken k

Begin forwarded message:

> **From:** Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
> **Date:** February 15, 2017 at 6:36:48 PM EST
> **To:** LEE John -TREASURY <john.s.lee@opg.com>
> **Cc:** "Veinot, Cindy (TBS)" <Cindy.Veinot@ontario.ca>, "Nadine Petsche (MOF)" <Nadine.Petsche@ontario.ca>, RYFA Ken -TREASURY <ken.ryfa@opg.com>, CHENG Alec -FIN & C CTRL <alec.cheng@opg.com>
> **Subject: Re: EXTERNAL â€“ RE: OEFC Funding of the Global Adjustment Deferral**
>
> Thanks John, it seems that what you are saying is OPG's net income will increase, all else being equal, by the amount of the interest relating to the equity injection.
>
> In which case upon consolidation there will be no fiscal impact to the Province.
>
> As you work through the options this needs to be fleshed out since the Trust will

be consolidated with OPG we need to understand how OPG will show a net interest income.

Thanks

Ken k

> On Feb 15, 2017, at 6:28 PM, LEE John -TREASURY <john.s.lee@opg.com> wrote:
>
> Ken:
>
> To clarify the expectation is that equity injected into OPG which is on-lend to the Trust would result in net interest income that would roll up to the Province and this would cover the interest expense for the associated debt at the Province. The dividend comment was meant to describe mechanism on how to get cash to the province.
>
> John
>
> -----Original Message-----
>
> From: Ken Kandeepan [mailto:Ken.Kandeepan@ofina.on.ca]
>
> Sent: Wednesday, February 15, 2017 5:51 PM
>
> To: LEE John -TREASURY; 'Veinot, Cindy (TBS)'
>
> Cc: Nadine Petsche (MOF)
>
> Subject: RE: EXTERNAL – RE: OEFC Funding of the Global Adjustment Deferral
>
> Hi John and Cindy
>
> I just realized that in the event of an equity injection by the Province to OPG for a maximum of 49%, will as we discussed, have no impact on the Province's net debt.

Unfortunately there will be an IOD impact. John, I remember you mentioning that OPG will increase the dividends it pays to the Province by an amount equivalent to the interest on the equity injection to date, however, that will only provide a cash and not a fiscal offset.

The only way a fiscal offset can be provided is if OPG's net income increases by an amount equal to the increase in the Province's IOD (all else being equal). In which case the Province will be fiscally whole upon consolidation.

But I am not sure that going to happen since the Trust will not contribute to OPG's bottom line, or at least that's my understanding.

As such the potential fiscal impact from the increased IOD may be an issue for the Province re this option. In any event I will check with Gadi and circle back.

Thanks

Ken k

-----Original Message-----

From: HAHN PARKER Janet -TREASURY [mailto:j.hahnparker@opg.com]

Sent: Wednesday, February 15, 2017 4:50 PM

To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>

Cc: LEE John -TREASURY <john.s.lee@opg.com>; 'Veinot, Cindy (TBS)' <Cindy.Veinot@ontario.ca>

Subject: RE: EXTERNAL – RE: OEFC Funding of the Global Adjustment Deferral

Thank you. Will do.

-----Original Message-----

From: Ken Kandeepan [mailto:Ken.Kandeepan@ofina.on.ca]

Sent: Wednesday, February 15, 2017 4:49 PM

To: HAHN PARKER Janet -TREASURY

Cc: LEE John -TREASURY; 'Veinot, Cindy (TBS)'

Subject: RE: EXTERNAL – RE: OEFC Funding of the Global Adjustment Deferral

Cindy is free now if you can set up the call.

Thanks

Ken k

-----Original Message-----

From: HAHN PARKER Janet -TREASURY [mailto:j.hahnparker@opg.com]

Sent: Wednesday, February 15, 2017 3:43 PM

To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>

Cc: LEE John -TREASURY <john.s.lee@opg.com>

Subject: RE: EXTERNAL – RE: OEFC Funding of the Global Adjustment Deferral

Thank you.

This is of utmost importance. Please advise soonest.

Janet

-----Original Message-----

From: Ken Kandeepan [mailto:Ken.Kandeepan@ofina.on.ca]

Sent: Wednesday, February 15, 2017 3:37 PM

To: HAHN PARKER Janet -TREASURY

Cc: LEE John -TREASURY

Subject: RE: EXTERNAL – RE: OEFC Funding of the Global Adjustment Deferral

My apologies for the delay, unfortunately I am yet to hear back from Cindy, will let you know as soon as I do.

Thanks

Ken K

-----Original Message-----

From: HAHN PARKER Janet -TREASURY [mailto:j.hahnparker@opg.com]

Sent: Wednesday, February 15, 2017 1:57 PM

To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>

Cc: LEE John -TREASURY <john.s.lee@opg.com>

Subject: RE: EXTERNAL – RE: OEFC Funding of the Global Adjustment Deferral

Ken,

Please advise on this call. Timing is important.

A prompt response would be most appreciated,

Thank you,

Janet Hahn Parker

416 592-6749

j.hahnparker@opg.com

-----Original Message-----

From: Ken Kandeepan [mailto:Ken.Kandeepan@ofina.on.ca]

Sent: Wednesday, February 15, 2017 9:30 AM

To: LEE John -TREASURY

Cc: CHENG Alec -FIN & C CTRL; RYFA Ken -TREASURY; LIU Sheen -TREASURY; HAHN PARKER Janet -TREASURY

Subject: EXTERNAL – RE: OEFC Funding of the Global Adjustment Deferral

*** Exercise caution. This is an EXTERNAL email. DO NOT open attachments or click links from unknown senders or unexpected email. ***

Thanks John for the quick response, I have forwarded your email to Cindy, since her presence and/or Nadine's is essential if we are having a conference call, will get back to you as soon as I hear from her.

Ken K

-----Original Message-----

From: LEE John -TREASURY [mailto:john.s.lee@opg.com]

Sent: Wednesday, February 15, 2017 9:09 AM

To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>

Cc: CHENG Alec -FIN & C CTRL <alec.cheng@opg.com>; RYFA Ken -TREASURY <ken.ryfa@opg.com>; LIU Sheen -TREASURY <sheen.liu@opg.com>; HAHN PARKER Janet -TREASURY <j.hahnparker@opg.com>

Subject: RE: OEFC Funding of the Global Adjustment Deferral

Ken:

Got your voice message with respect to your proposal to have OEFC fund the Global Adjustment deferral indirectly by lending to OPG and having OPG subsequently lend to a Financing Trust. I agree that this would be the simplest funding mechanism. However since the key objective for the Province to avoid having to recognize the debt and writeoff the Global Adjustment deferral OPG must maintain Government Business Entity (GBE) status. In order to remain a GBE, we must be able to "in the normal course of its operations, maintain its operations and meet its liabilities from revenue received from sources outside of the government reporting entity." I understanding from Alec Cheng (OPG accounting) who was on yesterday accounting call with Nadine (Controllers Office) that OPG GBE status would be put at high risk under the proposed scheme due to the proposed quantum of lending from the OEFC. Our accounting group along with Treasury will be performing some further assessment on this but it may be worth arranging another call with you and your accounting group to layout the issues since the Province seems to be driven by very tight and uncertain timelines and I want everyone to be up to speed.

We can make ourselves available for a call this morning. Please advise.

John

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From: Gadi Mayman
To: Ken Kandeepan
Cc: Ronald Kwan; Lynsey Wynberg; Mike Manning; Gavin He
Subject: Re: EXTERNAL – RE: OEFC Funding of the Global Adjustment Deferral
Date: Wednesday, February 15, 2017 11:53:40 PM

Hmmm. If I understand this chain correctly, and I'm likely missing something important, would we have a non-regulated entity making hundreds of millions of dollars a year that the ratepayers ultimately have to cover in the future? Or would it be OPG, not the trust, making that profit from the interest on their loan to the trust, and if it's OPG making the profit, can't the OEB weigh in? If either's the case, it would be kind of contrary to the very robust language the government has been using about the OEB providing ratepayer protection with privatized electrical utilities.

On Feb 15, 2017, at 10:36 PM, Ken Kandeepan <Ken.Kandeepan@ofina.on.ca> wrote:

> That's my understanding as well.
>
> Thanks
>
> Ken k
>
> On Feb 15, 2017, at 10:34 PM, Ronald Kwan <Ronald.Kwan@ofina.on.ca> wrote:
>
> > Hi. Ken, emails crossed. I agree, but it would mean OPG is not being regulated by the OEB on this.
> >
> > Ron
> >
> > On Feb 15, 2017, at 10:32 PM, Ken Kandeepan <Ken.Kandeepan@ofina.on.ca> wrote:
> >
> > > No, I was informed by OPCD that IESO will set up the reg asset as you point out but will promptly sell same to the Trust. So the expectation is that at the end of each fiscal year the reg asset set up in that year would be sold to the OPG Trust.
> > >
> > > Thanks
> > >
> > > Ken k
> > >
> > > On Feb 15, 2017, at 10:27 PM, Ronald Kwan <Ronald.Kwan@ofina.on.ca> wrote:
> > >
> > > > Hi,

I may be wrong on this, so correct me if so, as I have not been at the accounting meetings on this structure.

But, based on the Energy submission, I took it as IESO would have the regulatory asset. As such, I took it that the Trust would be outside of OPG's OEB regulated entity.

Ron

On Feb 15, 2017, at 10:21 PM, Gadi Mayman <Gadi.Mayman@ofina.on.ca> wrote:

> First getting it past their auditors will be a challenge, as you've said, and secondly getting the OEB to accept that OPG should be earning the extra $750 million per year that we'd need at the peak of the debt accumulation will be even more challenging. It would have to be a hit to ratepayers. That would be even harder to explain than a hit to them from an ROE to the Province, which, as you've seen, I've had trouble wrapping my mind around in earlier emails.
>
> On Feb 15, 2017, at 10:11 PM, Ken Kandeepan <Ken.Kandeepan@ofina.on.ca> wrote:
>
> > Not entirely, though the underlying concept is similar. This is just logical speculation on my part but what John is probably driving at is the Trust pays OPG the interest but instead of

expensing same it's capitalized.

As such when the Trust is consolidated with OPG the interest income remains in OPG's books since there is no expense to offset it in the books of the Trust.

Ergo, OPG has a net interest income which all else being equal increases its net income, which in turn when consolidated with Province, provides the required fiscal offset to the increase in the Province's IOD.

The problem here would be how willing OPG's auditors will be in recognizing an interest income on OPG books that will be paid in about 15 years time and that too on a piecemeal basis.

Having said all of this let me repeat I may be quite mistaken and John may have a more feasible solution in mind.

Thanks

Ken k

On Feb 15, 2017, at 9:36 PM, Gadi Mayman <Gadi.Mayman@ofina.on.ca> wrote:

> Sounds to me that they're going where Scott Nelms alluded to in his email with an ROE for the Province that would offset our borrowing cost?
>
> Adding Ron and Mike so that all of us at the OFA are aware

of the same facts, as this is moving quickly, and any of us may be asked at any time about it, including on Friday when you and I are away, Ken.

Gadi

From: Ken Kandeepan
Sent: Wednesday, February 15, 2017 9:19 PM
To: Gadi Mayman
Cc: Lynsey Wynberg
Subject: Fwd: EXTERNAL – RE: OEFC Funding of the Global Adjustment Deferral

Hi
Gadi

My
exchange
with
John,
as you
can see
little
short
on the
details.

Thanks

Ken k

Begin
forwarded
message:

From:
Ken
Kandeepan
<Ken.Kandeepan@ofina.on.ca>

Date:
February
15,
2017
at
6:36:48
PM
EST

To:
LEE
John
-
TREASURY
<john.s.lee@opg.com>

Cc:
"Veinot,
Cindy
(TBS)"

<Cindy.Veinot@ontario.ca>,
"Nadine
Petsche
(MOF)"
<Nadine.Petsche@ontario.ca>,
RYFA
Ken
-
TREASURY
<ken.ryfa@opg.com>,
CHENG
Alec
-
FIN
&
C
CTRL
<alec.cheng@opg.com>

Subject:
Re:
EXTERNAL
â
€“
RE:
OEFC
Funding
of
the
Global
Adjustment
Deferral

Thanks
John,
it
seems
that
what
you
are
saying
is
OPG's
net
income
will
increase,

all
else
being
equal,
by
the
amount
of
the
interest
relating
to
the
equity
injection.

In
which
case
upon
consolidation
there
will
be
no
fiscal
impact
to
the
Province.

As
you
work
through
the
options
this
needs
to
be
fleshed
out
since
the
Trust
will

be
consolidated
with
OPG
we
need
to
understand
how
OPG
will
show
a
net
interest
income.

Thanks

Ken
k

> On
> Feb
> 15,
> 2017,
> at
> 6:28
> PM,
> LEE
> John
> -
> TREASURY
> <john.s.lee@opg.com>
> wrote:
>
> Ken:
>
> To
> clarify
> the
> expectation
> is

that
equity
injected
into
OPG
which
is
on-
lend
to
the
Trust
would
result
in
net
interest
income
that
would
roll
up
to
the
Province
and
this
would
cover
the
interest
expense
for
the
associated
debt
at
the
Province.
The
dividend
comment
was
meant
to
describe
mechanism
on
how
to

get
cash
to
the
province.

John

-
-
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-
-
Original
Message-
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-

From:
Ken
Kandeepan
[mailto:Ken.Kandeepan@ofina.on.ca]

Sent:
Wednesday,
February
15,
2017
5:51
PM

To:
LEE
John
-
TREASURY;
'Veinot,
Cindy
(TBS)'

Cc:
Nadine
Petsche
(MOF)

Subject:
RE:
EXTERNAL
–
RE:
OEFC
Funding
of
the
Global
Adjustment
Deferral

Hi
John
and
Cindy

I
just
realized
that
in
the
event
of
an
equity
injection
by
the
Province
to
OPG
for
a
maximum
of

49%, will as we discussed, have no impact on the Province's net debt.

Unfortunately there will be an IOD impact. John, I remember you mentioning that OPG will increase the dividends it pays to the Province by an amount equivalent to the interest on the

equity injection to date, however, that will only provide a cash and not a fiscal offset.

The only way a fiscal offset can be provided is if OPG's net income increases by an amount equal to the increase in the Province's IOD (all else being

equal).
In
which
case
the
Province
will
be
fiscally
whole
upon
consolidation.

But
I
am
not
sure
that
going
to
happen
since
the
Trust
will
not
contribute
to
OPG's
bottom
line,
or
at
least
that's
my
understanding.

As
such
the
potential
fiscal
impact

from
the
increased
IOD
may
be
an
issue
for
the
Province
re
this
option.
In
any
event
I
will
check
with
Gadi
and
circle
back.

Thanks

Ken
k

-
-
-
-
-
Original
Message-
-
-
-
-

From:
HAHN
PARKER
Janet
-
TREASURY
[mailto:j.hahnparker@opg.com]

Sent:
Wednesday,
February
15,
2017
4:50
PM

To:
Ken
Kandeepan
<Ken.Kandeepan@ofina.on.ca>

Cc:
LEE
John
-
TREASURY
<john.s.lee@opg.com>;
'Veinot,
Cindy
(TBS)'
<Cindy.Veinot@ontario.ca>

Subject:
RE:
EXTERNAL
–
RE:
OEFC
Funding
of
the
Global
Adjustment
Deferral

Thank
you.
Will
do.

-
-
-
-
-
Original
Message-
-
-
-
-

From:
Ken
Kandeepan
[mailto:Ken.Kandeepan@ofina.on.ca]

Sent:
Wednesday,
February
15,
2017
4:49
PM

To:
HAHN
PARKER
Janet
-
TREASURY

Cc:
LEE
John
-
TREASURY;

'Veinot,
Cindy
(TBS)'

Subject:
RE:
EXTERNAL
–
RE:
OEFC
Funding
of
the
Global
Adjustment
Deferral

Cindy
is
free
now
if
you
can
set
up
the
call.

Thanks

Ken
k

-
-
-
-

-
Original
Message-
-
-
-
-

From:
HAHN
PARKER
Janet
-
TREASURY
[mailto:j.hahnparker@opg.com]

Sent:
Wednesday,
February
15,
2017
3:43
PM

To:
Ken
Kandeepan
<Ken.Kandeepan@ofina.on.ca>

Cc:
LEE
John
-
TREASURY
<john.s.lee@opg.com>

Subject:
RE:
EXTERNAL
–
RE:
OEFC
Funding
of
the
Global

Adjustment
Deferral

Thank
you.

This
is
of
utmost
importance.
Please
advise
soonest.

Janet

-
-
-
-
-
Original
Message-
-
-
-
-

From:
Ken
Kandeepan
[mailto:Ken.Kandeepan@ofina.on.ca]

Sent:
Wednesday,
February
15,
2017
3:37
PM

To:
HAHN
PARKER
Janet
-
TREASURY

Cc:
LEE
John
-
TREASURY

Subject:
RE:
EXTERNAL
–
RE:
OEFC
Funding
of
the
Global
Adjustment
Deferral

My
apologies
for
the
delay,
unfortunately
I
am
yet
to
hear
back
from
Cindy,
will
let
you
know

as
soon
as
I
do.

Thanks

Ken
K

-
-
-
-
-
Original
Message-
-
-
-
-

From:
HAHN
PARKER
Janet
-
TREASURY
[mailto:j.hahnparker@opg.com]

Sent:
Wednesday,
February
15,
2017
1:57
PM

To:
Ken
Kandeepan
<Ken.Kandeepan@ofina.on.ca>

Cc:
LEE
John
-
TREASURY
<john.s.lee@opg.com>

Subject:
RE:
EXTERNAL
–
RE:
OEFC
Funding
of
the
Global
Adjustment
Deferral

Ken,

Please
advise
on
this
call.
Timing
is
important.

A
prompt
response
would
be
most

appreciated,

Thank
you,

Janet
Hahn
Parker

416
592-
6749

j.hahnparker@opg.com

-
-
-
-
-
Original
Message-
-
-
-
-

From:
Ken
Kandeepan
[mailto:Ken.Kandeepan@ofina.on.ca]

Sent:
Wednesday,
February
15,
2017
9:30

AM

To:
LEE
John
-
TREASURY

Cc:
CHENG
Alec
-
FIN
&
C
CTRL;
RYFA
Ken
-
TREASURY;
LIU
Sheen
-
TREASURY;
HAHN
PARKER
Janet
-
TREASURY

Subject:
EXTERNAL
–
RE:
OEFC
Funding
of
the
Global
Adjustment
Deferral

***
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Thanks John for the quick response, I have forwarded your email to Cindy, since her presence and/or Nadine's is essential if we are having a conference call,

will
get
back
to
you
as
soon
as
I
hear
from
her.

Ken
K

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Original
Message-
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From:
LEE
John
-
TREASURY
[mailto:john.s.lee@opg.com]

Sent:
Wednesday,
February
15,
2017
9:09

AM

To:
Ken
Kandeepan
<Ken.Kandeepan@ofina.on.ca>

Cc:
CHENG
Alec
-
FIN
&
C
CTRL
<alec.cheng@opg.com>;
RYFA
Ken
-
TREASURY
<ken.ryfa@opg.com>;
LIU
Sheen
-
TREASURY
<sheen.liu@opg.com>;
HAHN
PARKER
Janet
-
TREASURY
<j.hahnparker@opg.com>

Subject:
RE:
OEFC
Funding
of
the
Global
Adjustment
Deferral

Ken:

Got your voice message with respect to your proposal to have OEFC fund the Global Adjustment deferral indirectly by lending to OPG and having OPG subsequently lend to a Financing Trust. I agree that this would be the simplest funding mechanism. However since the key objective for the

Province to avoid having to recognize the debt and writeoff the Global Adjustment deferral OPG must maintain Government Business Entity (GBE) status. In order to remain a GBE, we must be able to “in the normal course of its operations, maintain its operations and meet its liabilities from revenue received

from sources outside of the government reporting entity.” I understanding from Alec Cheng (OPG accounting) who was on yesterday accounting call with Nadine (Controllers Office) that OPG GBE status would be put at high risk under the proposed scheme due to the proposed quantum of lending from the OEFC. Our

accounting
group
along
with
Treasury
will
be
performing
some
further
assessment
on
this
but
it
may
be
worth
arranging
another
call
with
you
and
your
accounting
group
to
layout
the
issues
since
the
Province
seems
to
be
driven
by
very
tight
and
uncertain
timelines
and
I
want
everyone
to
be

up
to
speed.

We
can
make
ourselves
available
for
a
call
this
morning.
Please
advise.

John

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From: John Kim
To: Ronald Kwan
Cc: HO Philip -FIN & C CTRL; MAK Ricky -FIN & C CTRL; DYKXHOORN Sandra -STAKEREL; GORE Michael -FIN & C CTRL
Subject: Re: EXTERNAL – RE: OPG Q3 2017 Submission to Province
Date: Wednesday, November 08, 2017 5:46:27 PM

Thanks from me too. Will check to see if any conforming changes are needed in f/s

Sent from my iPad

On Nov 8, 2017, at 5:28 PM, Ronald Kwan <Ronald.Kwan@ofina.on.ca> wrote:

> Thanks Philip, John.
>
> Ron
>
> ---
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> **From:** HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
> **Sent:** November-08-17 17:27
> **To:** John Kim <John.Kim@ofina.on.ca>
> **Cc:** MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
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> Thank you.
>
> Philip
>
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>
> **From:** John Kim [mailto:John.Kim@ofina.on.ca]
> **Sent:** Wednesday, November 08, 2017 2:04 PM
> **To:** HO Philip -FIN & C CTRL <philip.ho@opg.com>
> **Cc:** MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
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>
> Thanks,
>
> John
>
> ---

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Sent: Wednesday, November 08, 2017 1:30 PM
To: John Kim <John.Kim@ofina.on.ca>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Subject: RE: EXTERNAL – RE: OPG Q3 2017 Submission to Province

Hi John,

Please see our responses to your three additional comments. Thank you.

Philip

From: John Kim [mailto:John.Kim@ofina.on.ca]
Sent: Monday, November 06, 2017 7:35 PM
To: HO Philip -FIN & C CTRL <philip.ho@opg.com>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
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Thanks,

John

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To: John Kim <John.Kim@ofina.on.ca>
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Philip

Philip Ho, CPA, CA | Senior Manager, External Reporting & Accounting Policy | Ontario Power Generation
700 University Avenue, Toronto ON M5G 1X6 | Phone: (416) 592-3320| E-mail: philip.ho@opg.com

From: John Kim [mailto:John.Kim@ofina.on.ca]
Sent: Monday, October 30, 2017 6:16 PM
To: HO Philip -FIN & C CTRL <philip.ho@opg.com>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
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These are staff level comments as Ron has not had a chance to review.

Thanks,

John

From: HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
Sent: Wednesday, October 25, 2017 12:22 PM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>; 'Montgomery, Kaitlin (MOF)' <Kaitlin.Montgomery@ontario.ca>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>
Subject: OPG Q3 2017 Submission to Province

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Kindly forward all comments directly to Philip Ho – philip.ho@opg.com.

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Highlights

Recent Developments	MD&A p.10-11
Darlington Refurbishment	MD&A p.13-15
Ontario's Fair Hydro Plan	MD&A p.10-11

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700 University Avenue, Toronto ON M5G 1X6 | Phone: (416) 592-3320| E-mail: philip.ho@opg.com

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From: John Kim
To: Ronald Kwan
Subject: Re: EXTERNAL – RE: OPG Q3 2017 Submission to Province
Date: Wednesday, November 08, 2017 5:44:34 PM

That's a good question....

Sent from my iPad

On Nov 8, 2017, at 5:30 PM, Ronald Kwan <Ronald.Kwan@ofina.on.ca> wrote:

> Hi John,
>
> Any need for conforming edits to the financial statement notes?
>
> Ron
>
> ---
>
> **From:** Ronald Kwan
> **Sent:** November-08-17 17:29
> **To:** 'HO Philip -FIN & C CTRL' <philip.ho@opg.com>; John Kim <John.Kim@ofina.on.ca>
> **Cc:** MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>
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From: John Kim
To: Ronald Kwan
Subject: Re: EXTERNAL – RE: OPG Q3 2017 Submission to Province
Date: Wednesday, November 08, 2017 6:29:31 PM

It was a gentle way of telling them to do it but don't mind doing it myself. John

Sent from my iPhone

On Nov 8, 2017, at 5:53 PM, Ronald Kwan <Ronald.Kwan@ofina.on.ca> wrote:

> Thanks John – though I was thinking you could just check with OPG that they had made any required conforming edits.
>
> Ron
>
> ---
>
> **From:** John Kim
> **Sent:** November-08-17 17:46
> **To:** Ronald Kwan <Ronald.Kwan@ofina.on.ca>
> **Cc:** HO Philip -FIN & C CTRL <philip.ho@opg.com>; MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>
> **Subject:** Re: EXTERNAL – RE: OPG Q3 2017 Submission to Province
>
> Thanks from me too. Will check to see if any conforming changes are needed in f/s
>
> Sent from my iPad
>
> On Nov 8, 2017, at 5:28 PM, Ronald Kwan <Ronald.Kwan@ofina.on.ca> wrote:
>
> > Thanks Philip, John.
> >
> > Ron
> >
> > ---
> >
> > **From:** HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
> > **Sent:** November-08-17 17:27
> > **To:** John Kim <John.Kim@ofina.on.ca>
> > **Cc:** MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
> > **Subject:** RE: EXTERNAL – RE: OPG Q3 2017 Submission to Province
> >
> > Hi John,
> >
> > Regarding comment on pg 8, we have removed 'for years 2017 to 2021' as suggested. Regarding comment on pg 10, we have edited the wording to read 'In order for the Trust to finance the deferred Global Adjustment costs …' as suggested.
> >
> > Thank you.
> >
> > Philip
> >
> > ---
> >
> > **From:** John Kim [mailto:John.Kim@ofina.on.ca]

Sent: Wednesday, November 08, 2017 2:04 PM
To: HO Philip -FIN & C CTRL <philip.ho@opg.com>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Subject: RE: EXTERNAL – RE: OPG Q3 2017 Submission to Province

Hi Philip,

On a couple of items, we have follow up. Pls. refer to p. 8 and p. 10.

Thanks,

John

From: HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
Sent: Wednesday, November 08, 2017 1:30 PM
To: John Kim <John.Kim@ofina.on.ca>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Subject: RE: EXTERNAL – RE: OPG Q3 2017 Submission to Province

Hi John,

Please see our responses to your three additional comments. Thank you.

Philip

From: John Kim [mailto:John.Kim@ofina.on.ca]
Sent: Monday, November 06, 2017 7:35 PM
To: HO Philip -FIN & C CTRL <philip.ho@opg.com>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Subject: RE: EXTERNAL – RE: OPG Q3 2017 Submission to Province

Hi Philip,

We have gone through again and some additional comment boxes and edits.

Thanks,

John

From: HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
Sent: Monday, November 06, 2017 6:19 PM
To: John Kim <John.Kim@ofina.on.ca>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Subject: RE: EXTERNAL – RE: OPG Q3 2017 Submission to Province

Hi John,

Please see our responses to your comments. Let us know if you have any others. Thank you.

Regards,

Philip

Philip Ho, CPA, CA | Senior Manager, External Reporting & Accounting Policy | Ontario Power Generation
700 University Avenue, Toronto ON M5G 1X6 | Phone: (416) 592-3320| E-mail: philip.ho@opg.com

---

From: John Kim [mailto:John.Kim@ofina.on.ca]
Sent: Monday, October 30, 2017 6:16 PM
To: HO Philip -FIN & C CTRL <philip.ho@opg.com>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>; Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Subject: EXTERNAL – RE: OPG Q3 2017 Submission to Province

*** Exercise caution. This is an EXTERNAL email. DO NOT open attachments or click links from unknown senders or unexpected email. ***

Hi Philip,

See attached with our comments on the MD&A.

These are staff level comments as Ron has not had a chance to review.

Thanks,

John

From: HO Philip -FIN & C CTRL [mailto:philip.ho@opg.com]
Sent: Wednesday, October 25, 2017 12:22 PM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>; 'Montgomery, Kaitlin (MOF)' <Kaitlin.Montgomery@ontario.ca>
Cc: MAK Ricky -FIN & C CTRL <ricky.mak@opg.com>; DYKXHOORN Sandra -STAKEREL <sandra.dykxhoorn@opg.com>; GORE Michael -FIN & C CTRL <michael.gore@opg.com>
Subject: OPG Q3 2017 Submission to Province

Hi All,

Please find attached OPG's draft Q3 2017 Financial Results Press Release, Management's Discussion and Analysis (MD&A), and Financial Statements for the

Province's review.

We would greatly appreciate comments on the above **no later than Monday, Oct 30th**.

These documents will be filed with the Ontario Securities Commission on **Thursday, November 9th** following OPG's Board of Directors meeting.

Kindly forward all comments directly to Philip Ho – philip.ho@opg.com.

To assist the review process, the following are the key items in the Q3 2017 MD&A:

Highlights	
Recent Developments	MD&A p.10-11
Darlington Refurbishment	MD&A p.13-15
Ontario's Fair Hydro Plan	MD&A p.10-11

Philip Ho, CPA, CA | Senior Manager, External Reporting & Accounting Policy | Ontario Power Generation
700 University Avenue, Toronto ON M5G 1X6 | Phone: (416) 592-3320| E-mail: philip.ho@opg.com

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From: Francisco Chinchon
To: Bruno Amara
Cc: John Kim; Ronald Kwan
Subject: Re: Electricity Outlook Update
Date: Friday, February 16, 2018 12:16:35 PM

Just in case is helpful, Ron's recollection with respect to when the cash was collected is correct.

On Feb 16, 2018, at 12:02 PM, Ronald Kwan <Ronald.Kwan@ofina.on.ca> wrote:

> Hi,
>
> I thought we had this discussion last year, and that the BSC tracks cash flow, and the Brampton PILs were paid in cash during 17-18, but accrued to 16-17. If so, backing that out, leaves MEU PILs way behind plan.
>
> Please check. I don't want to overstate PILs in this outlook run.
>
> Ron
>
> On Feb 16, 2018, at 9:33 AM, John Kim <John.Kim@ofina.on.ca> wrote:
>
> > I understood Brampton was paid in last fiscal so I don't think so but I would leave MEU Pils. There is some unknowns that require a closer look and I wouldn't prorate it as is.
> >
> > Sent from my iPhone
> >
> > On Feb 16, 2018, at 9:28 AM, Ronald Kwan <Ronald.Kwan@ofina.on.ca> wrote:
> >
> > > Do the cash MEU PILs not include from Brampton, which was accrued for last fiscal?
> > >
> > > Ron
> > >
> > > On Feb 16, 2018, at 7:42 AM, John Kim <John.Kim@ofina.on.ca> wrote:
> > >
> > > > Hi Bruno, Francisco,
> > > >
> > > > On BSC and MEU PILs, I think the status quo is fine. Numbers look fine (a bit lower for DRC and higher for MEU PILs, which could offset in the end) and not sure if updating for precision

especially in DRC is necessary. We will need to look at why MEU PILs are higher. Saved the two relevant BSC files in the Outlook folder.

On Lakeview, I think the idea is to ultimately coordinate with various groups as taking it out is simple to do.

On FHP impacts, since there are multiple components now – performance fees (both fixed and variable) and interest component, we need additional information from OPG before coordinating was my thought. I've asked Shajee to keep an eye on that if going to OPG with additional questions.

When doing the ONFA risk, don't forget the Bruce component – halving the effect essentially. Otherwise, we are overestimating it.

John

From: Ronald Kwan
Sent: February-16-18 12:38 AM
To: Bruno Amara <Bruno.Amara@ofina.on.ca>
Cc: John Kim <John.Kim@ofina.on.ca>; Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>
Subject: RE: Electricity Outlook Update

Hi Bruno,

I won't have time for a detailed review, but a preliminary revised outlook should be circulated tomorrow to the normal group. A few questions and comments below.

Based on the BSC, should DRC and MEU PILs numbers be adjusted downwards for 17-18?

In the comments on the impact of Lakeview, it has +200 in both OPG income and PILs rows. Should it be 70 for the PILs comment row? And should I assume that SIFB has backed out

Lakeview from Sales and rentals?

Why the big variance in 19-20 for OPG vs Budget 2017?

On the FHP impact on OPG, is there coordination with FTD on their IOD impact assumptions?

We should alert CQSD too on the ESDI projection update, to ensure the MOF PRRT is updated (and for Estimates).

Risks:

I think we should add in general OPG and Hydro One risks on OM&A too.

Shouldn't there be an ONFA funds return risk too?

Let's relabel the "Nuclear Reliability" risk to "Nuclear Output".

Should we update the Hydro One deferred tax benefit risk, given the drop in ownership share? Or will it be based on a weighted average over the year basis? And how should we reflect that the risk could be in 18-19 instead? Add an asterix or footnote to that cell too?

It should refer to stranded debt being "retired" (not defeased – that timing would be earlier – when residual stranded debt is retired, if it were still in the Act and being calculated)

Isn't the PILs leakage risk too big. Property tax PILs are only about $20 million – isn't that the case?

Thanks,
Ron

From: Bruno Amara

Sent: February-15-18 6:41 PM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: John Kim <John.Kim@ofina.on.ca>
Subject: RE: Electricity Outlook Update

File location

S:\Users\CEF\Hydro 2018\OEFC\RbP\Outlook\02. February

From: Bruno Amara
Sent: Thursday, February 15, 2018 6:39 PM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: John Kim <John.Kim@ofina.on.ca>
Subject: Electricity Outlook Update

Hi Ron

Please see attached our updated Electricity Sector Outlook.

This includes

- <!--[if !supportLists]-->● <!--[endif]-->OPG 2018-2021 Business plan updates including the inclusion now of the proceeds in 2017-18 from Lakeview properties.
- <!--[if !supportLists]-->● <!--[endif]-->Hydro One has also been updated to reflect year-end results for Hydro One. In particular 2017-18 is driven mainly by quarterly actual (the 2018 quarter is model projection. 2018-19 onward are also model projections.
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Thanks
Bruno

Bruno Amara
Sr. Manager, Financial and Regulatory Analysis
Electricity Finance Branch
Corporate and Electricity Finance Division
Ontario Financing Authority

Tel: 416-325-1489
Email: bruno.amara@ofina.on.ca

From: John Kim
To: Ronald Kwan
Cc: Bruno Amara; Francisco Chinchon
Subject: Re: Electricity Outlook Update
Date: Friday, February 16, 2018 9:33:44 AM

I understood Brampton was paid in last fiscal so I don't think so but I would leave MEU Pils. There is some unknowns that require a closer look and I wouldn't prorate it as is.

Sent from my iPhone

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> > On Lakeview, I think the idea is to ultimately coordinate with various groups as taking it out is simple to do.
> >
> > On FHP impacts, since there are multiple components now – performance fees (both fixed and variable) and interest component, we need additional information from OPG before coordinating was my thought. I've asked Shajee to keep an eye on that if going to OPG with additional questions.
> >
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> >
> > John
> >
> > ---
> >
> > **From:** Ronald Kwan
> > **Sent:** February-16-18 12:38 AM
> > **To:** Bruno Amara <Bruno.Amara@ofina.on.ca>
> > **Cc:** John Kim <John.Kim@ofina.on.ca>; Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>

Subject: RE: Electricity Outlook Update

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I think we should add in general OPG and Hydro One risks on OM&A too.

Shouldn't there be an ONFA funds return risk too?

Let's relabel the "Nuclear Reliability" risk to "Nuclear Output".

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It should refer to stranded debt being "retired" (not defeased – that timing would be earlier – when residual stranded debt is retired, if it were still in the Act and being calculated)

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Thanks,

Ron

From: Bruno Amara
Sent: February-15-18 6:41 PM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: John Kim <John.Kim@ofina.on.ca>
Subject: RE: Electricity Outlook Update

File location

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From: Bruno Amara
Sent: Thursday, February 15, 2018 6:39 PM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: John Kim <John.Kim@ofina.on.ca>
Subject: Electricity Outlook Update

Hi Ron

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This includes

- <!--[if !supportLists]-->• <!--[endif]-->OPG 2018-2021 Business plan updates including the inclusion now of the proceeds in 2017-18 from Lakeview properties.
- <!--[if !supportLists]-->• <!--[endif]-->Hydro One has also been updated to reflect year-end results for Hydro One. In particular 2017-18 is driven mainly by quarterly actual (the 2018 quarter is model projection. 2018-19 onward are also model projections.
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- <!--[if !supportLists]-->• <!--[endif]-->We also have updated IOD numbers from FTD today
- <!--[if !supportLists]-->• <!--[endif]-->SPFB indicated they will updated power purchase/recovery outlook early next week.

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On risk table we added possible PILs transfer to municipalities. Note that this outlook has SD defeased as of 2021-22.

I have added a temporary worksheet showing the changes since the last Outlook distribution in January. The main changes related to OPG, particularly the 2017-18 increase only partly explained by inclusion of Lakeview. Note that the OPG business plan noted that 2017-18 included a $325 hit related to the later effective date. That is consistent with our estimate.

Thanks
Bruno

Bruno Amara
Sr. Manager, Financial and Regulatory Analysis
Electricity Finance Branch
Corporate and Electricity Finance Division
Ontario Financing Authority

Tel: 416-325-1489
Email: bruno.amara@ofina.on.ca

From: Francisco Chinchon
To: Ronald Kwan
Cc: Bruno Amara; John Kim
Subject: Re: Electricity Outlook Update
Date: Friday, February 16, 2018 12:48:27 PM

It is, we have been collaborating on this point.

On Feb 16, 2018, at 12:44 PM, Ronald Kwan <Ronald.Kwan@ofina.on.ca> wrote:

> Hi Bruno,
>
> Thanks for the responses. And please remind on confirmation that the unpacking on Lakeview is consistent with SIFB recategorising out of sales and rentals too.
>
> Ron
>
> On Feb 16, 2018, at 12:02 PM, Bruno Amara <Bruno.Amara@ofina.on.ca> wrote:
>
> > Hi Ron
> >
> > Further on OPG 2019-20. 2020 earnings are likely weighted to the first part of the year as the drop in 2020 net income is due to larger planned Pickering outage including advancement of some outage from 2021. In that scenario, 2019-20 could indeed be higher than either of the calendar year amounts.
> >
> > In addition, OPG also notes higher nuclear production in 2019 reflecting outage optimization initiatives, higher earnings from the Nanticoke solar facility upon completion in 2019 and lower OMA in 2019 due to fewer major planned outages at Pickering and cost efficiencies.
> >
> > Bruno
> >
> > ---
> >
> > **From:** Bruno Amara
> > **Sent:** Friday, February 16, 2018 11:37 AM
> > **To:** Ronald Kwan <Ronald.Kwan@ofina.on.ca>
> > **Cc:** John Kim <John.Kim@ofina.on.ca>; Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>
> > **Subject:** RE: Electricity Outlook Update
> >
> > Hi Ron
> >
> > We are getting ready to distribute. Fyi, see below the changes we have made per your comments.

Thanks
Bruno

From: Ronald Kwan
Sent: Friday, February 16, 2018 12:38 AM
To: Bruno Amara <Bruno.Amara@ofina.on.ca>
Cc: John Kim <John.Kim@ofina.on.ca>; Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>
Subject: RE: Electricity Outlook Update

Hi Bruno,

I won't have time for a detailed review, but a preliminary revised outlook should be circulated tomorrow to the normal group. A few questions and comments below.

Based on the BSC, should DRC and MEU PILs numbers be adjusted downwards for 17-18?
Adjusted DRC downward based on DRC, will look into MEU

In the comments on the impact of Lakeview, it has +200 in both OPG income and PILs rows. Should it be 70 for the PILs comment row? And should I assume that SIFB has backed out Lakeview from Sales and rentals?
YES, correct

Why the big variance in 19-20 for OPG vs Budget 2017?
That is indirectly one our follow-up questions for OPG. OPG's calendar year net income for 2019 and 2020 are $968M and $764M respectively, but the Province's fiscal year amount for 2019-20 is $1,053. Not sure how fiscalizing gets to a higher number than each of those years.

On the FHP impact on OPG, is there coordination with FTD on their IOD impact assumptions?
Yes, have shared with FTD

We should alert CQSD too on the ESDI projection update, to ensure the MOF PRRT is updated (and for Estimates).
Yes, I had given them a heads-up on this and they have also alerted TPD

Risks:

I think we should add in general OPG and Hydro One risks on OM&A too.
Will look into appropriate metric

Shouldn't there be an ONFA funds return risk too?
Added a range based on historic results

Let's relabel the "Nuclear Reliability" risk to "Nuclear Output". Done

Should we update the Hydro One deferred tax benefit risk, given the drop in ownership share? Or will it be based on a weighted average over the year basis? And how should we reflect that the risk could be in 18-19 instead? Add an asterix or footnote to that cell too? Updated. I think that would be current as I think impact happens when decision is made. I made footnote n=more explicit to indicate impact could be in 2018-19.

It should refer to stranded debt being "retired" (not defeased – that timing would be earlier – when residual stranded debt is retired, if it were still in the Act and being calculated) Done

Isn't the PILs leakage risk too big. Property tax PILs are only about $20 million – isn't that the case? I had mistakenly included OPG Gross Revenue Charge - property tax component. We used $20m estimate for now, but need to look into breakdown of MEU PILs between income tax and property tax.

Thanks,
Ron

From: Bruno Amara
Sent: February-15-18 6:41 PM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: John Kim <John.Kim@ofina.on.ca>
Subject: RE: Electricity Outlook Update

File location

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Bruno

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Sr. Manager, Financial and Regulatory Analysis
Electricity Finance Branch
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Tel: 416-325-1489
Email: bruno.amara@ofina.on.ca

From: Ronald Kwan
To: Francisco Chinchon
Cc: John Kim
Subject: Re: Electricity Outlook
Date: Tuesday, March 07, 2017 9:08:59 AM

Hi Francisco, John,

Would it be helpful to send the two underlying spreadsheets together, noting the pivot to 70%, which is fiscally-neutral across the two products, but shown for interim actuals purposes to be closer to Public Accounts?

And note as well the OPG number adjustments to match the IOD adjustment (assuming those have gone up?).

Please bcc me.

Thanks,
Ron

On Mar 7, 2017, at 9:00 AM, Francisco Chinchon <Francisco.Chinchon@ofina.on.ca> wrote:

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John.

From: Ronald Kwan
Sent: Friday, March 03, 2017 5:04 PM
To: John Kim <John.Kim@ofina.on.ca>
Subject: RE: Electricity Outlook

Hi,

Are we now working on a 70% baseline, and coordinated with the AO numbers? What changed since the early February file and numbers coordination?

Ron

From: John Kim
Sent: March-03-17 16:03
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Gavin He <Gavin.He@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>
Subject: FW: Electricity Outlook

Pls. see attached.

Thanks,

John.

From: John Kim
Sent: Friday, March 03, 2017 3:56 PM
To: Bruno Amara <Bruno.Amara@ofina.on.ca>
Cc: Adam Prokop <Adam.Prokop@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>; Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Salman Qadir <Salman.Qadir@ofina.on.ca>
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From: Bruno Amara
Sent: Friday, March 03, 2017 2:29 PM
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Cc: Adam Prokop <Adam.Prokop@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>; Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>; Salman Qadir <Salman.Qadir@ofina.on.ca>
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To: Bruno Amara <Bruno.Amara@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>
Cc: Salman Qadir <Salman.Qadir@ofina.on.ca>
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TBS/OB.

S:\Users\CEF\Hydro 2017\OEFC\RbP\Outlook\02. February

Bruno

Gavin, we picked up the revised DRC forecast.

From: John Kim
To: Ronald Kwan
Subject: Re: Electricity Outlook
Date: Tuesday, March 07, 2017 7:25:18 AM

Hi Ron,

We are ready to go. Brampton was a miscommunication between staff.

If okay with you we will start the outreach to ensure other divisions are incorporating properly.

Thanks

John

On Mar 7, 2017, at 7:00 AM, Ronald Kwan <Ronald.Kwan@ofina.on.ca> wrote:

> Hi John,
>
> What's the status of this?
>
> Thanks,
> Ron
>
> ---
>
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> **Sent:** March-03-17 6:00 PM
> **To:** John Kim <John.Kim@ofina.on.ca>
> **Subject:** RE: Electricity Outlook
>
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S:\Users\CEF\Hydro 2017\OEFC\RbP\Outlook\02. February

Bruno

Gavin, we picked up the revised DRC forecast.

From: John Kim
To: Ronald Kwan
Cc: Gavin He; Francisco Chinchon
Subject: Re: Electricity Outlook
Date: Tuesday, March 07, 2017 6:35:44 PM

Hi Ron,

As far as I know we didn't send yet. Tomorrow AM was the target send time for the outlook.

John

On Mar 7, 2017, at 6:12 PM, Ronald Kwan <Ronald.Kwan@ofina.on.ca> wrote:

> Hi,
>
> I was talking to Gadi earlier today and he said that the IOD adjustment had not yet been provided for the fiscal roll-up, so the OPG net income numbers would be out of sync .
>
> Was anything sent to OB, OEP and TBS today? I didn't see an email.
>
> Was there a discussion with staff?
>
> Thanks,
> Ron
>
> ---
>
> **From:** Ronald Kwan
> **Sent:** March-07-17 09:09
> **To:** Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>
> **Cc:** John Kim <John.Kim@ofina.on.ca>
> **Subject:** Re: Electricity Outlook
>
> Hi Francisco, John,
>
> Would it be helpful to send the two underlying spreadsheets together, noting the pivot to 70%, which is fiscally-neutral across the two products, but shown for interim actuals purposes to be closer to Public Accounts?
>
> And note as well the OPG number adjustments to match the IOD adjustment (assuming those have gone up?).
>
> Please bcc me.
>
> Thanks,
> Ron

On Mar 7, 2017, at 9:00 AM, Francisco Chinchon <Francisco.Chinchon@ofina.on.ca> wrote:

> Hi,
>
> We are good too. I did share the latest AO slides with OEP and OTB and staff have been communicating.
>
> What takes more time for staff to fully grasp is how the unpacking of the multiple sales affect each line although neutral on aggregate.
>
> Thanks,
>
> Francisco
>
> On Mar 7, 2017, at 8:49 AM, Ronald Kwan <Ronald.Kwan@ofina.on.ca> wrote:
>
> > Hi,
> >
> > For sure. Last Friday would have been better.
> >
> > Ron
> >
> > On Mar 7, 2017, at 8:41 AM, John Kim <John.Kim@ofina.on.ca> wrote:
> >
> > > Hi Ron,
> > >
> > > Brampton is in AO….and we're both at 70%.
> > >
> > > We can coordinate the sending for sure, yes. We're planning to call a meeting of OB and OEP, as well as TBS to ensure we're all on the same page.
> > >
> > > The sooner the better would be my advice.
> > >
> > > John.
> > >
> > > ---
> > >
> > > **From:** Ronald Kwan
> > > **Sent:** Tuesday, March 07, 2017 8:29 AM
> > > **To:** John Kim <John.Kim@ofina.on.ca>
> > > **Cc:** Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>

Subject: Re: Electricity Outlook

Hi John,

Miscommunication in what way? That Brampton should or should not be in the Electricity Outlook to be consistent with the AO outlook, and on Hydro One's 70%?

And is SIFB ready to go to send a new version in if they are rebasing to 70% too?.

Looping in Francisco.

Thanks,
Ron

On Mar 7, 2017, at 7:25 AM, John Kim <John.Kim@ofina.on.ca> wrote:

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Bruno

Gavin, we picked up the revised DRC forecast.

From: Ronald Kwan
To: John Kim
Subject: Re: OFHP fees reg
Date: Thursday, October 12, 2017 5:52:41 PM

Thanks John. Please keep me apprised on these and other such requests from Energy and IGB, and on the proposed responses.

This morning the discussion was the regs going direct to Cabinet on the 18th (vs LRC on the 16th).

Ron

From: John Kim
Sent: October 12, 2017 5:27 PM
To: Ronald Kwan
Subject: FW: OFHP fees reg

Fyi, something that I'm working on with guys upstairs.

From: John Kim
Sent: Thursday, October 12, 2017 5:27 PM
To: Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>; Carlos Yep <Carlos.Yep@ofina.on.ca>
Cc: Mike Manning <Mike.Manning@ofina.on.ca>; James Devine <James.Devine@ofina.on.ca>; Anna Strathy <Anna.Strathy@ofina.on.ca>
Subject: FW: OFHP fees reg

Hi Ken, Carlos,

Just catching up on emails and attached see additional request related to the draft reg.

I will aim to provide draft response to the Qs below tomorrow based on our comments and CMD's, as well.

Thanks,

John

From: Katona, Keley (MOF) [mailto:Keley.Katona@ontario.ca]
Sent: Thursday, October 12, 2017 2:06 PM
To: John Kim <John.Kim@ofina.on.ca>
Cc: Tim Christie (ENERGY) <Tim.Christie@ontario.ca>; Daniel Cayley (ENERGY) <Daniel.Cayley@ontario.ca>; Montgomery, Kaitlin (MOF) <Kaitlin.Montgomery@ontario.ca>

Subject: FW: OFHP fees reg

Hi John,

Further to my call, attached is the latest draft reg. Could you review the NTD for the OFA and also address any outstanding questions per below? This was discussed at a meeting that Gadi and Ron attended this morning and it's likely tracking to Cabinet next week with the goal of finalizing before the weekend.

Thanks,
Keley

From: Cayley, Daniel (ENERGY)
Sent: October-11-17 2:04 PM
To: Kim, John (OFA)
Cc: Christie, Tim (ENERGY)
Subject: OFHP fees reg

Hi John – our lawyers have a few questions below related to the OPG fair hydro plan fees reg that they were hoping to get your input on as soon as possible. Please let me know if you think a call with us/our lawyers would be faster than getting us written answers.

#1 – On the process for establishing the base fee and variable fee, which could theoretically spill over into the year to which the new fees would apply (if OEB approval was not obtained until then), the thinking would be to have the old fees apply until the new fees were approved by the OEB, and then have a "retroactive" adjustment of the fees (retroactively adjusting them back to the beginning of the year the new fees take effect). Since the base fee and variable fee are payable monthly, the "retroactive" adjustment would be made in the month following the month in which the new fees were finalized. The question for OFA is whether it would be appropriate to have a retroactive fee adjustment.

#2 – Re: discussion between OPG and OFA about what "market comparable fees", OPG has proposed that there be a requirement for five sets of fees, four of which would be fees charged by full-service managers of securitization vehicles, and the fifth of which would be fees charged by an asset manager (or management and financial services provider) in respect of any one of pension funds, other structured investment funds, hedge funds or other similar structured funds. Does the OFA have any comments on this approach or the viability of finding five such comparators? The Board has suggested that the FSM be required to submit fee comparators but that the Board have the ability to also include comparators that it chooses (e.g. on the advice of consultants/experts it retains).

#3 – Are there “market comparable fees” that allow the person charging the fees to also recover out-of-pocket costs over and above the fees?

#4 – Can the OFA provide comments on the below draft definition of “market comparable fees” reads as follows (the NTDs are for OFA’s input)?

ıarket comparable fees” means fees, expressed as a **[yearly?]** percentage rate, charged by asset managers **[or management and financial service providers?]** in Canada or another jurisdiction specified by the Board for services that are similar to the services provided by the Financial Services Manager under the Act in terms of,

[NTD: (1) Confirm *yearly* percentage rate. (2) Confirm whether to include “or management and financial service providers”. If this is to be included, what does this mean? Is it a well-recognized industry term of art?]

the type of services provided, being services in respect of funds including **securitization vehicles**, pension funds, other **structured** investment funds, hedge funds and other similar **structured** funds, **[NTD: Confirm “securitization vehicles” and “structured”.]**

the scope of the services provided,

the level of the services provided, and

the dollar amount of assets under management;

Thanks,

Daniel

From:	Ronald Kwan
To:	Francisco Chinchon
Cc:	Gavin He; Darren Scanlan; John Kim; Bruno Amara
Subject:	Re: OPG BP Submission
Date:	Wednesday, April 26, 2017 5:33:46 PM
Attachments:	2017 04 26 OPG concurrence letter v9_markup2.docx

Thanks Francisco. I left out the square-bracketed ones.

Ron

From: Francisco Chinchon
Sent: April 26, 2017 4:44:45 PM
To: Ronald Kwan
Cc: Gavin He; Darren Scanlan; John Kim; Bruno Amara
Subject: RE: OPG BP Submission

I have a few edits on the concurrence letter. Except for confusing ONFA with the RP, there is nothing wrong with what they added but I think it could be said in a better way…

From: Ronald Kwan
Sent: Wednesday, April 26, 2017 4:34 PM
To: John Kim <John.Kim@ofina.on.ca>; Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>
Cc: Gavin He <Gavin.He@ofina.on.ca>
Subject: Fw: OPG BP Submission

Hi,

Comments?

Ron

From: Nelms, Scott (MOF) <Scott.Nelms@ontario.ca>
Sent: April 26, 2017 4:06 PM
To: Nancy Kennedy (MOHLTC); Ronald Kwan
Cc: Vivienne Skoberne (MOHLTC); Montgomery, Kaitlin (MOF)
Subject: OPG BP Submission

Hi Nancy, Ron,

Please see the attached OPG BP package and draft concurrence letter. This has been shared with ENE DMO / MO. Ron, I think you were planning to share up with MoF on our side.

Thanks,

Scott

Mr. Bernard Lord
Chair
Ontario Power Generation
1900-700 University Avenue
Toronto ON M5G 1X6

Dear Mr. Lord,

Thank you for your submission of Ontario Power Generation's (OPG) 2017-2019 Business Plan ("the Plan"). We have reviewed the Plan and find it to be consistent with our government's expectations.

I support the operational and financial targets set by OPG in its business plan. We recognize the substantial cost reductions that OPG has recently achieved and expect OPG to work closely with the Province to fully realize the additional efficiencies incorporated in the Plan in a manner that is consistent with the continued safe and environmentally responsible operation of OPG's facilities.

We commend OPG on its successful start to the Darlington Refurbishment Project, a key objective of Ontario's 2013 Long-Term Energy Plan (2013 LTEP). As a priority project for the government, I expect that OPG will continue to focus on delivering the project as per the schedule and budget contained in the Release Quality Estimate approved by the OPG Board and by the government. I also expect OPG to continue to minimize project risks consistent with the nuclear refurbishment principles set out in the 2013 LTEP, and seek concurrence prior to commencing ~~subsequent unit~~ refurbishment~~s after~~of Unit ~~2~~3 ~~is successfully returned to service~~before the end of 2017.

We continue to support the planned operation of Pickering units up to 2022/2024, subject to OPG obtaining necessary regulatory approvals, as the station's output will provide reliable, cost-effective and emission-free electricity supply during the Darlington and initial Bruce refurbishments. I expect OPG to keep the Ministry apprised throughout the regulatory processes and as we proceed to update the Long-Term Energy Plan. .

I understand that the recently approved Ontario Nuclear Funds Agreement (ONFA) Reference Plan has resulted in a reduction of the estimated liabilities for future decommissioning and long-term management of waste from Ontario's nuclear fleet. With many decades of nuclear generation in the Province's future, we expect OPG to continue managing its decommissioning and waste management obligations and related segregated funds in a prudent manner. I recognize that the ONFA Reference Plan is based on OPG's proposed siting of a Deep Geological Repository (DGR) for low and intermediate level waste at the Bruce site. OPG's DGR is a key component of Ontario's plans to ensure that nuclear remains the backbone of our electricity system for years to come.

I appreciate the efforts of OPG staff, management and the Board of Directors to date as we worked to develop a plan to refinance the Global Adjustment (GA). Refinancing the GA would provide significant and immediate rate relief by spreading the cost of electricity investments over the expected lifecycle of the infrastructure that has been

built. OPG will be instrumental to the success of this initiative and we plan to introduce legislation that would, if passed, enable OPG to work with the Independent Electricity System Operator (IESO) to implement this plan. I also expect to make the necessary changes to OPG's articles of amalgamation to provide the financing flexibility to implement the refinancing of the GA to meet the Province's price objectives announced on March 2, 2017.

I expect OPG to continue to keep the government informed with regard to the company's key ongoing and emerging initiatives and progress in achieving its financial and operational performance commitments. As OPG's performance directly impacts Ontario's fiscal plan, we note the importance of achieving or exceeding OPG's financial performance commitments

Consistent with Section 7 of the Memorandum of Agreement, in advance of commencing discussions for the renewal of its collective agreements with its unions, I expect that OPG shall seek advice from the Ministry on Provincial policy direction and relevant fiscal considerations affecting labour negotiations.

This letter constitutes our concurrence with OPG's Board approved 2017-2019 Business Plan as provided for under the Memorandum of Agreement between OPG and the Shareholder dated July 17, 2015.

This letter also confirms the approval of special status for OPG to approve international travel, under Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive. OPG shall submit semi-annual reports on international travel to the Ministry of Energy, as described in the submission received from OPG's President and CEO, dated January 24, 2017.

Sincerely,

Glenn Thibeault
Minister of Energy

c: Jeff Lyash, President and Chief Executive Officer, OPG
Serge Imbrogno, Deputy Minister, Ministry of Energy
Scott Thompson, Deputy Minister, Ministry of Finance
Andrew Teliszewsky, Chief of Staff, Ministry of Energy
Ali Ghiassi, Chief of Staff, Ministry of Finance

From: Ronald Kwan
To: John Kim
Cc: Deena Padamadan; Bruno Amara; Shajee Kathirgamanathan
Subject: Re: OPG Business Plan Meeting (2017 05 01 v2)_Markup.pptx
Date: Thursday, May 04, 2017 11:02:08 AM
Attachments: OPG Business Plan Meeting (2017 05 01 v3).pptx

Thanks John.

I updated the date and edited the footer.

Ron

From: John Kim
Sent: May 4, 2017 8:13:49 AM
To: Ronald Kwan
Cc: Deena Padamadan; Bruno Amara; Shajee Kathirgamanathan
Subject: RE: OPG Business Plan Meeting (2017 05 01 v2)_Markup.pptx

Hi Ron,

If I understand you right, yes, it is the 8M ONFA that is the difference. Made the change in red.

Thanks,

John

From: Ronald Kwan
Sent: Thursday, May 04, 2017 1:54 AM
To: John Kim <John.Kim@ofina.on.ca>
Cc: Deena Padamadan <Deena.Padamadan@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>
Subject: RE: OPG Business Plan Meeting (2017 05 01 v2)_Markup.pptx

Hi John,

I added in an extract of the appendix table from the TBS BN, but the net income difference does not seem to add up (differs by 8, which may be the ONFA adjustment amount) – does the table need to be fixed (on slide 3 as well as the appendix E table?

Ron

From: Ronald Kwan
Sent: May-03-17 6:26 PM
To: John Kim <John.Kim@ofina.on.ca>
Cc: Deena Padamadan <Deena.Padamadan@ofina.on.ca>; Bruno Amara

<Bruno.Amara@ofina.on.ca>; Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>
Subject: RE: OPG Business Plan Meeting (2017 05 01 v2)_Markup.pptx

Hi,

I took out the specific refurb example, and took out the 20-21 column in the additional IFRS risk, as we don't have it, not that it does not exist.

Ron

From: John Kim
Sent: May-03-17 18:10
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: Deena Padamadan <Deena.Padamadan@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>
Subject: OPG Business Plan Meeting (2017 05 01 v2)_Markup.pptx

Hi Ron,

Pls. see attached back pocket for tomorrow's meeting.

John

DRAFT

OPG Fiscal Impacts

Corporate and Electricity Finance Division
2017-05-05

DRAFT

OPG Fiscal Impact

- The table below illustrates OPG's fiscal impacts in the 2017 Budget forecast.

	2016-17	2017-18	2018-19	2019-20	2020-21
OPG Net Income - 2017 Ontario Budget / Fiscal Plan					
OPG 2017-19 Business Plan[1]	349	702	678	726	913[1]
OPG Monthly Shareholder Update (February 2017)	30				
OPG IFRS Consolidation Risk[2]	(75)	(400)	-	(200)	-
OPG Head Office Sales (Reported under Sales and Rentals)[3]		(222)			
GA Refinancing – OPG Trust Interest Revenue		17	54	99	153
OPG Net Income (After Tax, Adjusted)	**304**	**97**	**732**	**625**	**1,066**
ONFA Adjustments[4]	8	-	-	-	-
OPG Income Tax PILs - 2017 Ontario Budget / Fiscal Plan					
OPG 2017-19 Business Plan	96	166	135	170	298[1]
OPG Monthly Shareholder Update (February 2017)	(4)				
OPG Head Office Sales (Reported under Sales and Rentals)[3]		(74)			
OPG Income Tax PILs (Adjusted)	92	92	135	170	298

1 Fiscalized projection from OPG Business Plan

2 IFRS risk is related to Province's reporting of nuclear asset retirement obligations. The Ontario Auditor General recommended (2016 AG Report) that the Province include Hydro One and OPG financial information in the consolidated financial statements using the IFRS reporting framework as required by PSAB standards, versus the companies U.S. GAAP basis of reporting.

3 For public Budget reporting, projected net impacts of Province asset optimization strategy including, OPG Head Office sale, are reported under Sales and Rentals for commercial confidentiality. OPG proceeds estimate updated per 2017 Budget.

4 Provincial consolidation adjustments for unrealized earnings on decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds.

DRAFT

OPG Fiscal Impact Changes

- The table below illustrates OPG's fiscal impact variances in the 2017 Budget vs 2016 Budget.

OPG Net Income and Income tax ($ Millions)				
	2016-17	2017-18	2018-19	2019-20
2016 Budget[1]				
Net Income	471	586	673	
Income Tax	224	159	182	
2017 Budget				
Net Income 2017 Budget	312	97	732	625
Income tax 2017 Budget	92	92	135	170
2016 Budget vs. 2017 Budget (including IFRS and sales & rental adjustments)				
Net Income	-159	-489	59	
Income taxes	-132	-67	-47	
2016 Budget vs. 2017 Budget (Before IFRS and sales & rental adjustments)				
Net Income	-84	133	59	200
Income taxes	-132	7	-47	0

1. 2016 Budget fiscal plan was largely based on OPG's 2015 multi-year business plan, as the 2016 multi-year business plan was approved and submitted following the timeframe for locking the numbers for the early 2016 Budget.
2. OPG February 2017 Monthly Update
3. IFRS risk is related to Province's reporting of nuclear asset retirement obligations. The Ontario Auditor General recommended (2016 AG Report) that the Province include Hydro One and OPG financial information in the consolidated financial statements using the IFRS reporting framework as required by PSAB standards, versus the companies U.S. GAAP basis of reporting.
4. For public Budget reporting, projected net impacts of Province asset optimization strategy including, OPG Head Office sale, are reported under Sales and Rentals for commercial confidentiality. OPG proceeds estimate updated per 2017 Budget.
5. Provincial consolidation adjustments for unrealized earnings on decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds.

DRAFT

Updated OPG Fiscal Impacts

- The table below illustrates updated OPG's net income, income tax PILs and ONFA adjustment figures from the 2017 Budget forecast.

	2016-17	2017-18	2018-19	2019-20	2020-21
Other updates since Budget 2017					
March 2017 Shareholder Update: OPG Net Income	385	-	-	-	-
March 2017 Shareholder Update: Income Tax Expense	94	-	-	-	-
ONFA Adjustments (as at Mar 31, 2017)	49	-	-	-	-

Risks

- **OEB Risks:** OPG's multi-year rate application to the Ontario Energy Board for the period starting January 1, 2017, is currently in process. Potential OEB decisions providing for lower rates, including disallowance of recovery of OPG's operating costs, current or future deferral and variance account balances (including for the proposed nuclear rate smoothing) and unfavourable future treatment of pension costs would adversely affect OPG's results, resulting in negative fiscal impacts.
- **IFRS Risks:** A change in the basis of accounting used for consolidation of OPG results from U.S. GAAP to International Financial Reporting Standards (IFRS) on the Province's financial statements is expected to result in potentially significant fiscal impacts.

	2016-17	2017-18	2018-19	2019-20
Net additional OPG IFRS Consolidation Risks	-	(25)	(525)	(475)

- **Financing Costs:** Higher cost public capital market borrowing (vs the Province's borrowing cost for OEFC to lend to OPG) would have a negative fiscal impact.

Risks – Darlington Refurbishment

- **Darlington Refurbishment Risk:** Darlington Refurbishment is executed consistent with the approved project budget and schedule. Failure to maintain cost and schedule commitments for the project could potentially result in significant write-offs against net income as well as reputational damage. In addition, inability to carry out the refurbishment of the first unit as planned may result in the Province of Ontario (Province) not proceeding with OPG's refurbishment of the remaining units.

DRAFT

Electricity Sector Rules of Thumb

- **OPG Rule of Thumb**: For every $50M change in OPG revenues due to changes in regulated prices, all-in rate impact of about 0.04 ¢/kWh (less than 0.25% of total bill)

OPG Risks	Fiscal Impact
Realised gains in ONFA funds v plan -/+ 1%	-/+ $100 million
Change in Regulated Prices -/+ 1%	-/+ $40 million
Regulated ROE -/+ 1%	-/+ $45 million
Nuclear regulated price -/+ 0.1 ¢/kWh	-/+ $40 million
Hydro regulated price -/+ 0.1 ¢/kWh	-/+ $20 million
Nuclear output -/+ 1 TWh	-/+ $70 million
Hydro output -/+ 1 TWh	-/+ $45 million

From:	Ken Kandeepan
To:	John Kim
Cc:	Tobias P. Whitfield (MOF); Mike Manning; Ronald Kwan; Malle Hanslep (MOF); Carlos Yep; John Psinas; Shajee Kathirgamanathan
Subject:	Re: OPG Q4 reporting - relevant excerpts for FHP
Date:	Monday, February 26, 2018 6:55:52 PM

Sorry for the delay, agree with Toby's edits, I don't have any to add.

Thanks

Ken k

On Feb 26, 2018, at 5:38 PM, John Kim <John.Kim@ofina.on.ca> wrote:

> Thanks Toby….will send these back.
>
> John
>
> ---
>
> **From:** Whitfield, Tobias P. (MOF) [mailto:Tobias.Whitfield@ontario.ca]
> **Sent:** Monday, February 26, 2018 11:32 AM
> **To:** John Kim <John.Kim@ofina.on.ca>; Mike Manning <Mike.Manning@ofina.on.ca>; Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
> **Cc:** Ronald Kwan <Ronald.Kwan@ofina.on.ca>; Malle Hanslep (MOF) <Malle.Hanslep@ontario.ca>; Carlos Yep <Carlos.Yep@ofina.on.ca>; John Psinas <John.Psinas@ofina.on.ca>; Shajee Kathirgamanathan <Shajee.Kathirgamanathan@ofina.on.ca>
> **Subject:** RE: OPG Q4 reporting - relevant excerpts for FHP
>
> Please find attached comments on the excerpts. Let me know if you have any other questions.
>
> Toby
>
> Tobias Whitfield
> Counsel, Legal Services Branch
> Ministry of Finance
> tobias.whitfield@ontario.ca
> Phone: 416-325-1456
>
> ---
>
> **From:** John Kim [mailto:John.Kim@ofina.on.ca]
> **Sent:** February 26, 2018 11:04 AM
> **To:** Manning, Mike (OFA); Kandeepan, Ken (OFA)
> **Cc:** Kwan, Ronald (OFA); Hanslep, Malle (MOF); Whitfield, Tobias P. (MOF); Yep, Carlos (OFA); John Psinas; Kathirgamanathan,Shajee (OFA)
> **Subject:** OPG Q4 reporting - relevant excerpts for FHP
>
> Hi Mike, Ken,

We have the attached excerpts from OPG's draft Q4. Let me know if you have any comments on the draft wording, as highlighted.

I had shared these with Toby and Malle earlier this morning.

Thanks,

John

Y. John Kim
Director, Electricity Finance Branch
Ontario Financing Authority
e-mail: john.kim@ofina.on.ca
Ph: 416-212-6996

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From: Ronald Kwan
To: Bruno Amara
Cc: Usman Zahid; John Kim; Gavin He
Subject: Re: OPG Revenue
Date: Wednesday, November 29, 2017 11:46:34 AM
Attachments: OPG 2017 Budget_v4_Markup.xlsx

Hi Bruno,

Some suggestions for the spreadsheet. Are the IFRS numbers consistent with what we learned from OB & OPCD on the IFRS numbers subsequent to the 2017 Document?

Ron

From: Bruno Amara
Sent: Thursday, November 23, 2017 5:23 PM
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: John Kim <John.Kim@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>; Usman Zahid <Usman.Zahid@ofina.on.ca>
Subject: RE: OPG Revenue

Hi Ron

Answer limited to 18-19 and 19-20 per your comment. We added a footnote consistent with our FAO response re, prudence wrt to IFRS assumption in 16-17 and 17-18 etc. Also attached is source from OPG.

Bruno

From: Ronald Kwan
Sent: Thursday, November 23, 2017 3:32 PM
To: Usman Zahid <Usman.Zahid@ofina.on.ca>
Cc: John Kim <John.Kim@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>
Subject: RE: OPG Revenue

The request also seems to be just for 18-19 and 19-20. Is that right? Why provide more?

Ron

From: Ronald Kwan
Sent: November-23-17 15:30
To: Usman Zahid <Usman.Zahid@ofina.on.ca>

Cc: John Kim <John.Kim@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>
Subject: RE: OPG Revenue

Hi,

Do we know what Energy wants to use them for? And can we point directly to an OPG source document for the numbers, including on the IFRS side, even if not fully picked up?

Ron

From: Usman Zahid
Sent: November-23-17 15:27
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Cc: John Kim <John.Kim@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>; Gavin He <Gavin.He@ofina.on.ca>
Subject: FW: OPG Revenue

Hi Ron,

The Ministry of Energy has reached out requesting OPG revenue numbers built in budget 2017. EFB has prepared the attached table, including the IFRS adjustment built-in for Budget 2017.

They are also considering including the FAO response as part of the explanation. Are you okay with sending this table to Energy, or should we exclude the IFRS adjustment?

Regards,
Usman

From: Gavin He
Sent: Thursday, November 23, 2017 12:05 PM
To: Usman Zahid <Usman.Zahid@ofina.on.ca>
Cc: John Kim <John.Kim@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>
Subject: FW: OPG Revenue

Hi Usman,

The Ministry of Energy has reached out to us to acquire the OPG revenue numbers built-in for Budget 2017 for 2018-19 and 2019-20. We have prepared the attached table outlining the information they requested, including the IFRS adjustments built-in for Budget 2017. In addition, we are thinking about attaching the FAO response as part of the explanations to the table as well.

Could you please let us know if Ron is okay with this table going to Energy, or should we exclude the IFRS adjustments?

Thanks,
Gavin He

From: Young, Graham (ENERGY) [mailto:Graham.Young@ontario.ca]
Sent: Thursday, November 23, 2017 9:41 AM
To: Gavin He <Gavin.He@ofina.on.ca>
Cc: Talwar, Shruti (ENERGY) <Shruti.Talwar@ontario.ca>
Subject: OPG Revenue

Hi Gavin,

Can you provide me with the OPG revenue numbers used in Budget 2017 for 2018/19 and 2019/20? I'm not able to pull them out of the document because they're aggregated up with other GBE's. Please include net income, GRC, property tax payable and income tax PILS if possible.

Thank you,

Graham Young
Senior Policy Advisor
Strategic Policy and Analytics Branch
Ontario Ministry of Energy
77 Grenville Street | Toronto, ON
(416) 327-7302 | graham.young@ontario.ca

Budget 2017 Outlook for OPG

$ Millions	2018-19	2019-20
Ontario Power Generation Inc.[1]	678	726
GA - OPG Interest Revenue from OPG Trust[2]	*54*	*99*
IFRS Adjustment[3]	-	(200)
Total OPG Net Income	**732**	**625**

1. From OPG's 2017-19 Business Plan.

2. Note: Relates only to the portion financed by sub-debt related to the Province's equity injection into OPG. Values estimated by OFA based on an assumed fiscal neutrality between the Province's interest cost on the equity injection and higher OPG interest revenue related to the sub-debt related to the equity injection.

3. Note: IFRS Provincial consolidation adjustments provided by OPG were not fully reflected in Budget 2017, as determined at a centralised level during the fiscal plannning process. IFRS was fully picked up in 2016-17 and 2017-18 reflecting the higher degree of prudence included in the near term period. The out-year impacts, 2018-19 onwards will be assessed, pending receipt of revised IFRS consolidation adjustment estimates at the time of the next Budget and it is expected that these revised estimates will be reflected in the Province's income from OPG/Hydro One.

	2018-19	2019-20
Payments-in-lieu of tax:		
Income Taxes	135	170
GRC: Payable to OEFC	212	218.5
Proxy Property Tax	19	19
Total OPG PILs	**366**	**407.5**

From: Ronald Kwan
To: Bruno Amara
Cc: John Kim
Subject: Re: Revised Electricity Outlook
Date: Thursday, October 19, 2017 7:04:31 PM

Hi Bruno,

I thought we discussed making an adjustment to the Hydro One deferred tax benefit upfront hit risk to be scaled at a proportionate 50%. It could be footnoted as done this way vs the 70% assumption used for H1 generally, pending the recategorisation from the AO sales and rentals outlook. (As an aside, would it be fair to say that the incremental risk is also less than what is shown because built into the update is the annual impact of the deferred tax benefit decision of the OEB? In that light, for symmetry, should there be a positive risk shown for H1 should it be successful in its OEB Motion to Review?

Also, why not put into the OEFC tab an estimated s.50.3 amount for 17-18?

Also, why does the Budget 2017 tab for OEFC show an excess of revenue over expense of about $0.7bn. I thought it was about $1.1 bn at the time of Budget. You may need to add to the ESDI formula to reverse the IFRS assumption in the OEFC Budget tab -- and then putting in the 50.3 amount in the OEFC on-deck tab would more than offset that (for now, pending other updates, such as for H1).

Also, for clarity, on each worksheet where Hydro One proportionate numbers appear, please add a footnote on that row, as some people may just go to one work sheet, or print one worksheet (and has each worksheet been formatted for easy printing -- can help multiple users and down the line). This includes the Provision worksheet, where I assume the financing cost for the Hydro One row is based on the 70%, but will go down to under 50% ultimately.

On the OPG FHP Trust interest revenue, is that scaled to the new equity injection projections supplied to FTD so it would match the IOD side? Are we aligned to match FTD's IOD assumptions for borrowing for the equity injection?

Thanks,
Ron

From: Bruno Amara
Sent: October 19, 2017 3:54 PM

To: Ronald Kwan
Cc: John Kim
Subject: Revised Electricity Outlook

Hi Ron

Attached is the revised Electricity Sector Outlook (document pw). I want to point out one change on the risk page in particular. In the version we walked you through, I had included an OPG risks reflecting head office sales (currently in Sales and rentals) and the in–year update. You had asked about Lakeview which could have a similar note. Hydro One unpacking could also be included and other reclassification impacts e.g., revenue impact related to IOD savings current in AO numbers. I think that all this may be better handled through the AO unpacking/updating analysis that we worked on with SIFB. When we send the Outlook to our Frost colleagues, we were planning to set up a staff level meeting between EFB, OB, OEP and TBS to review the Outlook and answer questions. We could as an option also use this meeting to review the AO unpacking/updating analysis at the same time if that makes sense. That isn't needed for FES, but may be worth getting people familiar with it now.

Also attached is a draft of some follow-up for OPG in regard to their September monthly report per our discussion.

Bruno

Bruno Amara
Sr. Manager, Financial and Regulatory Analysis
Electricity Finance Branch
Corporate and Electricity Finance Division
Ontario Financing Authority

Tel: 416-325-1489
Email: bruno.amara@ofina.on.ca

From: Lewis, Brian (MOF)
To: Ronald Kwan
Subject: Re: Statement from the Minister of Energy on the Ontario Energy Board"s New Regulated Price Plan (RPP) Electricity Rate Announcement
Date: Thursday, April 20, 2017 6:51:50 PM

Thanks Ron. Much appreciated.

Sent from my BlackBerry 10 smartphone on the Rogers network.
From: Ronald Kwan
Sent: Thursday, April 20, 2017 6:49 PM
To: Lewis, Brian (MOF)
Subject: RE: Statement from the Minister of Energy on the Ontario Energy Board's New Regulated Price Plan (RPP) Electricity Rate Announcement

Hi Brian,

This is part of the impacts of the announced / proposed Fair Hydro Plan that was released Mach 2nd and built into the Fiscal Plan generally. The plan does not affect OPG's rate-regulated rates.

The Fiscal Plan does include some impact on OPG from its role under the proposed plan (not as a generator, but under the "refinancing" plan), but the actuals could vary.

And OPG's rate-regulated rates assumed in OPG's business plan results could also differ in the end, as OPG still has its rate application in the midst of the OEB process.

Ron

From: Lewis, Brian (MOF) [mailto:Brian.Lewis@Ontario.ca]
Sent: April-20-17 18:43
To: Ronald Kwan <Ronald.Kwan@ofina.on.ca>
Subject: FW: Statement from the Minister of Energy on the Ontario Energy Board's New Regulated Price Plan (RPP) Electricity Rate Announcement

I almost hate to ask…. But… does this represent a downside risk to the OPG net income forecast we are carrying?

From: Ontario News [mailto:newsroom@ontario.ca]
Sent: April-20-17 5:46 PM
To: Lewis, Brian (MOF)
Subject: Statement from the Minister of Energy on the Ontario Energy Board's New Regulated Price Plan (RPP) Electricity Rate Announcement

[Ontario Newsroom]

[Ontario Newsroom]

Statement

Statement from the Minister of Energy on the Ontario Energy Board's New Regulated Price Plan (RPP) Electricity Rate Announcement[news.ontario.ca]<https://urldefense.proofpoint.com/v2/url?u=http-3A__news.ontario.ca_mei_en_2017_04_statement-2Dfrom-2Dthe-2Dminister-2Dof-2Denergy-2Don-2Dthe-2Dontario-2Denergy-2Dboards-2Dnew-2Dregulated-2Dprice-2Dplan-2Drpp-2Delec.html-3Futm-5Fsource-3Dondemand-26utm-5Fmedium-3Demail-26utm-5Fcampaign-3Do&d=DwMGaQ&c=qG_YucLTZOaBAapRaQkKEgrMWFFI0Cr1_eykjn9FtiQ&r=lYqulJJnqfxO5431Uw8ghWAHz6F3PkI2znI7RPACN08&m=Qdb8DlRyrhF-BnNNMStvPu_K9dmASNTTUvd4S_3OzE0&s=98bjVq95Sw_609MEJJJm8I_SKxalWyLg5DO2eIS5aZI&e=>

April 20, 2017

Today, Glenn Thibeault, Minister of Energy, issued the following statement in response to OEB's plan to lower electricity costs for residents and small business customers on the Regulated Price Plan:

"In March, our government committed to reducing hydro rates by 25 per cent on average for all households that pay for electricity across the province. This includes the eight per cent rebate equal to the provincial portion of the HST that took effect on January 1, 2017.

Today's Ontario Energy Board (OEB) Regulated Price Plan (RPP) announcement includes a portion of this reduction, meaning residential households and as many as half a million small businesses and farms will see real savings sooner than expected.

This is an important first step to deliver on our government's commitment to lower rates by 25 per cent on average by this summer. Rates will also be held to inflation for the next four years. This is the largest rate cut in Ontario history.

Our government intends to introduce legislation that would, if passed, provide real relief for Ontarians and greater fairness in our electricity system. With the anticipated implementation of our government's proposed legislation, the OEB would be required to lower rates again this summer to fulfill our pledge to cut electricity bills for all residential consumers by 25 per cent on average and reduce rates for families in rural or remote areas of the province up to 40 to 50 per cent.

Premier Wynne committed to providing significant and real relief on hydro bills for people across Ontario, and our government is delivering on this pledge."

CONTACTS

Colin Nekolaichuk
Minister's Office
416-325-2690
Colin.Nekolaichuk@ontario.ca<mailto:Colin.Nekolaichuk@ontario.ca>

Natasha Demetriades
Communications Branch
416-326-5452
Natasha.Demetriades@ontario.ca<mailto:Natasha.Demetriades@ontario.ca>

Ministry of Energy
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From: John Kim
To: Ronald Kwan
Subject: Re: Summary of the OFHP
Date: Thursday, October 26, 2017 6:20:36 PM

I did partly and this is where it came from as OFA guys were saying there were no earnings while Steve was having a hard time. I told them let's leave #1 at that but to be discussed. I agreed with Steve. But I had to leave for the appointment

Sent from my iPhone

On Oct 26, 2017, at 5:53 PM, Ronald Kwan <Ronald.Kwan@ofina.on.ca> wrote:

> Hi John,
>
> Did you attend the 9:30 meeting this morning?
>
> Ron

From: John Kim
Sent: October 26, 2017 5:37 PM
To: Ronald Kwan
Subject: Fwd: Summary of the OFHP

Hi Ron,

Not sure what this is about but sharing first.

John

Sent from my iPhone

Begin forwarded message:

> **From:** Ken Kandeepan <Ken.Kandeepan@ofina.on.ca>
> **Date:** October 26, 2017 at 5:10:09 PM EDT
> **To:** John Kim <John.Kim@ofina.on.ca>

Cc: Carlos Yep <Carlos.Yep@ofina.on.ca>, John Psinas <John.Psinas@ofina.on.ca>, James Devine <James.Devine@ofina.on.ca>, Anna Strathy <Anna.Strathy@ofina.on.ca>
Subject: Summary of the OFHP

Hi john

The way I understand the operations of the OFHP at least for the first 4 years is as follows:

IESO pays 100% to the generators and charges ratepayers approximately 83%, with the difference set up as a regulatory asset funded vi a credit facility of $2 billion form the Province. On a quarterly basis the regulatory asset will be purchased by the Financing Entity with debt issued to OPG (49%) and the capital markets (51%).

Over the first four years the Financing Entity has no revenue sources hence interest on this debt will be paid via additional borrowings issued in the same proportion. Once the CEA kicks in, it will be used to pay interest and draw down debt as appropriate.

Happy to discuss, I am relatively free in the AM tomorrow.

Thanks

Ken k

From: Ronald Kwan
To: John Kim
Subject: Re: Summary of the OFHP
Date: Thursday, October 26, 2017 5:53:14 PM

Hi John,

Did you attend the 9:30 meeting this morning?

Ron

From: John Kim
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Subject: Fwd: Summary of the OFHP

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John

Sent from my iPhone

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Ken k

From: Ronald Kwan
To: John Kim
Subject: Re: Summary of the OFHP
Date: Thursday, October 26, 2017 6:40:07 PM

Wasn't the tax discussion from the OFA side way off base?

And I think they were not always attuned to the policy side either.

From: John Kim
Sent: October 26, 2017 6:20 PM
To: Ronald Kwan
Subject: Re: Summary of the OFHP

I did partly and this is where it came from as OFA guys were saying there were no earnings while Steve was having a hard time. I told them let's leave #1 at that but to be discussed. I agreed with Steve. But I had to leave for the appointment

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Happy to discuss, I am relatively free in the AM tomorrow.

Thanks

Ken k

From:	Veinot, Cindy (TBS)
To:	Ronald Kwan
Cc:	Scott Nelms (ENERGY)
Subject:	Re: What amounts if any have been provided to the budget process for GA refinancing re OPG?
Date:	Monday, April 17, 2017 3:34:59 PM

Thanks. Was that assumption validated with OPG?

Sent from my BlackBerry 10 smartphone on the Rogers network.
Original Message
From: Ronald Kwan
Sent: Monday, April 17, 2017 2:56 PM
To: Veinot, Cindy (TBS)
Cc: Nelms, Scott (MOF)
Subject: Re: What amounts if any have been provided to the budget process for GA refinancing re OPG?

Hi,

Staff used Ken's estimated UOD impact and added the same amount to OPG results to have no net impact, by assumption.

Ron

> On Apr 17, 2017, at 1:23 PM, Veinot, Cindy (TBS) <Cindy.Veinot@ontario.ca> wrote:
>
> Thanks. I confirmed with Ken re what OFA included re IOD, but don't have any visibility into what was included for OPG's role.
>
> Cindy
>
> Sent from my BlackBerry 10 smartphone on the Rogers network.
> From: Nelms, Scott (MOF)
> Sent: Monday, April 17, 2017 1:19 PM
> To: Veinot, Cindy (TBS); Kwan, Ronald (OFA)
> Subject: RE: What amounts if any have been provided to the budget process for GA refinancing re OPG?
>
>
> I'm copying Ron, in case he has more insight. I understand that OFA assumed incremental IOD using the ~$1.25B /yr equity infusion from the Province (consistent with the announced curve) and OFA's typical borrowing rate. On the other side OFA assumed equivalent incremental earnings from OPG to ensure the initiative is fiscally neutral. I don't have visibility into the specific numbers, but this is, in concept, what I understand was included.
>
> From: Veinot, Cindy (TBS)
> Sent: April-17-17 1:18 PM
> To: Nelms, Scott (MOF)
> Subject: What amounts if any have been provided to the budget process for GA refinancing re OPG?
>
>
>
> Sent from my BlackBerry 10 smartphone on the Rogers network.

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From:	Ronald Kwan
To:	Veinot, Cindy (TBS)
Cc:	Scott Nelms (ENERGY)
Subject:	Re: What amounts if any have been provided to the budget process for GA refinancing re OPG?
Date:	Monday, April 17, 2017 2:56:15 PM

Hi,

Staff used Ken's estimated UOD impact and added the same amount to OPG results to have no net impact, by assumption.

Ron

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> To: Nelms, Scott (MOF)
> Subject: What amounts if any have been provided to the budget process for GA refinancing re OPG?
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> Sent from my BlackBerry 10 smartphone on the Rogers network.

From: Veinot, Cindy (TBS)
To: Scott Nelms (ENERGY); Ronald Kwan
Subject: Re: What amounts if any have been provided to the budget process for GA refinancing re OPG?
Date: Monday, April 17, 2017 1:23:58 PM

Thanks. I confirmed with Ken re what OFA included re IOD, but don't have any visibility into what was included for OPG's role.

Cindy

Sent from my BlackBerry 10 smartphone on the Rogers network.
From: Nelms, Scott (MOF)
Sent: Monday, April 17, 2017 1:19 PM
To: Veinot, Cindy (TBS); Kwan, Ronald (OFA)
Subject: RE: What amounts if any have been provided to the budget process for GA refinancing re OPG?

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Sent: April-17-17 1:18 PM
To: Nelms, Scott (MOF)
Subject: What amounts if any have been provided to the budget process for GA refinancing re OPG?

Sent from my BlackBerry 10 smartphone on the Rogers network.

From: Ronald.Kwan@ofina.on.ca
To: Veinot, Cindy (TBS)
Cc: Scott Nelms (ENERGY)
Subject: Re: What amounts if any have been provided to the budget process for GA refinancing re OPG?
Date: Monday, April 17, 2017 3:42:36 PM

Hi Cindy,

I'd have to look to Scott on that.

I think Gadi and Ken felt that there had to be something picked in IOD, and to keep in fiscally neutral, OPG results were adjusted.

Not sure if Scott consulted OPG in the end.

Ron

> On Apr 17, 2017, at 3:34 PM, Veinot, Cindy (TBS) <Cindy.Veinot@ontario.ca> wrote:
>
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>
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> Sent: Monday, April 17, 2017 2:56 PM
> To: Veinot, Cindy (TBS)
> Cc: Nelms, Scott (MOF)
> Subject: Re: What amounts if any have been provided to the budget process for GA refinancing re OPG?
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From: Ronald Kwan
To: Usman Zahid; John Kim
Subject: Re: sensitive Fair Hydro Trust question
Date: Friday, April 27, 2018 3:37:24 PM

Hi,

While Lubna may not want OPG to get into it, I think we have to cite the borrowing cost on the equity injection. It would be good to know what sub-debt rates OPG assumed on its interest revenues over the life of the Trust.

Ron

From: Usman Zahid
Sent: April 27, 2018 3:25 PM
To: John Kim
Cc: Ronald Kwan
Subject: FW: sensitive Fair Hydro Trust question

Hi John,

Please see question from Energy below.

Regards,
Usman

From: Pichette, Marc (MOF) [mailto:Marc.Pichette@ontario.ca]
Sent: Friday, April 27, 2018 1:32 PM
To: Usman Zahid <Usman.Zahid@ofina.on.ca>
Subject: FW: sensitive Fair Hydro Trust question

Hi Usman, please see question below from the Ministry of Energy that was sent to my director.

From: Whytock, John (ENERGY) <John.Whytock@ontario.ca>
Date: Thursday, Apr 26, 2018, 4:45 PM
To: LeBlanc, Jenna (MOF) <Jenna.LeBlanc@ontario.ca>
Subject: FW: sensitive Fair Hydro Trust question

Hi Jenna. I've got a sensitive question for you. Our MO asked what the revenue implications of the Fair Hydro Trust were for OPG, and how much we estimated would return to the provincial coffers.

As you'll see below, OPG has put a number on their own expected revenues, but my policy folks were not in a position to say what it could mean for returns to government.

Is this a number that Finance can produce? More importantly, are you willing to share?

Thanks much

jw

From: ROWE Jennifer -CORPAFFAIRS [mailto:jennifer.rowe@opg.com]
Sent: April-23-18 10:19 AM
To: Whytock, John (ENERGY)
Cc: KELLY Neal -CORPCOMM
Subject: RE: EXTERNAL – Fair Hydro Trust question

John,

Here's a simplified version of what I just sent you:

The total amount of income that OPG expects to earn over the life of the Fair Hydro Plan is in the range of **$4.5 Billion to $4.9 Billion.** The actual amount will vary based on the actual debt issued and interest rates.

This is over a period of 30 years (2017 to 2047). The income will be earned gradually, and will peak around 2029/2030.

Since the Province owns OPG, and consolidates OPG into their books, the net income flows back to the Province.

Jennifer

From: LADAK Lubna -TREASURY
Sent: Monday, April 23, 2018 10:14 AM
To: ROWE Jennifer -CORPAFFAIRS <jennifer.rowe@opg.com>; KELLY Neal -CORPCOMM <neal.kelly@opg.com>; HARTWICK Ken -FINANCE <ken.hartwick@opg.com>
Cc: LEE John -TREASURY <john.s.lee@opg.com>; LIU Sheen -TREASURY <sheen.liu@opg.com>; LAURETA LAPIRA May -TREASURY <may.lapira@opg.com>
Subject: RE: EXTERNAL – Fair Hydro Trust question

The total amount of income that OPG expects to earn over the life of the Fair Hydro Plan is in the range of $4.5 Billion to $4.9 Billion.
It is comprised of about $200 M for management fees and $4.3 Billion to $4.7 Billion of interest income.

The actual amount will vary based on the actual debt issued and interest rates.

This is over a period of 30 years (2017 to 2047). The income will be earned gradually, and will peak around 2029/2030.

Since the Province owns OPG, and consolidates OPG into their books, the net income flows back to the Province.

FYI – I don't know how the Province funds the equity injections. If they borrow the funds, the overall net income impact in their books could be lower. I wouldn't get into this though.

Lubna Ladak | VP Treasury - FHP| Ontario Power Generation
700 University Avenue, Toronto, Ontario M5G 1X6 | 416-592-5984 | Cell 416-578-0219 | Fax 416-592-4189
lubna.ladak@opg.com

From: Ronald Kwan
To: John Kim; Usman Zahid
Subject: Re: sensitive Fair Hydro Trust question
Date: Friday, April 27, 2018 6:03:17 PM

Hi,

We should ask Energy what their timing is and what they want to use this for.

Qualitatively, we should definitely say that if they want to discuss or respond to questions on the impact of the FHP on OPG's net income, they should also note that the OPG return on equity to the Province related to the FHP would offset the Province's cost of borrowing for the equity injection, and that the net impact on the Province would depend on the spread between the Province's cost of borrowing and OPG's interest revenue from the Trust on that on-leant equity injection (aside from OPG's 5% financing and spread), and OPG's management fees.

We should ask if OPG can share their interest rate assumptions and spread assumptions on the sub-debt.

Ron

From: John Kim
Sent: April 27, 2018 4:22 PM
To: Ronald Kwan; Usman Zahid
Subject: RE: sensitive Fair Hydro Trust question

Hi Usman,

Adding to Ron's comments, we have debt costs related to the equity injection that needs to be accounted for.

We have OPG's insight into what the income attributed to FHT would be in their business plan.

We can produce this, yes, and in fact working towards it for ESDI reasons but we would need numbers from Risk.

Thanks,

John

From: Ronald Kwan

Sent: Friday, April 27, 2018 3:37 PM
To: Usman Zahid <Usman.Zahid@ofina.on.ca>; John Kim <John.Kim@ofina.on.ca>
Subject: Re: sensitive Fair Hydro Trust question

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Subject: FW: sensitive Fair Hydro Trust question

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To: LeBlanc, Jenna (MOF) <Jenna.LeBlanc@ontario.ca>
Subject: FW: sensitive Fair Hydro Trust question

Hi Jenna. I've got a sensitive question for you. Our MO asked what the revenue implications of the Fair Hydro Trust were for OPG, and how much we estimated would return to the provincial coffers.

As you'll see below, OPG has put a number on their own expected revenues, but my policy folks were not in a position to say what it could mean for returns to government.

Is this a number that Finance can produce? More importantly, are you willing to share?

Thanks much

jw

From: ROWE Jennifer -CORPAFFAIRS [mailto:jennifer.rowe@opg.com]
Sent: April-23-18 10:19 AM
To: Whytock, John (ENERGY)
Cc: KELLY Neal -CORPCOMM
Subject: RE: EXTERNAL – Fair Hydro Trust question

John,

Here's a simplified version of what I just sent you:

The total amount of income that OPG expects to earn over the life of the Fair Hydro Plan is in the range of **$4.5 Billion to $4.9 Billion.** The actual amount will vary based on the actual debt issued and interest rates.

This is over a period of 30 years (2017 to 2047). The income will be earned gradually, and will peak around 2029/2030.

Since the Province owns OPG, and consolidates OPG into their books, the net income flows back to the Province.

Jennifer

From: LADAK Lubna -TREASURY
Sent: Monday, April 23, 2018 10:14 AM
To: ROWE Jennifer -CORPAFFAIRS <jennifer.rowe@opg.com>; KELLY Neal -CORPCOMM <neal.kelly@opg.com>; HARTWICK Ken -FINANCE <ken.hartwick@opg.com>
Cc: LEE John -TREASURY <john.s.lee@opg.com>; LIU Sheen -TREASURY <sheen.liu@opg.com>; LAURETA LAPIRA May -TREASURY <may.lapira@opg.com>
Subject: RE: EXTERNAL – Fair Hydro Trust question

The total amount of income that OPG expects to earn over the life of the Fair Hydro Plan is in the range of $4.5 Billion to $4.9 Billion.
It is comprised of about $200 M for management fees and $4.3 Billion to $4.7 Billion of interest

income.

The actual amount will vary based on the actual debt issued and interest rates.

This is over a period of 30 years (2017 to 2047). The income will be earned gradually, and will peak around 2029/2030.

Since the Province owns OPG, and consolidates OPG into their books, the net income flows back to the Province.

FYI – I don't know how the Province funds the equity injections. If they borrow the funds, the overall net income impact in their books could be lower. I wouldn't get into this though.

Lubna Ladak | VP Treasury - FHP| Ontario Power Generation
700 University Avenue, Toronto, Ontario M5G 1X6 | 416-592-5984 | Cell 416-578-0219 | Fax 416-592-4189
lubna.ladak@opg.com

From: John Kim
To: Ronald Kwan
Cc: Bruno Amara
Subject: latest Outlook version
Date: Thursday, September 21, 2017 1:52:58 PM
Attachments: Electricity Sector Outlook (2017 09 21).xlsm

Hi Ron,

As discussed, pls. see attached Outlook version.

S:\Users\CEF\Hydro 2017\OEFC\RbP\Outlook\09. September

Thanks,

John

Y. John Kim
Director, Electricity Finance Branch
Ontario Financing Authority
e-mail: john.kim@ofina.on.ca
Ph: 416-212-6996

Electricity Sector Outlook
August 2017

Disclosure:

All information contained in this workbook are confidential and commercially sensitive

All projected numbers are estimates and subjected to change, and the focus is on OPG and Hydro One projections

This workbook and all information or analysis contained in it is property of the Ontario Financing Authority,
any disclosure or share of information should be first consulted with the owner.

Commercially Sensitive and Confidential Advice to Cabinet for Consideration of Options for Discussion Purposes Only

Commercially Sensitive and Confidential Advice to Cabinet for Consideration of Options for Discussion Purposes Only

Colour Codes

Formulas are in black text

Hard coded numbers are in blue text

References elsewhere are in purple

Green bold text with or without highlights mean updates required

Policies to follow when making updates to the Outlook

*** To quickly jump to the source numbers for a link, press "**Ctrl + [**"

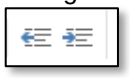
All new numbers must be fully sourced, and follow the colour codes above

Most numbers and text are Arial Size 10, unless it is a title

Add back up materials in a folder with the same numbers as in the 'Track Changes' tab

If there is a reason for italics, or other colours, or formatting make sure it is clear. Othe

Use indents to make things more clear to read



If numbers are taken from another tab they should ONLY be direct links, no calculation

Electricity Summary - (Budget17/On Deck) - Reflects Public Accounts/Financial Statem

OEFC - (Budget17/On Deck) - Reflects OEFC Annual Reports

*Due to slight discrepancies between Public Accounts reporting and OEFC Annual Rep

Outlook Updates Frequency

Frequency	Description	Tab
Monthly	OPG Net Income in-year forecast	OPG
Monthly	OPG PILs in-year forecast	OPG
Quarterly	ONFA Consolidation Adjustment	ONFA
Quarterly	OPG Cash vs Accrual Variance Account	Revenue (Risks)

ɔ.
rwise expect it to be cleared

ı, adjustment should be done. Even if its just making a negative to a positive. Perform all the calculations on the

ıents

ɔorts, the numbers may not be identical

source tab then bring the number into the next tab. (Eg. Formulas like this become hard to troubleshoot ='Hydro

One'!AR29+'Hydro One'!AR31+'Hydro One'!AR32), let's avoid them.

Electricity Sector Outlook
Line Items for Consolidation

Electricity Summary - On De

Type	Ministry Pickup	Line
Expense	MOF (OEFC)	38
Expense	MOF (OEFC)	40
Expense	MOF (OEFC)	41
Expense	MOF	17
Expense	MOF (OEFC)	42

Revenue	ENE	7
Revenue	ENE	8
Revenue	ENE	10
Revenue		11
Revenue	MOF (OEFC)	26
Revenue	MOF (OEFC)	29
Revenue	MOF (OEFC)	30
Revenue	MOF (OEFC)	31
Revenue	MOF (OEFC)	34

Electricity Summary - Budge

For Discussion

Type	Ministry Pickup	Line
Expense	MOF (OEFC)	38
Expense	MOF (OEFC)	40
Expense	MOF (OEFC)	41
Expense	MOF	17
Expense	MOF (OEFC)	42

Revenue	ENE	7
Revenue	ENE	8
Revenue	ENE	10

Revenue	MOF (OEFC)	25
Revenue	MOF (OEFC)	29
Revenue	MOF (OEFC)	30
Revenue	MOF (OEFC)	31
Revenue	MOF (OEFC)	34

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36

Electricity Summary - Chang

Type	Ministry Pickup	Line
Expense	MOF (OEFC)	69
Expense	MOF (OEFC)	71
Expense	MOF (OEFC)	72
Expense	MOF	48
Expense	MOF (OEFC)	73

Revenue	ENE	38
Revenue	ENE	39
Revenue	ENE	41
Revenue	MOF (OEFC)	25
Revenue	MOF (OEFC)	60
Revenue	MOF (OEFC)	61
Revenue	MOF (OEFC)	62
Revenue	MOF (OEFC)	65

17
36

FOR EFB USE ONLY

Type	Ministry Pickup	Line
Expense	MOF (OEFC)	69
Expense	MOF (OEFC)	71
Expense	MOF (OEFC)	72
Expense	MOF	48
Expense	MOF (OEFC)	73

Revenue	ENE	38
Revenue	ENE	39
Revenue	ENE	41
Revenue	MOF (OEFC)	25

Revenue	MOF (OEFC)	60
Revenue	MOF (OEFC)	61
Revenue	MOF (OEFC)	62
Revenue	MOF (OEFC)	65

	17
	36

Type	Ministry Pickup	Line
Expense	MOF (OEFC)	69
Expense	MOF (OEFC)	71
Expense	MOF (OEFC)	72
Expense	MOF	48
Expense	MOF (OEFC)	73

Revenue	ENE	38
Revenue	ENE	39
Revenue	ENE	41
Revenue	MOF (OEFC)	25
Revenue	MOF (OEFC)	60
Revenue	MOF (OEFC)	61
Revenue	MOF (OEFC)	62
Revenue	MOF (OEFC)	65

	17
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$ Millions

MOF Expense Items (consolidated)	Actual		Current
Item	**2016-17**	**2017-18**	**2018-19**
Power Supply Contract Costs	(838)	(292)	(325)
Demand Management Support Costs	(8)	(10)	-
Provision for Electricity Sector	290	269	-
Provision for Electricity Sector	(290)	(269)	-
Other (Finance)	(7)	(6)	(6)
Total MOF Expense	**(853)**	**(308)**	**(331)**
MOF Revenue Items (consolidated)			
OPG Income	299	198	732
OPG - ONFA and other Fair Value Adjustments	43	-	-
HOI Income	500	525	567
Brampton Income	18	-	-
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	334	407	488
Electricity Debt Retirement Charge	621	623	-
Power Supply Contract Recoveries	838	292	325
Net Reduction of Power Purchase Contracts	129	74	41
Miscellaneous	14	-	-
Total MOF Revenue	**2,795**	**2,119**	**2,153**
OFA IOD Expense			
Public Debt Interest - Electricity Sector	(514)	(454)	(454)
Interest on Debt	(513)	(475)	(438)
Total OFA IOD Expense	**(1,027)**	**(929)**	**(892)**
Impact on Surplus/Deficit	**915**	**883**	**930**
check	**-**	**-**	**-**

et17

$ Millions

MOF Expense Items (consolidated)	Interim		Pl
Item	**2016-17**	**2017-18**	**2018-19**
Power Supply Contract Costs	(739)	(292)	(325)
Demand Management Support Costs	(10)	(10)	0
Provision for Electricity Sector	342	125	0
Provision for Electricity Sector	(342)	(125)	0
Other (Finance)	(6)	(6)	(6)
Total MOF Expense	**(755)**	**(308)**	**(331)**
MOF Revenue Items (consolidated)			
OPG Income	304	97	732
OPG - ONFA and other Fair Value Adjustments	8	0	0
HOI Income	516	520	562
Brampton Income	15		

Electricity Payments-in-Lieu of Taxes (PILs), including CIT	373	405	476
Electricity Debt Retirement Charge	625	623	0
Power Supply Contract Recoveries	739	292	325
Net Reduction of Power Purchase Contracts	129	74	41
Miscellaneous	0	0	0
Total MOF Revenue	**2,709**	**2,011**	**2,136**
OFA IOD Expense			
Public Debt Interest - Electricity Sector	(492)	(492)	(492)
Interest on Debt	(532)	(422)	(374)
Total OFA IOD Expense	**(1,024)**	**(914)**	**(866)**
Impact on Surplus/Deficit	**930**	**789**	**939**
	-	-	-

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MOF Expense Items (consolidated)	**$ Millions**		
Item	**2016-17**	**2017-18**	**2018-19**
Power Supply Contract Costs	(99)	0	0
Demand Management Support Costs	2	0	0
Provision for Electricity Sector	(53)	145	0
Provision for Electricity Sector	53	(145)	0
Other (Finance)	(1)	0	0
Total MOF Expense	**(98)**	**0**	**0**
MOF Revenue Items (consolidated)			
OPG Income	(5)	101	0
OPG - ONFA and other Fair Value Adjustments	35	0	0
HOI Income	(16)	6	6
Brampton Income	3	0	0
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	(40)	2	12
Electricity Debt Retirement Charge	(4)	0	0
Power Supply Contract Recoveries	99	(0)	(0)
Net Reduction of Power Purchase Contracts	0	(0)	(0)
Miscellaneous	14	0	0
Total MOF Revenue	**87**	**108**	**18**
OFA IOD Expense			
Public Debt Interest - Electricity Sector	(22)	38	38
Interest on Debt	19	(53)	(64)
Total OFA IOD Expense	**(3)**	**(15)**	**(26)**
Impact on Surplus/Deficit	**(15)**	**94**	**(8)**
	0	***(0)***	***(0)***

Previous Changes Hard-coded

MOF Expense Items (consolidated)	**$ Millions**		
Item	**2016-17**	**2017-18**	**2018-19**
Power Supply Contract Costs	(99)	0	0
Demand Management Support Costs	2	0	0
Provision for Electricity Sector	(53)	145	0
Provision for Electricity Sector	53	(145)	0
Other (Finance)	(1)	0	0
Total MOF Expense	**(98)**	**0**	**0**
MOF Revenue Items (consolidated)			
OPG Income	(5)	101	0
OPG - ONFA and other Fair Value Adjustments	35	0	0
HOI Income	(16)	6	6
Brampton Income	3	0	0
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	(40)	2	12

Electricity Debt Retirement Charge	(4)	0	0
Power Supply Contract Recoveries	99	(0)	(0)
Net Reduction of Power Purchase Contracts	0	(0)	(0)
Miscellaneous	14	0	0
Total MOF Revenue	**87**	**108**	**18**
OFA IOD Expense			
Public Debt Interest - Electricity Sector	(22)	38	38
Interest on Debt	19	(53)	(64)
Total OFA IOD Expense	**(3)**	**(15)**	**(26)**
Impact on Surplus/Deficit	**(15)**	**94**	**(8)**

Impact of Current Updates

MOF Expense Items (consolidated)	**$ Millions**		
Item	**2016-17**	**2017-18**	**2018-19**
Power Supply Contract Costs	-	-	-
Demand Management Support Costs	-	-	-
Provision for Electricity Sector	-	-	-
Provision for Electricity Sector	-	-	-
Other (Finance)	-	-	-
Total MOF Expense	-	-	-
MOF Revenue Items (consolidated)			
OPG Income	-	-	-
OPG - ONFA and other Fair Value Adjustments	-	-	-
HOI Income	-	-	-
Brampton Income	-	-	-
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	-	-	-
Electricity Debt Retirement Charge	-	-	-
Power Supply Contract Recoveries	-	-	-
Net Reduction of Power Purchase Contracts	-	-	-
Miscellaneous	-	-	-
Total MOF Revenue	-	-	-
OFA IOD Expense	-	-	-
Public Debt Interest - Electricity Sector	-	-	-
Interest on Debt	-	-	-
Total OFA IOD Expense	-	-	-
Impact on Surplus/Deficit	-	-	-

Outlook

2019-20	2020-21
(301)	(273)
-	-
-	-
-	-
(6)	(6)
(307)	**(279)**

625	1,066
-	-
609	658
-	-
541	681
-	-
301	273
30	28
-	-
2,107	**2,705**

(454)	(454)
(411)	(348)
(865)	**(802)**
935	**1,624**
-	-

an

2019-20	2020-21
(301)	(273)
0	0
0	0
0	0
(6)	(6)
(307)	**(279)**

625	1,066
0	0
603	652

538	679
0	0
301	273
30	28
0	0
2,098	**2,697**

(492)	(492)
(342)	(250)
(834)	**(742)**
957	**1,676**
-	-

2019-20	2020-21
0	(0)
0	0
0	0
0	0
0	0
0	**(0)**

0	0
0	0
6	6
0	0
4	2
0	0
(0)	0
(0)	(0)
0	0
9	**8**

38	38
(69)	(98)
(31)	**(60)**
(22)	**(52)**
(0)	***(0)***

2019-20	2020-21
0	(0)
0	0
0	0
0	0
0	0
0	**(0)**

0	0
0	0
6	6
0	0
4	2

0	0
(0)	0
(0)	(0)
0	0
9	**8**
38	38
(69)	(98)
(31)	**(60)**
(22)	**(52)**

2019-20	2020-21
-	-
-	-
-	-
-	-
-	-
-	-
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Electricity Sector Outlook

$ Millions

	Actual 2013-14	Actual 2014-15	Actual 2015-16	Interim 2016-17	2017-18	Pl 2018-19
On Deck Outlook as of March 2017						
Income from Investment in Government Business Enterprises						
OPG Income[1]	334	817	291	304	97	732
OPG - ONFA and other Fair Value Adjustments[2]	475	239	172	8	-	-
Hydro One - Unrealized Gains Adjustment	10	(8)	-	-	-	-
HOI Income[3]	786	741	236	516	520	562
Brampton Income			20	15	-	-
Total OPG and HOI Income	**1,605**	**1,789**	**719**	**842**	**617**	**1,294**
Other Fees and Licences	**136**	**131**	**127**	**122**	**102**	**91**
Electricity Expenses of the Province						
Provision for Electricity Sector[4]	(599)	(1,038)	(3)	(342)	(125)	
Public Debt Interest - Electricity Sector	(520)	(520)	(520)	(492)	(492)	(492)
Subtotal	(1,119)	(1,558)	(523)	(834)	(617)	(492)
Public Debt Interest - Impact of ONFA	-					
Amortization of Deferred Revenue re profit on sale of H1 notes	-					
Total Electricity Expenses of the Province	**(1,119)**	**(1,558)**	**(523)**	**(834)**	**(617)**	**(492)**
OEFC Income						
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes (PILs), including CIT	543	180	3,228	373	405	476
Other Revenue						
Electricity Debt Retirement Charge[5]	954	956	859	625	623	-
Power Supply Contract Recoveries	1,296	950	875	739	292	325
Net Reduction of Power Purchase Contracts	243	217	172	129	74	41
Other Fees and Licences	(136)	(131)	(127)	(122)	(102)	(91)
Miscellaneous	8	9	9	-	-	-
Expenses						
Interest on Debt	(728)	(658)	(596)	(532)	(422)	(374)
Power Supply Contract Costs	(1,296)	(950)	(875)	(739)	(292)	(325)
Electricity Consumer Price Protection Fund	-	-	-	-	-	-
Demand Management Support Costs[6]		(9)	(8)	(10)	(10)	-
Provision for Electricity Sector	599	1,038	3	342	125	-
Other (Finance)	(7)	(6)	(7)	(6)	(6)	(6)
Total OEFC Income	**1,476**	**1,596**	**3,533**	**800**	**687**	**46**
Impact on Surplus/(Deficit)	**2,098**	**1,958**	**3,856**	**930**	**789**	**939**

Notes: The Hydro One net income outlook above (2016-17 to 2020-21) reflects the Province's current 70% ownership share, after the initial IPO in 2015 [and the secondary offering in April 2016]. Net estimated fiscal impacts from future Hydro One offerings are reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

Notes:

1.OPG's 2015-16 outlook reflected its reported earnings. 2016-17 outlook reflected OPG's November monthly update. Out-years reflect OPG's preliminary 2017-19 business plan and long-term outlook to 2019-20 (as fiscalized by OPG). 2020-21 estimates are based on OPG's calendar year-based business plan projections and as fiscalized by CEFD staff.

2. Provincial consolidation adjustments for unrealized earnings on the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds, as of the end of December 2016.

3. Hydro One 2015-16 income reflects its reported net income, adjusted for Hydro One IPO impacts. 2016-17 to 2020-21 projections are based on CEFD projections based on latest public information and modelling, including its 2015-17 distribution rate decision, adjustments to forecast ROEs based on current interest rate outlook and estimated Hydro One IPO and secondary share offering impacts.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial ONFA consolidation adjustments, minus the interest on debt payable ~~costs~~ to OEFC. The provision is currently assumed to end once the DRC ends on a legislated fixed end date of April 1, 2018.

5. Reflects April 23, 2014 announcement that DRC will be eliminated for residential users, after December 31, 2015. The end date of DRC for remaining users is legislated to be on April 1, 2018. Estimates are subject to change based on actual consumption.

6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Expenses	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
Power Supply Contract Costs	1,296	950	875	739	292	325
Demand Management Support Costs		9	8	10	10	-
Provision for Electricity Sector	(599)	(1,038)	(3)	(342)	(125)	-
Other (Finance)	7	6	7	6	6	6
SUBTOTAL - OEFC Consolidation	**704**	**(73)**	**887**	**412**	**183**	**331**
Provision for Electricity Sector (Dedicated Earnings)	**599**	**1,038**	**3**	**342**	**125**	**-**

Electricity Sector Outlook

$ Millions

	Actual 2013-14	Actual 2014-15	Actual 2015-16	Actual 2016-17	2017-18	Current 2018-19
On Deck Outlook as of August 2017						
Income from Investment in Government Business Enterprises						
OPG Income[1]	334	817	291	299	198	732
OPG - ONFA and other Fair Value Adjustments[2]	475	239	172	43	-	-
Hydro One - Unrealized Gains Adjustment	10	(8)	-	-	-	-
HOI Income[3]	786	741	236	500	525	567
Brampton Income			20	18	-	-
Total OPG and HOI Income	**1,605**	**1,789**	**719**	**860**	**724**	**1,300**
Other Fees and Licences (Debt Guarantee fee)	**136**	**131**	**127**	**122**	**102**	**91**
Electricity Expenses of the Province						
Provision for Electricity Sector[4]	(599)	(1,038)	-	(290)	(269)	
Public Debt Interest - Electricity Sector	(520)	(520)	(520)	(514)	(454)	(454)
Subtotal	(1,119)	(1,558)	(520)	(803)	(724)	(454)
Public Debt Interest - Impact of ONFA	-					
Amortization of Deferred Revenue re profit on sale of H1 notes	-					
Total Electricity Expenses of the Province	**(1,119)**	**(1,558)**	**(520)**	**(803)**	**(724)**	**(454)**
OEFC Income						
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Miscellaneous	8	9	9	14	-	-
Expenses						
Interest on Debt	(728)	(658)	(596)	(513)	(475)	(438)
Power Supply Contract Costs	(1,296)	(950)	(875)	(838)	(292)	(325)
Electricity Consumer Price Protection Fund	-	-	-	-	-	-
Demand Management Support Costs[6]		(9)	(8)	(8)	(10)	-
Provision for Electricity Sector	599	1,038	-	290	269	-
Other (Finance)	(7)	(6)	(7)	(7)	(6)	(6)
Total OEFC Income	**1,476**	**1,596**	**3,530**	**737**	**781**	**(6)**
Impact on Surplus/(Deficit)	**2,098**	**1,958**	**3,856**	**915**	**883**	**930**

Notes: The Hydro One net income outlook above (2016-17 to 2020-21) reflects the Province's current 70% ownership share, after the initial IPO in 2015 [and the secondary offering in April 2016]. Net estimated fiscal impacts from future Hydro One offerings are reported along with other planned Asset Optimization proceeds under "Sales and Rentals" in the Provinces Revenue outlook.

Notes:

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3. Hydro One 2015-16 income reflects its reported net income, adjusted for Hydro One IPO impacts. 2016-17 to 2020-21 projections are based on CEFD projections based on latest public information and modelling, including its 2015-17 distribution rate decision, adjustments to forecast ROEs based on current interest rate outlook and estimated Hydro One IPO and secondary share offering impacts.

4. Provision for electricity sector reflects OPG and Hydro One reported net income, excluding provincial ONFA consolidation adjustments, minus the interest on debt payable ~~costs~~ to OEFC. The provision is currently assumed to end once the DRC ends on a legislated fixed end date of April 1, 2018.

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6. Offset by incremental Debt Retirement Charge revenues related to the Industrial Electricity Incentive program.

Expenses	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
Power Supply Contract Costs	1,296	950	875	838	292	325
Demand Management Support Costs		9	8	8	10	-
Provision for Electricity Sector	(599)	(1,038)	-	(290)	(269)	-
Other (Finance)	7	6	7	7	6	6
SUBTOTAL - OEFC Consolidation	**704**	**(73)**	**890**	**563**	**38**	**331**
Provision for Electricity Sector (Dedicated Earnings)	**599**	**1,038**	**-**	**290**	**269**	**-**

Electricity Sector Change Since Budget

$ Millions

($million)	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Changes from Budget 2017 as of August 2017							***to update***
Income from Investment in Government Business Enterprises							
OPG Income	-	(5)	101	-	-	-	Slight decline mostly due to IFRS adjustment and revision of OPG Net Income. Increase in OPG net income in 17-18 mainly due to higher nuclear generation caused by strong performance at Pickering from early completion of planned outages, higher generation and lower OM&A expenses related to the deferral of the Pickering Unit 6, lower OM&A expenses from labour savings and lower project spending.
ONFA and other Fair Value Adjustments	-	35	-	-	-	-	Update based on fair market value as at march 31, 2017.
Hydro One - Unrealized Gains Adjustment	-	-	-	-	-	-	
HOI Income	20	(16)	6	6	6	6	2016-17 slight decrease fom Budget. 2017-18 onwards, update to model.
Brampton Income		3.3					
Total OPG and HOI Income	**-**	17	106.692	6	6	6	
Other Fees and Licences	**-**	-	-	-	-	-	
Electricity Expenses of the Province							
Provision for Electricity Sector	3	53	(145)	-	-	-	iance in 2017-18 primarily due to OPG's higher Net Income explained by higher generation and lower OM&A expenses related to the deferral of the Pickering Unit 6, along with lower OM&A expenses from labour savings and lower project spending.
Public Debt Interest - Electricity Sector	-	(22)	38	38	38	38	
Total Electricity Expenses of the Province	**3**	31	(107)	38	38	38	
OEFC Income							
Taxation Revenue							
Electricity Payments-in-Lieu of Taxes (PILs)	-	(40)	2	12	4	2	2016-17 decrease mostly due to due to lower Net Income of Hydro One.
Other Revenue							
Electricity Debt Retirement Charge	-	(4)	-	-	-	-	
Power Supply Contract Recoveries	-	99	(0)	(0)	(0)	0	The declines in volumes, payments and rates in 2017-18 and 2018-19 compared to the earlier forecast are due to the termination and suspension of several NUG PPAs for curtailments.
Net Reduction of Power Purchase Contracts	-	0.1	(0)	(0)	(0)	(0)	
Other Fees and Licences	-	-	-	-	-	-	
Revenue Pool Residual	-	-	-	-		-	
Miscellaneous	-	14	-	-	-	-	
Expenses							
Interest on Debt	-	19	(53)	(64)	(69)	(98)	2016-17 decrease in Interest on Debt mainly due to
Power Supply Contract Costs	-	(99)	0	0	0	(0)	OEFC's costs totalled $838 million and recovered OPG support contract costs of $2 million related to the settlement of a property tax assessment.
Electricity Consumer Price Protection Fund	-	-	-	-	-	-	
Demand Management Support Costs	-	1.8	-	-	-	-	
Provision for Electricity Sector	(3)	(53)	145	-	-	-	
Other (Finance)	-	(1.0)	-	-	-	-	
Total OEFC Income	**(3)**	(63)	94	(52)	(66)	(96)	
Impact on Surplus/(Deficit)	**-**	(14.58)	94	(8)	(22)	(52)	
Total revenue Impact	**-**	**87**	**108**	**18**		**8**	
Total revenue Impact - less power supply contract recoverie	-	(12)	109	18		8	
Total Expenditure impact	**-**	**101**	**15**	**26**		**60**	

(3.00)

Electricity Sector Outlook (PSAB)

Negative Revenue Risks	$ Millions			
($ millions)	Plan			
	2017-18	2018-19	2019-20	2020-21
Generic				
OPG Generation Risk: Nuclear Reliability (-1.6 TWh)[1]	(120)	(120)	(120)	(120)
ONFA Funds Return Risk[2]	(95)	(100)	(105)	(110)
~~Ministry of Energy's price mitigation initiative - OPG operational efficiencies[9]~~	~~(240)~~	~~(240)~~	~~(240)~~	~~(180)~~
Lower OPG's Equity weighting & Return on Equity (ROE)[3]	(12)	(20)	(25)	(43)
Lower Hydro One Return on Equity (ROE)[4]	(10)	(39)	(41)	(43)
Regulatory				
Hydro One Tx rate application - OEB staff report[5]	(50)	(50)	(50)	(50)
OPG Switch from accrual based to cash based accounting for pension and OPEB[6]	(533)			
Regulatory Risk - Timing of Rate Decision[7]	(480)			
~~OPG Submission Update (Dec 2016)~~	~~(61)~~	~~(46)~~	~~(49)~~	~~(61)~~
OEB Staff Recommendations to the Board (May 2017)[8]	(175)	(143)	(151)	(175)
Nuclear Liabilities Cash vs. Accrual[9]	(450)	(450)	(450)	(450)
Accounting				
OPG IFRS Consolidation Risks - Scenario 1b: 15 year historical, update discount rate each year.[10]	-	(475)	(500)	(750)
Other Risks				
H1 Quarterly Update	0	(0)	(0)	(0)
Avista Acquisition - Termination fee	(103)			
Avista Acquisition - 1 year of Debenture Interest Costs	(62)			

Electricity Sector Outlook (PSAB)

Positive Revenue Risks				
($ millions)	Plan			
	2017-18	2018-19	2019-20	2020-21
Generic				
OPG Generation Risk: Nuclear Reliability (+1.1 TWh)[1]	85	85	85	85
1% increase in Hydro One actual load[3]	15	15	15	15
Regulatory				
Positive OPG regulatory risk - Motion to Review[2]	-	-	-	-
Higher Hydro One Return on Equity (ROE)[4]	15	60	65	65
Higher OPG Return on Equity (ROE)[5]	6	25	30	55
~~Revenue risk if Scenario 2 IFRS Consolidation risk.[6]~~	~~#REF!~~	~~#REF!~~	~~#REF!~~	
	~~#REF!~~	~~#REF!~~	~~#REF!~~	~~220~~

ONTARIO ELECTRICITY FINANCIAL CORPORATION
On Deck Outlook as of March 2017

$ Millions

	Actual 2013-14	Actual 2014-15	Actual 2015-16	Interim 2016-17	2017-18	2018-19	Pl
Revenue							
Revenue Pool Residual							
Debt Retirement Charge	954	956	859	625	623	-	
Payments-in-lieu of tax:							
OPG	407	53	268	302	315	366	
Legacy Hydro One (Including Brampton)	98	95	2,929	7	2	2	
Hydro One CIT dedicated to OEFC			3	20	20	22	
MEUs	38	32	27	44	68	86	
Total PILs & CIT dedicated to OEFC[1]	543	180	3,228	373	405	476	
Interest :							
OPG	187	191	173	179	168	153	
H1							
IESO	2	3	2	3	3	3	
Province	520	520	520	492	492	492	
Other	10	13	28	10	5	5	
Total Interest	719	727	723	684	668	653	
Power Supply Contract Recoveries	1,296	950	875	739	292	325	
Amortization of NUG liability	243	217	172	129	74	41	
Electricity sector dedicated income	599	1,038	3	342	125	-	
Gain to OEFC under s. 50.3		-	172	-	-	-	
Miscellaneous	8	9	9	-	-	-	
	4,362	4,077	6,041	2,893	2,187	1,495	
Expense							
Debt interest	1,447	1,385	1,319	1,216	1,090	1,027	
Interest on nuclear risk funding							
Demand Management Support Costs		9	8	10	10	-	
Amortization of deferred debt costs	-	-	-	-	-		
Power Supply Contract Costs	1,296	950	875	739	292	325	
Debt Guarantee fee	136	131	127	122	102	91	
Operating	7	6	7	6	6	6	
	2,886	2,481	2,336	2,093	1,500	1,449	
Excess (Deficiency) of Revenue over Expense	**1,476**	**1,596**	**3,705**	**800**	**687**	**46**	
Prior period adjustment			87				
Stranded Debt - Year End	**9,781**	**8,185**	**4,393**	**3,593**	**2,906**	**2,860**	
	728	658	596	532	422	374	

ONTARIO ELECTRICITY FINANCIAL CORPORATION
On Deck Outlook as of August 2017

$ Millions

	Actual 2013-14	Actual 2014-15	Actual 2015-16	Actual 2016-17	2017-18	Current 2018-19
Revenue						
Revenue Pool Residual						
Debt Retirement Charge	954	956	859	621	623	0
Payments-in-lieu of tax:						
OPG	407	53	268	224	317	378
Legacy Hydro One (Including Brampton)	98	95	2,929	4	2	2
Hydro One CIT dedicated to OEFC			3	25	20	22
MEUs	38	32	27	112	68	86
Total PILs & CIT dedicated to OEFC[1]	543	180	3,228	364	407	488
Interest :						
OPG	187	191	173	167	169	179
H1						
IESO	2	3	2	2	3	3
Province	520	520	520	514	454	454
Other	10	13	28	20	20	20
Total Interest	719	727	723	703	646	656
Power Supply Contract Recoveries	1,296	950	875	838	292	325
Amortization of NUG liability	243	217	172	129	74	41
Electricity sector dedicated income	599	1,038	3	302	269	0
Gain to OEFC under s. 50.3		0	172	411	0	0
Miscellaneous	8	9	9	14	0	0
	4,362	4,077	6,041	3,382	2,311	1,510
Expense						
Debt interest	1,447	1,385	1,319	1,216	1,121	1,094
Interest on nuclear risk funding						
Demand Management Support Costs		9	8	8	10	0
Amortization of deferred debt costs	0	0	0	0	0	
Power Supply Contract Costs	1,296	950	875	838	292	325
Debt Guarantee fee	136	131	127	122	102	91
Operating	7	6	7	7	6	6
	2,886	2,481	2,336	2,191	1,531	1,516
Excess (Deficiency) of Revenue over Expense	**1,476**	**1,596**	**3,705**	**1,191**	**781**	**(6)**
Prior period adjustment			87			
Stranded Debt - Year End	**9,781**	**8,185**	**4,393**	**3,202**	**2,421**	**2,428**
	728	658	596			

ONTARIO ELECTRICITY FINANCIAL CORPORATION

Changes from Budget 2017 as of August 2017 **$ Millions**

	2016-17	2017-18	2018-19	2019-20	2020-21	Explanation of Change
Revenue						
Debt Retirement Charge	(4)	-	-	-	-	Updatedwith December 2016 Ontario Planning Outlook forecast Scenario A
Payments-in-lieu of tax:						
OPG	(78)	2	12	4	2	
Legacy Hydro One (Including Brampton)	(3)	-	-	-	-	
Hydro One CIT dedicated to OEFC	5	-	-	-	-	
MEUs	68	-	-	-	-	Large increase in 2016-2017 from $80M payment during transfer of H01 Brampton to new consolidated MEU Alectra.
Total PILs	(9)	2	12	4	2	
Interest :						
OPG	(12)	1	26	40	13	
H1	-	-	-	-	-	
IESO	(1)	-	-	-	-	
Province	22	(38)	(38)	(38)	(38)	
Other	10	15	15	5	5	
Total Interest	19	(22)	3	7	(20)	
Power Supply Contract Recoveries	99	(0)	(0)	(0)	0	
Amortization of NUG liability	0	(0)	(0)	(0)	(0)	
Electricity sector dedicated income	(41)	145	-	-	-	
Gain to OEFC under s. 50.3	411	-	-	-	-	
Miscellaneous	14	-	-	-	-	
	489	124	15	10	(18)	
Expense						
Debt interest	-	31	67	76	78	
Interest on nuclear risk funding	-	-	-	-	-	
Demand Management Support Costs	(2)	-	-	-	-	
Amortization of deferred debt costs	-	-	-	-	-	
Power Supply Contract Costs	99	(0)	(0)	(0)	0	
Debt Guarantee fee	-	-	-	-	-	
Operating	1	-	-	-	-	
	98	31	67	76	78	
Excess (Deficiency) of Revenue over Expense	**391**	**94**	**(52)**			
Stranded Debt - Year End	**3,202**	**2,421**	**2,428**	**2,361**	**2,087**	

Provision for Electricity Sector

(Dedicated Electricity Earnings/Electricity Sector Dedicated Earnings) **$ Millions**

	Actual	Current Outlook				
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Income from Investment in Government Business Enterprises						
OPG Income	291	299	198	732	625	1,066
Hydro One Income	232	501	525	567	609	658
Hydro One Brampton (if applied separately)		15				
Total Income	**523**	**815**	**724**	**1,300**	**1,234**	**1,723**
Public Debt Interest - Electricity Sector						
OPG			(300)	(300)	(300)	(300)
Hydro One			(154)	(154)	(154)	(154)
Public Debt Interest - Electricity Sector (OEFC Interest revenue)	**(520)**	**(514)**	**(454)**	**(454)**	**(454)**	**(454)**
MOF Provision Expense (before adjustments)	**3**	**302**	**269**	**846**	**780**	**1,269**
Other Adjustments						
Prior-year Adjustment[1]		3				
Exclude Brampton[2]		(15)				
MOF Provision Expense (after other adjustments)	**0**	**290**	**269**	**846**	**780**	**1,269**
Cumulative Shortfall Adjustment						
Opening Balance	0	0	0	0	0	0
Deduction / (Addition)	0	0	0	0	0	0
Ending Balance	0	0	0	0	0	0
Dedicated Electricity Earnings (all adjustments) (Public Accounts)	**0**	**290**	**269**	**846**	**780**	**1,269**
Electricity Sector Dedicated Income (OEFC Annual Report)	**3**	**302**	**269**			

Notes:

1. 2016-17 Adjustment was due to the discrepancy between the numbers in MOF expense in PA 2015-16 and OEFC Financials in 2015-16. $3M Serves to the rectify this discrepancy
2. Brampton was excluded from the Ministry of Finance's ESDI allocation.

Source Details	Source (Link)
OEFC 1999-2000 FS, pg 24	
OEFC 1999-2000 FS, pg 26	
Monthly Balances Shee	S:\Users\CEF\Hydro 2017\OEFC\RbP\Outlook\07. July\Backup\20170713-1\interest from Province.pdf
2015-16 Public Accoun	S:\Users\CEF\Hydro 2017\OEFC\RbP\Outlook\08. August\Backup\20170817-1 - Provision for Electricity Sector\PA 2015-16 - Vol 1.pdf

Ontario Power Generation

OPG Income - Budget 2017

$ Millions

	Actual	Interim	Plan			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
OPG Net Income After Tax (Adjusted)	291	304	97	732	625	1,066
OPG Net Income After Tax	*291*	*379*	*480*	*678*	*726*	*913*
Extraordinary Gains	-	-	-	-	-	-
GA - OPG Trust Interest Revenue			*17.2*	*54.4*	*99.4*	*152.5*
OPG IFRS consolidation risk picked up in Fiscal Plan		(75)	(400)		(200)	
ONFA and other Fair Value Adjustments	(75)	8				
ONFA Adjustments	-	8				
Other Fair Value Adjustments	(75)					

OPG PIL - Budget 2017

$ Millions

	Actual	Interim		Pl
	2015-16	2016-17	2017-18	2018-19
Net Income Before Tax	383	396	572	867
Net Income After Tax (Adjusted)	291	304	97	732
Income Taxes	92	92	92	135
GRC: Payable to OEFC	198	196	205	212
Proxy Property Tax	16	14	18	19
Ontario Capital Tax	0	0	0	0
Total	**306**	**302**	**315**	**366**

OPG Income - August 2017

$ Millions

	Actual	Actual	Current Outlook			
	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
OPG Net Income	291	377	803	678	726	913
Adjustment for OPG HQ gain on sale[1]			(222)			
Extraordinary Gains	0	0	0	0	0	0
GA Financing - OPG Trust Interest Revenue[3]			17	54	99	153
OPG IFRS consolidation risk reflected in Fiscal Plan[2]		(78.00)	(400)		(200)	
OPG Net Income (Adjusted before ONFA)	**291**	**299**	**198**	**732**	**625**	**1,066**
ONFA Adjustments	247	49				
Other Fair Value Adjustments	(75)	(6)				
ONFA and other Fair Value Adjustments	**172**	**43**				
OPG Net Income	**463**	**342**	**198**	**732**	**625**	**1,066**

1. As part of Asset Optimization Plan the projected proceeds are currently reported in OEP/MoF Sales and Rentals line. To be re-categorized after the transaction is completed and in coordination with OEP and SIFB.
2. See Risks tab for IFRS impacts that were not reflected in Fiscal Plan
3. This reflects interest earnings on GA financing costs which are consolidated back to Province (check wording)

OPG PIL - August 2017

$ Millions

	Actual	Actual		Current
	2015-16	2016-17	2017-18	2018-19
Income Before Tax	383	308	666	867
OPG Net Income (Adjusted before ONFA)	291	299	198	732
OPG Income Tax (PILs)	92	9	159	135
Tax adjustment for OPG HQ gain on sale[1]			(74)	
GRC: Payable to OEFC	198	201	214	224
Proxy Property Tax to OEFC	16	14	18	19
Ontario Capital Tax	0	0	0	0
Total OPG PILs	**306**	**224**	**317**	**378**

378
(296)

Hydro One Net Income and PILs

Hydro One Income - Budget 2017
($ millions)

	1999-00	2000-01	2001-02	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Hydro One Net Income After Tax	391	386	346	377	382	504	504	452	407	530	463	634	639.0	792	786	741	685	737	742	802	862	931
Hydro One - Unrealized Gains Adjustment												-23		4	10	-8						

2016-17 to 2020-21 from CEFD Hydro One 2016 model.

Hydro One PIL - Budget 2017
($ millions)

	2015-16	2016-17	2017-18	2018-19
Net Income After Tax	685	737	742	802
Income Taxes PILs	132	160	181	205
Proxy Property Tax	2	2	2	2
Ontario Capital Tax	0	0	0	0
Total	**134**	**162**	**183**	**207**

Hydro One Income - August 2017
($ millions)

	1999-00	2000-01	2001-02	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Hydro One Net Income After Tax	391	386	346	377	382	504	504	452	407	530	463	634	639	792	786	741	670	680	725	784	844	913
Hydro One - Net Income Attributable to Preferred Shareholders																	15	18				
Hydro One - Unrealized Gains Adjustment												(23)		4	10	(8)						

2017-18 to 2020-21 from CEFD Hydro One 2016 model.

Hydro One (100% Ownership)
($ millions)

	2015-16	2016-17	2017-18	2018-19
Net Income After Tax - Common Shares	670	680	725	784
Net Income After Tax - Preferred Shares	15	18		
Income Taxes PILs	132	160	181	205
Proxy Property Tax	2	2	2	2
Ontario Capital Tax	0	0	0	0

Hydro One Ownership Calculation:		SOURCE:
Total number of shares outstanding[1]	595,000,000	1. Hydro One Ltd Annual Report 2015, pg 94 of PDF, pg 92 of the Report.
IPO November 2015		
Initial Public Offering(2015)[2]	81,100,000	2. From news release: http://hydroone.mediaroom.com/2015-11-05-Hydro-One-Limited-Announces-Closing-of-IPO
Over allotment option (2015)[3]	8,150,000	3. From news release: http://hydroone.mediaroom.com/2015-11-12-Hydro-One-Limited-Announces-Closing-of-IPO-Over-Allotment-Option
Sales to PWU/SEP Trusts	5,646,340	
Total	94,896,340	
Province's remaining ownership, Nov 2015 (# Shares)	**500,103,660**	
Province's remaining ownership, Nov 2015 (%)	**84.05%**	
Secondary Offering April 2016		
Secondary Offering (2016)	72,434,800	4. Hydro One Ltd. Q2 Report, pg 1 http://www.hydroone.com/InvestorRelations/FinancialReporting/Documents/Hydro%20One%20Ltd%20Second%20Qu
Over allotment option (2016)	10,865,200	
Total	83,300,000	
Province's remaining ownership, Apr 2016 (# Shares)	**416,803,660**	
Province's remaining ownership, Apr 2016 (%)	**70.05%**	
Final Offering May 2017		
Final Offering (2017)	120,000,000	Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by
Over allotment option (2017)	-	Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by
Total	120,000,000	
Province's remaining ownership, May 8, 2017 (# Shares)	296,803,660	Source: http://hydroone.mediaroom.com/2017-05-17-Hydro-One-Limited-Announces-Closing-of-Secondary-Offering-of-Common-Shares-by
Province's remaining ownership, May 8, 2017 (%)	**49.88%**	
First Nations Sale, Assumed closing for December 31, 2017	14,875,000	
	2.5%	Source: https://news.ontario.ca/mei/en/2017/05/ontario-raises-28-billion-from-final-hydro-one-share-offering.html
Province's remaining onwership - post First Nations Sale (#Shares)	281,928,660	
Province's remaining onwership - post First Nations Sale (%)	**47.38%**	
Avista Impact (projected closing date 2nd half of 2018)		
Contingent Convertible Debenture	$1,540,000,000	
Conversion Price	$21	
Potential Dilution (# Shares)	71,962,617	
Revised Total number of shares outstanding	**666,962,617**	
Province's remaining onwership - post Avista Acquisition (#Shares)	281,928,660	
Province's remaining onwership - post Avista Aquisition (%)	**42.27%**	

Ownership Percentage in 2017-18 Fiscal Year	Number of Months	Percentage of Year
70.05%	1	8.3%
49.88%	8	66.7%
47.38%	3	25.0%
	12	
Average 2017-18 FY Ownership:	**50.9%**	

Ownership Percentage in 2018-19 Fiscal Year (assume Avista closing Send of September 2018)	Number of Months	Percentage of Year
47.38%	6	50.0%
42.27%	6	50.0%
	12	
Average 2018-19 FY Ownership:	**44.8%**	

Ownership Percentage in 2019-20 Fiscal Year Onwards
42.27%

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-the-Province-of-Ontario
-the-Province-of-Ontario

-the-Province-of-Ontario

Hydro One Public Debt Interest and Section 50.3 payments

	$ Millions		
	2015-16	**2016-17**	**2017-18**
Government Annual Interest Costs - Hydro One	220	220	220
Reduction in Interest Costs due to Broadening		(29)	(66)
Government Annual Interest Costs - Hydro One	220	191	154
Gain to OEFC under s. 50.3	172	411	0

OPG Public Debt Interest

	$ Millions		
	2015-16	**2016-17**	**2017-18**
OPG	300	300	300
Total Public Debt Interest	520	514	454

2018-19	2019-20	2020-21
220	220	220
(66)	(66)	(66)
154	154	154
0	0	0

ID# (Track Cha	Fiscal Year	alue (Hardcode
20170501-2	2016-17	411,152,733
20170501-3	2016-17	29
20170501-3	2017-18	66
20170501-3	n/a	220

ID# (Track Cha	Fiscal Year	alue (Hardcode
n/a	n/a	5126
n/a	n/a	5.85%
		299.871

2018-19	2019-20	2020-21
300	300	300
454	454	454

OPG's Annual Interest Costs:

20170713-1	2016-17	-513,768,361

Value (Linked)	Description	Source Details	Source (Link)
411,152,733	s 50.3 Gain for	Calculation provided by SIFB	
29	Reduction in Int	Internal Calculation	
66	Reduction in Int	Internal Calculation	
220	Annual Interest	Internal Calculation	

Value (Linked)	Description	Source Details	Source (Link)
	($M) Provinces	OEFC 1999-2000 FS, pg 24	
	Annual Interest	OEFC 1999-2000 FS, pg 26	

300

Provincial interest cost for equity investment in OPG, H1 in 2016-17
Monthly Balances Sheet (from FTD)
S:\Users\CEF\Hydro 2017\OEFC\RbP\Outlook\07. July\Backup\20170713-1\interest from Province.pdf

PROVINCIAL CONSOLIDATION ADJUSTMENTS
Ontario Nuclear Funds Agreement

Adjustment for Change in OPG Reported Net Income

Adjustment for DSF Unrealized Earnings

Unrealized Earnings as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Bruce Variance Account Adjustment
OPG Net Income Adjustment

Adjustment for UFSF Unrealized Earnings

Unrealized Earnings as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Bruce Variance Account Adjustment
OPG Net Income Adjustment

Unrealized Earnings -- Fiscal YTD

Adjustment for Change in Due to Province

Adjustment for DSF Due to Province
Due to Province (cost basis) as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Change in Due to Province -- Fiscal YTD

Adjustment for UFSF Due to Province

Due to Province (cost basis) as at beginning of year
Unrealized Earnings as at fiscal year end / latest quarter

Change in Due to Province -- Fiscal YTD

Provincial Consolidation Adjustment

Other Data

	Actual 2016-17	2017-18
Debt Retirement Charge	621	0

	2016-17	2017-18
Power Supply Contract Recoveries	838	292

	2016-17	2017-18
Interest		
OPG	167	169
IESO	2	3
Other (Net)	20	20
Expense		
Debt interest	1216	1121

	Actual 2016-17	2017-18
MEU - PIL Income Tax	109.8	
MEU - PIL Property Tax	0.6	
MEU - GRC	1.2	
TOTAL MEU PILs	111.6	

	Actual 2016-17	2017-18
Miscellaneous/Other (OEFC FS)	14	
Demand Management Support Costs (IEI)	8	10
Operating [Expense]	7	6
Interest on nuclear risk funding	-	-
Amortization of deferred debt costs	-	-
Amortization of NUG liability	129	74
Debt Guarantee Fee	122	

Expense (Electrictiy Summary Tab)		
Other (Finance)	-7	-6
Demand Management Support Costs (IEI)	-8	-10
Debt Guarantee Fee	(122)	

Plan		
2018-19	2019-20	2020-21
0	0	0

Plan		
2018-19	2019-20	2020-21
325	301	273

Plan		
2018-19	2019-20	2020-21
179	175	148
3	3	3
20	10	10
1094	1053	963

Plan		
2018-19	2019-20	2020-21

Plan		
2018-19	2019-20	2020-21
6	6	6
-	-	-
-	-	-
41	30	28
-6	-6	-6

ID# (Track Changes	Fiscal Year	Value (Hardcoded)	Value (Linked)
20170510-2	2016-17	$ 739,216,115	
20170510-2	2017-18	$ 291,629,707	
20170510-2	2018-19	$ 324,906,017	
20170510-2	2019-20	$ 300,648,570	
20170510-2	2020-21	$ 273,240,858	
20170501-4	2016-17	179	179
20170501-4	2017-18	169	169
20170501-4	2018-19	179	179
20170501-4	2019-20	175	175
20170501-4	2020-21	148	148
20170501-5	2016-17	1216	1,216
20170501-5	2017-18	1121	1,121
20170501-5	2018-19	1094	1,094
20170501-5	2019-20	1053	1,053
20170501-5	2020-21	963	963
20170731-3	2016-17	621	
20170811-1	2016-17	109.8	
20170811-1	2016-17	0.6	
20170811-1	2016-17	1.2	
20170815-5	2016-17	$ 838,000,000	
20170815-6	2016-17	$ 14,000,000	
20170815-8	2016-17	8	
20170815-9	2017-18	10	
20170815-10	2016-17	7	
20170815-10	2017-18	6	
20170815-10	2018-19	6	
20170815-10	2019-20	6	
20170815-10	2020-21	6	
20170815-7	2016-17	167	
20170815-7	2016-17	2	
20170815-7	2016-17	20	
20170815-7			

ID# (Track Changes	Fiscal Year	Value (Hardcoded)	Value (Linked)
20170905-1	2016-17	129	129
20170905-1	2017-18	74	74

20170905-1	2018-19	41	41
20170905-1	2019-20	30	30
20170905-1	2020-21	28	28
20170905-2	2016-17	122	
20170906-1	2017-18	3	3
20170906-1	2018-19	3	3
20170906-1	2019-20	3	3
20170906-1	2020-21	3	3
20170906-1	2017-18	20	5
20170906-1	2018-19	20	5
20170906-1	2019-20	10	5
20170906-1	2020-21	10	5

Description	Source Details	Source (Link)
The table below contains an updated preliminary N	SPFB Estimates, Email	
• The tables below provides both last year's submission for NUG costs by CEFD and this year's estimates (both of which exclude HST) based on the most recent NUG model.	SPFB Estimates, BN SPFB Estimates, BN SPFB Estimates, BN SPFB Estimates, BN	
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OPG - Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Interest	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
Updating DRC from OEFC AR (Drafts)	2017 OEFC DRAFT FS	S:\Users\CEF\Hydro 2017\OEFC'
MEU - PIL Income Tax	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
MEU - PIL Property Tax	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
MEU - GRC	PILs Summary provided	S:\Users\CEF\Hydro 2017\OEFC'
Updating to actuals	2017 OEFC AR	2017 OEFC Annual Report - Eng
Updating to actuals	2017 OEFC AR	2017 OEFC Annual Report - Eng
Updating to Actuals	2017 OEFC AR	S:\Users\CEF\Hydro 2017\OEFC'
OEFC 2017-18 IEI/Demand Management Suppor	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Operating Expense - Updating to Actuals	2017 OEFC AR	S:\Users\CEF\Hydro 2017\OEFC'
OEFC Operating Expense - No source available. Just brought the information to this tab.		
OPG Interest Revenue - Actuals 2016-17	Provided from FTD	S:\Users\CEF\Hydro 2017\OEFC'
IESO Interest Revenue - Actuals 2016-17		
Other (Net) Interest Revenue - Actuals 2016-17		

Description	Source Details	Source (Link)
		S:\Users\CEF\Hydro 2017\OEFC'
	Amortization Schedule.	S:\Users\CEF\Hydro 2017\OEFC'

Sourcing the NUG liability amortization schedule.	Tab: Summary Fiscal Impact	S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC' S:\Users\CEF\Hydro 2017\OEFC'
OEFC Debt Gurantee Fee - Updating to Actuals	2017 OEFC AR (pg 13 (	\\ofina.on.ca\ofadfs\Users\CEF\H
IESO Interest Revenue Plan	OEFC Revenue Forecast for Board - April 2017	\\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H
Other Interest Revenue Plan		\\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H \\ofina.on.ca\ofadfs\Users\CEF\H

\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board

\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board
\RbP\Outlook\05. May\Backup\20170501-4 (Revised OPG and Debt Interest)\OEFC revenue forecast for Board

\RbP\Outlook\07. July\Backup\20170731-3 - DRC Update\2017 OEFC Annual Report - English - DRAFT.PDF

\RbP\Outlook\08. August\Backup\20170811-1 - Updating PILs for 2016-17\OEFC 2016-17 Pils summary.pdf
\RbP\Outlook\08. August\Backup\20170811-1 - Updating PILs for 2016-17\OEFC 2016-17 Pils summary.pdf
\RbP\Outlook\08. August\Backup\20170811-1 - Updating PILs for 2016-17\OEFC 2016-17 Pils summary.pdf

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\RbP\Outlook\08. August\Backup\20170815-8 - 2016-17 Demand Management Support Costs (IEI)\2017 OEFC
\RbP\Outlook\08. August\Backup\20170815-9 - 2017-18 Demand Management Support Costs (IEI)\OEFC rever
\RbP\Outlook\08. August\Backup\20170815-10 - 2016-17 Operating (Expense)\2017 OEFC Annual Report - Enc

\RbP\Outlook\08. August\Backup\20170815-7 - 2016-17 Updated Interest on Debt Revenue\RE Revised OEFC

\RbP\Outlook\09. September\Backup\20170905-1 - Amortization of NUG Liability\NUG liability_estimated draw c
\RbP\Outlook\09. September\Backup\20170905-1 - Amortization of NUG Liability\NUG liability_estimated draw c

\RbP\Outlook\09. September\Backup\20170905-1 - Amortization of NUG Liability\NUG liability_estimated draw c
\RbP\Outlook\09. September\Backup\20170905-1 - Amortization of NUG Liability\NUG liability_estimated draw c
\RbP\Outlook\09. September\Backup\20170905-1 - Amortization of NUG Liability\NUG liability_estimated draw c

ydro 2017\OEFC\RbP\Outlook\09. September\Backup\20170905-2 - 2016-17 Debt Guarantee Fee\2017 OEFC
ydro 2017\OEFC\RbP\Outlook\09. September\Backup\20170906-1 - OEFC Revenue Forecast for Board
ydro 2017\OEFC\RbP\Outlook\09. September\Backup\20170906-1 - OEFC Revenue Forecast for Board
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ydro 2017\OEFC\RbP\Outlook\09. September\Backup\20170906-1 - OEFC Revenue Forecast for Board

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-April 2017.xlsx

Annual Report - English.pdf
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glish.pdf

Debt Interest Cost.msg

down_Mar15_if apply Jan1_Apr21.xls
down_Mar15_if apply Jan1_Apr21.xls

down_Mar15_if apply Jan1_Apr21.xls
down_Mar15_if apply Jan1_Apr21.xls
down_Mar15_if apply Jan1_Apr21.xls

Annual Report - English.pdf

Date	Change ID#	Source in File	Tab
5/1/2017	20170501-1	Link	ONFA
5/1/2017	20170501-2	Link	Hydro One
5/1/2017	20170501-3	Link	Hydro One
5/1/2017	20170501-4	Link	Other Data
5/2/2017	20170502-1	Link	OPG
5/9/2017	20170509-1	Link	OPG
5/10/2017	20170510-1	Link	Hydro One
5/10/2017	20170510-2	Link	Other Data
5/12/2017	20170512-1	Link	Hydro One
5/15/2017	20170515-1	Link?	
5/15/2017	20170515-2	Link	OPG
5/17/2017	20170517-1	Link	Hydro One
5/17/2017	20170517-2	Link	ONFA
5/17/2017	20170517-3		
5/18/2017	20170518-1	Link	OPG
5/18/2017	20170518-2	Link	OPG
5/18/2017	20170518-3		
6/15/2017	20170615-1	Link	OPG
6/22/2017	20170622-1	Link	Hydro One
6/22/2017	20170622-2	Link	Hydro One
6/26/2017	20170626-1		
6/29/2017	20170629-1		

7/6/2017	20170706-1		
7/11/2017	20170711-1		
7/13/2017	20170713-1	Link	Provision
7/17/2017	20170717-1	Link	Revenue (Risks)
7/24/2017	20170724-1	Link	Revenue (Risks)
7/25/2017	20170725-1	Link	Revenue (Risks)
7/26/2017	20170726-1	Link	Revenue (Risks)
7/27/2017	20170727-1	Link	Revenue (Risks)
7/27/2017	20170727-2	Link	Revenue (Risks)
7/31/2017	20170731-1		
7/31/2017	20170731-2	Link	Hydro One
7/31/2017	20170731-3	Link	Other Data
8/11/2017	20170811-1	Link	OPG
8/15/2017	20170815-1		
8/15/2017	20170815-2		
8/15/2017	20170815-3		
8/15/2017	20170815-4		
8/15/2017	20170815-5		Other Data
8/15/2017	20170815-6		Other Data
8/15/2017	20170815-7		Other Data
8/15/2017	20170815-8		Other Data
8/15/2017	20170815-9		Other Data
8/15/2017	20170815-10		Other Data
8/17/2017	20170817-1	Link	Provision
8/17/2017	20170817-2	Link	Hydro One
8/18/2017	20170818-1	Link	Revenue (Risks)
8/22/2017	20170822-1	Link	OPG
8/25/2017	20170825-1		Hydro One
8/29/2017	20170829-1		Revenue (Risks)
8/31/2017	20170831-1		Revenue (Risks)
9/5/2017	20170905-1		Other Data
9/5/2017	20170905-2		Other Data
9/5/2017	20170905-3	Link	OPG
9/6/2017	20170906-1	Link	Other Data
9/6/2017	20170906-2	Link	Revenue (Risks)

9/8/2017	20170908-1	Link	Hydro One
9/8/2017	20170908-2	Link	OPG

525
408
117

Track Changes in Surplus/Deficit

Budget 2017 Outlook
Current Outlook
Change Since Budget

Description of Update
ONFA Update as of March 31 2017
s. 50.3 Update for 2016-17
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Provincial Interest Costs, DforE
Revised Debt Interest
OPG IFRS Risk in 2019-20
Revised OPG 2016-17 Net Income
Revised OPG 2016-17 Net Income
Revised OPG 2016-17 Net Income
tech change: slight update to assumed Prov share 70.05% from 70%
tech change: slight update to assumed Prov share 70.05% from 70%
tech change: slight update to assumed Prov share 70.05% from 70%
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
tech change in calc of Hydro One Equity debt interest
Updating H1 2016-17 Net Income for ESDI
Updating H1 2016-17 Net Income for ESDI
Updating H1 2016-17 Net Income for ESDI
Power Purchase Supply
H1 Model Forecasts - No Fiscal Update Resaving Data
Update Budget 2017 Tabs to reflect fiscal plan
Update OPG forecasted PILS to reflect sources
Update H1 2016-17 CIT
Re-inputting ONFA updates
Updating H1 Net Income to include Pref Shares in 16-17
Updating OPG Income Tax Expense for 2016-17
Updating OPG non-income tax PILs
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2017
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2018
H1 Final Offering - Net Income Impacts and expected First Nations Sale at Dec 31, 2019
Updating with actual OPG IFRS Adjustment 2016-17
Updating with actual OPG IFRS Adjustment 2016-17
Updating with actual OPG IFRS Adjustment 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
Utilizing H1 IFRS Adjustment for 2016-17
[NOT APPLIED] Updating H1 Brampton (Interim Adjustments)
Shifted H1 Brampton 2016-17 NI to the 2017-18
Removed H1 Brampton for 2016-17 (pending finals)
Removed H1 Brampton for 2016-17 (pending finals)
Removed H1 Brampton for 2016-17 (pending finals)

add prior-year adjustment for 2016-17

add prior-year adjustment for 2016-18
Reconfigured calculation of ESDI and MOF ESDI Expense
Reconfigured calculation of OPG 2017-18 Net Income
Backup for the Provincial Interest cost
Linking source for Revenue Risks Tab
New source for Revenue Risks Tab
Revenue Risks Tab - ROE Risks
Updating OEB Risk for OPG
OEB Staff Report - H1 Tx - Revenue Risks
OPG Pensions - Cash vs Accrual Deferral Accounts
Updating Links in Electricity Summary Change and OEFC Change
Preliminary estimate for Hydro One Brampton
Preliminary estimate for Hydro One Brampton
Preliminary estimate for Hydro One Brampton

Updating DRC for Actuals 2016-17 (Based on draft FS)
Updating PILs for 2016-17 Baced on Actuals
OPG: Non-ONFA Fair Value Adjustment
Round all Hydro One ownership assumptions to two decimal places
H1 Equity Adjustment rounding.
Round all Hydro One ownership assumptions to two decimal places
Round all Hydro One ownership assumptions to two decimal places
Revising source of ESDI, Dedicated Electricity Earnings
2016-17 - Update Power Supply Recoveries to actuals
2016-17 - Update Power Supply Recoveries to actuals
2016-17 - Updating Miscellaneous OEFC Revenue to Actuals
Adj: Exclude Bramton $15m add prior year adjustment +$3M
Adj: Exclude Bramton $15m add prior year adjustment +$3M
Public Accts: Updated IESO debt interest Interest On Debt, 2016-17
Public Accts: 2016-17 - Demand Management Support Costs Update
2017-18 - Demand Management Support Costs (no change)
Public Accts: 2016-17 - Updating Operating Expense in OEFC
Sourcing Provision for Electricity Sector from Actual Public Accounts
Revised 2016-17 Brampton Amount for Public Accounts
OPG Pensions - Cash vs Accrual Deferral Accounts (Revenue Risks Tab)
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
OPG Net Income and PILs for June Results
Reverting H1 Ownership change (undoing 20170518-3)
Reverting H1 Ownership change (undoing 20170518-3)
Reverting H1 Ownership change (undoing 20170518-3)
Updating Risks based on Hydro One Q2 Results Model
Avista Acquisition Risks
NUG Amortization Liability (sourcing amortization schedule)
2016-17 Actuals - Debt Guarantee Fee
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results
OPG Net Income and PILs for July Results
Interest Revenue for IESO and "Other"
OPG Revenue Risks from OEB Filings

Net income corrected for Preferred Shares
Net income corrected for Preferred Shares
Net income corrected for Preferred Shares
Made link edits to OPG sheet so that the "Net Income Before Tax" 2017-18 number is not a h
Updated PILs to include OPCD public accounts adjustment
Provision tab fix to pick up Hydro One preferred share net income
Provision tab fix to pick up Hydro One preferred share net income
FTD Update to OEFC Outlook (Sep 19, 2017) OPG Interest
FTD Update to OEFC Outlook (Sep 19, 2017) Other Interest

Update impact: copy and paste as values above

Expense
Expense
Expense
Expense
Expense
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue
Revenue

$ Millions

		2016-17	2017-18
		930	789
	File	915	883
		-15	94
	check	***0***	***0***

Outlook line affected	**Expense / Rever**	**Impacts by FY →**	
ONFA and other Fair Value Adjustments	Revenue	41.0	0.0
N/A		0.0	0.0
?		0.000	0.000
Provision for Electricity Sector (OEFC)	Expense		38.083
Provision for Electricity Sector (MOF)	Expense		(38.083)
Public Debt Interest - Electricity Sector	Expense	0.000	38.083
Interest on Debt	Expense	0.0	(69.1)
OPG Income	Expense	0.0	0.0
OPG Income	Revenue	(2.0)	0.0
Provision for Electricity Sector (OEFC)	Expense	**(2.0)**	
Provision for Electricity Sector (MOF)	Expense	2.0	
HOI Income	Revenue	0.4	
Provision for Electricity Sector (OEFC)	Expense	0.4	
Provision for Electricity Sector (MOF)	Expense	(0.4)	
Public Debt Interest - Electricity Sector	Expense	1.7	
Provision for Electricity Sector (OEFC)	Expense	(1.7)	
Provision for Electricity Sector (MOF)	Expense	1.7	
Interest on Debt	Expense	(1.7)	
HOI Income	Revenue	(39.8)	0.0
Provision for Electricity Sector (OEFC)	Expense	**(39.8)**	
Provision for Electricity Sector (MOF)	Expense	39.8	
	Revenue	-	-
	Revenue	-	-
	n/a	-	-
		-	-
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	4.7	0.0
	Revenue	0.0	0.0
HOI Income	Revenue	18.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	7.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	8.0	9.0
HOI Income	Revenue	0.0	(141.5)
Provision for Electricity Sector (OEFC)	Expense		(141.5)
Provision for Electricity Sector (MOF)	Expense		141.5
OPG Income	Revenue	(3.0)	0.0
Provision for Electricity Sector (OEFC)	Expense	**(3.0)**	
Provision for Electricity Sector (MOF)	Expense	3.0	
HOI Income	Revenue	7.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**7.0**	
Provision for Electricity Sector (MOF)	Expense	(7.0)	
	Revenue	-	-
	Revenue	0.0	0.0
Brampton Income	Revenue	(14.7)	0.0
Provision for Electricity Sector (OEFC)	Expense	**(14.7)**	
Provision for Electricity Sector (MOF)	Expense	14.7	

Provision for Electricity Sector (OEFC)	Expense	3.2	
Provision for Electricity Sector (MOF)	Expense	(3.2)	
	Revenue	-	-
		-	-
	n/a	0.0000	0.0000
	n/a	0.0000	0.0000
	n/a	0.0000	0.0000
	n/a	0.0000	0.0000
	n/a	0.0000	0.0000
	n/a	0.0000	0.0000
	n/a	0.0000	0.0000
	n/a	0.0000	0.0000
Brampton Income	Revenue	15.0	0.0
Provision for Electricity Sector (OEFC)	Expense	**15.0**	
Provision for Electricity Sector (MOF)	Expense	(15.0)	
Provision for Electricity Sector (OEFC)	Expense	3.2	
Provision for Electricity Sector (MOF)	Expense	(3.2)	
Electricity Debt Retirement Charge	Revenue	(4.0)	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	(29.0)	0.0
OPG Income	Revenue	(6.0)	0.0
HOI Income	Revenue	(0.0070)	(0.0006)
HOI Income	Revenue	(1.6700)	0.0000
Provision for Electricity Sector (OEFC)	Expense		(0.0006)
Provision for Electricity Sector (MOF)	Expense		0.0006
	Revenue	0.0000	0.0000
Power Supply Contract Recoveries	Revenue	99.0	0.0
Power Supply Contract Costs	Expense	(99.0)	
Miscellaneous	Revenue	14.0	0.0
Provision for Electricity Sector (OEFC)	Expense	(12.0)	
Provision for Electricity Sector (MOF)	Expense	12.0	
Interest on Debt	Expense	(3.0)	0.0
Demand Management Support Costs	Expense	1.8	0.0
		0.0	0.0
Other (Finance)	Expense	(1.0)	0.0
	Revenue	-	-
Brampton Income	Revenue	3.0	0.0
		0.0	0.0
OPG Income	Revenue	0.0	85.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue		(6.0)
Provision for Electricity Sector (OEFC)	Expense		**85.0**
Provision for Electricity Sector (MOF)	Expense		(85.0)
HOI Income	Revenue	0.0	141.9
Provision for Electricity Sector (OEFC)	Expense		141.9
Provision for Electricity Sector (MOF)	Expense		(141.9)
	n/a	0.0	0.0
		0.0	0.0
Net Reduction of Power Purchase Contracts	Revenue	0.1	(0.1)
	Revenue	0.0	0.0
OPG Income	Revenue	0.0	16.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue		(1.0)
Provision for Electricity Sector (OEFC)	Expense		**16.0**
Provision for Electricity Sector (MOF)	Expense		(16.0)
		0.0	0.0
	n/a	0.0	0.0

HOI Income	Revenue	0.0	5.3
Provision for Electricity Sector (OEFC)	Expense		**12.4**
Provision for Electricity Sector (MOF)	Expense		(12.4)
ardcoded formula in the cell	n/a	0.0	0.0
Electricity Payments-in-Lieu of Taxes (PILs)	Revenue	(30.4)	0.0
Provision for Electricity Sector (OEFC)	Expense		17.8
Provision for Electricity Sector (MOF)	Expense		(17.8)
Interest on Debt	Expense	(0.0)	1.0
Interest on Debt	Expense	0.0	15.0
		0.000	0.000

Summary of Changes To date			
Power Supply Contract Costs		(99.0)	0.0
Demand Management Support Costs		1.8	0.0
Provision for Electricity Sector OEFC)		**(44.4)**	**169.7**
Provision for Electricity Sector (MOF)		44.4	(169.7)
Other (Finance)		(1.0)	0.0
OPG Income		(11.0)	101.0
ONFA and other Fair Value Adjustments		41.0	0.0
HOI Income		(16.1)	5.7
Brampton Income		3.3	0.0
Electricity Payments-in-Lieu of Taxes (PILs)		(39.7)	2.0
Electricity Debt Retirement Charge		(4.0)	0.0
Power Supply Contract Recoveries		99.0	0.0
Net Reduction of Power Purchase Contracts		0.05	(0.08)
Miscellaneous		**14.0**	**0.0**
Public Debt Interest - Electricity Sector		0.0	38.1
Interest on Debt		(3.0)	(53.1)
		-14.58	**93.62**
	check	*0.00*	*0.00*

Summary of Changes To date		
Power Supply Contract Costs	0.0	(0.4)
Demand Management Support Costs	(0.0)	0.0
Provision for Electricity Sector OEFC)	**8.4**	**25.0**
Provision for Electricity Sector (MOF)	(8.4)	(25.0)
Other (Finance)	0.0	0.0
OPG Income	(6.0)	0.0
ONFA and other Fair Value Adjustments	6.0	0.0
HOI Income	(0.0)	0.0
Brampton Income	0.0	0.0

Electricity Payments-in-Lieu of Taxes (PILs)	(0.0)	0.0
Electricity Debt Retirement Charge	0.0	0.0
Power Supply Contract Recoveries	0.0	0.4
Net Reduction of Power Purchase Contracts	(0.00)	(0.00)
Miscellaneous	**0.0**	**0.0**
Public Debt Interest - Electricity Sector	21.7	0.1
Interest on Debt	(21.7)	(0.1)
	0.00	**0.00**

2018-19	2019-20	2020-21
939	957	1,676
930	935	1,624
-8	-22	-52
0	***0***	***0***
0.0	0.0	0.0
0.0	0.0	0.0
0.000	0.000	0.000
38.083	38.083	38.083
(79.1)	(75.1)	(104.1)
0.0		0.0
0.0	0.0	0.0
0.0	(0.0)	0.0
-	-	-
-	-	-
-	-	-
-	-	-
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
12.0	3.5	1.8
(181.4)	(194.9)	(210.6)
0.0	0.0	0.0
0.0	0.0	0.0
-	-	-
0.0	0.0	0.0
0.0	0.0	0.0

-	-	-
-	-	-
0.0000	0.0000	0.0000
0.0000	0.0000	0.0000
0.0000	0.0000	0.0000
0.0000	0.0000	0.0000
0.0000	0.0000	0.0000
0.0000	0.0000	0.0000
0.0000	0.0000	0.0000
0.0000	0.0000	0.0000
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0000	0.0000	0.0000
0.0000	0.0000	0.0000
0.0000	0.0000	0.0000
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
-	-	-
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
181.8	195.4	211.1
0.0	0.0	0.0
0.0	0.0	0.0
(0.1)	(0.1)	(0.0)
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0

5.3	5.3	5.3
0.0	0.0	0.0
0.0	0.0	0.0
(0.0)	1.0	1.3
15.0	5.0	5.0
0.000	0.000	0.000
0.0	0.0	0.0
0.0	0.0	0.0
0.0	**0.0**	**0.0**
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
5.7	5.8	5.8
0.0	0.0	0.0
12.0	3.5	1.8
0.0	0.0	0.0
0.0	0.0	0.0
(0.10)	(0.06)	(0.03)
0.0	**0.0**	**0.0**
38.1	38.1	38.1
(64.1)	(69.1)	(97.8)
-8.38	**-21.81**	**-52.24**
0.00	*0.00*	*0.00*
(0.1)	(0.4)	0.2
0.0	0.0	0.0
0.0	**0.0**	**0.0**
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	0.0
0.0	0.0	(0.0)
0.0	0.0	0.0

0.0	0.0	(0.3)
0.0	0.0	0.0
0.1	0.4	(0.2)
(0.00)	(0.00)	0.00
0.0	**0.0**	**0.0**
0.1	0.1	0.1
(0.1)	(0.1)	0.1
0.00	**0.00**	**0.00**

Further Explanation of Change and source of data

Regular quarterly ONFA Update
Benefit to OEFC under s.50.3: $411M gain, SIFB
Change to OEFC payment for interest costs of Debt for Equity Swap

From FTD, revised Debt Interest (updated in 5/4/2017)
Revised numbers from OEP with 2019-20 Risk
Updated numbers from OPG Q1 2017 FS

Updating H1 Net Income for actuals. Note does not update Brampton Income at this point. Will update onc

No Change to numbers, just re-inputting data and saving sources
No Change to numbers, just re-inputting data and saving sources
No change to fiscal impact numbers. Deleting Budget 2016 and adding Budget 2017 fiscal impacts
No Change to numbers, just re-inputting data and saving sources
Updated with CIT Numbers received from H1 as part of s.91.2 MB20 allocation from MOF
No Change to numbers, just re-inputting data and saving sources
Only included H1 Net Income - Common Shareholders before. Added preferred shareholder impact as we
Updating OPG Income Tax Expense with info from OPG Monthly Presentation to Shareholder
Updating OPG GRC payable to OEFC and Proxy Property Tax from Answer back from OPG about the BP
Based on H1 final offering and expected First Nations Sale by the end of 2017 (CY), with a weighted avera

Based on EY analysis, and then applying fiscalization. Confirmation also received from OPCD.

Based on KPMG analysis, then fiscalization and other adjustments from OPCD.

[NOT APPLIED, CALCULATIONS AND DATA LEFT ON THE FILE] Used Brampton's Financial Stateme
Don't expect finalized 2016-17 data to become available in time for ESDI allocation. Will shift this to 2017-
make decision on shifting when we know 2016-17 status.

No change to numbers. Just re-organizing spreadsheet. No backup data.
No change to numbers. Just re-organizing spreadsheet. No backup data.
No change to numbers. Just provided actual backup/source.
No change to numbers. Just provided actual backup/source.
No change to numbers. Just provided another scenario backup/source
No change to numbers. Just provided actual backup/source.
No change to numbers. Just provided actual backup/source.
No change to numbers. Just provided actual backup/source.
No change to numbers. Just provided actual backup/source.
No change to numbers. Just updated the links to refer ot the delta between 2017 and On Deck (from 2016
Adjustment to ESDI to include Hydro One Brampton

Finalizing 2016-17 DRC Based on Draft OEFC AR
Received actual PILs amounts from FTD with breakdown of source. Updated 2016-17 numbers to reflect t
2016-17 - Non-ONFA Fair Value Adjustment
Round Hydro One ownership assumptions to 70.05% two decimal places to be consistent with OPCD.
Revising Hydro One Amount for consistency with OPCD. Equity Adjustments

Updated Provision tab. Made two separate Provision amounts for ESDI in OEFC AR and Dedicated Earnir
Updating Power Supply Recoveries to Public Accounts/OEFC AR actuals

Updating Miscellaneous to OEFC AR actuals

Updated 2016-17 Interest on Debt (IESO, OPG, Other (Net))

2017-18 - Demand Management Support Costs (no change) - Linking correctly
2016-17 - Updating Operating Expense in OEFC and corresponding changes elsewhere and sources.
No change to numbers. Just re-organized spreadsheet
Revised H1 Brampton Net Income (for GBE Line only)
Revising for OPG's Q3 Finances
Revising OPG's Net Income for latest monthly report

Reverting ownership back to 70.05% from change 20170518-3. Will coordinate with other areas to ensure

Updating Risks based on Hydro One Q2 Results Model
Updated two Risk components for the Avista Acquisition.
No significant changes, but used actual amortization liability schedule. Hence the rounding impacts/change
Updating Debt Guarantee for actuals based on OEFC AR
Revising OPG's Net Income for latest monthly report

Linking interest revenue data for 2017-18 to 2020-21
OPG Revenue Risks from: OEB Staff Submission and OPG Updated Filings

Corrected Net income for 100% ownership in preferred shares and 70.05% in Commons Shares

Updated the formula in the cell for 2017-18 Net Income Before Tax so that the numbers are not hardcodec
Updated PILs to include OPCD public accounts adjustment

Data Validation:
- Options
- Revenue (Risks)
- OPG
- Hydro One
- Provision

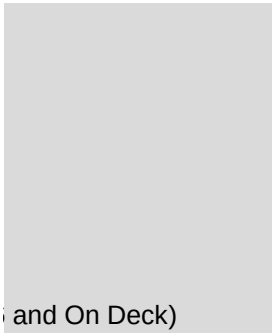
- ONFA
- Other Data

:e revised numbers are received.

ll.

ıge ownership for 2017-18. Also adjusted future net income attributed to the province.

nts to produce an estimate. May require additional calculations.
18.



and On Deck)

his.

gs in Public Accounts.

broadening change and reduction in net income happens concurrently in forecasts.

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ɪ directly

Electricity Sector Outlook (PSAB)

($ millions)	Budget 2015-16	2016-17	2017-18	Plan 2018-19	2019-20	2020-21
Approved Revenue Outlook as of Budget 2016						
Electricity Revenues						
Income from Investment in Government Business Enterprises[1]	719	842	617	1,294	1,229	1,717
Taxation Revenue						
Electricity Payments-in-Lieu of Taxes	3,228	373	405	476	538	679
Other Revenue						
Electricity Debt Retirement Charge	859	625	623	-	-	-
Power Supply Contract Recoveries	875	739	292	325	301	273
Net reduction of Power Purchase Contracts[2]	172	129	74	41	30	28
Miscellaneous	9	-	-	-	-	-
Total Electricity Revenue[3]	5,862	2,709	2,011	2,136	2,098	2,697

Notes:

1. Includes provincial consolidation adjustments for OPG's nuclear funds

2. Reflects the effective elimination of above-market NUG liability over a number of years starting January 1, 2005 (on a predetermined schedule).

3. Total reflects revenues from OPG, Hydro One, OEFC and PILS from MEUs, and excludes OPA and IESO and OEB.

Revenue Items On Deck - Changes Compared to Budget 2016

($ millions)	Budget 2015-16	2016-17	2017-18	Plan 2018-19	2019-20	2020-21
OPG August 2017 Financial Outlook[1]	0	(83)	103	12	4	2
ONFA and other Fair Value Accounting Adjustments[2]	(119)	(336)	(480)	(678)	(726)	(913)
Hydro One August 2017 Financial Outlook Update[3]	20	(23)	(12)	(12)	(12)	(12)
MEUs PILs	0	68	0	0	0	0
Other OEFC FS / Public Accounts Updates						
Electricity Debt Retirement Charge	0	(4)	0	0	0	0
Miscellaneous	0	14	0	0	0	0
;	0	99	(0)	(0)	(0)	0
Total Revenue Items On Deck	(99)	(266)	(389)	(678)	(735)	(923)

Notes:

1. OPG's 2015-16 outlook reflected its reported earnings. Out-years reflect OPG's 2017-19 business plan, November monthly update, and long-term outlook to 2019-20 (as fiscalized by OPG). 2020-21 estimates are based on OPG's calendar year-based long-term projections from the November business plan and fiscalized by CEFD staff. OPG Business Plan projections are also adjusted to remove amounts related to asset optimisation amounts (for real estate sales, to avoid double-counting) that are reflected in the fiscal plan under sales and rentals.

1. OPG Net Income is also adjusted for assumed equity return on Provincial equity injection to partially finance the Global Adjustment deferral -- designed to match FTD estimated IOD to finance the equity injection. See OPG Worksheet for annual breakdown.

2. Reflects provincial adjustment as at December 31, 2016, for net unrealized earnings in the decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated fund. Adjustment for 2014-15 also includes non-ONFA financial instruments.

3. Reflects CEFD forecasts based on latest available public information and modelling. Reflects an 70% Provincial share ownership, with impacts of future share sales incorporated into the asset optimisation projection in Other Non-Tax Revenues, Sales and Rentals

5. Reflects retroactive payment to applicant NUGs under the Global Adjustment lawsuit, based on payment in October 2016. Reflect updated forecast from 2016-17 to 2020-21, with the latest forecast from February 2017.

On Deck Revenue Outlook as of August 2017	Budget 2015-16	2016-17	2017-18	Plan 2018-19	2019-20	2020-21
Electricity Revenues						
Income from Investment in Government Business Enterprises	719	860	724	1,300	1,234	1,723
Taxation Revenue	3,228	334	407	488	541	681
Electricity Payments-in-Lieu of Taxes						
Other Revenue						
Electricity Debt Retirement Charge	859	621	623	-	-	-
Power Supply Contract Recoveries	875	838	292	325	301	273
Net reduction of Power Purchase Contracts	172	129	74	41	30	28
Miscellaneous	9	14	-	-	-	-
Total Electricity Revenue	5,862	2,795	2,119	2,153	2,107	2,705
Check Calculation:						
Revenue	5,763	2,443	1,622	1,458	1,363	1,774
Expense	2,006	1,779	1,253	1,238	1,178	1,087
Net	3,757	664	369	220	185	687
Electricity Summary - On Deck	3,856	957	626	728	728	1,401
	99	293	257	509	543	714

($ millions)	2016-17 Changes		
Revenue Items On Deck - Changes Compared to Budget 2	Net Income	PILs	Total
OPG August 2017 Financial Outlook	(5)	224	219
ONFA and other Fair Value Accounting Adjustments	(336)		(336)
Hydro One August2017 Financial Outlook	(24)	-	(24)
MEU PILs		80	80
	(365)	304	(62)

NEW HYDRO ONE AND RELATED WORKSHEETS DEVELOPED - CAN DELETE THIS AT SOME POINT.

Hydro One

Hydro One Income - Budget 2017
($ millions)

	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Hydro One Net Income After Tax	685	737	742	802	862	931
Hydro One - Unrealized Gains Adjustment						

2016-17 to 2020-21 from CEFD Hydro One 2016 model.

Hydro One PIL - Budget 2017
($ millions)

	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
Net Income After Tax	786	741	685	737	742	802
Income Taxes PILs	101	92	132	160	181	205
Proxy Property Tax	(3)	3	2	2	2	2
Ontario Capital Tax	0	0	0	0	0	0
Total	**98**	**95**	**134**	**162**	**183**	**207**

Hydro One Income - August 2017
($ millions)

	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Hydro One Net Income After Tax	685	680	725	784	844	913
Hydro One - Net Income Attributable to Preferred Shareh		18				
Hydro One - Unrealized Gains Adjustment						

2017-18 to 2020-21 from CEFD Hydro One 2016 model.

Hydro One (100% Ownership)
($ millions)

	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
Net Income After Tax - Common Shar	786	741	685	680	725	784
Net Income After Tax - Preferred Shares				18		
Income Taxes PILs	101	92	132	160	181	205
Proxy Property Tax	(3)	3	2	2	2	2
Ontario Capital Tax	0	0	0	0	0	0